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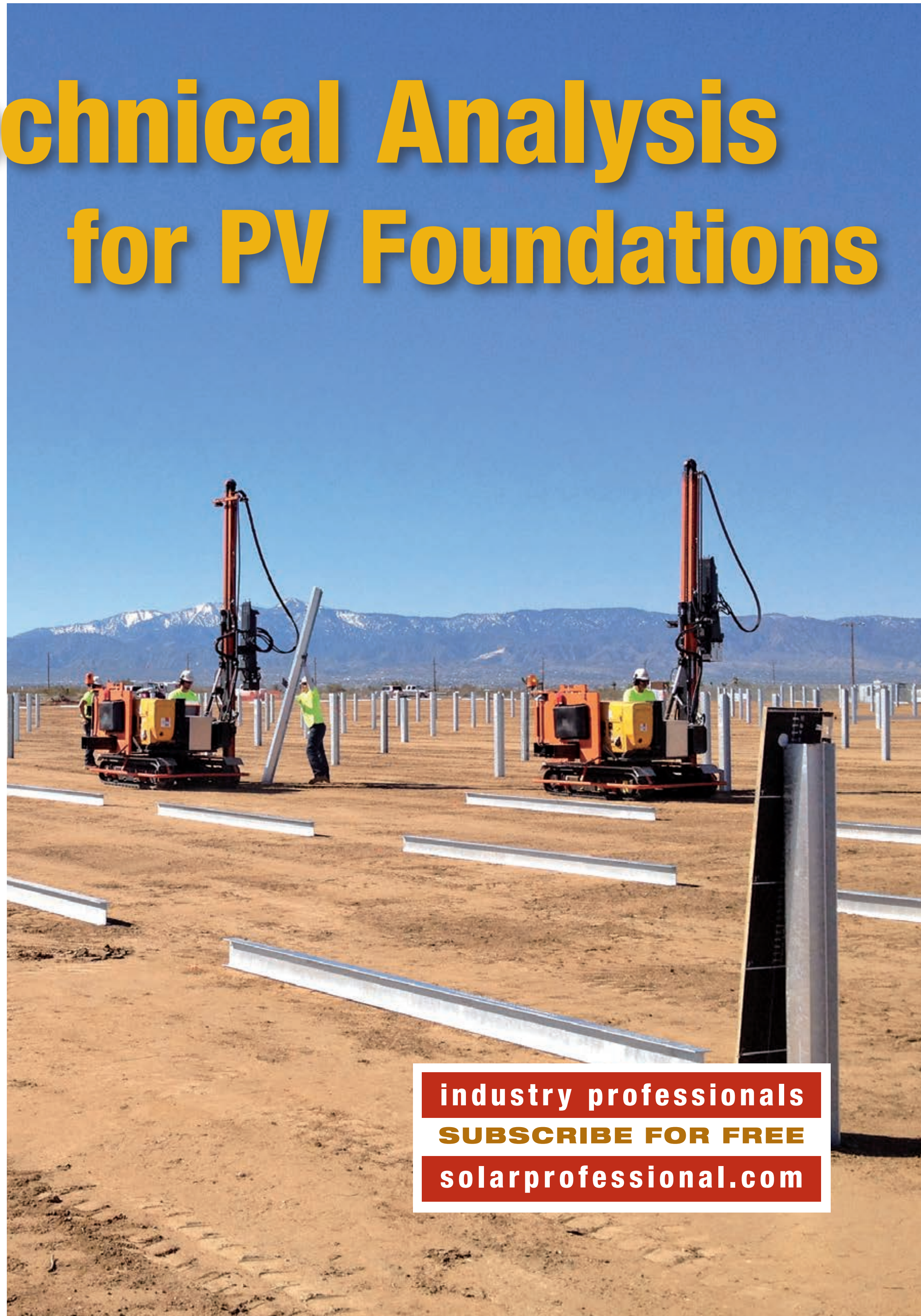

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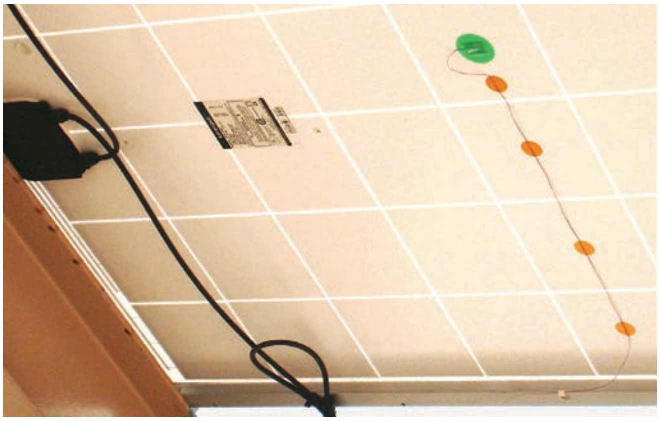

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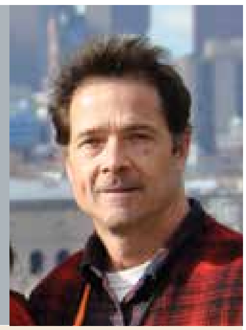
ON THE COVER Terra Posts PV crews install 14,600 driven piles for a 20 MWdc PV power plant in San Bernardino, California. Thirteen foundations support each row of Array Technologies' DuraTrack HZ single-axis tracking system: 12 are W6x9 beams driven to an embedment depth of 7 feet; an oversized W6x15 pile in the middle of the row supports the additional loads associated with the tracker's rotary drive shaft. Terra Posts PV completed the tracker foundation installation using four GAYK pile drivers in roughly 18 working days. Photo: Courtesy Terra Posts PV

Contributors

Experience + Expertise



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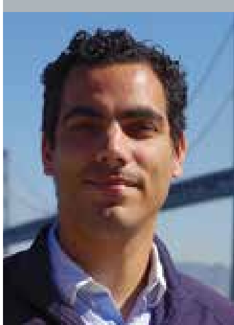
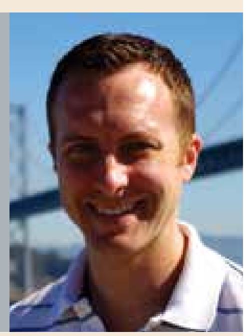


Paul Gibbs is the cofounder and CEO of Folsom Labs, the developer of HelioScope, a cloud-based software platform that integrates system design and performance modeling. Previously Gibbs spent 2 years at eIQ Energy and founded Nodal Exchange. He has degrees in physics and economics from the University of Chicago and an MBA from Harvard.



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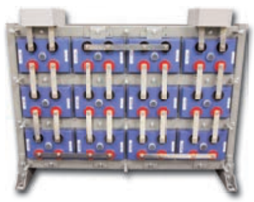

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Solar-Log Revenue-Grade Meter Shipping

[Bethel, CT] Solar Data Systems' innovative monitoring solution for residential-scale PV systems, the Solar-Log 350, is shipping. The ANSI-certified revenue-grade meter with integrated Solar-Log monitoring was first announced at Solar Power International in Las Vegas. Solar Data Systems partnered with GE to develop the plug-and-play socket meter–based solution. The Solar-Log 350 features built-in current transducers and 3G cellular communication to provide certified revenue-grade metering and incentive reporting. The product is compatible with all 240 Vac single-phase string and microinverter systems. Solar Data Systems plans to introduce additional socket meter–based models (Solar-Log 360 and Solar-Log 370) this summer. The new models will offer enhanced monitoring solutions such as self-consumption metering, weather information tracking, inverter direct monitoring and power management.

Solar Data Systems / 203.702.7189 / solar-log.net

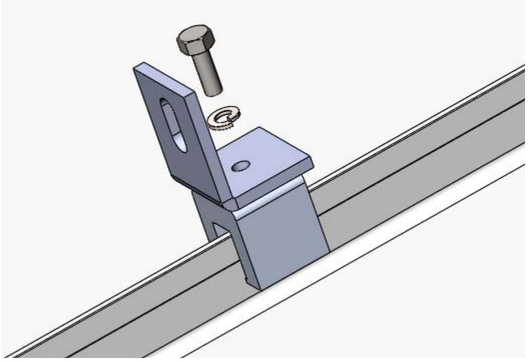
SolarBOS Introduces Wire Harness Solutions

[Livermore, CA] SolarBOS recently released new wire harness and cable assembly solutions. The products include overmolded "Y" harnesses with inline fuses, homerun cable assemblies and combiner box whips. All wire harness assemblies are custom manufactured to client specifications. Customers can choose from various American wire gauges (AWGs) and conductor jacket colors, industry-standard connectors and custom labels at each connection point. SolarBOS manufactures its wire harness and cable assembly solutions at its Grand Rapids, Michigan, facility using automated Schleuniger wire cutting, stripping and labeling equipment.

SolarBOS / 925.456.7744 / solarbos.com

GameChange Announces Standing Seam Products

[New York] The GS Standing Seam Roof System is the most recent addition to GameChange Racking's product portfolio. Designed for both rail-mounted and direct-mount railless PV arrays, GameChange offers seam clamps for all standard standing seam roofing profiles. The Rail Mount option includes seam clamps, L-feet, aluminum rails, bonding jumpers, self-grounding module clamps and all hardware. The Direct Mount system substitutes module-mounting plates for L-feet and rails. Both systems are rated for 130 mph wind loads and 60 psf snow loads, and they carry a 20-year warranty. Testing to UL 2703 is in progress.



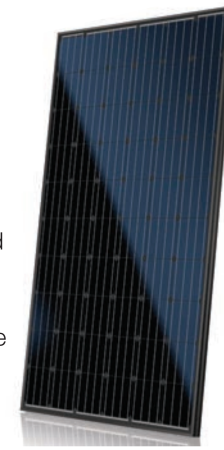
GameChange Racking / 212.359.0205 / gamechangeracking.com

Fall Protection Distributors Offers Specialty Roof Anchor

[Trinity, FL] Manufactured by Castle Rock, Colorado–based Action Manufacturing and available from Fall Protection Distributors, the Standing Seam Roof Anchor 1 (SSRA1) is a nonpenetrating, removable fall protection anchor for metal standing seam roof systems. The SSRA1 consists of a solid 6061-T6 aluminum body with 12 stainless steel set screws and a D-ring attachment. The anchor is lightweight (4.5 lbs) and OSHA/ANSI tested to 5,000 lbs in all directions of pull, allowing installers to access both sides of a pitched roof without having to reposition the anchor. The SSRA1 is compatible with more than 500 standing seam panel profiles and can be powder coated to match the roofing color in permanent installations. For short-term anchor attachment, the distributor recommends its nylon-tipped setscrews to minimize panel seam scratching. The SSRA1 is available for $189; a set of 12 nylon-tipped set screws is $24.

Fall Protection Distributors / 863.703.4522 / standingseamroofanchor.com

Canadian Solar Introduces All-Black Modules



[West Guelph, Ontario] Targeting residential applications, Canadian Solar is releasing a new all-black module line to the North and South American markets. The product family includes the CS6K-M monocrystalline module and the CS6K-P polycrystalline module. Both models feature a black frame and backsheet as well as dark cells. The CS6K-M has a module efficiency of 16.19% and will be available with power ratings of 255 W, 260 W and 265 W STC. The CS6K-P has a module efficiency of 15.58% and will be available with power ratings of 250 W and 255 W STC. Production runs for the CS6K-M are scheduled to begin in May, with production runs for the CS6K-P expected to begin in early June.

Canadian Solar / 888.998.7739 / canadiansolar.com

May Brings Southeast and Northwest Solar Conferences

[Atlanta, GA] SEIA and SEPA are presenting the inaugural Solar Power Southeast conference at the Atlanta Marriott Marquis on May 7–8. Conference attendees will participate in forward-looking discussions on policy, regulatory and technical topics facing the PV industry in the southeastern US, with a particular focus on Georgia, Florida and the Carolinas. Confirmed exhibitors include AllEarth Renewables, APS America, Eaton, Enphase Energy, Fronius USA, GameChange Racking, OMCO Solar, RBI Solar and tenKsolar.

SEIA / 202.682.0556 / seia.org/events/solar-power-southeast
SEPA / 202.857.0898 / solarelectricpower.org

[Portland, OR] On the West Coast, the Oregon Solar Energy Industries Association (OSEIA) is presenting its 8th Oregon Solar Energy Conference. This year's event will have a strong focus on safety and best practices, and will offer technical design and installation training as well as continuing education opportunities. The event will be held on May 13–14 at the Oregon Convention Center. Confirmed exhibitors include ABB, APS America, Canadian Solar, IronRidge, Quick Mount PV, Renusol, Roof Tech, SolarEdge, SolarWorld, SunModo and SunPower.

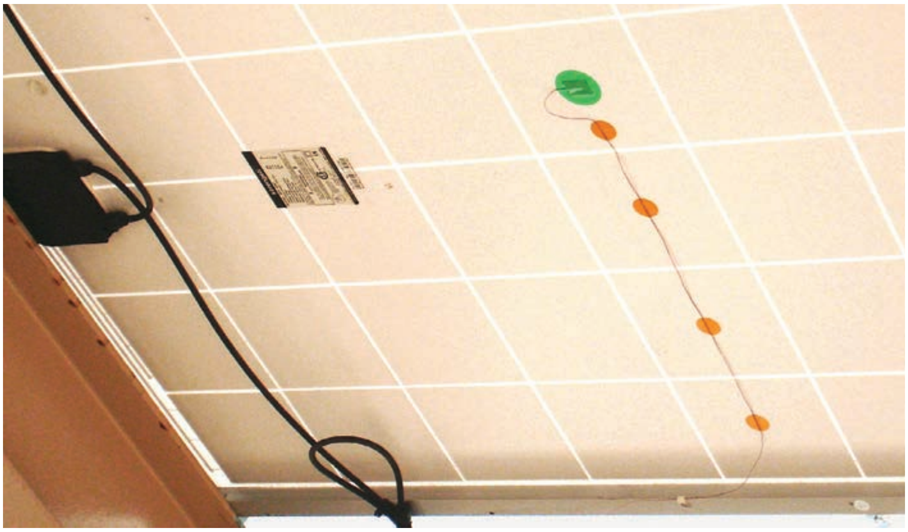
OSEIA / 503.853.5804 / www.oseia.org/osec

QA Quality Assurance

Improving Long-Term Back-of-Module Temperature Measurements

Accurate and reliable back-of-module temperature measurements are essential for evaluating PV array performance. When you include other electrical and meteorological data, you can use back-of-module temperature measurements in concert with module temperature coefficients to monitor PV system performance, model predicted power output or assess warranty claims. (See "PV System Energy Performance Evaluations," *SolarPro* magazine, October/November 2014.)

Many parameters drive back-of-module measurement accuracy and reliability, including sensor placement on the module, sensor technology, attachment method, and the balance of components in the data acquisition system. The better you understand the impacts of various measurement decisions—particularly, sensor type and attachment method—the more you can improve the accuracy and reliability of these measurements. Here I provide background on the topic and detail some best practices for measuring back-of-module temperature with improved confidence.



Courtesy Pordis

Recommended method This photo generally illustrates my preferred method of measuring back-of-module surface temperature. You attach the sensor—a 30-gauge thin-film type-T thermocouple—to the backsheet near the center of the module with a thin layer of silicone adhesive; you then cover the sensor package with a die-cut disc of green polyester tape. In this case, the technician secured the sensor leads using round polyimide tape discs (acceptable) rather than polyester dots (preferred).

Measured vs. Actual Temperature

In considering the thermal environment of a photovoltaic cell, you are primarily interested in the temperature of the semiconductor (p-n junction). This is a difficult temperature to measure, since you cannot directly probe operating PV cells in fielded modules. As a proxy, you can use an open-circuit reference cell—which is a similarly packaged PV cell of the same technology—and extrapolate cell temperature from changes in open-circuit voltage. However, reference cells are built typically for measuring irradiance and are not readily available for measuring cell temperature.

As a result, you generally measure back-of-module temperature using traditional technologies, such as external temperature probes, and use these data as an approximation of the temperature at the semiconductor junction. Since multiple materials lie between the measurement probe and the p-n junction—including backsheet, encapsulant and semiconductor material—your back-of-module temperature measurements never perfectly reflect the temperature at the junction itself. Therefore, you must minimize the differential between the measured back-of-module temperature and the actual temperature at the semiconductor junction.

On one hand, the temperature coefficient of power for PV modules is a negative value, meaning that higher cell temperatures result in lower power output. On the other, poorly executed back-of-module temperature measurements usually result in measured temperature values that are lower than actual temperature values. If you inaccurately report the apparent back-of-module temperature as lower than it is in reality, you will overpredict the expected power output. As an example, the relative temperature coefficient of power for crystalline silicon modules is typically -0.45% per degree Celsius; therefore, if your measured back-of-module temperature is 7°C low, you will overpredict the expected dc power output by about 3.2%, which is a significant amount for large PV systems.

Sensor Selection

The sensors you are most likely to use for measuring back-of-module temperature include CONTINUED ON PAGE 14

thermocouples, thermistors, resistive temperature detectors (RTDs) and infrared thermocouples. While each technology is theoretically capable of delivering reliable measurements over the lifetime of the device, I generally recommend Type T or Type E thin-film thermocouples for measuring back-of-module temperature. Within each device class, however, you must select among the available types or models to identify the specific sensors most suitable to the temperature range and environmental conditions that the fielded modules experience. Regardless of sensor technology, you must also pay attention to the sensor wire gauge or thickness. The data acquisition system (DAS) itself may also influence component specification.

Thermocouples. Thermocouples are constructed out of dissimilar metals or semiconductor materials, and they produce voltage in a predictable relation to temperature. While you may choose among many styles, thin-film and beaded thermocouples are most applicable for measuring back-of-module temperature. Thin-film thermocouples are formed from flattened

Empirical Testing at NREL and Beyond

I based the observations and recommendations in this article on personal experience, as well as the results of extensive empirical field tests. While employed at the National Renewable Energy Laboratory (NREL), I helped conduct two rounds of tests to review different temperature sensor attachment methods. My colleagues and I subsequently published the results of these tests in the article “Back-of-Module Temperature Measurement Methods” (*SolarPro,* October/November 2011).

As detailed in that article, surface temperature measurements taken on the back of a simulated module are always lower than the average bulk-plate temperature, which is the test value designed to best approximate the actual temperature at the semiconductor junction. However, when we charted the distribution of deviation between the average bulk-plate temperature and the measured back-of-module temperature (ΔT_{sensor}) for various sensor attachment methods, we found that the shape of different distribution charts varied significantly. These differences are important because you can qualitatively evaluate different attachment methods—based on general characteristics such as adhesion method, insulation thickness or thermocouple style—by comparing the mean and standard deviation between the measured back-of-module temperature and the average bulk-plate temperature. Ideally, you want to identify and use in-the-field temperature measurement configurations with both a small mean deviation of ΔT_{sensor} and a low standard deviation of ΔT_{sensor}.

Nearly 4 years have passed since NREL conducted the original round of sensor attachment method tests. The attachment methods used for the second round of NREL tests remained in the field for further study and evaluation. NREL graciously provided me with this test apparatus so that I could conduct additional follow-up tests in Austin, Texas. Figure 1 details the best- and worst-performing attachment methods, based on the combined results of the previously reported NREL data and my subsequent round of follow-up testing.

One of my primary follow-up test goals was to determine the extent of long-term drift in the deployed sensors. While I did not test resistive devices for drift, my tests on thermocouples

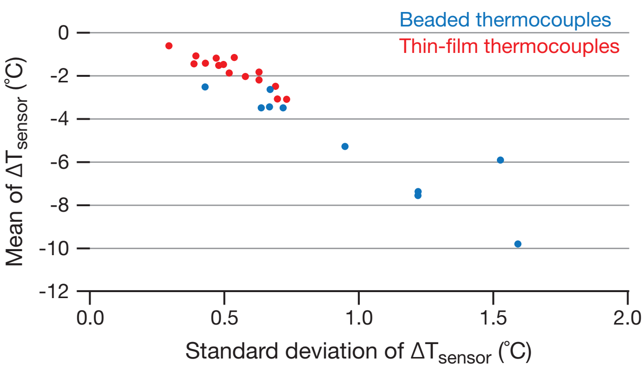


Figure 1 Thin-film thermocouples generally have a smaller mean deviation and a lower standard deviation than beaded thermocouples, regardless of attachment method, based on the difference between the average bulk-plate temperature and the measured back-of-module surface temperature. These results are based on data gathered during two test rounds conducted at NREL in 2011 and a follow-up round conducted nearly 4 years later in Austin, TX.

indicate that thin-film devices show an average 4-year drift of less than -0.9°C. By comparison, beaded devices showed an average 4-year drift of -1.7°C. Certain attachments, however, showed no significant drift. Upon review, these specific attachments are notable in that the contact between the sensor and the back-of-module surface is firm, with no apparent gaps, bubbles or delaminations. This emphasizes the need for strict attention to detail when initially attaching the sensor, as minor flaws can have a detrimental effect over the long term.

Another follow-up test goal is to characterize other back-of-module temperature measurement methods, especially those that are commonly deployed in the field. If there are specific sensor types and attachment methods that you would like to see evaluated, please complete the following back-of-module temperature measurement survey: surveymonkey.com/s/Pordis_BOM_Survey.

or deposited metal traces on a plastic carrier. Beaded thermocouples are formed from twisted and soldered wire ends or by crimping the wires within a metal bead. As detailed in "Empirical Testing at NREL and Beyond," test results indicate that thin-film thermocouples are typically more accurate than beaded thermocouples for back-of-module applications.

You want to select a thermocouple type where the temperature range of interest constitutes the highest proportion of the overall temperature range for that device. Therefore, Type T thermocouples, which have a measurement range of –200°C to 300°C, are generally best suited for back-of-module applications. Type E thermocouples, which have a measurement range of –200°C to 900°C, are also an option. Do not use probes encased in cylindrical metal sleeves, as these are not designed to measure surface temperatures.

Thermistors and RTDs. Thermistors and RTDs are resistive devices that change their resistance in relation to temperature. While thermocouples generate a signal voltage, both thermistors and RTDs require excitation. The DAS must provide an excitation signal to the thermistor or RTD to measure the variable resistance across the device. Like thermocouples, thermistors and RTDs are available in packages that are suitable for measuring the surface temperature on the back of a PV module, such as a flat element sandwiched between layers of plastic.

You may need to install a completion resistor when using thermistors or RTDs with some DAS. Where required, use a high-accuracy completion resistor with a low temperature coefficient of resistance. For example, low-cost completion resistors rated at 10 parts per million per degree Celsius (ppm/°C) are readily available.

Infrared thermocouples. Infrared thermocouples use optical elements to measure the temperature of a surface. The color and reflectivity of the surface at which they are aimed impact the accuracy of these devices. I do not recommend infrared thermocouples for long-term surface temperature measurements on fielded modules because extensive maintenance is required to keep these devices clean.

Environmental ratings. In accordance with the product qualification standards for crystalline silicon and thin-film PV modules (IEC 61215 and IEC 61646, respectively), Nationally Recognized Testing Laboratories conduct thermal cycle tests for PV modules across a temperature range of –40°C to 85°C. It is safe to assume that back-of-module sensors experience similar temperatures, so the sensors should be rated to this range. They should also be rated to experience 0%–100% relative humidity (condensing and noncondensing); UV radiation of varying intensity and duration; and exposure to dirt, sand and non-neutral pH (for instance, acid rain). For long-term reliability, all the associated temperature measurement system components and accessories—connectors, extension cables, weather protection boots and so forth—must be appropriately rated for these temperature and environmental conditions. Note that corrosion within connectors is a significant reliability concern.

Wire gauge. Wires in the 30–20-gauge range are generally well suited for back-of-module applications, as these provide a balance between response time and mechanical strength. While a fine-gauge thermocouple—such as one constructed of 40-gauge wire—is very responsive to back-of-module surface temperature changes, it is also highly susceptible to breakage, even from ordinary handling. The same is true of fine-gauge leads on resistive measurement devices.

DAS considerations. Select temperature sensors that the DAS natively accommodates and consider the measurement system as a whole. For example, if the on-site DAS is capable of directly measuring low-level voltage signals but does not produce an excitation signal, then a thermocouple may be a better sensor option than an RTD. However, if the thermocouple is located a significant distance from the DAS, then the installation may be susceptible to noise, which will show up in the data. For the DAS to accurately measure the signal voltage from the thermocouple, you may need to install and properly ground shielded extension cables to eliminate the stray noise associated with the long cable run. In some cases, you will need additional signal conditioning components to complete the system.

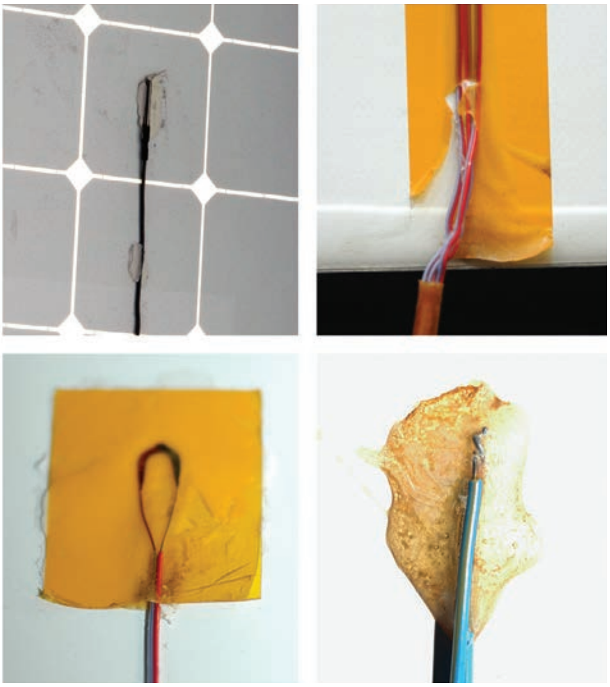
Sensor Attachment

Regardless of measurement device accuracy, a temperature sensor's utility for back-of-module applications is directly related to the quality and longevity of the attachment method. I have reviewed a wide variety of attachment methods, both in the field and in controlled tests, and I have found that many of these methods experience significant physical degradation over time. Invariably, attachment degradation leads to measurement inaccuracies, which manifest as increasingly large deviations from the actual semiconductor junction temperature and an increase in the range of these deviations.

The most common methods for attaching temperature sensors to the back of a PV module include various kinds of tapes or adhesives. I recommend using UV-resistant polyester tape for sensor attachment, as it outperforms most other types of tape and is easier to use in the field than adhesives. The shape of the attachment method also impacts its long-term field performance.

Tape. Technicians use a wide variety of tapes to attach temperature sensors to module backsheets in residential and commercial PV systems, including electrical tape, packing tape, aluminum foil tape, duct tape, polyimide-film tape and polyester tape. The vast majority of these products are not intended for continuous outdoor exposure to moisture, UV radiation and elevated temperatures. When used incorrectly, tape can lose its adhesive properties, which eventually results in a loss of contact between the temperature sensor and the module backsheet.

Electrical tape, which is constructed of vinyl backing with a rubber adhesive, releases from the backsheet at common module operating temperatures. Packing tape, which is constructed of a polyester or polypropylene film backing with a low-strength adhesive, becomes brittle over time and may release from the module. Aluminum foil tape tears easily and may pose a safety concern since it is electrically conductive. The plastic coating on duct tape becomes brittle, and the adhesive also tends to degrade over time at



Common mistakes
You can improve the accuracy and reliability of long-term back-of-module temperature measurements by avoiding common mistakes such as (clockwise from upper left) using cylindrical probes that are not designed for surface measurements; using unprotected polyimide tapes that become brittle and flake; using quick-set or 5-minute epoxies that crack and chip; using rectangular-shaped films that delaminate from the corners.

Courtesy Pordis

elevated temperatures. None of these products should ever be used in back-of-module applications.

While polyimide-film tape—most commonly sold under the brand name Kapton—is ideal for high- and low-temperature applications, it performs best in the low-oxygen environments experienced by spacecraft. In a summary of product properties, DuPont notes: “There is a synergistic effect upon Kapton if it is directly exposed to some combinations of ultraviolet radiation, oxygen and water.” These effects can cause polyimide tapes to become brittle in back-of-module applications. In fact, since many vendors encase thin-film thermocouples in polyimide-film tape, you should select an attachment method that protects this sensor package.

Given that many backsheets are constructed of multiple layers of polyester, polyester tape is the most appropriate for attaching temperature sensors to the back surface of a PV module. This tape typically is composed of a translucent green polyester backing material with a silicone adhesive. While polyester tape holds up well against moisture, temperature and UV radiation, it does not conform to the shape of the sensors well. Therefore, you need to use relatively flat temperature sensors with this type of tape.

Adhesives. It is also possible to bond temperature measurement devices directly to module backsheets, most commonly with silicone adhesives or epoxies. To use silicone adhesives successfully, you must minimize the thickness of the silicone layer, which can insulate the sensor from the back of the module. This insulating effect tends to result in a low apparent temperature measurement and a wide spread in the data. At the same time, you must not introduce bubbles into the silicone between the sensor package and the backsheet, as this can lead to delamination and long-term measurement drift.

Because they are thermally conductive, thermal epoxies are well suited for these applications. Other types of epoxies may not be appropriate, however. Avoid clear epoxies, for example, as these tend to degrade when exposed to back-of-module environmental conditions. Pourable low-viscosity epoxies tend to drip and allow for sensor movement during the curing process. Regardless of adhesive type, you must secure the sensor and cable in place while the material hardens and cures. You can use temporary strips of tape for this purpose or, better yet, die-cut adhesive discs or overlays.

Shape of attachment. Field testing indicates that the shape of the attachment impacts its longevity in the field. While many industries use rectangular polymeric films to attach surface measurement devices, the corners of these films tend to detach from the adhesive over time. Once this process starts, the film continues to slowly delaminate. This same process happens when you use rectangular polymeric film to attach a temperature sensor to a module backsheet.

One way to reduce the likelihood of this type of delamination is to trim the film or tape into a round shape, which eliminates the corners where the degradation first manifests. Die-cut polyester dots or round overlays are particularly immune to this type of failure, and quite affordable as well. Multiple vendors sell green polyester dots in a variety of diameters as masking discs for powder coaters; these products work well for attaching temperature sensors to module backsheets.

Recommended Best Practices

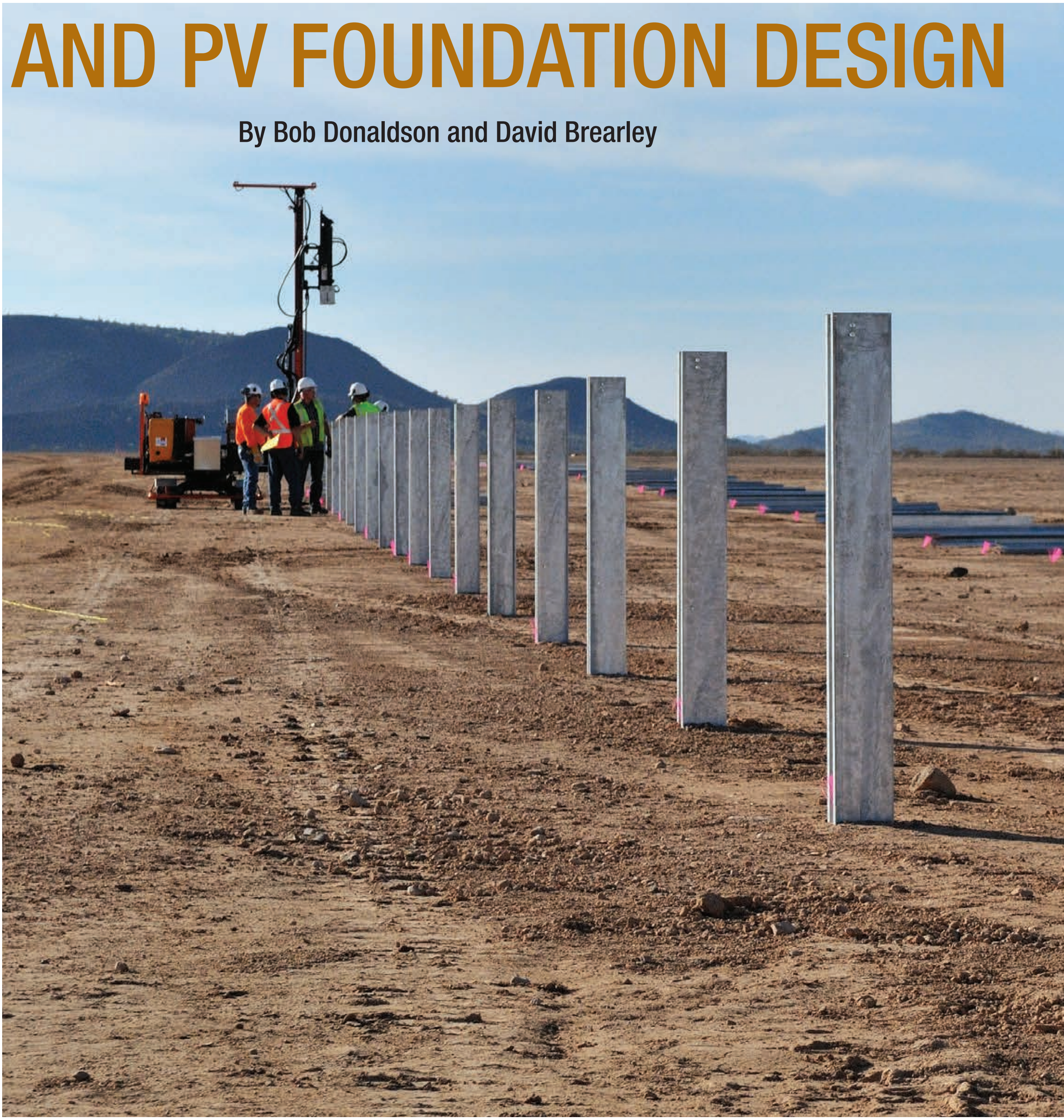
The most successful way to measure the back surface temperature of fielded modules is to use a thin layer of silicone adhesive to attach a 30-gauge thin-film Type-T thermocouple to the backsheet, and then cover the sensor package with a round disc of green polyester tape to protect the sensor against UV damage and to provide a modest amount of insulation to temper the effects of wind. This specific configuration of components illustrates three best practices that generally improve measurement reliability. First, it uses a sensing element with a small physical package that is designed for surface measurements. Second, it ensures that the sensing element is firmly in contact with the backsheet. Third, it minimizes the amount of adhesive required, which limits insulating layers between the sensor and the backsheet.

My preference is to locate sensors near the middle of the most central PV cell and to secure the sensor leads with round polyester discs in a manner that provides some measure of strain relief. For sites that require multiple measurements, use the same sensors and attachment methods where possible. This consistency can help you differentiate between a sensor that is failing or drifting and an actual system performance issue. It is important that the module backsheet be clean and dry before you attach any sensors. Sterile 70% isopropyl alcohol wipes work well for this purpose.

—*Ryan Smith / Pordis / Austin, TX / pordis.com*

GEOTECHNICAL ANALYSIS AND PV FOUNDATION DESIGN

By Bob Donaldson and David Brearley



Courtesy Schletter

Inadequate site assessments can lead to overengineered and unnecessarily expensive foundations. Worse, they can lead to costly foundation failures.

Ground-mounted PV power plants require two basic foundation design components: geotechnical engineering and structural engineering. Geotechnical engineering focuses on evaluating soil mechanics so that the foundation design can incorporate these characteristics. Structural engineering focuses on modeling the foundation as a supported beam to ensure that it can successfully support the design loads.

Of the factors that determine optimal foundation design, geotechnical site characterization is arguably the most challenging. This is partially due to the fact that feedback from the field about long-term foundation performance invariably lags behind project deployment. Given the risk associated with foundation problems, which can impact both short-term and long-term project profitability, geotechnical investigation is one of the solar industry's most overlooked site-selection criteria.

Here we briefly consider the unique nature of PV system foundations. We detail the challenges and basic components of a geotechnical site assessment. We explain why analyzing load-test data is essential to a site-optimized foundation design. Finally, we review why designing from the ground up is essential to your bottom line, in terms of both up-front costs and long-term profits.

Solar-Specific Foundation Design

Given that the utility sector has driven much of the US solar growth in recent years, it is easy to forget that large-scale ground-mounted PV power plants are a relatively recent phenomenon. Veteran project developers might have a decade of experience in designing and deploying solar farms. Further, the market has changed dramatically, in terms of both typical project capacity and average installed costs. As a result, solar-specific geotechnical engineering is in its infancy compared to geotechnical engineering for more conventional applications such as vertical construction, buildings, bridges or dams.

AquaSoli CEO Jürgen Schmid has specialized in solar-specific geotechnical analysis and foundation design since 2004. He notes that solar foundations present unique design challenges: "PV power plants have a very high number of relatively small piles. People tend to underestimate the skills required to use small piles effectively, because the design loads are very low compared to those for a high-rise building or a bridge. However, there is a considerable need for

"Everyone knows that a structure is only as good as the foundation that supports it."
—Daniel Stark, PE, CEO, Stark Foundations

pile optimization in terms of economic material utilization and embedment depth. Further, climatic effects that influence the first six feet of soil can lead to plastic deformation of soils and structural fatigue of the piles."

In other words, a well-designed solar foundation needs to be cost-effective without sacrificing reliability. While the design loads associated with ground-mounted PV systems may be small compared to those for other structures, the foundation still needs to support considerable dynamic loads. In the Boston area, for example, design wind loads approach 120 miles per hour and static snow loads are roughly 60 pounds per square foot. Some mounting systems have almost 70 square feet of rigid sail per foundation. Depending on rack design and static and dynamic loads, this can translate to as much as 5 tons of force per foundation. Any foundation system can fail over time when subjected to these forces, and foundation system failures are expensive to mitigate.

Quality geotechnical data are key to designing a reliable and cost-effective foundation. "Without the proper geotechnical information, we have to make conservative foundation design assumptions," notes Daniel Stark, PE, CEO of Stark Foundations. "While design conservatism is not necessarily a bad thing, being overly conservative can cost our clients money. This could make the difference between a project moving forward or not, between winning a project or not. The minimal expense to conduct a proper geotechnical analysis at the beginning of a project far outweighs the cost of an overdesigned foundation system on the back end of the project."

Costly foundation failure The small piles characteristic of PV system foundations are susceptible to climatic effects on the first six feet of soil. Weak and wet soils, for example, caused this foundation failure.

Courtesy AquaSoli

Given the considerable price pressures that factor into the development of large-scale PV plants, foundation design must be based on adequate site characterization. The better you understand these conditions, the more effectively you can work with your engineer to optimize the foundation. "Geotechnical engineering is the first step to a well-engineered project," explains Adam Tschida, PE, a principal engineer at Kleinfelder. "Proper geotechnical engineering requires a good understanding of what you will be building and how the development will interact with the earth and the environment. This is especially true for PV project development."

Geotechnical Site Assessment

The fundamental challenge in a solar-specific geotechnical site assessment is to gather enough data about site characteristics—including soil composition, bearing capacity, groundwater level and surface water runoff—so that you can characterize soil strength sufficiently to allow for foundation optimization. This is a tall order given that large-scale PV power plants typically range in area from 30 to 600 acres, and much larger projects are in the works. SunPower's 579 MW Solar Star Projects, for example, will cover approximately 3,200 acres. Of course, the scale of these projects is also why foundation optimization is so important.

The basic components of a quality solar-specific geotechnical investigation—site research, soil investigation and load testing—lead to a site-optimized foundation design.

SITE RESEARCH

A geological site assessment starts with site research. This process is important because it informs subsequent on-site investigations. Armed with basic data—such as site address or coordinates and property boundaries—investigators can research soil maps, topographical maps, aerial imagery and so forth. Published records may describe the typical geological setting of the area, bedrock depth, soil types, seasonal water table height or fault lines.

Public records may also detail land uses. "Most sites near urban areas have some percentage of nonnative fill," notes Ed Ayala, president of Eco Foundation Systems. "In some cases, major site improvements—such as roads or grading activities—make it difficult to identify the origin and level of compaction of recent substrates. We can identify potential issues such as fill, compaction or

CONTINUED ON PAGE 24

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SALES@AEESOLAR.COM 800 777 6609 AEESOLAR.COM underground utilities by paying attention to the recent site history."

Geotechnical engineers can learn a great deal about what to expect at a site from these resources. For example, they may be able to identify subsurface soil anomalies, contact zones between soil types, manmade features or disturbed agricultural areas. They can also gain insight into seismic risk and susceptibility to frost, erosion and flooding. They can use these data to identify potential soil problems and prioritize on-site investigations.


Courtesy AquaSoli

Test pit This test pit turned up not only shallow groundwater, which reduces soil-bearing capacity, but also the construction debris shown on the right, which was causing foundation refusal. AquaSoli completed this work to support a foundation installer's change order claim for unanticipated soil conditions.

SOIL INVESTIGATION

Soil conditions vary across any site, both vertically and horizontally. Basic soils are horizontally layered deposits comprised of particles eroded and transported from their parent material over time by motive forces such as water, wind, volcanism, glaciation and seismic activity. The size of the materials transported depends on the energy of the motive force. Subsequent geologic activity changes the deposited soils. A flood may wash away the top of a soil column. Other soils may replace removed material so that two different soil columns end up adjacent to or even on top of each other.

From a foundation design perspective, one of the primary goals of a geotechnical site assessment is to evaluate the ability of these soils to resist and support loads from the mounting structure. The strength of a soil column depends on its composition and its density. Soil composition is a function of the texture and grain of constituent parts, such as clays, silt, sands and gravels. Soil density is a function of the age, materials and methods of the original deposition, as well as the material depth. Soils compact over time, and deeply buried soils are generally more compacted than those located closer to the surface.

> "When a project is new, the inaccurate application of geotechnical design may not be visible. However, with time, poorly designed foundations can become a major problem."
> —Ken Allen, COO, Principal Solar

In addition to observing general surface conditions, geotechnical soil investigators employ subsurface exploration, soil corrosivity and resistivity testing, and laboratory testing.

Subsurface exploration. The primary subsurface investigation methods are to either drill boreholes into the ground or dig test pits. Both of these sampling methods allow geotechnical engineers to vertically classify soil composition and stratification at specific locations. However, drilled boreholes can miss or misidentify important soil features, such as the percentage of rocks and cobbles, that test pits are more likely to characterize. For example, when drilled boreholes reach refusal—the depth at which the drill encounters an impenetrable bottom—the operator cannot distinguish between a boulder and bedrock, which is an important distinction.

Operators typically drill boreholes with a truck-mounted drill rig equipped with a 4-inch hollow-stem auger. Investigators can insert a 2-inch diameter sampling device through this hollow stem to collect soil core samples, either continuously or at 2- to 4-foot intervals. However, a 2-inch diameter sampling device cannot recover material larger than coarse gravel, and in some cases this boring technique does not identify cobbles and boulders that will cause foundation refusal during installation. While soil samples collected using 6- or 8-inch–diameter hollow-stem augers are generally more representative, the cause of boring refusal may still remain unclear.

The best soil sampling method for proposed PV project development, therefore, is to dig test pits to a depth of at least 10 feet below ground level. The process is relatively simple and affordable, since excavators typically dig test pits with a rubber-tired backhoe or similar equipment. This process allows the geotechnical engineer to directly inspect 10 cubic yards or more of soil, which makes it easy to identify and document soil boundaries, the seasonal high-groundwater level, the percentage and size of rock fragments, unsuitable soil horizons, depth to bedrock and so forth.

Regardless of the sampling method, a geotechnical engineer maintains a log of the soils encountered and the sampling depth. The subsequent geotechnical report identifies the approximate location of all boreholes or test pits on the site map. The report also includes a log entry for each location that identifies the soil classification (according to the Unified Soil Classification System) in relation to the sampling depth, plus the depth of any groundwater encountered.

Soil corrosivity and resistivity testing. A comprehensive geotechnical investigation also characterizes soil corrosivity, which oxygen, moisture and chemicals influence. Ensuring foundation longevity in corrosive soils requires protective coatings, thicker piles or sacrificial anodes. (See "Corrosion Impacts on Steel Piles," *SolarPro* magazine, December/January 2012.)

Soil corrosivity is inversely related to soil resistivity. Technicians evaluate in-situ soil resistivity by performing a Wenner four-pin test (see p. 30), which directly measures resistivity between four metal electrodes driven into the ground at equal distances from one another. The final geotechnical report includes these results.

Laboratory testing. During on-site investigations, a geotechnical engineer collects soil samples from boreholes or test pits, as well as samples of relatively undisturbed soils, and then sends them off for laboratory testing. The investigation typically optimizes these tests to the application. For example, a solar site assessment might include thermal resistivity testing, because electrical engineers can use these results to calculate allowable ampacities for directly buried cables. Laboratories can also conduct chemical analyses to evaluate the soil's corrosive potential in relation to concrete and steel, generating useful data for structural engineers. Laboratory tests may also be useful for identifying and mitigating expansive soils.

In some cases, the assessment uses laboratory tests to classify and describe soils according to engineering parameters such as soil strength, compressibility and relative density—but any conclusions about soil-bearing capacity or foundation-embedment depth based on lab results are too conservative for design purposes. To optimize PV power plant foundations, your geotechnical engineer needs to collect load-test data in the field, and you need to base your foundation design on an analysis of these data.

Courtesy AquaSoli

Load testing A typical foundation load-test setup is shown here. The strain gauge (top center) measures the vertical force that heavy construction equipment applies (out of frame to right); the string gauge (bottom center) measures displacement. Both gauges are connected to a laptop (not shown), allowing the geotechnical engineer to view, analyze and graph data in real time. Real-time data analysis informs the testing parameters for more-accurate foundation design optimization.

LOAD TESTING

To collect load-test data, geotechnical engineers install full-scale, site-appropriate test foundations. The engineer can then use heavy equipment, hydraulic jacks or chain hoists to apply horizontal and vertical foundation design loads. Applying the down forces for compression tests requires heavy equipment. For example, a horizontal load test quantifies how much a foundation deflects laterally when subjected to expected design loads. An axial tension test quantifies how well a foundation resists uplift forces and estimates the ultimate pull-out load. An axial compression test describes how well the foundation withstands down forces. CONTINUED ON PAGE 28

Collectively, these tests directly measure soil bearing capacity based on the specific design loads and foundation type.

Geotechnical engineers typically plan preliminary load-test locations for a site in advance and then adapt the plan in the field based on subsurface discoveries. For optimal coverage, your geotechnical engineer might perform load tests at regular intervals around the perimeter and across the interior of a site. In many cases, however, engineers have to prioritize field activities based on the number of days they have on-site, which means they must adequately characterize major soil types and boundaries, and then prioritize further testing based on those data.

In many cases, geotechnical engineers perform load tests at different foundation depths, such as 6 feet and 8 feet below ground. In some cases, they use a single-pile profile—such as a W6x9 wide-flange steel I-beam or H-pile—for all the load tests conducted across a site. This does not mean the final mounting system has to use this pile profile; your foundation engineer can extrapolate these measured load-test results to different pile profiles. In other cases, engineers conduct groups of load tests across a site using multiple pile profiles, such as W6x7, W6x9 and W6x15. These additional data may allow you to consider different mounting options (fixed tilt versus tracking) and mounting-system geometries (single post versus double post), or may simply permit more-detailed foundation design optimization across a site with variable soils.

The process of driving test foundations also provides valuable information about how practical it is to install a specific type of foundation. For example, if you drive 50 piles across a site and 10 of them encounter refusal, then you may need a different type of foundation. At a minimum, you need to ask your foundation engineer to design an alternative for occasions when the pile encounters rejection. Installability can also be an issue with thin-walled foundations, which can buckle and fail in hard soils.

According to Steve Swern, project engineer at Standard Solar, load testing is nearly as important as geotechnical analysis. He notes: "We can avoid major installation problems in the field by performing pull tests. We can validate pile-driving feasibility in high-blow count soils. We can determine pile performance in loose or wet soils. We can identify things such as widespread buried construction debris that a standard geotechnical analysis might not discover or characterize."

Courtesy AquaSoli

Foundation refusal After encountering unacceptably high refusal rates with the earth screw foundation specified for this site, the EPC used test pit findings collected by AquaSoli to justify a change order. The customer could have avoided this if the original geotechnical investigation had included load testing and high-volume test pitting.

Site-Optimized Foundation Design

The ultimate goal of a solar-specific geotechnical analysis is to use site research, soil investigation and empirical load-test data to optimize the foundation for the specific site. For example, site research might give you an idea about the basic distribution of soil types. Geotechnical engineers can then use soil investigation to verify soil classification and map distribution more accurately. After collecting load-test data for these soil types, they can correlate these results to areas across the site with analogous soil conditions.

Foundation engineers can analyze all these data and optimize PV power plant foundation designs in terms of foundation type and geometry, embedment depth, corrosion control, mounting-system geometry, material costs, installation costs and so forth. Some foundation types and geometries better suit specific soil or site conditions than others. On smaller projects, it often makes sense to design around a single foundation type to simplify project logistics. However, an optimized design for larger sites often eschews a one-size-fits-all approach in favor of multiple pile profiles, embedment depths or even foundation types.

Driven pile. From a foundation optimization standpoint, driven-pile foundations are appealing because they generally offer the most attractive price point while providing good lateral and vertical bearing. Driven piles are most appropriate where soils are firm and compacted, with enough fine-grain materials

> "In cases where project developers do not conduct soil investigations in advance, racking companies often use disclaimers and ceiling amounts to mitigate their risk."
>
> —Wolfgang Fritz, VP of engineering and product development, Schletter

(silt or clay) to offer high skin friction. Softer soils require deeper embedment depths and larger cross-sectional profiles. Driven piles are problematic in soils that resist installation, such as soils with very coarse gravel or rock fragments, very hard soils or bedrock.

Andrew Worden, CEO of GameChange Racking, notes that installers have three options when a site refuses a pile: "One option is to conduct a pull test to see if the driven pile has sufficient pull-out resistance as it is installed, in which case you can cut the pile to the desired height and use it. A second option is to remove the pile and reinstall it nearby, provided that the mounting-system tolerances allow for this. The third option is to remove the pile, drill an oversized hole, insert the pile into the hole and use cement, as detailed by a structural engineer, to grout the pile in place."

Steel piles are available in a wide variety of profiles, providing design flexibility. Options for pile driving equipment provide installation flexibility. Worden elaborates: "Some of these machines are highly sophisticated—with GPS guidance and automated installation technology—and allow for a very low pile-installation cost, considerably below that of other foundations." However, equipment access limitations typically constrain driven pile foundations to slopes less than 15°.

Earth screw. Compared to driven piles, earth screws can adapt to a wider range of soil and site conditions. If you pre-drill pilot holes, you can install earth screws in rocky soils and even bedrock. While drilling pilot holes typically increases the

Courtesy Terra Posts PV

Driven piles Each of the GAYK pile drivers shown here can install an average of 200 piles per day, which makes driven piles the most economical foundation for soils with good cohesion and low refusal rates.

foundation cost compared to driven piles, using earth screws may increase the deployable area. For example, earth screw installation is feasible on slopes up to roughly 30°. In softer soils, you can install earth screws without pilot holes. However, softer soils require deeper embedment depths.

> "A complete and concise geotechnical report is imperative to foundation design and ground-mount project feasibility. Not only is it a matter of structural integrity, it also ensures that the owner receives accurate pricing for the scope of the mechanical installation."
> —David Sharrow, director of operations, Terra Posts PV

For sites with high refusal rates, earth screws may be more economical than driven piles, simply because of the high costs associated with using drilled and grouted piles whenever you encounter refusal.

Earth screws offer good pullout resistance. While the screws offer good lateral resistance in firm soils, foundation engineers may need to find ways to increase lateral bearing in softer soils. A structural engineer may also need to adapt the mounting-system design for an earth screw foundation.

Helical anchor. All else being equal, helical anchors are generally less economical than driven piles or earth screws. However, they suit soft soils such as clean sand or weak saturated soil especially well. The anchor consists of a helical bearing plate welded near the bottom of a narrow central shaft.

Lessons Learned:

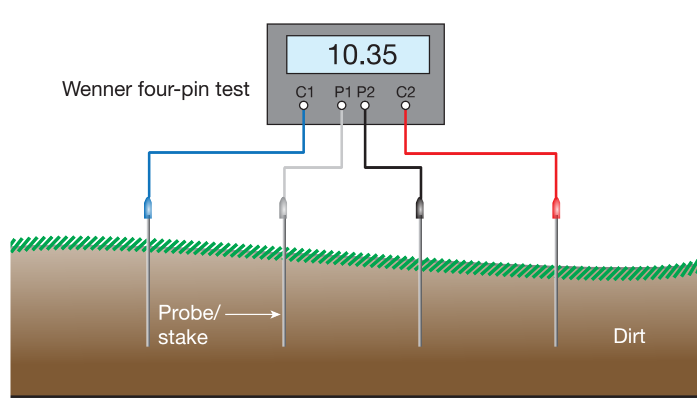
A Project Developer's Perspective

Standard Solar is a full-service PV system provider based in Rockville, Maryland. We develop, design, engineer, finance and construct solar electric systems for nonresidential and utility applications. Many of our largest projects are ground-mounted PV arrays with geotechnical engineering and foundation design requirements. Following are some of the real-world lessons that we have learned.

Pull tests are essential. It is impossible to overstate the importance of pull tests. Pull tests allow us to identify hidden conditions and plan accordingly. We use pull-test results not only to validate engineering assumptions, but also to reduce costs by optimizing our use of structural materials or minimizing pile embedment depth. We also use pull tests to confirm the practical viability of a proposed foundation design before ordering large quantities of materials and deploying a full crew.

The best time to perform pull tests is when a crew is in the field collecting boring samples for the geotechnical analysis. The pull-test results are effectively supplier agnostic. A qualified geotechnical engineer can use load-test data from any driven pile to calculate the required embedment depth for every driven-beam cross section. If you hire a subcontractor to perform pull tests up front, you may be able to capture some savings later. While mounting system vendors are ideally positioned to commission or perform pull tests—and some include pull tests in their total delivered costs—collecting these data early in project development offers advantages.

The schedule—expiring incentives, liquidated damages, weather and seasonal constructability and so on—drives most solar projects to some degree, so any opportunity to gain float in the timetable or mitigate delays is of benefit. Selecting a racking vendor can take time, and you might not finalize the process until the 30% design stage, at which point engineering needs to move quickly to develop permitting and construction design documentation. Waiting for a racking provider to mobilize to a site, perform pull tests and then analyze these results can delay the project construction schedule a month. To avoid this delay, spend a little more during due diligence by having a third-party geotechnical engineer and subcontractor perform pull tests during the geotechnical analysis.



Courtesy McCarthy Building Companies

Corrosion impacts To characterize soil corrosivity, Standard Solar recommends conducting Wenner four-pin resistivity tests on ground-mounted projects over 1 MW.

The surface area of the bearing plate provides high pullout resistance, even in loose soils. However, the narrow shaft offers minimal lateral bearing capacity. As is the case with earth screws, you would use construction equipment with an auger attachment to drive helical anchors into the ground.

While helical anchors are ideal for sites with poor soil cohesion, they are not well suited to hard soils and soils with very coarse gravel or rock fragments. A structural engineer needs to ensure that design elements minimize horizontal loading, and may also need to adapt the mounting system design to use a helical anchor foundation.

Ballast. Precast or pour-in-place concrete ballast foundations best suit sites where soil penetration is undesirable or impractical. For example, project developers often deploy ballast foundations at PV power plants installed over landfills or

Courtesy AquaSoli

Earth screw Developers can deploy earth screw foundations in soils and on slopes that will not accommodate driven piles. With a predrilled pilot hole, crews can even install earth screws in bedrock.

Define the scope of work. The geotechnical analysis should include soil corrosivity and resistivity testing. For 1 MW and larger PV systems, we recommend performing Wenner four-pin soil resistivity tests during the initial geotechnical investigation. For systems under 1 MW, we suggest performing four-pin resistivity tests if laboratory tests for soil corrosivity indicate that the site requires cost-prohibitive materials such as epoxy coatings or highly galvanized racking foundations.

The geotechnical analysis should also include water level observations, and the report should note any potential issues related to water table height. With driven-beam foundations, for example, a high water table can significantly reduce soil load-bearing capacity. Water level can also be an issue with drilled holes that you must fill with concrete, as might be the case with a carport foundation. Sometimes it is feasible to use pumps to deal with this water; if so, it is best to have the pumps and the water discharge management plan in place before beginning construction. These are the types of system stability and foundation installation issues that a solar-specific geotechnical site assessment report should include.

Connect the dots. It is important for the project developer to manage responsibilities between the geotechnical engineer and the racking supplier's structural engineer, particularly when sharing reports and calculations. In the assessment report, for example, the geotechnical engineer might recommend a particular foundation size or type and detail assumptions and safety factors. If so, the project developer needs to communicate this information clearly to the racking supplier's structural engineer to avoid overly conservative designs. If the structural engineer applies redundant safety factors, the result could be foundation embedment details that are unnecessary for the site conditions.

Expect the unexpected. Make sure that subsurface exploration is adequate to properly characterize soil conditions. With soil boring samples, for instance, this is a function of the number or volume of samples collected across a site, as well as the equipment used. We do not recommend hand-operated boring equipment because it may hit refusal before reaching the depth needed for a full analysis.

Disturbed or contaminated soils present challenges that geotechnical engineers are uniquely qualified to address. If you want to develop an inner-city parking lot as a solar carport, for example, it is important to investigate whether there is a reason that others have not already developed the site. A geotechnical site assessment can identify whether the site contains undesirable fill, such as large rocks, concrete or bricks; if so, the geotechnical engineer can suggest engineering responses, such as a spread-footing foundation, that avoid the costs associated with drilling into buried debris. For contaminated soil, the geotechnical engineer can help navigate environmental permitting requirements and determine whether you need a contaminated material management plan.

Understand AHJ requirements. Some AHJs require that a licensed geotechnical engineer supervise the work on-site and certify that workers complete the foundation and mounting structure as designed. If the project requires construction verification, integrate this scope of work into the development schedule and budget as early as possible. Communication is essential. The project development team needs to know which activities the geotechnical engineer has to supervise, and the geotechnical engineer needs to know the schedule for these activities. The engineer of record needs to evaluate any changes made to the mounting structure or foundation and provide documentation approving the change.

—Steve Swern, project engineer, Standard Solar

brownfields. Sites with bedrock, a high water table or unconsolidated soils with high refusal rates may also benefit from a ballasted foundation. The mass of the ballast material resists the applied load, and the foundation distributes these loads across a large bearing surface.

Drilled and grouted piles. The best application for drilled and grouted piles in PV power plants is as an engineered foundation used in case of pile rejection. Drilled and grouted piles are otherwise prohibitively expensive, as they require drilling and concrete equipment. Further, the concrete needs to cure before you install the mounting system. However, drilled and grouted piles are suitable for most soil types and provide good load resistance.

Foundation geometry. The two basic geometries used for PV power plants are center-post foundations and double-post foundations. In a center-post foundation, a single row of foundations supports each mechanical array section or table. In a double-post foundation, two rows of foundations—a north row and a south row—support each table.

Typically, vertical and horizontal loads are greater with center-post designs than with double-post designs. Each center-post foundation usually supports a relatively large surface area, and a comparatively longer lever arm applies horizontal forces to the foundation. In contrast, double-post foundations typically support a smaller surface area, and the structural design shortens the lever arm. These load characteristics are useful in some applications. For example, structural engineers almost always use double-post foundations with helical anchors, and specify longitudinal bars between the rows to reduce horizontal loads.

Site variability. Economies of scale favor using a single foundation type on small projects, even if that foundation is overdesigned for some site locations. The opposite is true on large projects, where it is most cost effective to vary foundation design, type and embedment depth according to different soil conditions. For example, soil investigation at the proposed site for a 20 MW PV power plant in the Philippines identified five layers of soil in seven horizontal combinations. The soils included beach sand; cemented sand; clean stream deposits of mixed sand, gravel and cobbles; mud slide deposits of sand, clay, silt, gravel, cobbles and boulders; and decomposed volcanic ash. This site required five foundation details to account for different soil bearing capacities, mitigate the potential for foundation refusal, and optimize material and installation costs.

"If I were to make one recommendation," says David Sharrow, director of operations at Terra Posts PV, CONTINUED ON PAGE 34

Courtesy AquaSoli

Inadequate site assessment AquaSoli's remedial investigation at this site revealed why 3,000 posts failed due to frost heaving. The foundation designers did not account for shallow groundwater at the site.

"it would be that developers choose a racking system that conforms to their geotechnical and topographical conditions. I have seen too many projects where the design team chose a racking system based solely on price per watt, neglecting grade and soil conditions, and expecting a result that will not and cannot meet expectations."

According to Worden at GameChange Racking, a quality geotechnical analysis is essential for a well-planned and executed project: "In the context of developing a ground-mounted PV power plant, a thorough geotechnical investigation with high-volume test pitting is analogous to the carpenter's proverb, 'Measure twice and cut once.' For 1 MW–2 MW projects, we recommend drilling boreholes and conducting a complete geotechnical investigation at five to nine locations, as well as digging roughly five times as many test pits across the site to evaluate soil type and water table level. These investigations need to scale according to project size. For example, 3 MW–5 MW sites might require a geotechnical investigation of 10 to 15 boreholes, and larger sites will require even more."

Wolfgang Fritz, VP of engineering and product development for Schletter, agrees: "From a risk management perspective—both for the client and for us—it is quite important to perform geotechnical investigations. As soils can vary significantly across project sites, it is almost negligent to work off assumptions not backed by testing data that may lead to cost overruns for which the client has not budgeted."

"Skimping on the geotech investigation is a very bad idea that comes with the potential for substantial negative impacts to short- and long-term profitability."
—Andrew Worden, CEO, GameChange Racking

Designing from the Ground Up

Some in the industry have the perception that solar foundation design is simple—dirt simple, in fact. The fact that in the planning stage the foundation typically represents about 6% of the total project budget reinforces this perception. During construction, however, the foundation is more likely to run significantly over budget than big-ticket items such as modules and inverters. Geotechnical-related change orders and project delays can triple foundation costs. Once the project is complete, foundation failure is the single greatest risk to long-term profitability. In worst-case scenarios, the cost to remediate failures can exceed the initial installation costs. In best-case scenarios, ongoing O&M costs may increase beyond projections.

"We've acquired systems with foundation issues," notes Ken Allen, COO at Principal Solar, "that forced us to divert funds set aside for making improvements to the maintenance of a failing support system—simply to keep things from breaking. These problems divert manpower and resources to activities that do not enhance return on investment. A little extra money spent to gather good geotechnical information oftentimes can eliminate these problems."

AquaSoli's Schmid has more than 10 years of experience with remediating solar foundation failures. He notes: "Forensic analyses demonstrate that foundations generally do not fail because the system exceeded design loads. Foundations fail for reasons such as loss of soil-bearing capacity due to high groundwater level, or soil erosion and liquefaction. Foundations fail from frost heaving or because of expansive clay soils. They fail because construction activities destabilize the soil or impair drainage. These are all failures that we can avoid with better geotechnical data."

"The primary way to mitigate these issues," concludes Kleinfelder's Tschida, "is to engage a firm that provides both geotechnical engineering and PV foundation design. This option provides an integrated design approach where each discipline is not working in a silo, but rather will engage the other to provide an efficient design for the project."

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Courtesy RBI Solar

Ground-Mount for Commercial and

The large-scale ground-mount installation market segment presents tremendous opportunities. In *U.S. Solar Market Insight Report: 2014 Year in Review,* GTM Research and the Solar Energy Industries Association (SEIA) project 8.1 GW of new PV capacity in 2015 and forecast that large-scale ground-mount installations will comprise approximately 5 GW of that. However, the development of large-scale ground-mounted PV power plants has become increasingly competitive and cost sensitive. These pressures have been driving changes in racking system design, materials and deployment.

Racking systems for commercial and utility PV plants are just that—systems. Effective designs balance materials and manufacturing cost, component count and shipping cost with speed of installation, adjustability for varied site terrain and foundations, and, of course, durability. For this article, I researched the wide range of ground-mount racking vendors and product lines that are available to project developers and integrators in the US. I include background information on the vendors themselves and overviews of their solutions for commercial and utility array fields. With a few exceptions, all the products presented here are scalable for large projects.

AP Alternatives

Headquartered in Ridgeville Corners, Ohio, AP Alternatives was founded in 2008 and launched its racking systems and related services in 2010. Its offerings include UL-listed racking system design and manufacture, as well as preassembly services intended to improve quality control and decrease installation time in the field. AP Alternatives' mobile assembly lines can be moved anywhere in the US and set up to prepanelize modules on racking cartridges or sections. Depending on the model, each cartridge uses helical anchors, four posts (individual cartridges share adjacent east-west posts) and stainless steel cable bracing to support four 60-cell (MOD 60), three 72-cell (MOD 72) or 10 thin-film (MOD FS) modules. AP Alternatives' GPS-guided anchor drivers can simultaneously drive two posts (north and south). Modules are electrically bonded during prepanelization, and a prewiring option is available. AP Alternatives also operates a separate division, Ready Rack, that offers

Vendors and Systems

Utility Applications

By Joe Schwartz

racking systems for commercial and utility projects where field assembly is preferred over preassembly.

AP Alternatives / 419.267.5280 / apalternatives.com

Applied Energy Technologies (AET)

A division of The Applied Group, AET was founded in 2009 and is headquartered in Clinton Township, Michigan. Its racking product family includes UL 2703–listed pitched roof and ballasted flat-roof systems. AET's solution for ground-mounted commercial and utility PV plants is the Rayport-G Eco ground mount. AET designed the system to use a single row of driven posts for anchoring, but helical- and screw-pile foundations, as well as a ballasted option, are also available. Installers mount modules in two-high portrait orientation, and an adjustable plate installed between the post and strut allows for ¾-inch height adjustment per post. A brace installed between the post and strut provides structural rigidity to the racking system. Top-down clamps offer integrated module-to-racking system electrical bonding to the requirements of UL 2703. AET provides a full layout and loading analysis for each Rayport-G Eco ground-mount project.

Applied Energy Technologies (AET) / 586.466.5073 / aetenergy.com

Brilliant Rack

Lilburn, Georgia–based Cantsink launched Brilliant Rack in 2014. Cantsink dates back to 1988, when it originally served as a foundation repair specialist for residential and commercial projects. It developed a manufacturing division in 2000 to produce helical piles for foundation stabilization. In 2010, the company shifted its core focus and manufacturing facility to anchoring systems for large-scale ground-mounted PV projects. Brilliant Rack is introducing a turnkey UL 2703–certified racking solution that is compatible with Cantsink's helical piles, as well as driven piles and ground screws. The galvanized steel racking system uses a single-row post system in conjunction with a tilt beam (strut) and brace for a triangulated structural configuration. To simplify installation, the assembly process requires only two bolt sizes and a single nut and washer size. Brilliant Rack's design includes three-axis installation tolerance and is compatible with east-west grades of up to 10%. Brilliant Rack also offers geotechnical testing, engineering and installation services.

Brilliant Rack / 678.280.7453 / brilliantrack.com

DCE Solar

The Daetwyler Group designated DCE Solar as a specialized division within the Daetwyler Clean Energy family of companies in 2015 and established its headquarters in Huntersville, North Carolina. Worldwide, the Daetwyler Group is involved in high-precision machine engineering, including a focus on the design, manufacture and support of products for the printing industry. DCE Solar offers rooftop and parking canopy array-mounting solutions, as well as several variations of its Modu-Rack ground-mount system. The Modu-Rack product has galvanized steel structural members and DCE Solar designed it to facilitate module prepanelization. Modu-Rack model variations include single-row and dual-row post configurations and anchoring systems such as helical and driven piles, micropiles, and soil and rock anchors. DCE Solar's ground-mount product portfolio also includes two racking systems, the Cap-Rack driven-beam system and the Cap-Rack ballasted system, developed for landfills and other contaminated sites that do not allow for ground disturbance.

DCE Solar / 704.659.7474 / dcesolar.com

DPW Solar

Headquartered in Albuquerque, New Mexico, DPW Solar was founded in 1993 as Direct Power and Water. The PV racking system provider is currently a wholly owned subsidiary of Preformed Line Products, a component designer and supplier for industries that include communications and energy. DPW Solar has an extensive line of roof-, pole- and ground-mount PV racking products. The most recent addition to its ground mount line is the Power Peak large-scale ground mount system. Intended for commercial and utility PV plants, the Power Peak combines a galvanized steel driven-pile anchoring system with preassembled aluminum assemblies that include the rack's strongback, strut and rail brackets. Installers unfold the assemblies on-site and attach them to the vertical piles via adjustable galvanized steel attachment brackets. DPW manufactures the rails from aluminum extrusions that include built-in wire channels. DPW Solar's factory-preassembled RAD module clamps provide a built-in electrical grounding option.

DPW Solar / 505.889.3585 / dpwsolar.com

Courtesy GameChange Racking

Low parts count One approach to driving down a racking system's material cost and speeding up installation is minimizing required components. GameChange Racking's Max-Span ground mount uses nested structural members, eliminating the need for separate attachment brackets to join the substructure components.

GameChange Racking

Launched in 2011, GameChange Racking is owned by Barron Group Holding and headquartered in New York. It offers a full line of PV racking products that include roof mounts, carport structures, and anchored and ballasted ground mounts. Two recent additions to GameChange's ground-mount line include the Max-Span post system and GC Pour-In-Place ballasted system. The Max-Span ground mount's structural members are galvanized steel. To reduce parts count and streamline installation, the system features nested components with slotted attachment points, eliminating the need for separate brackets to connect the main structural members. The Max-Span system's direct purlin mount option enables an 8% east-west grade, while its purlin bracket mount option enables an east-west grade of up to 17%. For landfill or brownfield sites, the GC Pour-In-Place ballasted system uses leave-behind recycled high molecular weight polyethylene (HMWPE) plastic forms that installers fill with concrete on-site.

GameChange Racking / 212.359.0205 / gamechangeracking.com

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Courtesy RBI Solar

No concrete For large projects on sites where conditions allow for penetrating foundation systems and soil disturbance, lower-cost and more easily scaled foundation systems have replaced concrete-encased anchors. These foundation types include driven piles and micropiles, screw-in helical piers and ground screws.

IronRidge

Headquartered in Hayward, California, IronRidge was founded in 1996. The company's racking family includes fixed and ballasted products for rooftop array mounting, as well as pole mounts and ground mounts. Its Ground Mount product for commercial and industrial systems combines IronRidge's XR1000 aluminum rail with installer-supplied 2- or 3-inch Schedule 40 galvanized steel pipe. The system uses connectors with U-bolt attachments between the racking system's rails, cross-pipes (purlins) and vertical piers. IronRidge's Ground Mount is compatible with a variety of foundation options, including concrete piers and driven piles. It can support up to five modules per column in landscape orientation. The XR1000 rails allow for spans of up to 17 feet between east-west foundation piers.

IronRidge / 800.227.9523 / ironridge.com

Mounting Systems

Founded in 2010, West Sacramento, California–based Mounting Systems is the US affiliate of Mounting Systems, GmbH, headquartered in Rangsdorf, Germany. In January 2015, Mounting Systems GmbH expanded via the acquisition of racking manufacturer HatiCon Germany GmbH and its US affiliate, HatiCon Solar, from Sapa, a global aluminum solutions provider. Mounting Systems' product portfolio provides mounting solutions for pitched and low-slope roofs as well as three ground-mount products for open-field commercial and utility PV arrays. Its Sigma I product is a single-row system that features a custom galvanized steel driven-micropile anchoring system. The Sigma I XL product combines a single-row anchoring system with aluminum rails to enable large-format array configurations of up to four-module columns in landscape orientation. The Sigma II product is a two-post system that can be anchored with driven micropiles, helical piles or footplates on ballast. Sigma II's use of micropiles instead of large beam-type piles allows the use of smaller, less expensive hydraulic driving equipment and simplifies material transport and handling.

Mounting Systems / 855.731.9996 / mounting-systems.us

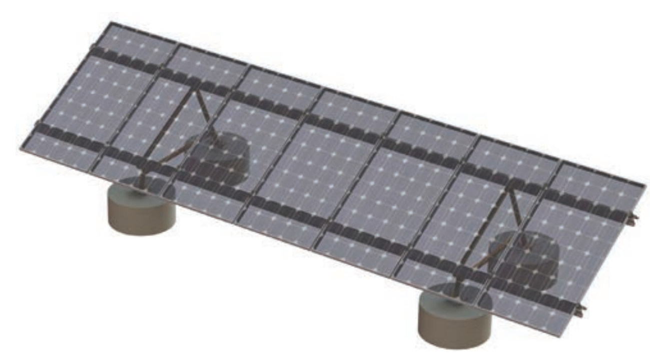
MT Solar

MT Solar is a small, privately held racking system manufacturer located in Charlo, Montana. While its products fall outside the general scope of this article (racking solutions that installers can efficiently scale for large commercial and utility projects), its Solar Pole Mount system features a unique design that integrators should be aware of for ground-mounted small commercial and residential installations. MT Solar has designed its Solar Pole Mount system for waist-level array assembly and wiring, and it features a manual and removable hoist system that raises the array to top-of-post level. The innovative design eliminates the need for cranes for preassembled array lifting and placement, scaffolding for pole-top mount assembly or overhead work from ladders during array installation. Additionally, installers can fully adjust the mounts from 0° to 90° by twisting a crank from the ground. Single-pole models designed to support two to 12 modules are available, as are larger multipole models for higher-capacity, continuous pole-top arrays.

MT Solar / 844.687.6527 / mtsolar.us

Patriot Solar Group

Founded in 2006, Patriot Solar Group (PSG) is a privately held company headquartered in Albion, Michigan. The origins of the company date back to 2006 when it was involved in the telecommunications industry and operated as Patriot



Courtesy SunLink

Nonpenetrating Racking system manufacturers are developing and refining ballasted ground-mount products for deployment on landfill and brownfield sites that require developers to limit soil disturbance. SunLink offers both precast and a new cast-in-place ballasted option for its GMS racking line.

Courtesy Mounting Systems

Material cost The development of large-scale ground-mounted PV plants has become increasingly competitive and cost sensitive. These pressures have resulted in changes in racking system design, materials and deployment. The Sigma I XL product from Mounting Systems uses a single-post foundation and a combination of steel and aluminum structural members to support large-format array configurations.

Antenna Systems. PSG manufactures rooftop, carport and ground-mount racking systems, as well as dual-axis trackers and portable stand-alone power systems. PSG's solutions for commercial and utility systems include its Post Driven Ground Mount and Ballasted Ground Mount products. Foundation options for the galvanized steel Post Driven Ground Mount include driven piles, helical piles, screw piles and concrete piers. The single-post system is built in five-module sections with modules in a single row in portrait orientation. This system is unique in that its adjustable trusses connect to the driven posts and allow for tilt angles ranging from 10° to 40°. PSG's Ballasted Ground Mount also supports five modules in portrait orientation, and it relies on two 1,850-pound precast concrete ballast blocks per racking section for anchoring.

Patriot Solar Group / 517.629.9292 / patriotsolargroup.com

Polar Racking

Headquartered in Toronto, with US offices in New York, Polar Racking's product family includes solutions for residential, commercial and utility rooftop and ground-mount applications. Polar Racking offers eight configurations of its PRU utility-scale ground mount. Compatible foundation types include helical and driven piles, micropiles, ground screws and ballasted options. The galvanized steel racking system is available in single- and dual-post models that use either round or flat (rectangular) post types. The system has east-west and north-south adjustability of ±2 inches. Polar Racking offers models for both landscape and portrait module orientation, and custom array tilt angles from 5° to 35°. The PRU systems' mid-clamps provide integrated grounding. Prepanelized module options are also available for the PRU racking systems.

Polar Racking / 844.860.6722 / polarracking.com

PV Racking

Founded in 2010, PV Racking is headquartered in Southampton, Pennsylvania. A manufacturer of racking systems for roof-, ground- and carport-mounted arrays, the company is unique in that it offers a slide-in module mounting design. Instead of the typical use of top-down module mounting clamps, PV Racking's aluminum rail profile allows installers to slide modules into place, where they are held securely as installers place successive rails and module rows. The manufacturer recommends the use of DynoBond jumpers manufactured by DynoRaxx for module-to-rail electrical bonding. PV Racking's Ground Mount system is typically anchored with galvanized steel helical piers that also serve as the main posts for the racking structure. Five rail profiles accommodate module frame thicknesses of 1.16–2 inches. PV Racking's design allows for portrait or landscape module orientation at tilt angles of 5° and higher.

PV Racking / 610.990.7199 / pvracking.us

RBI Solar

RBI Solar is a privately held provider of solar racking solutions headquartered in Cincinnati. It operates additional US offices in Washington, North Carolina, as well as a facility in Temecula, California, which opened in 2015. The company made two notable acquisitions in 2014, including PV carport manufacturer and installer ProtekPark Solar, and Renusol GmbH and its subsidiary, Renusol America, providers of rooftop mounting solutions that include HMWPE ballasted mounts. The Renusol acquisition adds the Renusol GS, a non-penetrating ballasted one-piece mounting system for ground-mount applications, to RBI Solar's product portfolio. Intended for sites such as landfills and brownfields, the Renusol GS accommodates 72-cell modules at a 10° tilt angle. RBI Solar also offers a range of all-steel ground mounts that it developed for large commercial and utility-scale projects. Its GM-I and GM-T ground-mount products are listed to the UL 2703 standard and can be configured for portrait or landscape module orientations with tilt angles of 0°–45°. Foundation options include concrete piers, precast or cast-in-place concrete ballast, driven posts, and screw or helical piles.

RBI Solar / 513.242.2051 / rbisolar.com

Courtesy RBI Solar

Terrain following Limiting site excavation and preparation requirements is another development variable that offers first-cost savings. Many racking systems designed for large-scale ground-mounted plants, such as RBI Solar's GM-T and GM-I products, include adjustability that allows joined racking tables or sections to flow with changes in site elevation.

Schletter

Privately held Schletter GmbH has a 40-year history in the design and manufacture of steel and aluminum products; it has been active in the solar industry for approximately 20 years. The company founded its US subsidiary in 2008 with the launch of a sales and manufacturing facility in Tucson, Arizona. In 2012, Schletter relocated its US headquarters to Shelby, North Carolina. Its product portfolio includes mounting structures for carports, roofs and ground-mounted PV systems. Schletter designed its fully ballasted PvMax system for commercial and utility PV projects on landfill or brownfield sites. It uses a cast-in-place ballast system and arrives partially preassembled to speed installation time. The aluminum PvMax system is available in several configurations for portrait and module orientations and layouts. Schletter's ETL-classified FS System uses a galvanized steel single-row driven-pile anchoring system and aluminum upper-racking components. The system features a high level of preassembly and integrated module-to-rail grounding. Schletter's all-steel ground-mount model is the FS Uno. Like the FS System, the FS Uno uses single-row driven pile anchoring and arrives partially preassembled. Connector hooks connect module rails to the rack substructure, and a unique mid- and end-clamp design allows installers to mount modules anywhere along the rails. Schletter offers engineering support and geotechnical testing services, and is also the exclusive North American distributor of the GAYK Hydraulic Ram pile driver.

Schletter / 888.608.0234 / schletter.us

S:FLEX

With its global headquarters in Hamburg, Germany, privately held S:FLEX GmbH was founded in 2009 and has its US headquarters in Denver. S:FLEX's racking-system portfolio includes solutions for pitched and low-slope roof-, carport- and ground-mount applications. Its Ground Mount System product line supports both portrait and landscape module layouts, as well as framed or frameless modules, at an array tilt angle of up to 45°. Preassembled parts include height-adjustable, click-in module clamps. The dual-post racking structures are compatible with driven pile, helical pier, ground screw and embedded-in-concrete anchoring. Sites with a maximum east-west terrain slope of 8° can utilize the system, and it provides 12 inches of vertical adjustability on-site with no cutting or welding.

S:Flex / 303.522.3974 / sflex.com

Solar FlexRack

Headquartered in Youngstown, Ohio, Solar FlexRack is a division of privately held Northern States Metals, a designer and manufacturer of extruded aluminum industrial products. In 1997, the company diversified and began to manufacture PV module frames, eventually producing aluminum PV mounting clamps in 2008. In 2009, Northern States Metals launched its solar racking division. Solar FlexRack designs products with partially preassembled structural components that

Courtesy Solar FlexRack

Preassembly Factory preassembly of racking-system components has become increasingly common. The degree of preassembly varies from manufacturer to manufacturer and product to product. Solar FlexRack's G3-L model features partially preassembled structural components that installers can expand or unfold on-site. To meet the requirements of projects that prioritize material cost savings over labor savings, Solar FlexRack's new all-steel Series G3-X model ships with less preassembly than its G3-L model.

installers can expand or unfold on-site to reduce labor costs for large-scale PV plants. Solar FlexRack's Series G3-L is also an all-steel, single-post racking system. The company ships the vertical and horizontal rack components to the jobsite as a fully assembled unit. To meet the requirements of projects that prioritize material cost savings over labor savings, Solar FlexRack's new all-steel Series G3-X model ships with less preassembly than its G3-L model. The G3-X is Solar FlexRack's most cost-effective solution. It is value engineered to optimize materials, components and fasteners. Solar FlexRack has streamlined the all-steel system for field assembly, permitting easy staging on the jobsite. The G3-X is compatible with all standard foundation types, and built-in tolerances allow the system to adjust to varying topographies and challenging terrain. Integrated bonding and wire management round out the G3-X system. Solar FlexRack offers pullout testing, as well as geotechnical, engineering and turnkey installation services.

Solar FlexRack / 888.380.8138 / solarflexrack.com

Courtesy GameChange Racking

Cast-in-place GameChange Racking developed its GC Pour-In-Place ballasted system for landfill and brownfield sites, and other locations where conditions prevent extensive site preparation or penetrating foundations. Compared to precast ballast, cast-in-place ballasted systems minimize the requirement for heavy-equipment operation on sensitive sites and can drive out the significant freight costs associated with moving large precast ballast foundations.

SunLink

Founded in 2004, SunLink had a pioneering role in the introduction of ballasted racking systems for large-scale commercial and industrial arrays on low-slope rooftops. Since then, the privately held San Rafael, California–based company has diversified its product line to include ground-mount racking systems and BOS components such as disconnecting source-circuit combiners. SunLink's galvanized steel Large-Scale GMS uses a single-row driven-pile anchoring system. Installers can prepanelize landscape-oriented modules on vertical rails with three or four modules per column. For landfill and brownfield sites, SunLink offers its precast Ballasted GMS system. Earlier this year, SunLink added a cast-in-place ballast option for its GMS racking line. The new ballasted anchoring option uses locally sourced off-the-shelf concrete forms and allows casting of foundations at varying heights to account for uneven site terrain. Both the penetrating and ballasted versions of the GMS line offer integrated grounding and are listed to UL 2703. SunLink recently announced the completed acquisition of ViaSol Energy Solution's single-axis tracker. Developed for deployment in large-commercial and utility PV plants, the tracked solution rounds out SunLink's racking system product line.

SunLink / 415.925.9650 / sunlink.com

SunModo

SunModo is a privately held racking system manufacturer headquartered in Vancouver, Washington. Its products include flashed mounts for composition roofs and EPDM gasketed mounts for metal roofs, as well as racking systems for pitched and low-slope rooftops and ground-mounted arrays. SunModo has based its ground-mount systems on a double-row 2- or 2.5-inch Schedule 40 steel pipe substructure that is braced front to rear. The manufacturer offers a range of galvanized steel caps, sliders, splices and U-bolt kits for various racking system configurations in both landscape and portrait module orientations. Foundation options include earth anchors, concrete encased pipe and ballast. SunModo offers both extruded aluminum and galvanized steel module rail options.

SunModo / 360.844.0048 / sunmodo.com

TerraSmart

TerraSmart, a PV racking-system manufacturer and ground-screw distributor, was launched in 2009. Headquartered in Estero, Florida, the privately held company also operates a facility in Chambersburg, Pennsylvania. TerraSmart is the US distribution partner for German ground-screw manufacturer Krinner GmbH. TerraSmart has designed its TerraFarm ground-mount system for installation on its ground-screw anchoring system. North and south leg assemblies bolt directly to the top flange of each ground screw. The system's galvanized steel structure combines pipe, U-bolt and other attachment fittings with wire rope bracing to form a structure that supports up to 63 60-cell or 56 72-cell modules in landscape orientation, in seven-module columns. TerraSmart's ground screws and associated drilling equipment are well suited for challenging sites with poor or rocky soils. TerraSmart offers services that range from earth screw foundation installation to full turnkey ground-mount array systems.

TerraSmart / 239.362.0211 / terrasmart.com

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Courtesy Unirac

Bringing it all together Racking systems for commercial and utility array fields are just that—systems. Effective designs balance materials cost and component count with freight costs, speed of installation and adjustability to account for varied site terrain and foundation requirements. Unirac's Ground Fixed Tilt (GFT) racking system features a single-row, driven pile foundation; a combination of steel and aluminum structural components; significant adjustability; and integrated module-to-rail grounding.

Unirac

Headquartered in Albuquerque, New Mexico, Unirac was founded in 1998. It designs, manufactures and supports an extensive mounting and racking product portfolio that includes roof- and ground-mount solutions for residential, commercial, industrial and utility applications. (Hilti Group, a privately held global construction equipment provider, acquired Unirac in 2010.) Unirac developed its Large Array (U-LA) system for commercial-scale roof- and ground-mount PV installations. The U-LA system uses installer-supplied Schedule 40 or 80 galvanized steel pipe in conjunction with Unirac's aluminum attachment components and SolarMount rails. For utility-scale PV plants, Unirac offers its single-row, driven-pile Ground Fixed Tilt (GFT) racking system. The GFT has a galvanized steel substructure (pile, top chord and diagonal braces) featuring a single-bolt top-of-pile connection and a preassembled diagonal brace that unfolds on-site. The top chord assembly and pile have a prepunched hole pattern that provides north-south and vertical adjustability. Four east-west aluminum beams support a two-module column layout in portrait orientation; top-down clamps provide integrated module-to-rail grounding.

Unirac / 505.242.6411 / unirac.com

U.S. Solar Mounts

Sparta, Wisconsin–based U.S. Solar Mounts is a privately held racking manufacturer that PV installation company Pipkin Electric launched in 2010. U.S. Solar Mounts can scale its Adjustable Ground Mount (AGM) system for commercial PV arrays. The AGM uses a single-row galvanized steel pipe anchoring system that is typically concrete encased. Preassembled torque cradles installed on each pipe support two 4-inch galvanized steel torque tubes. Aluminum rails support modules in landscape orientation in three-module columns. The racking system allows for easy manual adjustment of the tilt angle from 0° to 50°. Customers can add an optional linear actuator, along with optical or GPS controls, to enable automatic elevation adjustment or solar azimuth tracking.

U.S. Solar Mounts / 608.272.3999 / ussolarmounts.us

Zilla

Zilla is a privately held PV racking- and mounting-system designer and manufacturer headquartered in Lafayette, Colorado. Its product line includes solutions for pitched and low-slope rooftops, as well as ground-mounted PV arrays. Zilla's Ground Mount Systems use a prefabricated aluminum triangular truss that is compatible with the company's helical piers as well as with contractor-supplied ballasted or concrete-encased anchor systems. The standard truss design layout is two-module columns in portrait orientation with a 30° tilt angle. Various sizes of the ground mount are available, and Zilla designs and manufactures custom trusses to meet specific project requirements. Zilla has designed the trusses for securing to a two-row anchor layout. Aluminum cross rails and bracing tie the trusses together. Zilla's integrated grounding Top Clip provides module mounting and bonding.

Zilla / 855.670.1212 / zillarac.com

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Reassessing DC VOLTA Conventions

While 2% voltage drop has become a de facto design standard for sizing PV system conductors, our data suggest that the acceptable voltage drop threshold is actually higher than current industry practice.

Courtesy Robert A. Bothman

By Ryan Mayfield, Paul Gibbs and Paul Grana

Ask almost anyone who works for a system integrator how to size PV system conductors with respect to voltage drop, and the nearly unanimous answer is "Keep voltage drop to less than 2%." Typically, PV system designers hold a maximum 2% standard on both the dc and ac sides of the inverter. When pushed to explain why, nearly everyone (ourselves included) answers with some form of "That's how it's always been done." As the industry continues to reduce system costs, however, we must reassess this rule of thumb to see if it still applies.

The industry, after all, is changing quickly. System costs and PPA costs are falling faster than anyone anticipated. System voltages are moving from 600 V to 1,000 V, and, in some applications, up to 1,500 V. System dc-to-ac ratios—the ratio of module power to inverter nameplate power—are increasing, from 1.2 to much larger numbers. These facts can have significant effects on optimal conductor sizing. In light of these changes, engineering analyses completed in 2012 may not be relevant in 2015.

We decided to dig a bit deeper into the voltage drop on the dc side of the inverter to see if the 2% threshold is still ideal.

GE DROP

Courtesy Array Technologies

We started by surveying system integrators and learned that many are making conductor-sizing decisions based on the 2% voltage drop standard. However, some system integrators have developed extremely complicated in-house models to analyze in intense detail the cost and energy trade-offs associated with conductor sizing.

In this article, we attempt to split the difference. We put the 2% rule under the microscope to see if it pencils out economically. We also rigorously analyze the effects of changing system costs and design techniques. Rather than propose a single model that will automatically determine the ideal dc conductor sizes on any project, our objective is to help system designers develop a stronger and more nuanced understanding of the factors driving their decisions. For this article, we base all of our initial voltage drop calculations on standard test condition (STC) ratings, as is most common within the industry. We use production modeling and financial analysis tools to quantify and monetize the actual voltage drop and wire loss values. This helps us draw some realistic conclusions regarding optimal conductor sizing.

CALCULATING VOLTAGE DROP

The voltage drop calculation itself is actually quite straightforward. The formula that we use as the basis for this article's calculations is Equation 1:

$$VD\% = (((2 \times L \times I \times R_C) \div 1{,}000) \div V_{SOURCE}) \times 100\% \qquad (1)$$

where *VD%* is the voltage drop percentage, *L* is the one-way circuit length, *I* is the operating current, R_C is the conductor resistance per 1,000 feet and V_{SOURCE} is the voltage of the power source.

You can use several voltage drop calculators to derive the answer to Equation 1 simply by entering the required inputs. At first glance, the inputs to the equation seem simple enough. However, if you want to analyze the impacts of voltage drop, each input is critical and can drive the results in different directions. So what are the correct reference values for calculating voltage drop?

PV circuit parameters. If you consider a single PV source circuit, V_{SOURCE} varies for nearly every hour of the day, not to mention from one day to the next. Early in the mornings, before the modules have heated up, the operating voltage is higher than in the middle of the afternoon. Average hourly cell temperature values—which directly influence operating voltage—vary from day to day, month to month and location to location. Operating current is also highly variable, based on system design detail and environmental conditions. However, operating current varies based on irradiance in the plane of the array rather than on cell temperature. Therefore, it is actually rather difficult to choose a single power-source voltage and operating-current value.

Some rebate programs require that designers estimate system voltage at a specific temperature for these types of calculations. Typically, these requirements specify an elevated design temperature based on summertime conditions. The concept is similar to sizing source circuits based on extreme cold temperatures: If you design for worst-case conditions, the array operates much better than calculated the majority of the time. This approach is valid for hard-stop design limits, such as maximum system voltage, intended to protect the equipment from damage. However, it does not provide as much value when applied to voltage drop, which is not a product-safety concern, because the worst-case design condition represents only a small number of hours per year.

A more common and simpler approach is to calculate voltage drop based on maximum power voltage and current values (V_{MP} and I_{MP}) at STC, which assumes a cell temperature of 25°C and an irradiance of 1,000 W/m^2. Over the course of a year, the V_{MP} value at STC is higher than the average operating voltage for the array; at the same time, the I_{MP} value at STC is higher than the average operating current. In a sense, these two components offset each other, but the offset is not linear. As the analyses that follow illustrate, voltage drop estimates based on STC ratings produce conservative results compared to voltage drop calculations based on actual operating voltage and current values.

Circuit length. Circuit length is another important variable in voltage drop calculations. If you are looking at PV source circuits, for example, one option is to use the length of the string that is farthest from the combiner box. While this length determines the largest possible voltage drop, this is again a worst-case scenario that affects only a small portion of the total array. Another method that designers employ is to calculate the voltage drop for each individual source circuit, and then determine a weighted average based on the length of the source circuits in relation to the combiner box. Of course, for a large-scale array, the task of evaluating the voltage drop for each source circuit is daunting, even for arrays with a uniform layout. This process may be less challenging for smaller arrays, but still requires the designer to tabulate and evaluate different data points.

> At first glance, the inputs to Equation 1 seem simple enough. However, if you want to analyze the impacts of voltage drop, each input is critical and can drive the results in different directions.

This same issue applies to output circuits, which connect source-circuit combiner boxes to subarray combiners or inverter-input combiners. It tends to be easier for designers to evaluate voltage drop in PV output circuits than in source circuits, simply because they are fewer in number. But it still takes time to calculate the length of each circuit, determine voltage drop percentage and apply these results to conductor sizing. At the same time, designers need to account for mismatch losses associated with having circuits with different voltage drop values—due to different circuit lengths and conductor sizes—connected to the same MPPT zone.

Conductor resistance. The last equation input to consider is conductor resistance. The *NEC* details direct current resistances in Chapter 9, Table 8, for both copper and aluminum conductors. The values used for the table are based on 75°C temperatures. The table notes indicate that the values given are for the properties listed and may change as the properties vary, especially the temperature. While the notes accompanying the conductor properties in Table 8 detail an equation for accounting for temperature change, we have used the conductor resistance values at 75°C in our analyses for consistency.

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MODELING VOLTAGE DROP

The alternative to performing static voltage drop calculations is to use software to model voltage drop over a typical meteorological year. One benefit to production modeling is that it accounts for all array operating conditions. This approach also allows you to vary specific input parameters and see how this affects system performance, in terms of both energy yield and cost.

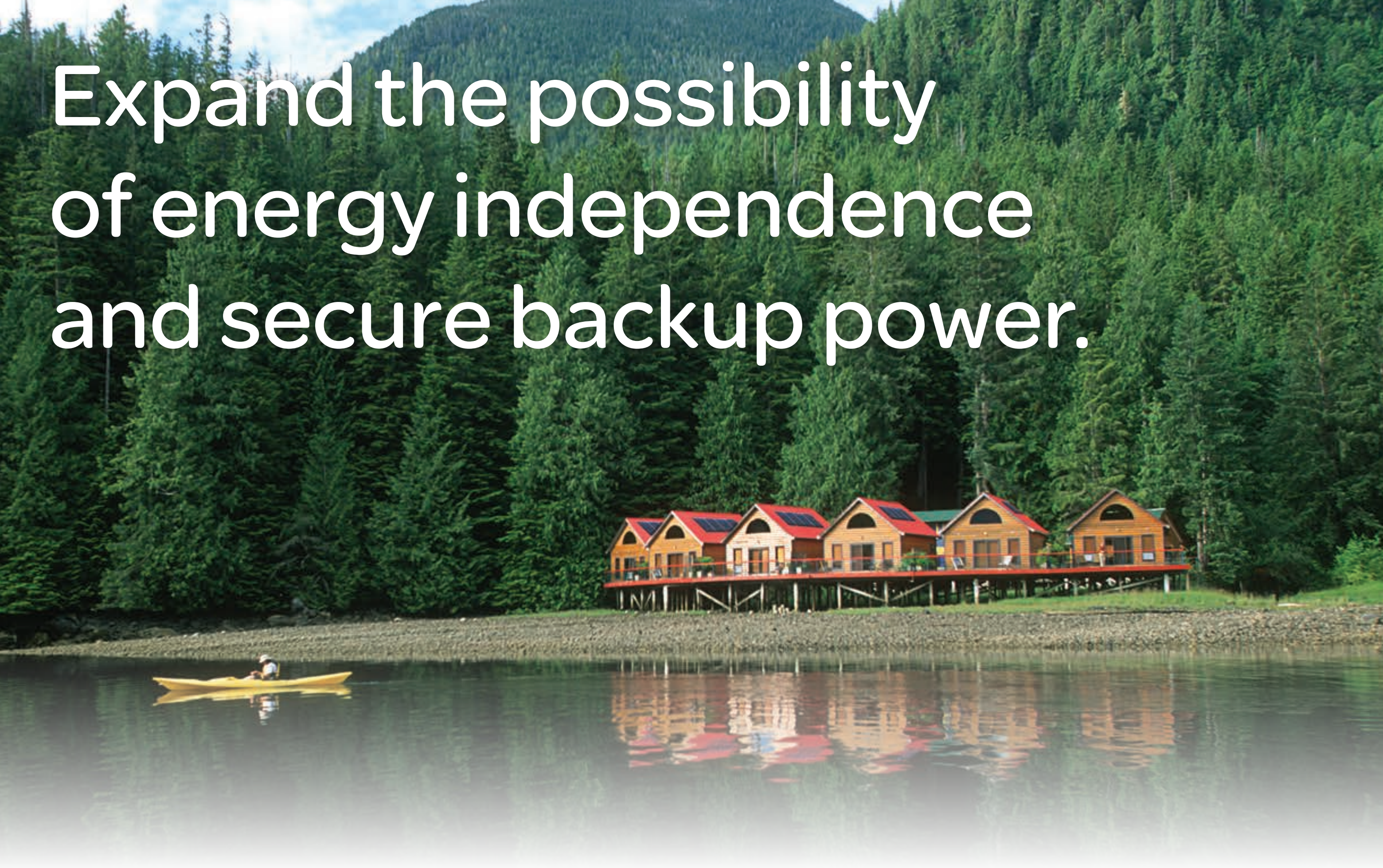
> When we model voltage drop in systems with a high inverter load ratio, we find that the effective wire losses are much lower than expected.

In the analyses that follow, we summarize the modeled results for various voltage drop scenarios. For example, we illustrate that designing for 2% voltage drop based on STC ratings does not result in 2% wire losses in the real world. We model how voltage drop effects vary according to system voltage and inverter loading. We also model parallel mismatch losses resulting from different conductor lengths.

We modeled the scenarios using HelioScope, a software program by Folsom Labs that integrates system design functionality with component- and conductor-level performance modeling. We used the program's design component to lay out a reference array. Based on this design, the program determined actual PV source circuit and output conductor lengths, and modeled system performance based on variables such as PV module and inverter model, circuit conductor sizes and so forth.

Other production modeling programs can also model conductor losses based on various inputs. For example, PVsyst can model many of the scenarios that we analyzed, and it produces similar results. However, the results would not be identical to those modeled using HelioScope, simply because minor differences between modeling methodologies would ripple through the outcomes.

Wherever possible, we kept design variables constant from one analysis to the next. Our intention is not to reduce the importance of different design variables or decisions, but rather to limit the number of permutations for analysis. For example, we assume in every case that the PV source-circuit conductors are copper (Cu), while the PV output-circuit conductors are aluminum (Al). This is certainly not CONTINUED ON PAGE 54



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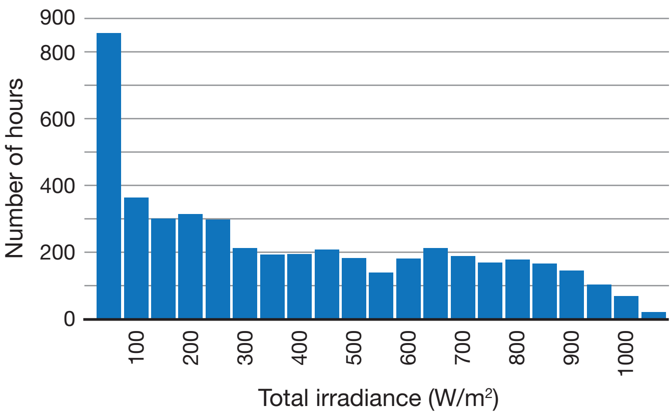

Figure 1 While a PV system in Atlanta operates approximately 4,700 hours per year, it is exposed to high-irradiance conditions (over 800 W/m^2) only 11% of the time, roughly 500 hours per year.

the case on every project. However, based on our conversations with system integrators, such a scenario is representative of many large-scale systems.

In some cases, the design variables are analogous from one analysis to another, rather than constant. For example, in each case source circuits are designed so that the array operating voltage is always within the inverter's MPPT input window, even in high voltage drop scenarios. In other words, we assume that a skilled engineer can select compatible components and size source circuits appropriately. (For more information, see "Array Voltage Considerations," *SolarPro* magazine, October/November 2010.)

2% voltage drop at STC. While designers often use voltage drop at STC as a proxy for line losses in a PV system, this is an imperfect measure if we want to understand the actual energy losses over the course of the year. Specifically, estimating voltage drop based on STC ratings tends to overstate the actual energy losses. This is because STC ratings are measured at an irradiance of 1,000 W/m^2, and plane-of-array irradiance is seldom this high in the field. Instead, fielded PV arrays typically operate at lower power and current levels than their nameplate ratings.

As an example, the average irradiance intensity for a south-facing PV array with a 15° tilt in Atlanta, Georgia, is just over 600 W/m^2, as illustrated in Figure 1. Since the operating current of a PV source is directly proportional to irradiance, average irradiance intensity impacts wire loss calculations. According to Ohm's Law—specifically, the expression $P = I^2 \times R$—wire losses are a function of the square of the circuit current. This means that reduced irradiance intensity results in reduced effective wire losses, the losses calculated for actual operating conditions over a year. In fact, when we model the effective wire losses for a PV system in Atlanta designed for 2% wire losses at STC, we find out that the actual wire losses are 1.2%, as shown in Table 1, which is 60% less than expected.

Furthermore, the actual energy losses over the course of the year differ from location to location, due to weather patterns and irradiance intensity. For example, Phoenix has more high-intensity sun than Atlanta, with 21.6% of sun hours greater than 800 W/m^2 and an average irradiance of 708 W/m^2. As a result, an array in Phoenix designed for 2% voltage drop at STC has an effective wire loss of 1.4%. By comparison, a system designed to the same 2% voltage drop at STC standard in Seattle, where the average irradiance is 537 W/m^2, has an effective voltage drop of just 1%.

Increasing system voltage. As 1,000 V PV systems increase in popularity, designers need to analyze voltage drop at these higher voltage levels. How much does an increase in the nominal system voltage actually affect voltage drop?

Assuming the same power, system designers intuitively recognize that increasing voltage decreases current. All else being equal, 1,000 V PV systems have fewer conductors compared to 600 V systems. As you increase the number of modules per series string, you also decrease the total number of PV source circuits. Both of these factors have a positive impact on the overall voltage drop in the system.

With PV source circuits, the amount of current in the conductors is the same regardless of the number of modules per string, but increasing the nominal system voltage from 600 V to 1,000 V helps to reduce line losses. In addition, designers may be able to decrease the length of the source-circuit homerun based on the array layout and wiring methods used. Depending on the number of source circuits per combiner box, the amount of current in the output-circuit conductor may or may not be reduced. On one hand, you could have less current per output-circuit conductor; on the other, you could have fewer output conductors overall.

For our system voltage analyses, we modified the previous model for Atlanta by increasing the number of modules per source circuit without adjusting the PV CONTINUED ON PAGE 56

Effective Annual Wire Losses

Location	Percentage of high-irradiance (>800 W/m^2) operating hours	Average annual irradiance (W/m^2)	Effective wire losses (VD%)
Seattle	6.6%	537	1.0%
Atlanta	10.7%	604	1.2%
Phoenix	21.6%	708	1.4%

Table 1 This table shows the effective wire losses—modeled hourly over the course of one year for Seattle, Atlanta and Phoenix—for south-facing PV arrays tilted at 15° and designed for 2% voltage drop at STC ratings.

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source or output conductor sizes. In this scenario, the effective voltage drop decreased from 1.2% for the 600 V system to 0.8% for the 1,000 V system. Additional modeling indicates that voltage drop losses are minimal in 1,000 V PV systems even when you use *Code*-minimum conductor sizes.

Increasing inverter loading. Another trend in large-scale PV projects is the use of higher inverter load ratios (the ratio of dc to ac power in the system). The popularity of this design approach is directly related to module price declines. (See "Optimizing Array-to-Inverter Power Ratio," *SolarPro* magazine, October/November 2014.) Our analyses indicate that this trend has a dramatic—though not entirely self-evident—impact on voltage drop considerations.

Designers naturally expect voltage drop increases when operating current values are highest. In systems with a high inverter load ratio, however, elevated operating current conditions are coincident with periods of inverter power limiting. In other words, when the solar resource is greatest, the array is capable of producing more power than the inverter can process. On clear days, this phenomenon results in a clipped or flat-topped power curve. These periods have interesting and far-reaching system design implications.

When we model voltage drop in systems with a high inverter load ratio, we find that the effective wire losses are much lower than expected. This is largely because inverter power limiting prevents the realization of potential wire losses during high irradiance, as shown in Figure 2. Technically, the

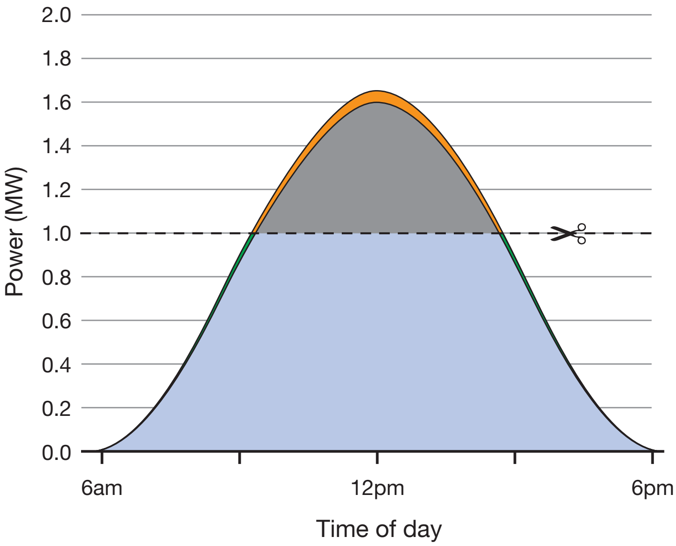

Figure 2 This figure shows wire losses in relation to an idealized power curve for a system with a high dc-to-ac loading ratio. Since the power curve will be clipped above 1 MW, designers can ignore any wire losses that occur during periods of inverter power limiting.

wires are still losing energy due to their resistance during these periods. However, as long as the inverter determines the system output, it does not matter whether the resistance of the circuit conductors is relatively higher or lower. In other words, there is no financial impact associated with wire losses whenever the inverter power curve is clipped.

As a result, designers can actually dismiss wire losses that occur during periods of inverter power limiting. This means that the effective wire losses, which should drive our design decisions, are only those wire losses that occur below the inverter power-limiting threshold. As shown in Figure 3, the results are striking when we model the relationship between inverter load ratio and effective wire losses. At an inverter load ratio of 1.1, the wire losses for our reference system in Phoenix are nearly 1.2%. If we increase the load ratio to 1.6, that cuts the effective losses roughly in half.

Mismatch losses. To many people, mismatch is synonymous with hard shade that results in series mismatch: differences in output current between modules in the same string. But parallel mismatch can also affect an array. When strings connected in parallel feed a common inverter circuit, they must harmonize to the same voltage at the inverter input. To the extent that homerun conductor length varies, these source circuits experience different amounts of voltage drop and operate at a different voltage level.

An inverter with a single MPPT zone, for example, instantaneously operates an array based on a single input voltage that is optimal for source circuits in the middle of the array, but not for the shortest or longest strings. Strings that are farthest from the inverter operate at a higher native voltage to compensate for the increased voltage drop. The opposite is true for strings with shorter homeruns. Since HelioScope models the performance of each system component individually, we can use it to calculate parallel energy losses associated with voltage drop mismatch.

Our analyses indicate that these energy losses are lower than most would expect. In a typical commercial array, parallel mismatch losses associated with voltage drop range from just 0.05% to 0.10%. Even when we model an array with 5% voltage drop, the overall impact of mismatch losses on total energy production remains negligible, on the order of 0.03%. These results suggest that designers can generally disregard parallel mismatch losses due to voltage drop.

FINANCIAL ANALYSIS

Conductor sizing represents a tradeoff between up-front hardware cost and lifetime energy yield. Money saved on smaller conductors will result in greater resistive losses and therefore reduced revenue over the lifetime of the system. In addition, *Code*-mandated minimum conductor sizes are based on the required ampacity of the conductor. Ideally, designers choose conductors that minimize total cost of ownership, balancing

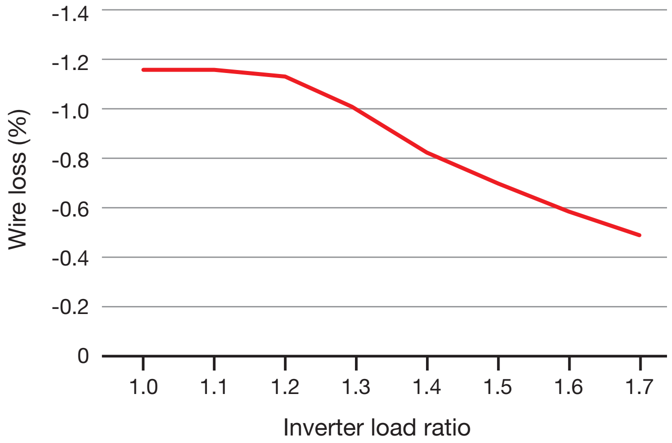

Figure 3 This figure shows how the effective wire losses for a reference system in Phoenix change according to inverter load ratio.

the up-front cost of conductors and the future cost of resistive losses, while adhering to *Code* requirements.

To estimate these costs and compare conductor sizing options, we used Microsoft Excel to develop a financial modeling tool that accounts for relevant design and financial variables. Design variables include conductor size, length and cost per linear foot, and dc resistance per 1,000 feet. Financial variables include estimated annual energy production, value of the energy delivered to the utility, annual energy escalation rate and discount rate. We then used this spreadsheet to analyze three design scenarios: Scenario A is a reference 1,000 V nominal PV system. Scenario B is a system with a high inverter load ratio. Scenario C is a 600 V nominal PV system.

Scenario A. We developed the following 1,000 V nominal reference system as a baseline for comparison:

ARRAY CAPACITY: 1.58 MWdc
MODULES: 5,184 Trina TSM-305 PA14, 305 W_{STC}
INVERTERS: three Sunny Central 500CP XT, 500 kVA nominal
ARRAY: 18 modules per 5,490 W source circuit and 16 source circuits per combiner
LOCATION: Atlanta, 33°N

We then modeled the total cost of ownership associated with four PV source- and output-circuit conductor sizes, as

Scenario A: 1,000 V Nominal System

Conductor size option: source and output circuit	System voltage (Vdc)	Nominal wire losses at STC	Effective wire losses	Source circuit cost	Output circuit cost	Lifetime energy cost	Total cost of ownership
Option 1: 14 AWG Cu and 300-kcmil Al	1,000	2.6%	1.9%	$9,583	$21,762	$31,743	$63,088
Option 2: 12 AWG Cu and 300-kcmil Al	1,000	2.1%	1.5%	$10,308	$21,762	$25,034	$57,104
Option 3: 10 AWG Cu and 300-kcmil Al	1,000	1.8%	1.2%	$12,691	$21,762	$20,805	**$55,258**
Option 4: 10 AWG Cu and 400-kcmil Al	1,000	1.5%	1.0%	$12,691	$26,000	$17,411	$56,102

Table 2 This table details total cost of ownership—including conductor material and labor costs, and revenue opportunity costs associated with resistive losses—based on different conductor sizes. In this scenario, which depicts a 1.58 MWdc system with a dc-to-ac ratio of 1.05, Option 3 provides the lowest total cost of ownership.

detailed in Table 2, assuming a reasonable Year 1 energy value ($0.09/kWh) and representative conductor material and installation labor costs. In many cases, the minimum source-circuit conductor size required by *Code*—based on a maximum series fuse rating of 15 A—is actually 14 AWG copper, as assumed in Option 1. However, due to voltage drop considerations, few system designers we polled use 14 AWG source-circuit conductors in practice. Designers effectively use 12 AWG source-circuit conductors as a de facto industry minimum conductor size, as specified in Option 2. In some cases, you might upsize PV source-circuit conductors to 10 AWG copper, as detailed in Option 3. If you wanted to drive down CONTINUED ON PAGE 60

Scenario B: High Inverter Load Ratio

Conductor size option: source and output circuit	System voltage (Vdc)	Nominal wire losses at STC	Effective wire losses	Source circuit cost	Output circuit cost	Lifetime energy cost	Total cost of ownership
Option 1: 14 AWG Cu and 300-kcmil Al	1,000	2.6%	0.5%	$9,583	$21,762	$14,584	$45,929
Option 2: 12 AWG Cu and 300-kcmil Al	1,000	2.1%	0.4%	$10,308	$21,762	$11,319	**$43,389**
Option 3: 10 AWG Cu and 300-kcmil Al	1,000	1.8%	0.4%	$12,691	$21,762	$9,442	$43,895
Option 4: 10 AWG Cu and 400-kcmil Al	1,000	1.5%	0.2%	$12,691	$26,000	$5,044	$43,735

Table 3 This table details total cost of ownership associated with different conductor sizes for a PV system with a 1.58 dc-to-ac ratio. In this scenario, Option 2 provides the lowest total cost of ownership.

voltage drop further, you could upsize the PV output-circuit conductors, as modeled in Option 4.

The goal of our financial analysis is to determine which of these design options is optimal, based on the total cost of ownership for the conductors. Table 2 (p. 58) details the results of our financial analysis for Scenario A, breaking out the estimated costs to install the PV source- and output-circuit conductors based on representative material prices (in Q1 2015). We also assumed a negligible labor cost differential to install different-diameter PV source-circuit conductors. The data in the *lifetime energy cost* column quantify the economic value of the wire losses associated with different conductor sizes. To arrive at this value, we held the array layout constant while changing the conductor sizes. This allowed us to determine the resistive losses associated with each design option. We then used a net present value formula to monetize the value of the energy lost due to voltage drop over 25 years, assuming a 7.5% discount rate.

The data in the *total cost of ownership* column are the sum of the PV source-circuit conductor costs, the PV output-circuit conductor costs and the lifetime energy costs. We can compare these values in Table 2 to determine the optimal conductor sizing for different design scenarios. For example, in our reference system, we can reduce the total cost of ownership nearly $6,000 by increasing the source-circuit conductor size from 14 AWG (Option 1) to 12 AWG (Option 2). While we can squeeze a little more value out of the system by upsizing the source-circuit conductors to 10 AWG (Option 3), upsizing the output-circuit conductors to 400-kcmil (Option 4) is too much of a good thing.

Scenario B. In this scenario we eliminated one of the 500 kVA inverters from the previous example, increasing the dc-to-ac load ratio to 1.58. To the extent possible, we did not change any other system design or array layout parameters. We then modeled the total cost of ownership based on the four conductor sizes described for Scenario A. The results of this analysis are presented in Table 3.

Two things are striking when we compare the total cost of ownership associated with different conductor sizes in this scenario with a high inverter load ratio. First, compared to our reference scenario, which assumes a 1.05 dc-to-ac ratio, Scenario B has a significantly reduced lifetime energy cost and lower total cost of ownership values. This is largely because we can ignore wire losses that occur during periods of inverter power limiting. Second, in this scenario, the optimal configuration of conductor sizes shifts to Option 2.

While the nominal wire losses at STC do not change between Scenarios A and B, the effective CONTINUED ON PAGE 62

Scenario C: 600 V Nominal System

Conductor size option: source and output circuit	System voltage (Vdc)	Nominal wire losses at STC	Effective wire losses	Source circuit cost	Output circuit cost	Lifetime energy cost	Total cost of ownership
Option 1: 14 AWG Cu and 600-kcmil Al	600	3.6%	2.5%	$12,821	$36,153	$39,099	$88,073
Option 2: 12 AWG Cu and 600-kcmil Al	600	2.8%	1.9%	$13,791	$36,153	$30,959	$80,903
Option 3: 10 AWG Cu and 600-kcmil Al	600	2.3%	1.6%	$16,979	$36,153	$25,308	**$78,440**
Option 4: 10 AWG Cu and 1,000-kcmil Al	600	1.8%	1.2%	$16,979	$46,150	$19,009	$82,138

Table 4 This table details total cost of ownership associated with different conductor sizes for a 600 V nominal PV system with a 1.05 dc-to-ac ratio. In this scenario, Option 3 provides the lowest total cost of ownership.

wire losses are much lower in systems with a high inverter load ratio, as illustrated in Table 3. This means that upsizing the PV source-circuit conductors from 12 AWG to 10 AWG in Scenario B effectively provides less benefit than it does in Scenario A. This is an important distinction, and one that is not self-evident in the absence of a financial analysis.

Scenario C. For our last scenario, we wanted to analyze the cost of ownership of conductors in a 600 V nominal PV system. In this case, the total array capacity does not change; further, the system uses the same modules and inverters described in Scenario A. The new array configuration is as follows:

ARRAY: 12 modules per 3,660 W source circuit and 24 source circuits per combiner

In this scenario, modeled in Table 4 (p. 60), we have the same number of modules per source-circuit combiner box (288). Because the array operating voltage is lower, however, the design current for the PV output-circuit conductors is higher. As a result, the *Code*-minimum PV output conductor size is 600-kcmil, as shown in Options 1–3. We increase the size of the PV output-circuit conductor to 1,000-kcmil in Option 4.

Compared to the previous scenarios, the total cost of ownership of the conductors is highest in the 600 V nominal system. We expect this result, since the lower voltage system requires more PV source circuits. The costs are also significantly higher for the larger-diameter output-circuit conductors.

In Scenario C, Option 3 provides the lowest total cost of ownership based on the size of the PV source and output conductors, which parallels the results in Scenario A. It is notable that the optimal conductor configuration in this case does not result in a nominal voltage drop of 2% or less as calculated based on STC ratings. While Option 4 succeeds in getting the nominal voltage drop percentage below 2%, the total cost of ownership for this configuration is actually higher than for Options 2 or 3.

SIZING THINGS UP (OR DOWN)

In the previous scenarios, we did not intend to define the optimal conductor sizes for every application. Instead, we illustrated how you can structure a financial analysis to model the impact of design variables. Further, we showed that design variables such as system voltage or inverter load ratio drive the optimal conductor configuration. While our scenarios are illustrative rather than prescriptive, the results underscore the importance of basing final design decisions on financial metrics rather than rules of thumb.

You typically get the most bang for the buck by upsizing PV source-circuit conductors rather than PV output-circuit conductors.

Financial analyses are extremely sensitive to cost inputs, and no single set of assumptions is appropriate across different geographies and system sizes. You must use accurate input data. Compared to the total project costs and revenues over 25 years, we are looking at very small amounts of money. Therefore, very small changes in one value can change the optimal conductor configuration. For example, our analyses assume that the price differential between 12 AWG and 10 AWG copper conductors is $0.046 per foot. If that price differential increases to just $0.07 per foot, then the results in Scenarios A and C tilt in favor of the 12 AWG source-circuit conductors in Option 2, despite the higher energy losses.

Equipment selection and configuration will also influence the outcome of these analyses. In each of the scenarios we analyzed, increasing the size of the source-circuit conductor relative to the minimum conductor size allowed by *Code* is financially beneficial. However, these results are specific to modules with a 15 A series fuse rating. For a system designed using modules with a 20 A or 25 A series fuse rating, *Code*-minimum conductors may prove optimal. Further, PV systems with a high inverter load ratio generally favor smaller source-circuit conductors since the effective wire losses are relatively low in these designs.

Having modeled multiple scenarios and design options, we observed that you typically get the most bang for the buck by upsizing PV source-circuit conductors rather than PV output-circuit conductors. In many of the systems we modeled, the overall wire losses were roughly evenly split between the source circuits and the output circuits, suggesting that the opportunities for conductor optimization are equal. This is not the case in reality, however. Even though the total length of the source circuits is many times longer than that of the output circuits, the incremental cost to upsize from 12 AWG to 10 AWG, as an example, is small compared to the incremental cost to upsize from 300-kcmil to 400-kcmil. Therefore, it is generally more cost effective to reduce wire losses by upsizing PV source-circuit conductors.

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Paul Grana / Folsom Labs / San Francisco / paul.grana@folsomlabs.com / folsomlabs.com

Deacon

Washington Plaza Apartments

Courtesy Deacon (3)

Overview

CONTRACTOR: Deacon, remcodeacon.com

DESIGNER: John Stimac, system designer, Renewable Energy Associates, renewableassociates.com

LEAD INSTALLER: Matt Evans, operations manager, Barnum & Celillo Electric, barnumcelillo.com

DATE COMMISSIONED: December 2014

INSTALLATION TIME FRAME: 90 days

LOCATION: Sacramento, CA, 38°N

SOLAR RESOURCE: 5.5 kWh/m²/day

ASHRAE DESIGN TEMPERATURES: 99°F 2% avg. high, 27°F extreme min.

ARRAY CAPACITY: 42.8 kWdc

ANNUAL AC PRODUCTION: 56,400 kWh

The Washington Plaza complex provides low-income housing for residents in downtown Sacramento, California. The building's owner contacted Deacon, a building restoration specialist, to perform a complete building remodel that included stripping the building to its core and upgrading nearly every component. The housing authority in charge of the facility strives for LEED accreditation in its remodels, and the Washington Plaza owner has facilitated remodels that incorporate PV and solar heating systems.

The primary driver of the PV design for the complex was to generate as much energy as possible from areas that were suitable for locating modules. The team determined a target energy value early in the renovation design process to meet LEED requirements.

Another key design driver was the owner's desire to incorporate module-level monitoring. The housing authority's previous PV installations utilize microinverters, and it was very happy with the granularity of operation and performance data that module-level power electronics systems offer.

Renewable Energy Associates (REA) generated multiple design iterations for the project, including arrays mounted on the rooftop and on covered parking structures at ground level. Given the number of rooftop units, and an elevator penthouse and stairwell on the south end of the building, the only viable option to meet the project's energy requirements was to elevate the array above the roof. The project team designed and installed an 8-foot trellis exclusively to support the PV array.

They maintained a construction-free roof zone for a solar heating system that they designed and installed separately from the PV array. The project owner ultimately opted to temporarily place the planned ground-level arrays on hold, but the design and construction teams included the infrastructure required to install these additional arrays in the future.

The project team custom-engineered the trellis structure in conjunction with the building remodel. The array support structure's design minimizes the number of pillars attached to the building while meeting seismic and wind-loading requirements. The crew made the pillar connections below the roof deck directly to the building's concrete support columns. The design uses DPW Solar's P6 Power Rail system to mount the modules to the elevated structure at a 15° tilt angle that maximizes both available space and energy production. To accommodate the owner's requirement for a high-efficiency array with module-level monitoring, REA specified SunPower modules, Tigo maximizers and SMA inverters. Module-level dc optimization allowed for module placement in less-than-ideal rooftop locations while minimizing potential energy losses.

The original main distribution switchgear, which remained in place, and the metering arrangement somewhat complicated the utility point of interconnection. The original main distribution panel includes a main disconnect for the entire service, metering for the common area loads and feeders for meter centers located on each floor of the building, which provide individual apartment metering. To properly net-meter the PV system, installers had to make the point of common coupling on the line side of the common area distribution panel. The electrical installation includes provisions for future solar inputs from the ground-level arrays via additional spaces in the dedicated inverter aggregation panelboard.

"The Washington Plaza building presented a number of challenges, from design through construction, but the team members always found the best solutions to overcome these challenges. Working with the solar team to meet our energy generation target was a fun process for all of us that resulted in a great PV installation."

—Jeremy Dietz, business development manager, Deacon

Equipment Specifications

MODULES: 124 SunPower X21-345, 345 W STC, +5/-0%, 6.02 Imp, 57.3 Vmp, 6.39 Isc, 68.2 Voc

INVERTERS: 3-phase 120/208 Vac service, three SMA America Sunny Boy SB10000TL-US (10 kW, 600 Vdc maximum input, 300–480 Vdc MPPT range), one SMA America Sunny Boy SB7000TL-US (7 kW, 600 Vdc maximum input, 300–480 Vdc MPPT range), four SMA America Sunny Boy Combiner Box TLUS-SBCBTL6, 15 A fuses

ARRAY: Seven modules per source circuit typical (2,415 W, 6.02 Imp, 401.1 Vmp, 6.39 Isc, 477.4 Voc), five source circuits per inverter typical (12,075 W, 30.1 Imp, 401.1 Vmp, 31.95 Isc, 477.4 Voc), one Tigo Energy Dual Maximizer MM-2ES75 per two modules typical, 42.8 kWdc array capacity total

ARRAY INSTALLATION: Custom elevated steel I-beam structure, DPW Solar P6 Power Rail, 199° azimuth, 15° tilt

SYSTEM MONITORING: Tigo Gateway and Maximizer Management Unit

Advertiser *Index*

Panasonic-Coronal **Hanford**

Overview

DEVELOPERS: Panasonic Eco Solutions, panasonic.com/business/pesna; Coronal Group, coronalgroup.com; ImMODO Energy Services, immodoenergy.com

ENGINEERING & CONSTRUCTION: ImMODO Energy Services; Panasonic Eco Solutions

DATE COMMISSIONED: August 2014

INSTALLATION TIME FRAME: 60 days

LOCATION: Hanford, California, 36.3°N

SOLAR RESOURCE: 5.7 kWh/m^2/day

ASHRAE DESIGN TEMPERATURES: 102°F 2% avg. high, 27°F extreme min.

ARRAY CAPACITY: 3.6 MWdc

ANNUAL AC PRODUCTION: 6,324 MWh

Equipment Specifications

MODULES: 11,800 Jinko JKM305P, 305 W STC, +5/-0%, 8.16 Imp, 37.4 Vmp, 9.05 Isc, 45.6 Voc

INVERTERS: 3-phase 12 kV medium-voltage interconnection; two Eaton Power Xpert Solar 1500 kW, 1,500 kW rated output, 1,000 Vdc maximum input, 550–1,000 Vdc MPPT range

ARRAY: 20 modules per source circuit (6,100 W, 8.16 Imp, 748 Vmp, 9.05 Isc, 912 Voc), two source circuits paralleled in array field (12.2 kW, 16.32 Imp, 748 Vmp, 18.1 Isc, 912 Voc), 10–12 input circuits per combiner, 13 combiners per inverter

ARRAY COMBINERS: 26 Shoals disconnecting combiners

ARRAY INSTALLATION: Custom fixed ground mount designed and manufactured by ImMODO Energy Services, two-module columns in portrait orientation, 180° azimuth, 20° tilt

SYSTEM MONITORING: ImMODO Energy Services monitoring system

Courtesy Panasonic Eco Solutions (2)

Panasonic Eco Solutions partners with Coronal Group to deliver comprehensive solutions for the development, engineering, financing, construction and long-term O&M of PV projects in the commercial, industrial, municipal and small utility markets. The Panasonic-Coronal partnership has developed nine projects in California under its 16.2 MW Central Valley portfolio, including the 3.6 MWdc Hanford PV plant. ImMODO Energy Services and Panasonic built the projects, which have PPAs with Southern California Edison as part of its CREST Feed-In Tariff Program.

Panasonic-Coronal had to consider many elements throughout the various stages of the Hanford development. The generation facility required a conditional use permit (CUP), as is the case for most PV projects in California that export power directly to the grid. The CUP approval process involved extensive archaeological, environmental, biological and wildlife studies that took approximately eight months. In addition, the project required an SCE Rule 21 interconnection approval, a process that took roughly four months.

Once the plan met the appropriate requirements, construction began. Hydraulic equipment drove the foundation piles for the fixed mounting system, eliminating the need for drilling and concrete. The system's two 1,000 Vdc Eaton Power Xpert Solar inverters and 1,000 Vdc BOS components allowed for high design voltages and reduced the project's first cost. To ensure the success of this installation, Panasonic is providing comprehensive, ongoing O&M services and a long-term production guarantee.

> "Significant solar projects are beneficial to the economy and how we produce and consume energy, but their financial and structural complexities are a big challenge for companies interested in adopting clean, sustainable energy. The Panasonic-Coronal platform is a proven integrated business model that removes those obstacles and helps to deliver affordable, reliable, clean energy."
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> *—Jamie Evans, managing director, Panasonic Eco Solutions*