July/August 2018

Simulating Maximum Voltage and Current

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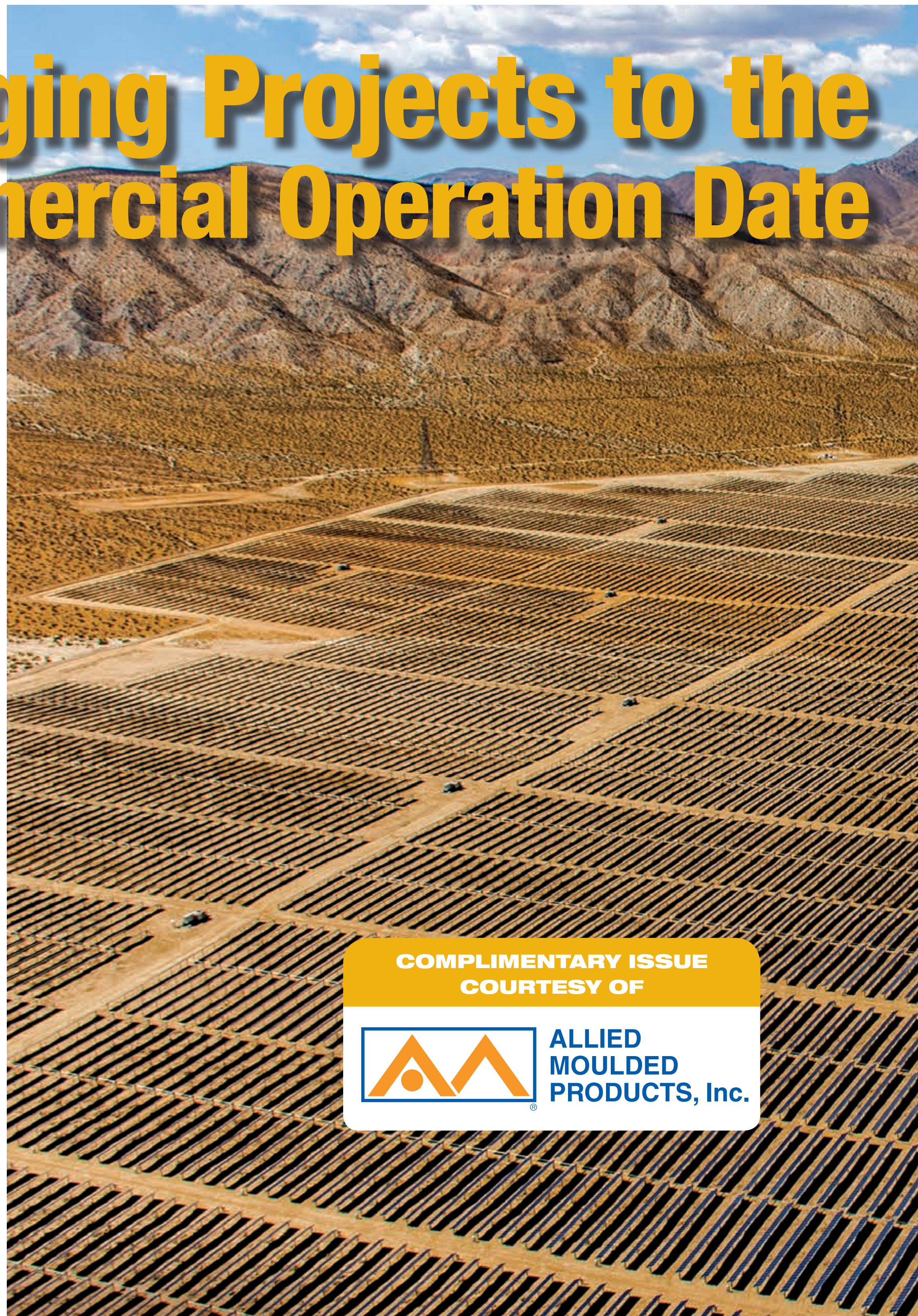

Optimizing DER Interconnections

Speeding Deployment While Unlocking Locational Benefits

Single-Phase String Inverters

Comprehensive Specifications for 77 Inverter Models

Project

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Recurrent Energy Barren Ridge Project Kern County, CA

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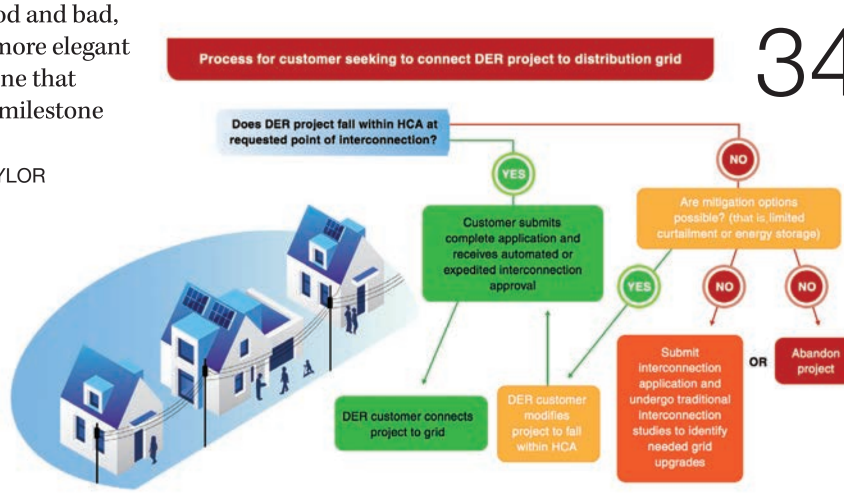

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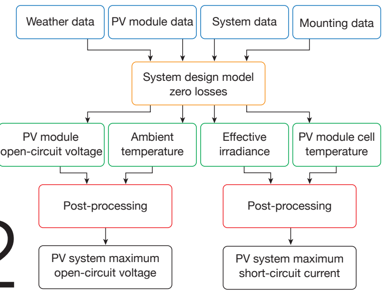

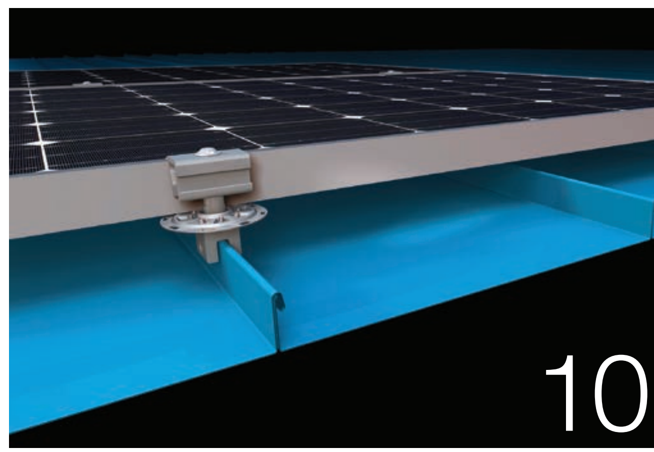

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ON THE COVER

Recurrent Energy built a two-mile gen-tie line to connect its Barren Ridge Solar Project to LADWP's electrical grid at the Barren Ridge Switching Station in Kern County, California. The project commenced commercial operations in late 2016.

Photo: Courtesy Recurrent Energy

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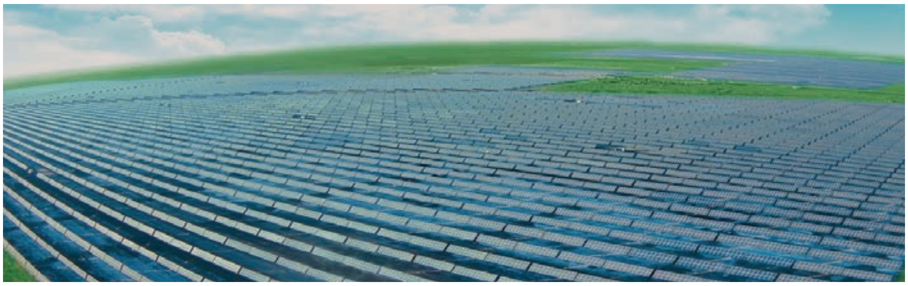
Why Mega Solar Projects Are Turning to String Inverters



The use of string inverters in US projects over 5 MW in size is expected to grow more than four-fold over the next 5 years, according to GTM Research. Unlike central inverters, the same string inverter can be used on projects ranging in size from just 1 MW to 1 GW. That sort of flexibility is especially important in today's ultra competitive marketplace.

Traditionally, developers of large-scale utility solar power plants used large central inverters for a very understandable reason. "In the past, lower capex leaned toward central inverters for large projects," said Sham Ramnarain, chief engineer of Huawei FusionSolar Smart PV Solution for North America. "With today's innovations and mass production in string inverters, that advantage now leans toward string inverters."

"Today, developers and EPCs have to bid more projects, and they have to bid more variations of projects. Customers are interested in looking at not only traditional and poly modules, but also bifacial and split cells, and there's always interest in looking at fixed-tilt versus tracking," said Bates Marshall, vice president and general manager of Huawei FusionSolar Smart PV Solution for North America, who notes that Huawei typically defines megaprojects as anything above 200 MW.

"In the past, you had to use different inverters for different project designs, and you'd have a file drawer full of designs and optimizations and tradeoffs," added Marshall. "From a velocity and flexibility standpoint, giving EPCs the ability to rely on a string inverter as one universal building block that doesn't change at scale is very appealing."

As much as flexibility is important, this transition to string inverters for solar megaprojects is primarily being driven by economics. Even before Section 201 tariffs were imposed, EPCs and developers faced enormous pressure to drive down project costs.

The tariff decision has only exacerbated those pressures, forcing EPCs and developers to scour the designs and equipment used in projects for savings. Just a few years ago, the capital expense of string inverters was a financial deal-breaker. "You'd get a quote for the inverter and lay out the preliminary design and bill of materials. And when you looked at it in Excel, the stark reality of capex was staring you in the face," said Marshall. "The typical 3-phase string inverter was twice the price."

Thanks to a massive ramp-up in production—led by Huawei, which GTM Research ranks as the largest inverter manufacturer in the world—the capex advantage of legacy central inverters has all but disappeared.

Cost savings related to balance-of-system outlays are also making string inverters more attractive for large projects. Because central inverters were long the standard for large solar developments, EPCs lacked a design methodology suited for string inverters. Huawei has developed a block design approach that divides projects into 3–4 MW sections, each integrated with a medium-voltage transformer.

The result of developing and encouraging best practices around design has driven down cost. "We have pulled out 3–4 cents per watt with block design and technologies such as our cluster rack and integrated transformer to consolidate components, reduce wiring and improve quality," said Marshall.

In the North American market, EPCs generally walk away from projects once they're built. But the long-term project owners reap the O&M cost benefits of string inverters; Marshall estimates a net present value economic benefit resulting from O&M savings of between 5 and 7 cents per watt.

The use of cloud computing, artificial intelligence and data analytics also drive reliability improvements and cost reductions with megaprojects. String inverters can collect enormous amounts of data that can be analyzed in real time to pinpoint potential problems.

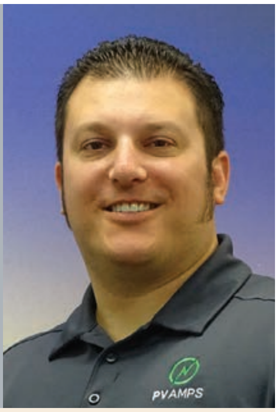
All of these advantages that come from the use of string inverters in megaprojects are important because they deliver the lower levelized cost of energy that is required in today's utility-scale market. "They provide better economic outcomes that are necessary to meet today's more aggressive PPA requirements," said Marshall. "That is where the rubber meets the road."

—Huawei / Cupertino, CA / solar.huawei.com

Contributors

Experience + Expertise

Anastasios Hionis, PE, founded PV AMPS in 2014 and serves as its president and principal engineer. An engineer in boots with more than 10 years' experience, he focuses on PV technical development, troubleshooting and performance testing. Hionis is dedicated to the successful launch, verification and optimization of commercial and utility-scale renewable energy projects.



Charles (Chuck) Ladd is a professional engineer and architect and the director of electrical engineering at Ecoplexus. His PV experience includes system design, utility interconnection design, owner's engineering, independent engineering, system commissioning, inverter technical analysis and construction monitoring. Ladd is the designer of record for PV systems totaling more than 700 MW.

Tim McDuffie, PE, is the chief engineer at CalCom Solar and has designed 50-plus PV projects totaling more than 60 MW over the last 10 years. McDuffie earned his bachelor's degree from the University of South Florida in 2006 and is a licensed electrical engineer in four states.

Mat Taylor is a consulting engineer specializing in PV system performance. He has been in the solar industry for more than 20 years and has advanced degrees in engineering and architecture. He has been doing performance-related work for utility-scale EPC and O&M companies since 2008. Taylor works closely with PV AMPS on commissioning and performance-testing projects.

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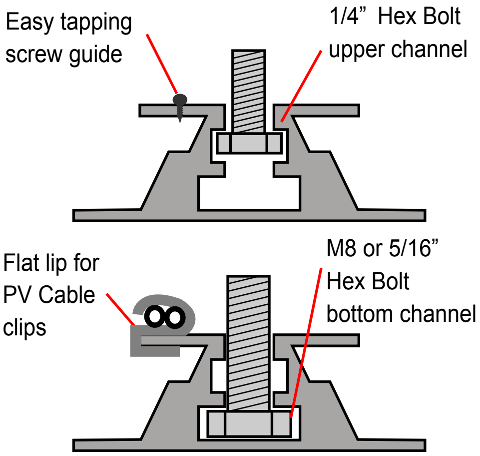
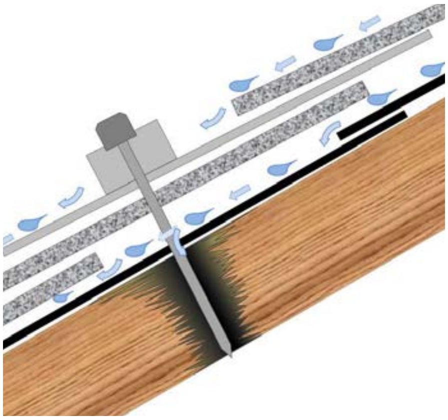


Dual bolt design: M8 or 5/16" for L-Foot & 1/4" for EMC

Metal Flashing Retrofit



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SMA Introduces Next-Generation Monitoring and Control Platform

[Rocklin, CA] SMA's new Data Manager M monitoring and control platform is the result of the company's ongoing development efforts to digitize and streamline commercial energy management. When paired with SMA's new ennexOS-powered web-based Sunny Portal, the Data Manager M allows optimized communication, monitoring and control of decentralized PV systems containing up to 50 devices, and provides an intuitive user interface for system commissioning and operation. The Data Manager M replaces SMA's Cluster Controller. The new platform's modular design and systematic support of industrial standards such as Modbus TCP allows integrators to expand systems with components including I/O systems or energy meters from SMA or other suppliers.

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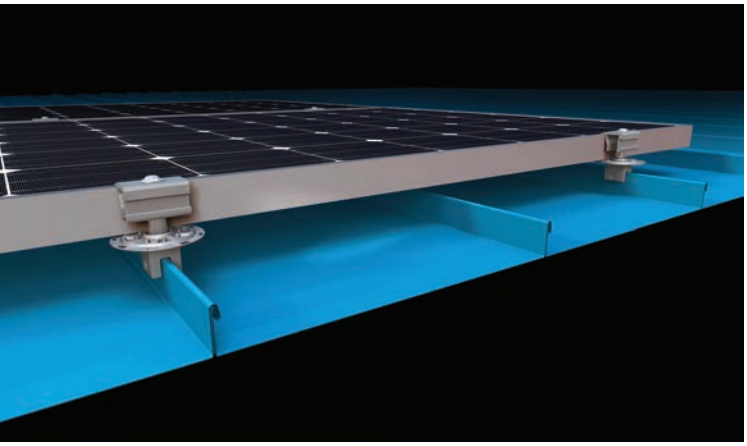
S-5! Releases PV Kit 2.0

[Colorado Springs, CO] S-5! introduced its original direct-attachment PV mounting system in 2007. Its recently introduced PV Kit 2.0 offers design refinements on S-5!'s field-tested railless mounting system. The PV Kit 2.0 includes preassembled EdgeGrab and MidGrab module clamping assemblies that are compatible with all S-5! standing-seam roofing panel clamps and exposed-fastened brackets. Installing PV Kit 2.0 components requires only one tool. The kit creates a 1-inch gap between modules, reducing the load per ASCE-7.

S-5! / 888.825.3432 / s-5.com



Clean Energy Credit Union Launches

[Boulder, CO] Clean Energy Credit Union (CECU), the first institution of its kind in the nation, has officially launched and is now taking savings account deposits and making clean energy loans. CECU is an online-only financial institution that focuses exclusively on providing loans that help people throughout the US afford clean energy products and services such as solar electric systems, electric vehicles, home energy efficiency retrofits, electric-assist bicycles and homes that use net zero energy. CECU's operational model functions exclusively online and via phone, and does not include traditional brick-and-mortar branches. The organization passes the resulting overhead savings to credit union members. CECU will initially offer savings accounts, clean energy CDs, clean energy vehicle loans, PV system loans and green home improvement loans. Starting in 2019, it plans to offer checking accounts, debit cards, credit cards and green home mortgages.

Clean Energy Credit Union / 720.479.7900 / cleanenergycu.org

Simulating *NEC* Voltage and Current Values

The 2017 edition of the *National Electrical Code* introduces alternative methods for deriving maximum voltage and current values for PV power systems. Specifically, new language in sections 690.7 and 690.8 allows licensed professional engineers to use simulation programs to determine these values for PV systems with a generating capacity of 100 kW or greater. In this article, I review the new subsections, provide a detailed case study and consider the potential benefits of calculating maximum voltage or current values based on simulation program results.

Maximum Voltage

The voltage from a PV power source is inversely proportional to temperature, meaning that maximum system voltage is a function of the lowest expected ambient temperature. To account for temperature dependency, since *NEC 1999* section 690.7 has included a table with voltage correction factors for crystalline and monocrystalline silicon modules. Since this table is not module specific, its correction factors are inherently conservative.

To better represent module-specific temperature effects, the *Code*-making panel introduced an allowance in *NEC 2008* allowing for maximum voltage calculations based on manufacturer-provided temperature coefficients. Since the minimum expected ambient temperature for most locations occurs before sunrise, this calculation method is also inherently conservative. (See "Array Voltage Considerations," *SolarPro,* October/November 2010.)

NEC 2017 includes both of these well-known methods: 690.7(A)(1) details the temperature coefficient–based calculation allowance, and 690.7(A)(2) details the table-based correction factor calculation allowance. What is new is the allowance in 690.7(A)(3): "For PV systems with a generating capacity of 100 kW or greater, a documented and stamped PV system design, using an industry-standard method and provided by a licensed professional electrical engineer, shall be permitted."

> *NEC 2017* allows licensed professional electrical engineers to calculate maximum voltage and current values based on simulation program results.

An informational note directs supervising engineers to Sandia National Laboratories' Photovoltaic Array Performance Model. Simulation programs that include Sandia's industry-standard calculation method can calculate maximum voltage while accounting for product-specific temperature coefficients as well as site-specific meteorological data. Engineering calculations based on these modeled results should provide a good representation of the maximum voltage in the fielded array.

Maximum Current

PV source- and output-circuit current are both directly proportional to irradiance, meaning that short-circuit current increases or decreases linearly according to changes in irradiance. To account for the effects of high-irradiance conditions, the *Code*-making panel responsible for *NEC 1999* introduced a 125% solar enhancement multiplier for maximum PV source- and output-circuit calculations. This multiplier is very conservative given that elevated irradiance conditions associated with edge-of-cloud or similar effects are unlikely to continue for 3 hours.

While five subsequent *Code* editions mandated the use of the 125% irradiance multiplier, *NEC 2017* allows for two maximum current calculation methods. 690.8(A)(1)(1) details the traditional method, based on a 125% multiplier, to account for high-irradiance conditions. Alternatively, 690.8(A)(1)(2) allows licensed professional engineers to simulate this value for PV systems with a generating capacity of 100 kW or greater. In the latter case, it says: "The calculated maximum current value shall be based on the highest 3-hour current average resulting from the simulated local irradiance on the PV array accounting for elevation and irradiance. The current value used by this method shall not be less than 70 percent of the value calculated using 690.8(A)(1)(1)."

An informational note directs supervising engineers to the Photovoltaic Array Performance Model and notes that the System Advisor Model (SAM) from the National Renewable Energy Laboratory (NREL) uses Sandia's model. Calculating maximum current values based on simulation program results accounts for system-specific installation variables as well as location-specific weather data. These modeled and averaged results should provide an accurate representation of the actual 3-hour maximum current values in a fielded PV array.

Case Study

Table 1 provides system and component specifications required for

Example PV System Specifications

System overview		Inverter specifications		Module specifications	
Location	Morrisville, NC	Manufacturer	SMA	Model	Yingli YL330P-35b
TMY3 data source	RDU International Airport	Model	Tripower 30000TL-US	Power	330 Wp
Inverter capacity	120.0 kWac	Number of inverters	4	Vmp	37.4 V
Array capacity	125.4 kWdc	Maximum power	30 kWac/each	Imp	8.84 A
Number of modules	380	Output voltage	480 Vac, 3-phase	Voc	46.4 V
Modules per inverter	95	Output current	36.2 A	Isc	9.29 A
PV source circuits	19 modules in series	Maximum dc operating current	66.0 A	NOCT	46°C
Inverter input	5 PV source circuits	Maximum dc input current	106.0 A Isc	TC of Pmp	-0.42%/°C
Array tilt angle	25°	Maximum operating voltage	1,000 Vdc	TC of Voc	-0.32%/°C
Array azimuth	180°	MPPT range	150–1,000 Vdc	TC of Isc	0.05%/°C

Table 1 Detailed system, inverter and module data are required to calculate maximum voltage and current based on simulation program results.

calculating maximum voltage and current based on simulation program results. Figure 1 provides a high-level overview of the basic calculation process. As this flowchart illustrates, I start by entering project data into a system design model. I then select specific model data for post-processing to calculate maximum voltage and current values.

The calculations recommended in this example are appropriate for standard nonconcentrating crystalline silicon PV modules, but may not be appropriate for all module technologies. The *Code* specifically requires that a licensed professional electrical engineer document and stamp these calculations. I recommend further that supervising engineers have training and experience relevant to PV power systems and hold an AHJ-accepted state license.

Generating capacity. The dc side of the example PV system integrates 380 Yingli polycrystalline PV modules, rated 330 W each, into 19-module source circuits; the 20 source circuits are split evenly across four 30 kW–rated 3-phase string inverters, with five source circuits per inverter. A new definition in Article 690 defines the *generating capacity* of a PV power system as "the sum of the parallel-connected inverter maximum continuous output power at 40°C in kilowatts." The example PV system has a generating capacity of 120 kW (4 x 30 kW), which exceeds the $\geq$100 kW threshold in 690.7(A)(3) and 690.8(A)(1)(1). Therefore, the *Code* allows a licensed professional electrical engineer to calculate maximum voltage and current based on simulation program results.

Weather data. Reliable calculations require high-quality data, especially for weather. The example PV system connects directly to the local utility grid in Morrisville, North Carolina, home to the Raleigh-Durham (RDU) International Airport. The National Solar Radiation Data Base categorizes the typical meteorological year 3 (TMY3) data for RDU International (site number 723060) as a Class I dataset, which is the most certain weather data classification. While TMY3 weather data selection is outside the scope of this article, Class II datasets are relatively less certain, and Class III datasets are incomplete. (See "PV Performance Modeling: Assessing Variability, Uncertainty

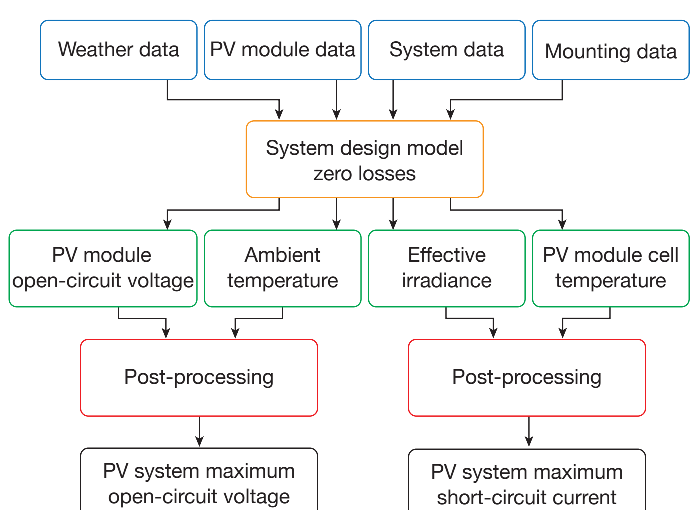


Figure 1 This flowchart provides a high-level overview of the model inputs and outputs and post-processing steps used to derive the maximum voltage and current values.

QA

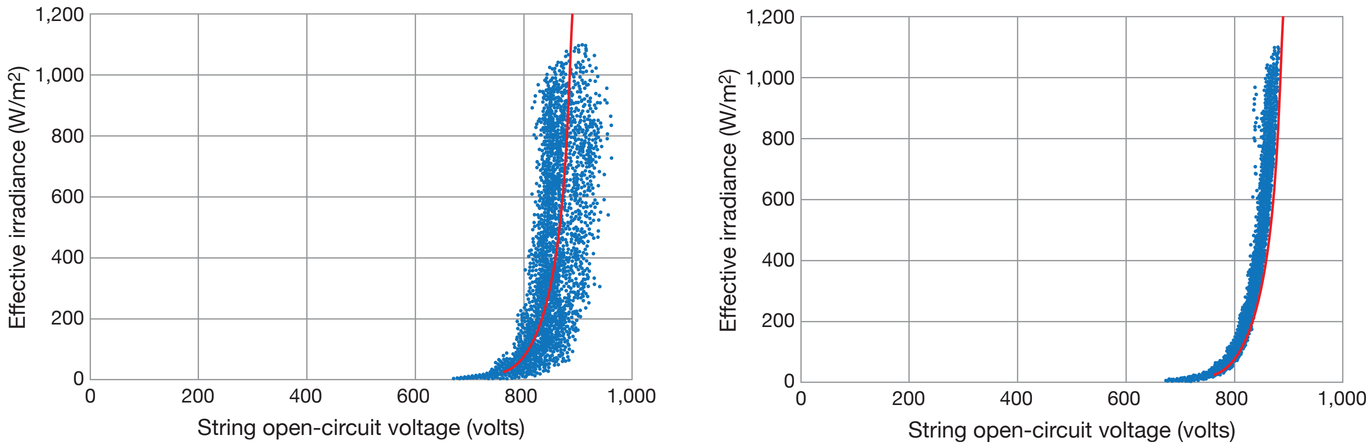


Figure 2 I derived the reference curve (solid line) in these figures by curve-fitting an exponential function to the module test data. While irradiance and Voc plots based on ambient temperature (left) do not match the reference curve, the STC temperature-corrected plots (right) are a good match. This graphical relationship shows that the model-calculated Voc values are reasonable.

and Sensitivity," *SolarPro,* September/October 2015.)

Simulation model. The PV Performance Modeling Collaborative (PVPMC) is an excellent resource for identifying industry-standard calculation methods that meet the new *Code* requirements in 690.7(A)(3) and 690.8(A)(1)(2). For example, the PVPMC website (pvpmc.sandia.gov) clarifies that Sandia utilizes a point-value model that defines five points on an I-V curve and uses these to predict performance as a function of environmental variables. The industry-standard method I used for this example is a single diode–equivalent circuit model known as the *De Soto model* or the *five-parameter module model.* This model can define the entire I-V curve as a continuous function of cell temperature and total absorbed irradiance. The PVsyst module model is another industry-standard single diode–equivalent model.

Modeling tool. PVsyst (pvsyst.com) is perhaps the industry's best-known performance modeling tool , but it is a fee-based platform available only to licensed users. Therefore, I chose NREL's free performance modeling tool for this example, specifically version 2017.9.5, 64 bits, revision 3. Interested parties can download SAM software via NREL's website (sam.nrel.gov).

Model inputs. To input project data, I started a new detailed PV project without the optional financial model. The inputs to the model are organized by input page and include location and resource, module, inverter, system design, shading and snow, and losses.

Location and resource: I specified the weather data by selecting the TMY3 dataset for RDU. In most cases, you will choose a location at or near your site from the solar resource library. If you have a custom weather file, you can upload these data via this input page.

Module: I selected "CEC performance model with user-entered specification" from the menu. This selection allows users to manually enter specific PV module data. The CEC performance model is an extension of the original De Soto five-parameter model, which uses a database of module parameters that the CEC maintains. As such, the CEC performance model meets the *Code* requirement for an industry-standard calculation method. I entered the module specification from the manufacturer's datasheet. To simulate the ground-mounted array, I selected "ground or rack mounted" and "one story building height or lower."

Inverter: I selected "inverter datasheet" from the menu. This allows users to manually enter inverter-specific data. While inverter data are not as important to the results as module data, I recommend using a model that is as accurate as possible. I entered inverter specifications from the manufacturer's datasheet, and I left the inverter losses at the default settings.

System design: I specified an array design with 19 modules per string, 20 strings and four inverters. I modeled the system as a single dc array (subarray 1) with a fixed tilt of 25° and a 180° azimuth. I left the ground-coverage ratio at the default value.

Shading and snow: Since the intent of this exercise is to model the worst-case (maximum) voltage and current, the results should not take any shading or snow effects into account, so I turned all shading and snow input off. With self-shading turned off, factors such as row pitch and ground-coverage ratio are irrelevant to the results.

Losses: The same logic applies to system losses. I set all the loss values to 0%. Ignoring electrical losses and soiling losses ensures that the calculations will return the worst-case design values.

CONTINUED ON PAGE 16

Having set all of the inputs, I saved the project settings, ran the simulation and collected the following data for each hour of the model year: weather file ambient temperature (°C), subarray 1 cell temperature (°C), subarray 1 POA total irradiance nominal (W/m^2) and subarray 1 open-circuit voltage (V). In Figure 1 (p. 13), these are the values in the third row of the flowchart (boxed in green) derived by entering project specifications into a no-loss system design model. Additional data processing is required to arrive at the maximum voltage and current values.

Maximum voltage calculation. To calculate the maximum open-circuit voltage for each hour of operation, I used Equation 1 (see "Post-Processing Equations"), where V_{oc0} is the calculated open-circuit voltage at that hour, V_{ocm0} is the open-circuit voltage from the model for that hour, β_{Voc} is the PV module temperature coefficient of Voc (in this case, 0.32%/C), T_{amb0} is the weather file ambient temperature for that hour, and T_{c0} is the PV module cell temperature from the model for that hour.

Equation 1 corrects modeled Voc values, which are based on module cell temperature, to a Voc based on ambient temperature, the worst-case condition for that hour. After processing the modeled Voc values, I sorted the data to identify the maximum open-circuit voltage for any hour of the year. In this case, the calculated maximum PV system voltage based on simulation program results is 967.5 V. By comparison, the maximum voltage based on the voltage correction factors in Table 690.7(A) is 981.9 V, assuming an extreme minimum temperature of -10.3 °C.

Maximum current calculation. To calculate the maximum short-circuit current for each hour of operation, I used Equation 2 (see "Post-Processing Equations"), where I_{sc0} is the calculated short-circuit current for that hour, I_{SC} is the PV module nameplate short-circuit current at STC (in this case, 9.29 A), E_{e0} is the POA total irradiance nominal from the model for that hour, E_{STC} is the STC irradiance (1,000 W/m^2), α_{Isc} is the PV module temperature coefficient of Isc (in this case, 0.05%/C), T_{c0} is the PV module cell temperature from the model for that hour and T_{STC} is the STC cell temperature (25°C).

Equation 2 calculates the short-circuit value for a given hour based on the POA total irradiance and module cell temperature, which is the worst-case condition for that time. I then calculated 3-hour average short-circuit current values and found the maximum of those 3-hour averages. In this example, the maximum 3-hour current average is 9.95 A. By comparison, the traditional Isc value according to 690.8(A)(1)(1) is 11.61 A (9.29 A × 125%). It is important to remember that the 690.8(A)(1)(2) current value may not be less than 70% of the value calculated in 690.8(A)(1)(1). In this example, 9.95 A fulfills that criterion as it is greater than 8.12 A (11.61 A × 70%).

Validation. I used three basic techniques to validate the output of these maximum voltage and current calculations. First, I verified at each step that the results were reasonable. Second, I changed variables in both the performance model and the post-processing spreadsheet to verify that the outputs changed as expected. This is how I discovered that a no-loss system design model produces the worst-case maximum voltage and current values. Lastly, I used graphical techniques, such as the plots in Figure 2 (p. 14), to verify that the outputs were statistically significant.

Potential Benefits

The engineering analysis in the previous example lowered both the maximum voltage and current values compared to traditional methods. Does this provide any real benefit to the client or project developer? Do the potential benefits outweigh the additional engineering costs? Perhaps not in this simple string inverter–based example, but consider the implications in large-scale PV power systems deployed using central inverters.

In the case study, the new current calculation method CONTINUED ON PAGE 18

Post-Processing Equations

Equation 1:

$$V_{oc0} = V_{ocm0} \times \left(1 + \frac{\beta_{Voc}}{100} \times (T_{amb0} - T_{c0})\right)$$

Equation 2:

$$I_{sc0} = I_{SC} \times E_{e0} \div E_{STC} \times \left(1 + \frac{\alpha_{Isc}}{100} \times (T_{c0} - T_{STC})\right)$$

Engineering analyses allowed under *NEC 2017* can lower maximum voltage and current values compared to traditional calculation methods.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Maximum PV Source-Circuit Current Comparison

The case study illustrates that using the new *NEC 2017* maximum circuit-current calculation method results in a 15.4% improvement in PV source-circuit values compared to the traditional calculation method. Since the 690.8(A)(1)(2) calculation is based on the highest 3-hour current average and irradiance is the primary driver of PV source-circuit currents, maximum current calculations based on simulation results will vary from system to system.

The data in Table 2 illustrate how the percentage improvement associated with the new PV source-circuit current calculation method varies according to location, weather file and array orientation. Some trends are clearly evident in these results.

Location. On average, the percentage improvement is biggest at cold-weather sites. The average benefit (across racking type and weather files) in both Boston and Minneapolis is over 20%, while the average benefit in Phoenix is just 14%.

Orientation. On average, the percentage improvement is biggest in systems with lower tilt angles. The average benefit (across all sites) in dual-tilt (east-west) mounting systems is 21%, whereas the average improvement is just over 15% at a 25° tilt.

Weather data. The percentage difference associated with weather data source is relatively small. On average, satellite-based Prospector data resulted in a 1% improvement compared to ground measurement–based TMY2 or TMY3 data.

In the case of location and orientation, there is a strong inverse correlation between kWh/kWp and percentage benefit. This makes sense because lower total irradiance will typically lead to lower peak irradiance values. Since the rated current is calculated based on the peak irradiance, lower-irradiance systems will get the most benefit from the new calculations.

While this analysis does not include different modules, the results should be relatively agnostic to module selection. The temperature coefficient of current is the only module-specific factor in the calculations. This factor has a small impact on the results in comparison to irradiance.

—Paul Grana / Folsom Labs / San Francisco / folsomlabs.com

Percentage Improvement in Maximum Current

Array orientation	Meteorological data source TMY3	TMY2	Prospector
Phoenix			
25° tilt	10.6%	11.5%	14.3%
10° tilt	12.2%	13.1%	15.6%
E/W tilt	14.9%	14.8%	18.4%
Denver			
25° tilt	14.2%	13.4%	13.5%
10° tilt	16.4%	16.2%	16.0%
E/W tilt	18.9%	19.3%	18.6%
Raleigh-Durham, NC			
25° tilt	15.4%	16.5%	17.1%
10° tilt	18.6%	18.0%	19.3%
E/W tilt	21.4%	22.3%	22.2%
Minneapolis			
25° tilt	17.0%	15.9%	17.1%
10° tilt	19.5%	19.0%	20.5%
E/W tilt	23.7%	23.5%	24.8%
Boston			
25° tilt	18.6%	18.0%	18.3%
10° tilt	19.8%	20.0%	21.3%
E/W tilt	23.9%	23.9%	24.6%

Courtesy Folsom Labs

Table 2 This table summarizes the percentage difference in the maximum current calculation result using 690.8(A)(1)(2) rather than 690.8(A)(1)(1) based on location, weather data source and array orientation.

reduced the maximum PV source-circuit current from 11.61 A to 9.95 A, which is a 14.3% reduction or a percentage difference or improvement of 15.4%. In a central inverter–based system, this lower current value could result in a design that requires fewer combiner boxes. In some scenarios, these reduced string-current values could produce cost savings for parallel circuit array harnesses and custom homerun harnesses. As systems scale, these balance of system cost savings add up and offset additional engineering costs.

There may be instances where the ability to add a module to a PV source circuit results in a design that improves overall system economics. However, from a financial performance perspective, improvements in source-circuit current values are likely a more interesting avenue of exploration and optimization. The maximum current comparison sidebar above illustrates how these improvements will vary predictably based on project location, weather data source and mounting details. These data will help project stakeholders identify opportunities for design optimization based on PV source-circuit current improvements.

—Charles Ladd, PE / Ecoplexus / Durham, NC / ecoplexus.com

Achieving Commercial Operations in Large-Sc PV Power Systems

By Anastasios Hionis, PE and Mat Taylor

Courtesy Recurrent Energy

The common goal of PV industry stakeholders is to deliver high-quality, reliable energy assets. But do planning and testing methods support this goal?

A PV project's transition from the construction phase to the operations phase is a flurry of activity. Project stakeholders must coordinate schedules, materials, trades, troubleshooting and testing while adhering to design documents, contractual requirements and project milestones. As such, the sprint to achieve commercial operations is a busy time with many challenges. The shared goal is to get the project to the commercial operations date (COD), the point at which the asset begins to generate revenue.

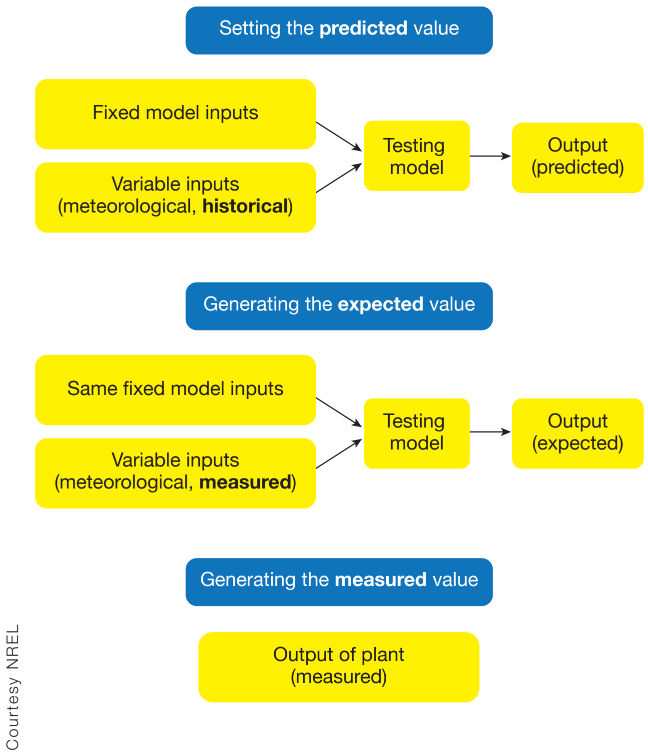
As independent engineers, we work alongside all of the project stakeholders—owners, financiers, and EPC firms—to help steward large-scale PV projects to the finish line, the COD milestone. We have participated in projects where partners from all trades and disciplines walked away with a profound feeling of satisfaction. We have also seen some unmitigated disasters, which left all project team members frustrated and at significant financial risk.

The worst-case scenario is when a project falls short of its performance test goals and the remedies are not readily apparent. This performance-related impasse is a precarious place to be at the end of a project. The resolution usually takes place at a conference table—or, worse, in a room full of lawyers—and involves discussions of liquidated damages. When projects get to this point, there is little that we as independent engineers can do to solve the problems. This article's goal is to help you avoid such an impasse.

Here we share lessons learned from our project completion experiences, both good and bad, and our recommendations for a more elegant path to commercial operations, one that starts with the performance-test milestone in mind. While there are many possible paths for getting a project into operation, we frame our discussion around performance testing because this is the last big step before a PV project achieves COD. Our experience is that a collaborative and transparent performance evaluation process that fairly allocates risk delivers high-value PV assets while minimizing conflict and financial risk. While we are not contending that an open project–delivery model eliminates problems, we can certify that it solves problems much faster than more antagonistic approaches.

Performance Testing

The goal of performance testing is to benchmark system performance against a set of contractually mandated performance parameters such as system capacity, efficiency (performance ratio) and energy yield over time to ensure that a PV asset will meet owners' performance and financial expectations. A successful performance testing process saves time, money and resources. It also provides valuable baseline information for ongoing operations. (See "PV System Energy Performance Evaluations," *SolarPro,* October/November 2014.)



Performance testing Acceptance tests compare predicted, expected and measured performance to demonstrate proper installation and operation and to reassure investors.

Unrealistic expectations—often based on proprietary energy models, weather data files and evaluation tools—are the most common cause of end-of-project delays. For example, we have been involved in projects that stretched performance expectations for every subsystem to their physical limits, tacitly requiring chronic overperformance to achieve a passing evaluation.

Performance testing is especially onerous when the terms and conditions effectively require that all subsystems must perform at or above expected efficiency; module capacity must exceed nameplate power ratings; modules must be perfectly clean for the duration of the test; dc, ac, inverter and transformer losses must be at or below expected levels; and, most problematically, all measurements must be perfectly representative and accurate with no uncertainty. These requirements are not an exaggeration, but rather an example of what happens when one party dictates all contractual testing and completion terms.

The scramble to meet a nearly unattainable goal is unbelievably expensive. One-sided terms are a setup for disappointment and contribute to an antagonistic project delivery model that we believe is both counterproductive and avoidable. Unreasonable or unattainable goals do not improve system performance.

CRITICAL NEGOTIATIONS

Having sat on all sides of the negotiating table when COD was looming, we are strong proponents of an open performance-evaluation model based on mutually agreed upon expectations and a reasonable assignment of risk. It is possible and, indeed, preferable to navigate commissioning, start-up, testing and project completion in a way that is acceptable to all interested parties; that facilitates and expedites final payments; and, most important, that provides a detailed characterization of expected plant behavior. A process built around mutual agreement and consent best serves this outcome.

Once you have assembled a project team, it is critically important for stakeholders to engage in a candid discussion of performance test methods, objectives and constraints. These early planning decisions will guide the team members during project development and construction through the COD milestone. The below topics always come up during the project testing phase and invariably cause problems when team members have conflicting expectations. We recommend discussing these subjects at project inception, establishing clear rules and contractual definitions, and revisiting the plan often.

Testing model. It is essential for team members to develop an energy model specifically for the performance test. The testing model will be similar to the accepted annual energy model, but it will be tuned to reflect the expected conditions at the time of testing. Develop a testing model that reflects contractual obligations above all else, meaning that contract language and terms should inform the modeling assumptions and performance risk allocations. The testing model must be dynamic and able to adapt to changes in design, implementation, testing methods and site conditions.

Uncertainty. All operational measurements have uncertainty, and the performance testing process must acknowledge this fact. Ignoring or negating uncertainty fails to allocate risk equitably. The argument that measurement uncertainty "can go either way" only applies if the installing contractor is contractually incentivized for performance in excess of 100%. As a starting point, we recommend estimating measurement uncertainty at 2%. Team members can revise this value after finalizing equipment selection and completing the performance test plan.

Module output. Assign the risk associated with increased nameplate power ratings to whichever party buys the PV modules. If the installing contractor procures the modules, then it can dictate how much positive power tolerance it will backstop. If the owner buys the modules, the installing contractor has no recourse in the event that the project does not realize an expected increase in power; in this scenario, it may not be appropriate to include CONTINUED ON PAGE 24

assumptions of positive power tolerance in the performance evaluation model.

Soiling. The possibility of zero percent soiling is a myth, especially in the context of long-duration performance tests. Contracts for performance testing must include a soiling allowance in some form, through either direct measurement at the time of testing or a reasonable estimate based on the wash cycle prior to testing. Reliably assessing soiling at the time of testing dramatically improves troubleshooting efforts and investigations of performance shortfalls. (See “Soiling Assessment in Large-Scale PV Arrays,” *SolarPro,* November/December 2016.)

Loss models. AC loss, dc loss, transformer efficiency and inverter efficiency assumptions mature over time. Any model used for performance evaluation must evolve as the team better quantifies these values through design, equipment selection and installation. Equipment test sheets, particularly for transformers, are a good source of the data. When modeled and measured quantities diverge during testing, you can usually trace the root cause back to unrevised model assumptions that made their way to the testing phase.

Test methods. We strongly recommend using unmodified, standard test methods and shared evaluation tools. For example, the American Society of Testing and Materials (ASTM) has published a PV performance test standard (ASTM E2848-13) and the International Electrotechnical Commission (IEC) has published a suite of technical standards for PV system performance monitoring (IEC 61724-1), capacity testing (IEC 61724-2) and energy yield evaluation (IEC 61724-3). Testing methodologies based on technical standards are inherently an open-book approach. Energy models, input assumptions, performance targets and evaluation methods should follow suit. Using intellectual property claims to hide evaluation test methods is a weak argument at best. There is nothing inherently secret about a spreadsheet tool. Our view is that any party at risk during the testing process has a right to review the performance assessment methodology.

Transparency. It is impossible to overstate the importance of transparency. To set up a project for a successful closeout, all project stakeholders need to understand the performance testing process long before testing takes place. Black boxes do not encourage cooperation or help characterize measured performance. Using opaque evaluation methods with propriety module files, meteorological data, inverter models or ac loss models invariably causes problems. If there are no secrets, there are no surprises.

Courtesy Recurrent Energy

Soiling losses It is important that long-duration performance test results account for soiling effects, based either on site-specific soiling measurements or soiling buildup rate estimates.

The following are guidelines to help ensure an equitable performance test process, free of misunderstandings, that enables ongoing operations:

- Create and maintain a project closeout team that can meet as necessary during testing to solve immediate problems. The team should consist of knowledgeable members representing the EPC team, supervisory control and data acquisition (SCADA) integrator, owner, owner's and EPC's engineers, inverter vendor and tracker provider (if applicable).

- Ensure that project team members have access to any information relevant to system commissioning, including array test reports, inverter burn-in test results, module flash test data and manufacturer start-up test reports.

- Use a dedicated performance testing energy model that represents site and plant conditions at the time of testing and incorporates simulation assumptions and parameters mutually derived by the owner, builder and performance engineering personnel.

- Share all the testing model inputs and outputs—including module files (.pan), inverter files (.ond), shading files (.shd), meteorological files (.met), hourly output data files (8,760 exports) and test target derivations (typically spreadsheets)—and performance test evaluation methods.

- Establish standard testing data downloads that all stakeholders can access.

While this degree of transparency is a departure from convention, we have found that it really works. Sharing the means and methods for testing essentially enlists a team of troubleshooters—an extremely valuable tool—to expedite test and project completion. In the words of one owner: "When we all work together, we have fewer fingers pointing and more fingers fixing."

TEST PREPARATION

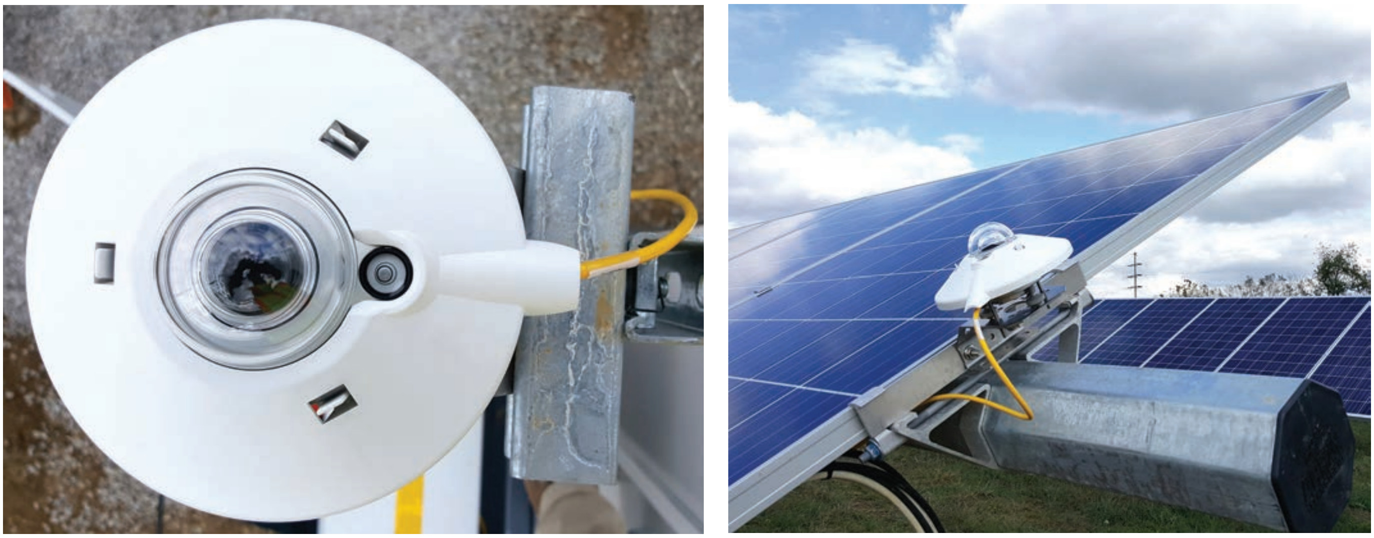
Planning for commercial operation starts with a thorough understanding of the contract and performance test requirements. These requirements inform the strategy that project stakeholders use to prepare project documentation, evaluate SCADA requirements, specify and install measurement devices and validate sensors. To the extent that the leadership team understands the deliverables in advance, it can have all the documentation and requirements ready for the field team. This guidance ensures that the project team installs the system correctly the first time and accurately documents key information in the process.

Test implementation starts in the back office, with the procurement of the data acquisition system and measurement devices, and continues in the field as the project nears mechanical completion. These general steps in the process can easily mature into a working, dynamic checklist.

Precommissioning. During precommissioning, assemble a dedicated team, representing all the relevant project stakeholders, to lead the performance testing process. As a team, generate the documents needed for performance testing; create a testing model that is separate from the yearly model; and determine the plant-testing configuration, reporting conditions and targets. Next, review the SCADA and sensor installation plans and specifications to make sure these meet the requirements of the performance test standard. Verify the data collection rate and list of data points for the test. Coordinate with the field crew to document inverter and subarray mapping, and validate input channel labeling and reporting.

Start-up and commissioning. Since the activities in this step start the countdown to project completion, it is important to coordinate with all the stakeholders and set the dates and schedule for performance testing. At start-up, commission and validate the SCADA system and sensor accuracy. Next, troubleshoot the inverters and field wiring. Conclude with a final commissioning to close out any punch-list items, run practice tests, validate performance evaluation tools and verify data streams.

Performance testing. Once everything is working, the project team can determine the start and stop times for



Courtesy PV AMPS

Pyranometers Performance test results are especially sensitive to irradiance sensor measurements. For accurate results, install GHI sensors (left) with the bubble centered in the bubble-level window and POA sensors aligned to the array.

the performance test. As data come in, run the analysis, disseminate the data sets, compare evaluations and determine test results. Given decent weather, a transparent process and reasonable parties, you will obtain definitive results: The project will pass or the cause of failure will be clear, and the team can try again after fixing the problem.

Project finalizing. Once the plant passes, the team can finalize the project test results, document the process, develop a baseline performance model for the plant and assemble a final punch list for completion. Organized and meticulous documentation at this stage is critical if the project is to achieve sign-off for commercial operations. This documentation also provides the site records that the owners, asset managers, system auditors and operations teams will rely on in the years to come. Most important, good documentation saves everyone time and money.

DOCUMENTATION

High-quality documentation facilitates future transactions and forms the foundation for successful operations. With a standards-based performance test process, end-of-project documentation provides a baseline for benchmarking system performance against other assets in an owner's portfolio, informs the operations and maintenance bid, and serves as a starting point for the plant evaluation documentation required when the asset is sold. Think of the standards-based performance test documentation as a factory acceptance test certificate for a fielded PV power plant. Without proper documentation, the asset is more difficult to maintain and sell for a high price because there is no proof that the site performs as expected.

At the precommissioning stage, it is useful to create a commissioning folder prepopulated with relevant forms and lists of required information. As the project approaches completion, this folder becomes a central repository for all of the documents and data that the project team will pass on to the owner and operations team. At project closeout, this folder should include the following:

- Contracts and addenda related to the performance test
- Test model, including descriptions of inputs, all assumptions and detailed output
- Performance test technical standards
- Performance test workbook with open-source evaluation methods and formulas
- Combiner box as-builts identifying string counts, physical locations and names
- Detailed map of inverters, combiners and current measurement channels
- Datasheets and calibration certificates for all equipment
- Plans and documents required for correct sensor installation
- SCADA platform permissions and log-in information
- Functional testing checklist and test results
- Mechanical completion certification and substantial completion forms
- Form for permission to operate, as well as other COD forms and requirements

Knowing what deliverables you need at project closeout is crucial to identifying and collecting the information and documentation for each successive step. Anyone who has gone through project closeout knows that proper documentation is conducive to a smooth and orderly process, whereas incomplete documentation results in a scrambling series of fire drills that waste time and resources.

Identifying string outages, for example, is a labor-intensive process unless you have accurately mapped the path of the combiner box wires to the inverter input channels. If you do not properly identify and map data points in the SCADA system, operations personnel cannot use the monitoring system to identify missing string inputs remotely. To obtain this information before energizing the plant, the project team needs to ensure that field personnel fill out forms documenting as-built field wiring conditions, and then pass the completed forms on to the SCADA vendor. If the team fails to do this work in advance, technicians can waste an entire day in the field as they will have to shut down each inverter in succession to document the wiring.

It is important to assign meaningful sensor names to aid with troubleshooting activities in both the near term and the future. Proper documentation also extends to naming conventions in the SCADA interface, as well as the labels inside equipment boxes. Since underperformance investigations typically start in the SCADA portal and lead to the field, we recommend assigning descriptors that identify the inverter, combiner box and string count. With a standard naming convention in place, performance analysts and service technicians can look at a label such as “02-04 [22]” and know immediately that there are 22 strings on combiner box 4 of inverter 2. This encoded information is useful for repairing problems or identifying any changes in field conditions after commissioning.

NO DATA, NO DICE

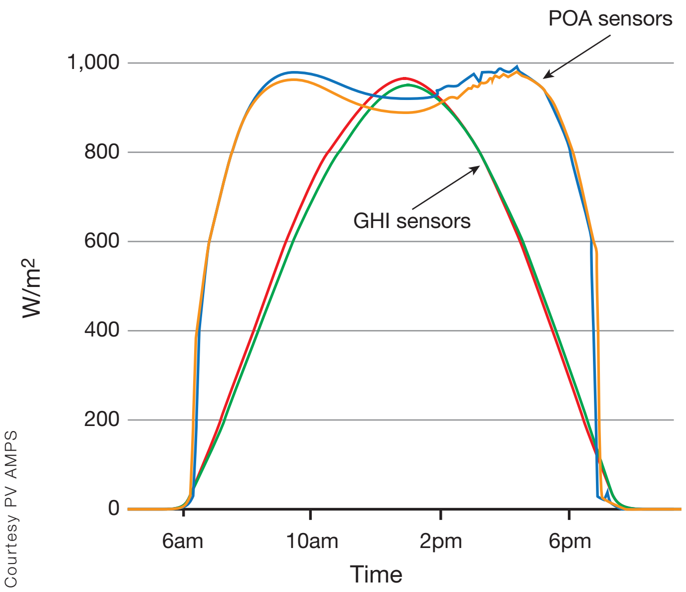
Proper planning, installation, commissioning and validation of the SCADA system and its meteorological sensors are essential to bringing a project to a successful close. Early in project development, the project team must discuss SCADA specifications and the associated design and installation details. Gathering this information cannot be an afterthought, as data acquisition is the single most decisive factor in the performance test outcome, pass or fail. To close the project out, the SCADA system needs to not only meet utility requirements, but also fulfill any contractual obligations related to performance testing. (See “SCADA Systems for Large-Scale PV Plants,” *SolarPro,* May/June 2017.)

The SCADA vendor needs to field the right gear and specify the proper data collection rate. To get meaningful values, the system should have the ability to roll up multiple data points per test interval. For example, if the performance test calls for 1-minute data sets, then the data-polling rate might be set for 5 seconds. Coincident measurement is key to accurate, high-resolution performance analysis; the faster the data collection rate, the more measurement coincidence matters. Some SCADA systems do not sync time stamps to a network clock or GPS, thereby calling measurement simultaneity into question. SCADA providers must be aware of these types of test requirements, both explicit and implicit.

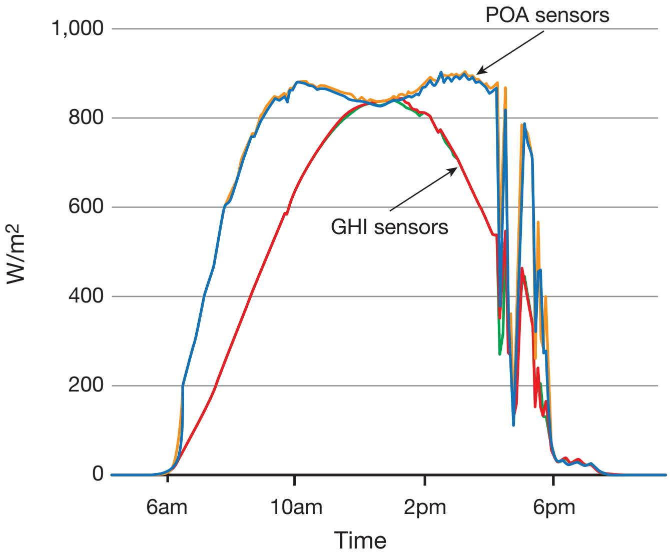
The details matter most when it comes to installing the monitoring system so that it properly reports field conditions. A correctly installed system allows remote troubleshooting and expedites the process of identifying and resolving problems. At the end of a project, this efficiency can save a lot of labor costs and shorten the schedule. More important, the system will produce data that represent the installed system, allowing it to pass the performance test with indicative results.

Performance assessment, whether at the time of testing or in operation, directly depends on reliable, accurate measurements of primary data. The team must install sensors correctly and validate, cross-check and correctly map them in the SCADA. The testing protocol will dictate the primary measurement sensors, which typically include irradiance sensors, power meters and temperature sensors.

Irradiance sensors. Pyranometer installation errors are the most common cause of perceived performance problems. As an example, imagine a north-sloping tracking array that uses plane-of-array (POA) irradiance sensors leveled to



Sensor alignment In the figure on the left, data from two GHI and two POA irradiance sensors do not agree at solar noon. The figure on the right shows the same data feeds after technicians have carefully aligned the four sensors.



a horizontal axis rather than aligned to the axis of the modules. In this scenario, the array is canted away from the sun, but the POA sensor is not. As a result, the performance test results will tend to incorrectly indicate that the system is underperforming, especially if the energy model assumes a perfectly flat site. While the energy model and sensor placement will match up well, neither will match the as-built condition. This seemingly small difference in modeled and measured conditions will likely result in an inaccurate evaluation of the system as underperforming.

Energy test results are especially sensitive to irradiance data. If you do not install a POA irradiance sensor at the same angle as the array, the resulting measurements will not accurately reflect module orientation. Similarly, if you do not make sure the bubble level is centered in the level window on a global horizontal irradiance (GHI) sensor, the accuracy of these data will suffer. It is easy to overlook small alignment issues, but they can have a large impact. Misaligned pyranometers are sometimes the source of hard-to-diagnose errors that can lead to performance test failures. Fortunately, a field team can easily identify and correct these problems using digital levels and careful measurements to properly adjust sensors.

POA irradiance, because it directly affects output power, is perhaps the single most important parameter to verify and capture as accurately as possible. For best results, irradiance sensors must be stable, firmly mounted and easy to adjust. A great way to accomplish this is to mount pyranometers to a rigid object using an adjustable bracket. After verifying that you have firmly mounted the pyranometer to the bracket, you can make final adjustments to the sensor orientation. Multi-direction adjustable brackets with leveling screws make it easy to perform fine adjustments quickly, which not only reduces labor costs but also improves job site safety by minimizing the time a technician spends on a ladder.

Because irradiance measurements are so important, we suggest installing at least two sensors for redundancy and using additional sensors as appropriate in larger systems. In addition to providing redundant data streams, the extra sensors allow project stakeholders to compare measurements from multiple sensors, which will either improve confidence in the values or identify possible outliers. With single-axis trackers, it is particularly important to verify that the POA and GHI sensors agree at solar noon. Validating this one item answers three important quality assurance questions: Is the SCADA system scaling the POA and GHI measurements correctly? Are the POA sensors installed correctly? Is the tracker functioning properly and at the right angle (0°) at solar noon?

Power measurements. While testers typically assume that utility meters, check meters and inverter output data are accurate, that is not necessarily the case. To ensure appropriate readings, it is important to understand power measurement accuracy parameters and multi-measurement accumulation (roll-up) methods, as well as validate meter programming. If the SCADA provider has not worked with a particular meter before, ask its team to exercise due diligence in advance so it does not waste time in the field when the clock is ticking.

Temperature sensors. While temperature measurements tend to be accurate, their use in performance evaluation is tricky. It is important to select temperature sensors and placement locations that capture measurements representative of the array at large or a specific subset thereof. Unrepresentative measurements will skew performance evaluation results, in some cases significantly.

Ambient temperature measurements tend to be very accurate and reliable if the team takes care to install the sensors correctly. By comparison, back-of-module (BOM) temperature measurements do a poor job of representing the entire array. The attachment method, sensor location on the module and module location within the array all affect temperature measurements taken on the back of a module.

Under most environmental conditions, BOM temperature measurements do not represent the array at large. As a result, you must translate these values to derive a cell temperature value, modified by a reported ΔT (temperature difference) condition; translate them again to derive thermal loss or gain based on documented module performance parameters; and, finally, extrapolate them to an effective output power value. Each step in this process introduces uncertainty and room for error.

Thermal loss models for PV arrays based on BOM temperature measurements are in no way mature enough for teams to use for performance testing evaluations where a tenth of a percent difference translates to hundreds of thousands of dollars. While some independent engineers, developers and owners still ask for BOM measurements, you should avoid performance evaluations that use BOM temperature as a primary measurement. To lower uncertainty and reduce the complexity of data acquisition and analysis, the working groups responsible for performance test standards such as "ASTM 2848-13: Standard Test Method for Reporting Photovoltaic Non-Concentrator System Performance" have written BOM measurements out in favor of ambient temperature measurements.

In the event that contract terms require the project team to use cell temperature values derived from BOM sensors as the basis for performance testing, team members need to have a detailed discussion about the associated risks and implications. It is certainly possible to address the uncertainty this practice builds into the test protocol. The project team just needs to make sure to do so, as this is sometimes overlooked.

Strategies for Success

While we recognize that project team members may need to deviate from their conventional delivery models to accommodate the performance testing means and methods we have described here, our experience shows that such deviation is both necessary and beneficial. Although the solar industry has rigorously optimized system design, engineering, procurement and installation via iteration and continuous improvement, the performance testing process remains relatively immature and is ripe for development.

We have based our perspective on project closeout on the testing and commissioning problems our clients have encountered in the real world, as well as on our (sometimes limited) ability to identify root causes and solutions. While contract closeout problems are unpredictable and usually very complex, our experience is that hard work and high-quality data analysis can solve most of these issues. With adequate monitoring and commissioning documentation, a project team can investigate, diagnose and correct the majority of performance shortfalls within the timeframe of the project schedule. The following is a summary of project closeout practices that have worked well for us.

Say no to secrets. We strongly advocate an open and transparent project delivery model, in which the team shares energy models, design documents, testing target, evaluation methods and commissioning reports. While this approach may not be right for every team, all parties need to recognize that any insistence on secrecy or confidentiality introduces risk. Secrecy impedes troubleshooting. It is a risk to propose keeping other stakeholders in the dark or to accept this secrecy. A transparent and collaborative testing and closeout process works well precisely because it allows the team to find solutions more quickly.

Centralize data. Create a central repository for all relevant project information. This data center should contain any resources that affect, inform or influence performance testing and project closeout. As a general rule, the data center should contain all the information a completely uninformed third party would need to validate or conduct performance testing from scratch without help. This information archive should include commissioning data, testing model, target results with derivations, test evaluation tools, unrestricted access to operational data downloads and backup data for troubleshooting.

Establish a tiger team. Assemble a group of smart people from multiple disciplines to shepherd the project from inception to closeout. The configuration of this team will evolve as the project matures. At the time of performance testing, the closeout team should include agents representing the owner, EPC firm, SCADA provider, inverter supplier, independent engineering providers, design engineering team and party responsible for energy modeling. This team of experts will meet on an as-needed basis during the project development process and on a daily basis during the big push to complete performance testing. Membership continuity is critical to the team's success. It is also important to keep all team members fully informed at every step of the process.

Ready triage teams. Closeout team members must assure they have adequate backup resources available for problem-solving and troubleshooting. It is especially important to have a backup squad available during the run-up to the performance tests, as projects approaching COD cannot wait for a given vendor to assemble an ad hoc squad to solve problems. It is the direct responsibility of each closeout team member to ensure that he or she has the right engineers, programmers or field personnel available at the time of the performance evaluation test.

Courtesy Revision Energy

Documentation
To build a foundation for successful operations, create a central repository for project information and carefully map, identify and label components in the field, as well as monitoring system inputs.

Conduct preliminary tests. While project schedules often omit this step, it is critical for success. Come test time, everything has to work reliably, accurately and simultaneously. A single stakeholder running behind schedule will delay the test schedule. One wayward sensor will jeopardize the accuracy of the performance evaluation. The failure of any major component will invalidate the test results. These examples illustrate why it is essential to have triage teams at the ready. Conducting a preliminary test run—or a series of runs, if necessary—can potentially save weeks by obviating test period extensions. Preliminary test runs eliminate nuisance problems, provide a forum for multi-disciplinary validation of system operation and significantly speed up the formal testing process.

Keep all eyes on the prize. At the time of testing, the closeout team should meet every day to evaluate preliminary test results, troubleshoot problems and validate operational information. Problems are easy to identify and solve when you make data sets available to all participants, who bring different points of view to bear on the issue. This is the greatest advantage of the process and the most useful part of the open approach to testing. When you have a team of experts dedicated to making a system work, amazing things happen.

Strive for consensus. Those who are used to more-hierarchical methods of project delivery sometimes deride consensus methods as "group therapy." Our response is simple: What is wrong with group therapy? We all know that things can and do go wrong. Some schedules will slip. Some system will underperform. Some liquidated damages will require negotiation. But these risks are independent of delivery method. The thing we should be concerned about is how we are going to work through these problems. If we all work together, we can fix problems faster, and we can all take pride in a job well done. The overarching goal—and the likely end result—of the open project–delivery process is a shared sense of accomplishment when the project reaches COD.

With mutually agreed upon assumptions, models and test methods, each team participant can revisit individual processes based on testing outcomes. The owner and developer can apply results to future projects and adjust business models accordingly. EPC teams can perform subsystem analyses to better predict under- or overperforming systems. Independent engineers can review and analyze reliable data sets. Regardless of any individual outcome, the information gathered from an open testing process is valuable for everyone involved, especially future owners and operators. There is no better foundation for long-term viability than an asset that is fully documented and complete when it enters commercial operations.

CONTACT

Anastasios Hionis, PE / PV AMPS / Sacramento, CA / stas@pvamps.com / pvamps.com

Mat Taylor / PV AMPS / Paradise, CA / mat@pvamps.com / pvamps.com

Distributed Energy Resource Optimization

By Tim McDuffie, PE

At the beginning of a solar project, every customer or potential customer asks two fundamental questions: How much is the system going to cost? How long will it take to complete the project? To their credit, most solar developers do everything in their power to paint an accurate picture of interconnection costs and construction schedules. However, two major variables get in the way of that effort: the utility review and the interconnection timeline.

As I explained in a previous *SolarPro* article, "Distributed Energy Resource Saturation" (July/August 2017), the solar industry has no tool at its disposal to provide any real certainty surrounding the scope, cost and time frame of utility upgrades. The reality is that it could take 60 days or 2–3 years. The cost of the upgrades could be nothing or could be $2 million. The developer will not know for sure until completion of the utility interconnection study. These wide ranges of uncertainty do not help with financial planning, especially when a client is looking to secure financing for project development.

Here I elaborate on the distribution planning tools that stakeholders in California are developing to streamline distributed energy resource (DER) interconnections and proactively identify optimal locations for DER deployment. The days of anxiously waiting for the Rule 21 process to run its sometimes excruciatingly long course may soon become a thing of the past because of the keen foresight of California's Distribution Resource Plan working group. It seeks to expedite review timelines based on proposed DER interconnection locations and establish a mechanism for assigning the real avoided utility-upgrade cost associated with these interconnections. For many solar industry stakeholders, the development of these new tools is very welcome news. Furthermore, the distribution resource plans developed in California will likely serve as models for future DER integration throughout the US—and perhaps even in other parts of the world.

The way that utilities study distributed energy resource interconnections in California is about to change dramatically. Depending on whom you ask, this has the potential to be a good thing—or a great thing.

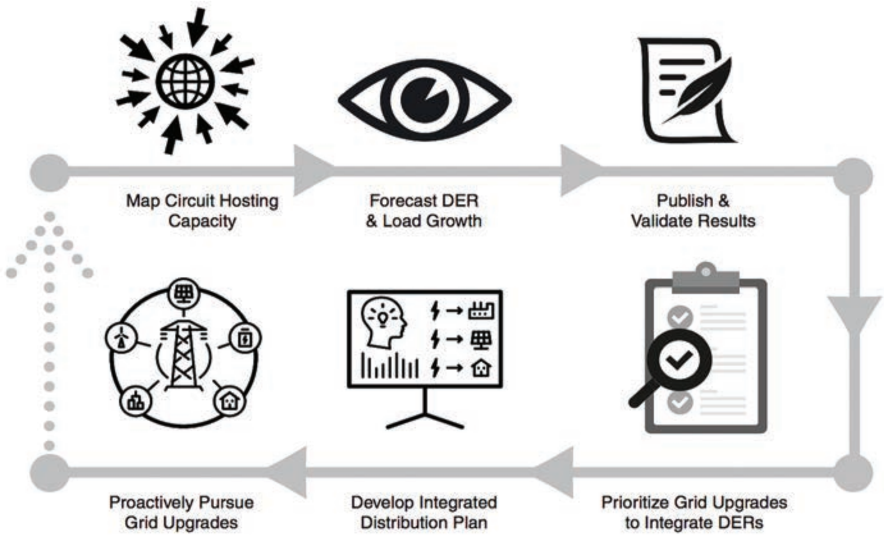
Distribution Resource Planning in California

In October 2013, Gov. Jerry Brown signed Assembly Bill 327, the net metering and rate reform bill, into law in California. Section 8 established Public Utilities Code Section 769, which requires investor-owned utilities (IOUs) to develop distribution resource plans identifying optimal DER deployment locations. The California Public Utilities Commission (CPUC) initiated the process for these plans in August 2014 and issued a ruling in May 2016 establishing the Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA) working groups, comprised of stakeholders representing the IOUs, the DER industry and ratepayer advocacy groups. While there is synergy between the two working groups, they serve different functions with regard to streamlining and promoting DER integration. The goal of these efforts is to move from a reactive distribution planning process with minimal transparency and public involvement to a proactive integrated distribution planning process, as illustrated in Figure 1 (p. 36).

INTEGRATION CAPACITY ANALYSIS

As detailed in the final ICA working group report filed on March 15, 2017 (see Resources), there are two primary use

Courtesy Recurrent Energy



Courtesy IREC

Figure 1 This figure from the Interstate Renewable Energy Council's "Optimizing the Grid" report (see Resources) illustrates the basic components of an integrated distribution planning process, which can allow utilities to proactively respond to new conditions associated with scenarios such as distributed solar, dispatchable energy storage or demand-response technologies.

cases for the ICA: "The first and most developed use case… is to improve interconnection, which includes a more automated and transparent interconnection process and the publication of data that helps customers design systems that do not exceed grid limitations. The second and currently less developed use case…is to utilize the ICA to inform distribution planning processes to help identify how to better integrate DERs onto the system." The first use case is most relevant to solar industry stakeholders in the short term.

Intent. Interconnecting DER in California currently is a bit like playing Minesweeper on a PC from the early 1990s, which involves a fair amount of guesswork. You might pick a good square (interconnection location) and open up half the board, or you might hit a mine that ends the game (kills the project). The ICA working group seeks to transform this game of chance into a predictable process by identifying optimal locations for solar development and quantifying the available interconnection capacity well before submission of an interconnection application. Consider that it currently takes at least 110 business days to complete a detailed interconnection study under California's Rule 21 engineering review process. The ICA process, in contrast, will effectively run a detailed study for every node of an IOU's grid on a monthly basis.

Brad Heavner, the policy director for the California Solar and Storage Association (CALSSA, formerly the California Solar Energy Industries Association), notes, "If the ICA is successful in making project development go smoother, it will avoid the many cases where customers are paying financing costs while interconnection delays keep them from achieving bill savings. Happier customers should lead to more business for solar developers." He adds, "The ICA will not lead to an overall increase in hosting capacity throughout the state. Rather, we will know ahead of time what the available interconnection capacity is in any location."

It is tempting to draw parallels between the ICA and the Renewable Auction Mechanism (RAM) program maps the CPUC has made available for several years now. However, there are several key differences. RAM maps are not connected to the Rule 21 tariff in any meaningful way, so there is no guarantee that the hosting capacity indicated in a RAM map will hold true when a project enters the Rule 21 process. In addition, the RAM maps are very broad and only illustrate capacity at the feeder level based on very conservative rules of thumb. Having run into these limitations on several occasions, I and many other stakeholders have abandoned using the RAM maps altogether.

The ICA approach is different. Because IOUs will use ICA results to fast-track existing Rule 21 tariff screening procedures, the hosting capacity values will be much more accurate. In addition, the ICA methodology is far more comprehensive than that used to produce RAM maps.

Heavner explains, "While the theory behind RAM maps is good—showing circuits as red, yellow or green depending on their hosting capacity—the maps have been so inaccurate and out of date in practice that they are barely useful. The ICA takes the theory behind RAM maps and does a much better job in practice by conducting a functional analysis with monthly updates. The analysis will not only be baked into the interconnection application process, but also the maps will include downloadable data on hourly and seasonal constraints."

Demo A. The Distribution Resource Plan working group mandated that all three IOUs in California test and demonstrate two methodologies—a streamlined method and an iterative method—for development of the ICA tool. On the one hand, the streamlined approach uses complex computer algorithms to draw conclusions on DER hosting capacity at specific points within the IOU's system. On the other, the iterative approach simulates power CONTINUED ON PAGE 38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flows based on different DER levels at each node on the distribution system. As the CPUC mandates, the IOUs executed Demonstration Project A, or simply Demo A, with the goal of developing a common ICA methodology that works across all utilities.

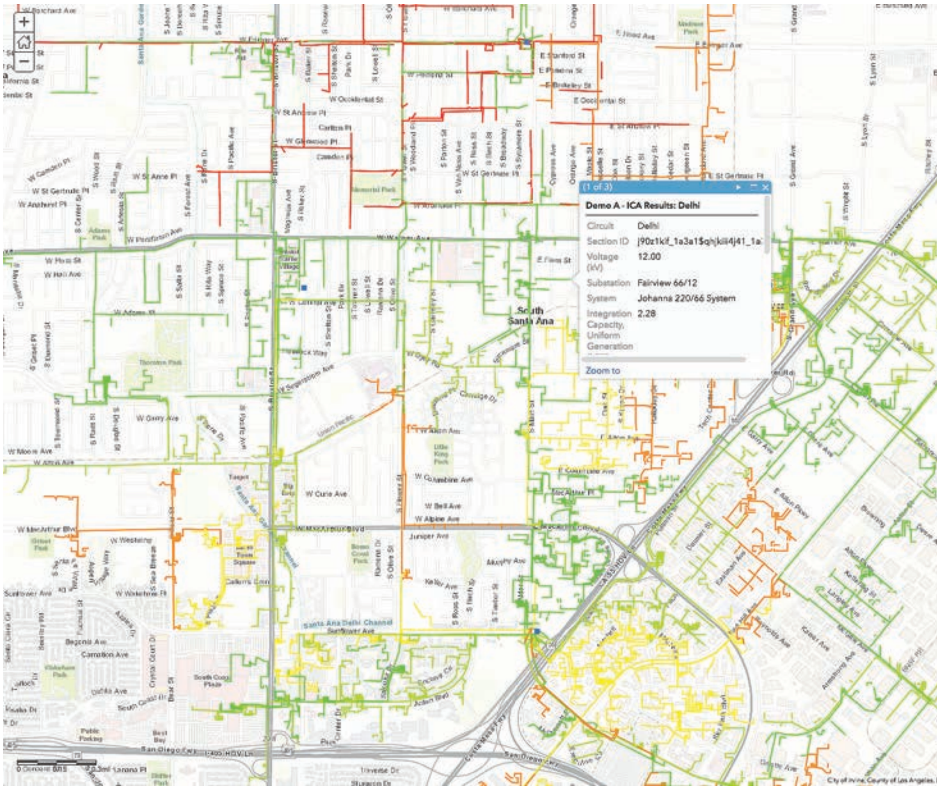
The IOUs concluded that while the streamlined method uses simpler equations and enables faster computations, the results lack the level of granularity needed to replace major choke points in the Rule 21 review process. Though the streamlined method provides a reasonably good measure of hosting capacity, its results still require confirmation by a standard review process. In comparison, the iterative approach provides a more accurate and thorough assessment of DER hosting capacity but requires much longer processing times. This is because this approach must accommodate millions of iterations to model the almost infinite combinations of DER and load power flows that can arise throughout the system.

For industry stakeholders, a high level of accuracy is necessary to instill confidence in the process and to encourage active use of the ICA. In the end, the ICA working group settled on having all three IOUs utilize the iterative method for development of the ICA tool. The IOUs published the results of their first Demo A test cases on their graphical information system mapping tools in 2017. Stakeholders now have an opportunity to use Demo A and play an active role in its refinement prior to computing the ICA for entire service areas.

As shown in Figure 2, the ICA tool operates based on relatively easy-to-read heat maps that graphically illustrate optimal DER locations by overlaying ICA analysis data on a graphical information system map, accessible to the public via a web portal. The ICA tool assigns a green color to any distribution-line segment that can support a relatively large amount of DER; orange and red line sections represent locations with a decreased ability to support DER capacity. By selecting a line segment, users can access additional data-defining limits for different types of DERs. These specified limits do not rule out interconnections that exceed these limits, but rather set the expectation that larger systems should prepare for longer interconnection review timelines and substantial upgrade costs.

LOCATIONAL NET BENEFIT ANALYSIS

Per the final LNBA working group report filed on March 15, 2017 (see Resources), the LNBA "evaluates DERs' benefits at



Data courtesy Southern California Edison

Figure 2 The ICA results in Demo A provide a color-coded visual indication of the DER hosting capacity on individual feeder circuits.

specific locations" with the ultimate goal of ensuring that "DERs are deployed at optimal locations, times and quantities so that their benefits to the grid are maximized and utility customer costs are reduced." The starting point in this effort is the CPUC-approved "Cost-Effectiveness Calculator" developed by Energy + Environmental Economics, which the LNBA methodology enhances to include location-specific values and avoided-cost considerations. The LNBA utilizes much of the same data as the ICA, but its intended use is different.

Intent. At times it can appear that IOUs view DERs as a hindrance rather than an asset. Since the LNBA seeks to quantify the benefits of DERs at specific locations, it may change the way IOUs view DERs. The basic idea is that optimally sited DERs can serve a load more directly than a remote power plant and provide other grid-stabilizing services that will in turn negate the need for costly transmission and subtransmission upgrades. The final LNBA report clarifies that the working group's primary focus "has been on creating a methodology for identifying opportunities to defer investments that are already in utility upgrade plans within a certain time horizon." In the long term, the LNBA could also provide a compensation framework for DERs deployed in certain areas.

Sahm White, the director of policy and economic analysis at the Clean Coalition, a nonprofit working to accelerate the adoption of a more efficient energy system, notes that the 2017–18 Transmission Plan recently released by the California Independent System Operator canceled $2.6 billion in planned transmission project upgrades. He explains, "The forecasted need for transmission projects was lowered mostly because of higher than forecasted impacts of distributed solar and energy efficiency. Since the $2.6 billion in savings reflects only the initial capital costs of the planned upgrades, the actual savings to ratepayers are much higher after accounting for the high return on equity payments to transmission owners as well as avoided O&M costs."

The fate of the proposed Gates-Gregg 230 kV transmission line in Fresno, California, is a good example of how distributed solar power can provide avoided-cost benefits. The California Independent System Operator identified the Gates-Gregg 230 kV line as a necessary reliability-driven project in its 2012–13 Transmission Plan and opened the project for competitive solicitations. In October 2014, the Federal Energy Regulatory Commission approved transmission rate incentives for the project. Barely 2 years later, in November 2016, the regional transmission manager for Northern California noted, "There do not appear to be sufficient economic benefits to support the Gates-Greg 230 kV transmission line project." The cause of this dramatic reversal was the rapid growth of distributed solar capacity in the central San Joaquin Valley. The California Energy Commission has forecast that interconnected solar capacity in the region will grow to more than 260 MW by 2021 (it was just 60 MW in 2016).

Demo B. The Distribution Resource Plan working group mandated the development of a unified locational net benefit methodology consistent across all three IOUs. Per the LNBA working group's final report, the LNBA framework needs to evaluate "the full range of electric services that result in avoided costs," including "any and all services associated with distribution grid upgrades," whether these are identified during the utility distribution planning process, the circuit reliability improvement process or the maintenance process. In other words, the LNBA must consider any positive impacts associated with incremental DER interconnections.

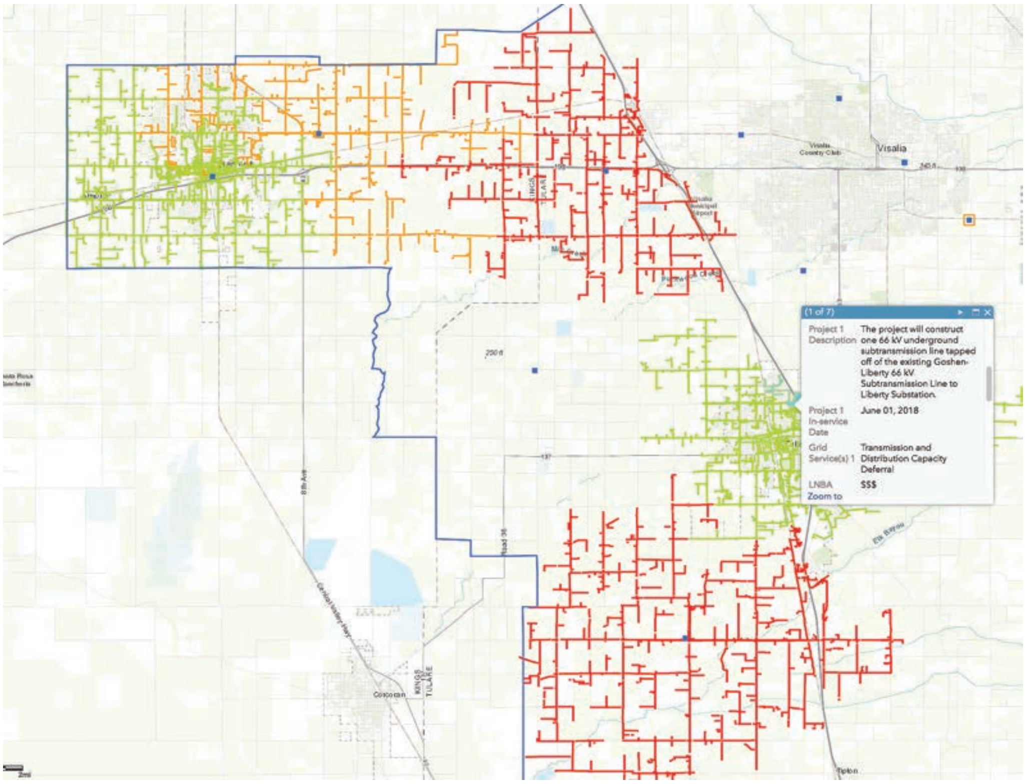


Figure 3 The LNBA results in Demo B provide a visual indication of the benefits of hosting DERs at specific locations on the grid. As shown in the heat map key in Figure 4, these benefits are largely based on opportunities to defer planned investments associated with transmission and distribution (T&D) upgrades.

Data courtesy Southern California Edison

A May 2016 ruling approved the framework for the LNBA and authorized the utilities to use this methodology in Demonstration Project B, which serves as the beta test for the LNBA methodology prior to a wider rollout. The LNBA working group monitored and consulted with the utilities on Demo B, which uses the approved LNBA methodology to evaluate one distribution planning area in each IOU's service area. The approved LNBA methodology relies on planned utility upgrades to assess the value of DERs to the IOUs in certain areas. While transmission and distribution avoided costs are most sensitive to location, DERs also provide other system-level avoided costs, such as avoided generation capacity, avoided energy and avoided ancillary services. Demo B leverages an existing CPUC-approved DER avoided-cost calculator to estimate the value of these system-level benefits.

As executed in Demo B, the LNBA results appear in a heat map, with distribution circuits highlighted in an easy-to-read color-coded scheme, shown in Figure 3. The colors correspond with avoided-cost metrics that the LNBA working group has defined, shown in Figure 4. When users select individual circuits, an informational pop-up box identifies the specific avoided cost that DER interconnection in that area would offset, and indicates the date on which transmission upgrade projects are scheduled to go into service. The pop-up box also provides a generalized visualization of avoided-cost and upgrade-deferral values that allows IOU planners to quickly compare and prioritize interconnections at different locations.

While the LNBA's visual approach is similar to the ICA's, the data serve a different purpose. LNBA results aim to help IOU planning engineers understand the benefits in terms

Demo B LNBA Results Heat Map Key

$	Indicates only system-level avoided cost and no T&D deferral value
$$	Indicates only system-level avoided cost plus 0 to <100 $/kW deferral value
$$$	Indicates only system-level avoided cost plus 100 to <500 $/kW deferral value
$$$$	Indicates only system-level avoided cost plus >500 $/kW deferral value

Figure 4 This table details the color-coding conventions that California's IOUs selected for the distribution feeder heat maps, which provide a visual depiction of the LNBA results in Demo B.

of avoided costs that result from hosting DERs at specific locations in the system. Installers can also utilize these data to prioritize interconnections in areas where utilities see DERs as a benefit to the overall electric grid. On the policy side, policymakers may be able to use LNBA data to develop programs or incentives targeting specific locations through distributed resource planning processes, such as the Community Choice Aggregation program or the Integrated Distributed Energy Resources proceeding for IOUs.

Implementation Timeline

For many stakeholders, the adoption of advanced distribution planning tools cannot come fast enough. The number of interconnection applications and associated engineering reviews has skyrocketed in recent years, and the resulting bottlenecks have increased interconnection timelines in California. An automated and clear interconnection process would improve transparency for project developers, minimize uncertainty for customers, reduce strain on utility engineering staff and meet the CPUC's mandate for dramatically streamlined interconnections. As a peripheral benefit, advanced planning tools would free up bandwidth, allowing IOU interconnection staff to focus on larger, more-complex interconnections.

ICA implementation. With regard to the ICA, the implementation date is well within sight. The CPUC requires that all three major IOUs—Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric—submit full ICA maps to the ICA working group in Q3 of 2018. From that point forward, the utilities will update the ICA maps on a monthly basis using the iterative method.

It is important to note that the initial ICA maps will serve as a general planning tool only—all projects must still submit to and pass through the Rule 21 process. To remedy anticipated conflicts between the ICA and the existing process, the CPUC opened a rulemaking proceeding in March 2018 to begin re-evaluating Rule 21 based on the real-time results of the ICA, with the intent of streamlining the most troublesome screens. This rulemaking process is expected to close in late 2018, setting the stage for adoption in early 2019.

Sky Stanfield, the senior special counsel for Shute, Mihaly & Weinberger, a law firm representing the Interstate Renewable Energy Council, cautions that full ICA implementation is not likely to occur before summer 2019: "While the Rule 21 rulemaking incorporating the ICA may end in late Q4 2018 or early Q1 of 2019, full implementation will likely be delayed until Q2 2019, at the earliest." She explains, "The utilities will need to file advice letters implementing any order from the commission, and there will need to be resolutions approving those advice letters."

LNBA implementation. The LNBA has a longer timeline for implementation than the ICA. Eventually, the LNBA will likely inform future net-energy metering (NEM) rates. However, the metrics for assessing avoided costs on a per-MW-of-DER basis need significant refining. While the LNBA working group makes it clear that the LNBA does not have any framework or mandate to assign credits to DER providers as a function of avoided IOU upgrades, the work it is now doing appears to be geared toward achieving this goal.

According to the LNBA final report, two future rulemaking proceedings—Net Metering 3.0 and future cycles of the Integrated Resource Planning process—may allow stakeholders to use the LNBA for assigning additional compensatory mechanisms to DER development in areas where utilities can use interconnected DER capacity to avoid future upgrades. The working group notes that recent CPUC decisions have deferred significant changes to NEM incentive levels because "the NEM successor tariff is expected to consider LNBA-derived locational values." Such statements hint that the LNBA is much more than a planning tool for IOUs. However, only time will tell if and when LNBA data could facilitate additional compensation for DERs.

POTENTIAL CHALLENGES

Anytime regulators introduce a new tool into an emerging market, they run the risk of unintended consequences. The ICA working group has expressed concern, for example, that developers will clog up the Rule 21 queue by using the ICA to beat their competitors to certain sections of the utility grid. Another concern is that developers will hold queue positions by submitting bogus interconnection requests.

While these fears may seem unrealistic at first glance, unscrupulous stakeholders could in fact game the system if policymakers do not put the proper safeguards in place during the rulemaking proceeding surrounding the ICA. One proposed method of managing disingenuous interconnection applications is to shorten the timeline for meeting certain financial and contractual milestones required to keep a project moving through the Rule 21 process. Another idea is to require that developers provide a contract signed by a verified landowner or facility operator to demonstrate that a project is legitimate.

The lag time between the release of complete ICA maps in July 2018 and the full incorporation of the ICA methodology into the Rule 21 tariff is another sore point for many stakeholders. It is likely that in some instances the unofficial ICA map results will conflict with the results of traditional Rule 21 studies. This will present an early test for IOUs and regulators, who will need to examine what is causing the discrepancy. For this reason, DER project developers should use the initial ICA maps as an informational tool only—much as they do the current RAM maps—until the Rule 21 tariff officially includes the ICA results.

Some stakeholders worry that the ICA will fall short of its promise—see an example of a possible use case in Figure 5 (p. 44)—as long as a gap exists between policy and implementation. Tony Pastore, the principal at AgEnergy Systems, a company that specializes in helping California farmers integrate solar, energy efficiency and monitoring projects, worries about this potential issue: "I do not see where the utilities are committing to the ICA as a 100% accurate tool to expedite engineering studies. The only thing that will increase interconnection speeds is to have CPUC-imposed timelines with consequences for utilities that miss deadlines. Improving the transparency and accuracy of utility infrastructure mapping may make it easier for utilities to perform interconnection studies, but utilities will not complete the engineering reviews any more quickly unless the CPUC imposes rules on them."

The gap between policy and implementation is most apparent with regard to the LNBA. No plan is in place to translate LNBA results into compensation for optimally located DER interconnections. This gap will probably lead most of the DER industry to avoid using the LNBA in the short term. However, developers should keep an eye on the LNBA map when considering long-term development opportunities. By the time a project reaches maturity, compensation mechanisms may fall into place that award additional compensation based on location.

Pastore continues, "In California, stakeholders are still deeply at odds, arguing about the value of solar generated energy. Conservative think tanks say that solar customers are not covering their fair share of grid costs and are deeply gouging nonsolar customers. Solar advocates think that the value to solar generated energy is ever increasing, especially with the addition of energy storage to improve resource dispatchability and provide ancillary grid services. Until we can all agree on the value of solar generated energy, both sides will continue to lobby CPUC staff and legislators from their viewpoint. The locational value of DER should be specific, but it also must be dynamic as the grid is always in flux. Modern technology is facilitating better mapping, real-time facility status, instant communications, better monitoring and asset assignment algorithms, and other tools that will allow us to see a clearer picture of the grid. Over time, it will become easier to assign value to the various grid services that DERs can provide, especially as deployment of these technologies scales."

ENGAGING THE PROCESS

The ICA and the LNBA are not a panacea. They will face trials and require continuous refinement. However, it is important to acknowledge that the magnitude of this rule-making effort is unprecedented. The boldness of California Assembly Bill 327 is commendable, regardless of any short-comings in the distribution planning tools. Furthermore, the tools cannot and will not meet their objectives without the involvement of DER industry stakeholders. Both the ICA and the LNBA are still in development; all proceedings surrounding these tools are open forums. Interested parties not only can access Demo A and Demo B right now, but also are welcome to share ideas on how to refine these tools to elevate DER installations.

Industry advocacy is especially important if the LNBA is to realize its full potential as a tool for improving the economic viability of DER interconnections. Heavner at CALSSA notes, "The LNBA may create opportunities to get direct compensation for targeting solar and storage development in locations where it will defer specific upgrades, but whether the value is worth the trouble remains to be seen." He cautions, "I am not hopeful that the LNBA, as it has been developed so far, will open a lot of new doors."

This sobering assessment of the LNBA development process underscores the need for stakeholder involvement. The full 30% federal investment tax credit is in place only through 2019; the tax credit steps down to 26% in 2020 and 21% in 2021 before dropping to 10% in 2022. The LNBA could be a vital tool for replacing these dwindling tax credits, but only if solar industry stakeholders put their shoulders to the wheel. The path from planning tool to industry compensation engine will be long and arduous. The DER industry will get there more quickly if more people are involved and calling for this change. Things will move slowly, but new compensation mechanisms are essential to make sure that DER industry growth remains strong.

Regulatory and government leadership, both in California and elsewhere, is also key to ensure that hosting capacity programs are developed and used to support DER development. Says Stanfield, "The ICA and LNBA are likely to serve as a model for other high-penetration markets in the near term; for many emerging DER markets, there

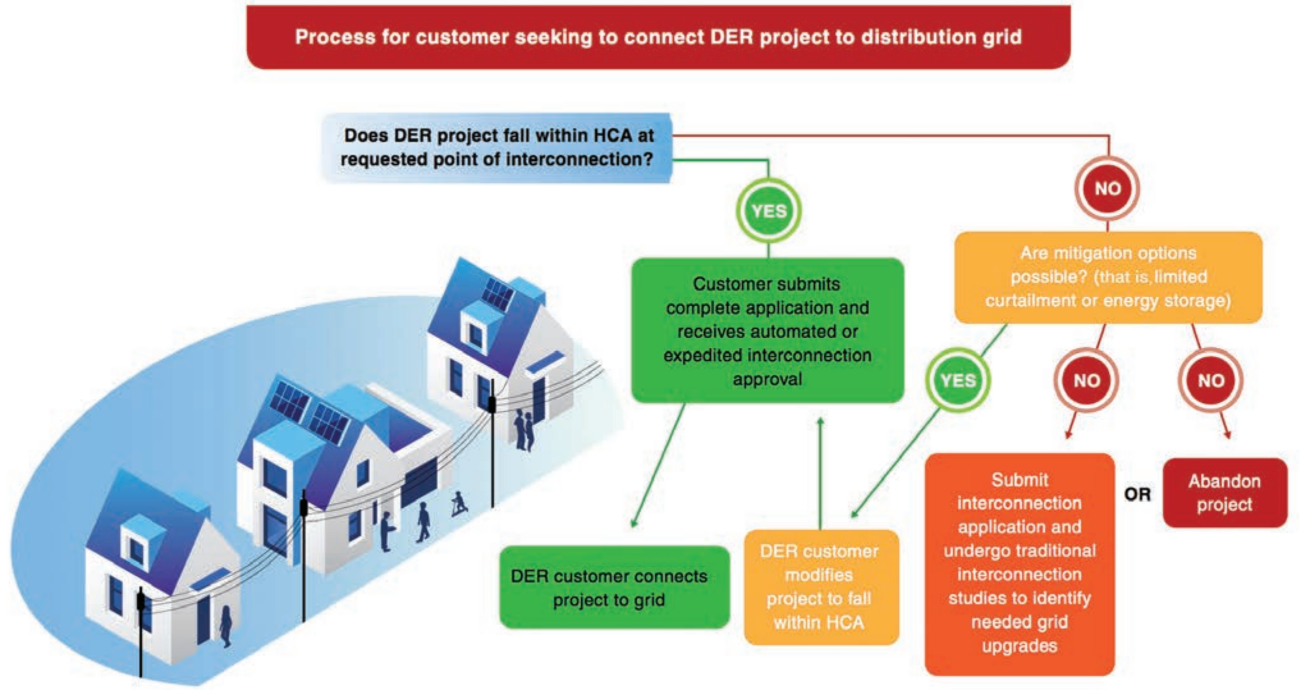


Figure 5 This figure from the Interstate Renewable Energy Council's "Optimizing the Grid" report illustrates one possible use case for hosting capacity analyses such as California's ICA. The process provides a quick screen for interconnecting or abandoning projects, which limits the number of projects that must undergo traditional interconnection studies.

will likely be more of a gradual evolution toward adopting these approaches to proactively integrating DERs on the grid." To help guide state regulators along the way, the Interstate Renewable Energy Council released "Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources" (see Resources) in December 2017. Efforts such as these to normalize and standardize hosting capacity analysis are key to grid modernization and achieving high DER penetration levels.

One state program similar in scope to California's distribution resources planning is New York's Reforming the Energy Vision (REV). REV partners utility operators such as Avangrid, which serves over 3.1 million customers in upstate New York, with companies such as Smarter Grid Solutions, which provides software platforms that integrate and control high levels of DER penetration. One such collaboration is the Flexible Interconnection Capacity Solution demonstration project. DER customers who opt to participate in this project can avoid massive utility upgrades by allowing Avangrid to curtail DER production when power levels approach predefined critical set points.

Most utility upgrades are designed to manage specific worst-case power flow scenarios that are possible in theory but extremely rare in reality. In effect, the Flexible Interconnection Capacity Solution allows DER to generate normally during most operating conditions and curtail production only during those unusual time frames when grid conditions are approaching worst-case limits. Therefore, the actual cost impact of DER curtailment on the customers' bottom line is minimal and quantifiable in advance.

Like many DER industry stakeholders, Heavner is ready to see the CPUC take the next steps: "CALSSA has been part of the working group developing the ICA for several years and is helping to lead the charge on integrating it into Rule 21. We are excited that it's about to get real." The functionality and financial benefit of both the ICA and the LNBA are largely as yet to be determined. It is certain, however, that these tools represent the future of DER interconnection in California and will play a key role in how the solar industry develops for years to come.

CONTACT

Tim McDuffie, PE / CalCom Solar / Visalia, CA / tim@calcomsolar.com / calcomsolar.com

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Locational Net Benefit Working Group, "LNBA Working Group Final Report," drpwg.org, March 2017

2018 Single-Phase
String Inverter Specifications

		Input Data (dc)								
Manufacturer	Model	Maximum recommended PV power at STC (W)	Maximum open-circuit voltage	PV start voltage	Operating voltage range	Number of MPP trackers	MPPT voltage range	Number of dc source circuits	Maximum usable input current[1]	Maximum short-circuit current
ABB	UNO-DM-3.3-TL-PLUS-US	4,000	600	200[2]	140–580	2	160–530/170–530	2	10	2 x 12.5
ABB	UNO-DM-3.8-TL-PLUS-US	6,000	600	200[2]	140–580	2	120–530/140–530	2	16	2 x 25
ABB	UNO-DM-4.6-TL-PLUS-US	6,000	600	200[2]	140–580	2	140–530/150–530	2	16	2 x 25
ABB	UNO-DM-5-TL-PLUS-US	7,000	600	200[2]	140–580	2	130–530/145–530	2	19	2 x 25
ABB	UNO-DM-6-TL-PLUS-US	8,000	600	200[2]	140–580	2	160–480	2	20	2 x 24
Delta	M4-TL-US	6,000	600	DNR	50–480	2	DNR	2	12	2 x 15
Delta	M5-TL-US	7,500	600	DNR	50–480	2	DNR	2	12	2 x 15
Delta	M6-TL-US	9,000	600	DNR	50–480	3	DNR	3	12	3 x 15
Delta	M8-TL-US	12,000	600	DNR	50–480	3	DNR	3	12	3 x 15
Delta	M10-TL-US	15,000	600	DNR	50–480	2	DNR	2	20	2 x 25
Fronius USA	Galvo 1.5-1[3]	2,400	420	140	120–420	1	120–335	3	13.4	20.1
Fronius USA	Galvo 2.0-1[3]	3,200	420	140	120–420	1	120–335	3	17/17.9	26.8
Fronius USA	Galvo 2.5-1[3]	3,800	550	185	165–550	1	165–440	3	16.1	24.1
Fronius USA	Galvo 3.1-1[3]	4,500	550	185	165–550	1	165–440	3	18.7/20	30.1
Fronius USA	Primo 3.8-1	6,000	600	80	80–600	2	200–480	4	2 x 18	2 x 22.5
Fronius USA	Primo 5.0-1	7,800	600	80	80–600	2	200–400	4	2 x 18	2 x 22.5
Fronius USA	Primo 6.0-1	9,300	600	80	80–600	2	240–480	4	2 x 18	2 x 22.5
Fronius USA	Primo 7.6-1	11,700	600	80	80–600	2	250–480	4	2 x 18	2 x 22.5
Fronius USA	Primo 8.2-1	12,700	600	80	80–600	2	270–480	4	2 x 18	2 x 22.5
Fronius USA	Primo 10.0-1	12,000	1,000	80	80–1,000	2	220–800	6	33/18[4]	49.5/27[4]
Fronius USA	Primo 11.4-1	13,700	1,000	80	80–1,000	2	240–800	6	33/18[4]	49.5/27[4]
Fronius USA	Primo 12.5-1	15,000	1,000	80	80–1,000	2	260–800	6	33/18[4]	49.5/27[4]
Fronius USA	Primo 15.0-1	18,000	1,000	80	80–1,000	2	320–800	6	33/18	49.5/27[4]
Ginlong Solis	Solis-1P2.5K-4G-US	DNR	600	60	50–450	2	DNR	4	2 x 11	DNR
Ginlong Solis	Solis-1P3K-4G-US	DNR	600	120	90–520	2	DNR	4	2 x 11	DNR
Ginlong Solis	Solis-1P3.6K-4G-US	DNR	600	120	90–520	2	DNR	4	2 x 11	DNR
Ginlong Solis	Solis-1P4K-4G-US	DNR	600	120	90–520	2	DNR	4	2 x 11	DNR
Ginlong Solis	Solis-1P4.6K-4G-US	DNR	600	120	90–520	2	DNR	4	2 x 11	DNR
Ginlong Solis	Solis-1P5K-4G-US	DNR	600	120	90–520	2	DNR	6	2 x 11	DNR
Ginlong Solis	Solis-1P6K-4G-US	DNR	600	120	100–500	3	DNR	6	3 x 10	DNR
Ginlong Solis	Solis-1P7K-4G-US	DNR	600	120	100–500	3	DNR	6	3 x 10	DNR
Ginlong Solis	Solis-1P7.6K-4G-US	DNR	600	120	100–500	3	DNR	8	3 x 10	DNR
Ginlong Solis	Solis-1P8K-4G-US	DNR	600	120	100–500	4	DNR	8	4 x 10	DNR
Ginlong Solis	Solis-1P9K-4G-US	DNR	600	120	100–500	4	DNR	8	4 x 10	DNR
Ginlong Solis	Solis-1P10K-4G-US	DNR	600	120	100–500	4	DNR	8	4 x 10	DNR

Footnote Key

[1] Per MPP tracker
[2] Adjustable 120–350 Vdc
[3] High-frequency transformer topology
[4] MPPT 1/MPPT 2
[5] Module-level MPP tracking
[6] Rated dc input voltage
[7] Supplies PV power at < 550 Vdc
[8] With optional PSD disconnect
[9] PV Link S2501 subarray optimizer specification
[10] String-level MPP tracking
[11] -40–104°F version available
[12] -40–140°F version available
DNR = Does not report

Output Data (ac)			Operation		Integrated Disconnects and Combiners			Mechanical			Contact
Rated power (W)	Nominal output voltage	Rated output current	CEC-weighted efficiency (%)	Ambient temperature range (ºF)	DC disconnect standard	AC disconnect standard	Fused combiner standard	Cooling method	Dimensions H x W x D (in.)	Weight (lbs.)	Website
3,300	208/240	14.5	96.5	-13–140	option	no	no	passive	34 x 16.4 x 6.9	33	abb.com/solarinverters
4,200	208/240	16	96/96.5	-13–140	option	no	no	passive	34 x 16.4 x 6.9	33	
4,600	208/240	20	96/96.5	-13–140	option	no	no	passive	34 x 16.4 x 6.9	33	
5,000	208/240	22	96.5/97	-13–140	option	no	no	passive	34 x 16.4 x 6.9	33	
6,000	208/240	30	96.5/97	-13–140	option	no	no	passive	28.6 x 21.7 x 7	47	
4,000	208/240	16	97.5	-22–149	yes	no	no	passive	23.2 x 16.7 x 5.7	42	delta-americas.com
5,000	208/240	20	97.5	-22–149	yes	no	no	passive	23.2 x 16.7 x 5.7	42	
6,000	208/240	24	97.5	-22–149	yes	no	no	passive	23.2 x 16.7 x 5.7	43	
8,000	208/240	32	97.5	-22–149	yes	no	no	active	23.2 x 16.7 x 5.7	44	
10,000	208/240	40	97.5	-22–149	yes	no	no	active	23.2 x 16.7 x 5.7	44	
1,500	208/240	7.2/6.3	94/94.5	-40–122	yes	no	no	active	24.7 x 16.9 x 8.1	36	fronius-usa.com
2,000	208/240	9.1/8.3	94.5	-40–122	yes	no	no	active	24.7 x 16.9 x 8.1	36	
2,500	208/240	12/10.4	95	-40–122	yes	no	no	active	24.7 x 16.9 x 8.1	37	
3,100	208/240	14.1/12.9	95/95.5	-40–122	yes	no	no	active	24.7 x 16.9 x 8.1	37	
3,800	208/240	18.3/15.8	95	-40–131	yes	no	no	active	24.7 x 16.9 x 8.1	47	
5,000	208/240	24/20.8	95.5	-40–131	yes	no	no	active	24.7 x 16.9 x 8.1	47	
6,000	208/240	28.8/25	96	-40–131	yes	no	no	active	24.7 x 16.9 x 8.1	47	
7,600	208/240	36.5/31.7	96	-40–131	yes	no	no	active	24.7 x 16.9 x 8.1	47	
7,900/8,200	208/240	38/34.2	96.5	-40–131	yes	no	no	active	24.7 x 16.9 x 8.1	47	
9,995	208/240	48.1/41.6	96/96.5	-40–140	yes	no	yes	active	28.5 x 20.1 x 8.9	83	
11,400	208/240	54.8/47.5	96/96.5	-40–140	yes	no	yes	active	28.5 x 20.1 x 8.9	83	
12,500	208/240	60.1/52.1	96/96.5	-40–140	yes	no	yes	active	28.5 x 20.1 x 8.9	83	
13,750/15,000	208/240	66.1/62.5	96.5/97	-40–140	yes	no	yes	active	28.5 x 20.1 x 8.9	83	
2,500	208/240	12/10.4	97.1	-13–140	yes	no	no	passive	28.5 x 12.2 x 6.3	31	ginlong.com
3,000	208/240	14.4/12.5	97.1	-13–140	yes	no	no	passive	28.5 x 12.2 x 6.3	31	
3,600	208/240	17.3/15	97.1	-13–140	yes	no	no	passive	28.5 x 12.2 x 6.3	31	
4,000	208/240	19.2/16.7	97.3	-13–140	yes	no	no	passive	28.5 x 12.2 x 6.3	31	
4,600	208/240	22.1/19.2	97.3	-13–140	yes	no	no	passive	28.5 x 12.2 x 6.3	31	
5,000	208/240	24/20.8	97.3	-13–140	yes	no	no	passive	28.5 x 12.2 x 6.3	31	
6,000	208/240	28.8/25	97.5	-13–140	yes	no	no	passive	25.8 x 13.1 x 9.8	43	
7,000	208/240	33.7/29.2	97.5	-13–140	yes	no	no	passive	25.8 x 13.1 x 9.8	43	
7,600	208/240	36.5/31.7	97.5	-13–140	yes	no	no	passive	25.8 x 13.1 x 9.8	43	
8,000	208/240	38.5/33.3	97.5	-13–140	yes	no	no	passive	25.8 x 13.1 x 9.8	44	
9,000	208/240	43.3/37.5	97.5	-13–140	yes	no	no	passive	25.8 x 13.1 x 9.8	44	
10,000	208/240	43.3/41.7	97.5	-13–140	yes	no	no	passive	25.8 x 13.1 x 9.8	44	

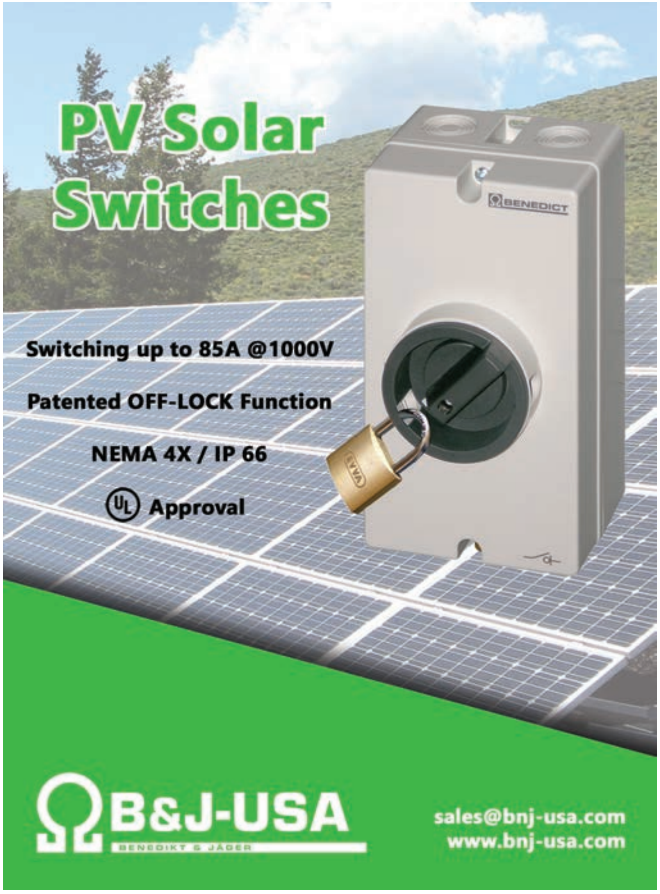
2018 Single-Phase String Inverter Specifications

		Input Data (dc)								
Manufacturer	Model	Maximum recommended PV power at STC (W)	Maximum open-circuit voltage	PV start voltage	Operating voltage range	Number of MPP trackers	MPPT voltage range	Number of dc source circuits	Maximum usable input current [1]	Maximum short-circuit current
Growatt	4000 MTLP-US	8,000	600	150	100–600	2	120–500	4	2 x 18	42
Growatt	5000 MTLP-US	10,000	600	150	100–600	2	120–500	4	2 x 18	47
Growatt	6000 MTLP-US	12,000	600	150	100–600	2	120–500	4	2 x 18	56
Growatt	7000 MTLP-US	11,800	600	150	100–600	2	120–500	4	20/10	47
Growatt	7600 MTLP-US	12,400	600	150	100–600	2	120–500	4	20/10	47
Growatt	8000 MTLP-US	13,000	600	150	100–600	3	120–500	1/1/2	9.5/9.5/19	DNR
Growatt	9000 MTLP-US	13,000	600	150	100–600	3	120–500	1/1/2	9.5/9.5/19	DNR
Growatt	10000 MTLP-US	13,000	600	150	100–600	3	120–500	1/1/2	9.5/9.5/19	DNR
Huawei	SUN2000-3.8KTL-USL0	5,130	500	varies[5]	325/370[6]	varie[5]	varies[5]	DNR	DNR	30
Huawei	SUN2000-5KTL-USL0	6,750	500	varies[5]	325/370[6]	varies[5]	varies[5]	DNR	DNR	30
Huawei	SUN2000-7.6KTL-USL0	10,260	500	varies[5]	325/370[6]	varies[5]	varies[5]	DNR	DNR	30
Huawei	SUN2000-9KTL-USL0	12,150	500	varies[5]	325/370[6]	varies[5]	varies[5]	DNR	DNR	35
Huawei	SUN2000-10KTL-USL0	13,500	500	varies[5]	325/370[6]	varies[5]	varies[5]	DNR	DNR	35
Huawei	SUN2000-11.4KTL-USL0	15,400	500	varies[5]	325/370[6]	varies[5]	varies[5]	DNR	DNR	35
KACO new energy	2.0 TL1	DNR	600[7]	150	125–550	1	190–510	1	11	13
KACO new energy	3.0 TL1	DNR	600[7]	150	125–550	2	140–510	2	2 x 11	2 x 13.2
KACO new energy	4.0 TL1	DNR	600[7]	150	125–550	2	185–510	2	2 x 11	2 x 13.2
KACO new energy	5.0 TL1	DNR	600[7]	150	125–550	2	215–510	2	2 x 11	2 x 13.2
Pika Energy	X7600	10,000	420	60	380[6]	varies[10]	60–360[9]	varies[10]	20	DNR
SMA America	SB 3.0-US	4,800	600	125	100–550	2	155–480	2	2 x 10	2 x 18
SMA America	SB 3.8-US	6,080	600	125	100–550	2	195–480	2	2 x 10	2 x 18
SMA America	SB 5.0-US	8,000	600	125	100–550	3	220–480	3	2 x 10	3 x 18
SMA America	SB 6.0-US	9,600	600	125	100–550	3	220–480	3	2 x 10	3 x 18
SMA America	SB 7.0-US	11,200	600	125	100–550	3	245–480	3	2 x 10	3 x 18
SMA America	SB 7.7-US	12,320	600	125	100–550	3	270–480	3	2 x 10	3 x 18
SolarEdge	SE3000H-US	4,650	480	varies[5]	380[6]	varies[5]	varies[5]	2	8.5	45
SolarEdge	SE3800H-US	5,900	480	varies[5]	380[6]	varies[5]	varies[5]	2	9/10.5	45
SolarEdge	SE5000H-US	7,750	480	varies[5]	380[6]	varies[5]	varies[5]	2	13.5	45
SolarEdge	SE6000H-US	9,300	480	varie[5]	380[6]	varies[5]	varies[5]	2	13.5/16.5	45
SolarEdge	SE7600H-US	11,800	480	varies[5]	400[6]	varies[5]	varies[5]	2	20	45
SolarEdge	SE10000H-US	15,500	480	varies[5]	400[6]	varies[5]	varies[5]	3	27	45
SolarEdge	SE3000A-US	4,050	500	varies[5]	325/350[6]	varies[5]	varies[5]	2	9.5	45
SolarEdge	SE3800A-US	5,100	500	varies[5]	325/350[6]	varies[5]	varies[5]	2	13	45
SolarEdge	SE5000A-US	6,750	500	varies[5]	325/350[6]	varies[5]	varies[5]	2	16.5/15.5	45
SolarEdge	SE6000A-US	8,100	500	varie [5]	325/350[6]	varies[5]	varies[5]	2	18	45
SolarEdge	SE7600A-US	10,250	500	varies[5]	325/350[6]	varies[5]	varies[5]	2	23	45
SolarEdge	SE10000A-US	13,500	500	varies[5]	325/350[6]	varies[5]	varies[5]	3	33/30.5	45
SolarEdge	SE11400A-US	15,350	500	varies[5]	325/350[6]	varies[5]	varies[5]	3	34.5	45
Yaskawa–Solectria Solar	PVI 3800TL	5,320	600	150	120–550	1	200–500	2	20	24
Yaskawa–Solectria Solar	PVI 5200TL	7,280	600	150	120–550	2	200–500	4	2 x 15	2 x 24
Yaskawa–Solectria Solar	PVI 6600TL	9,240	600	150	120–550	2	200–500	4	2 x 18	2 x 24
Yaskawa–Solectria Solar	PVI 7600TL	10,640	600	150	120–550	2	200–500	4	2 x 20	2 x 24

Footnote Key

[1] Per MPP tracker
[2] Adjustable 120–350 Vdc
[3] High-frequency transformer topology
[4] MPPT 1/MPPT 2
[5] Module-level MPP tracking
[6] Rated dc input voltage
[7] Supplies PV power at < 550 Vdc
[8] With optional PSD disconnect
[9] PV Link S2501 subarray optimizer specification
[10] String-level MPP tracking
[11] -40–104°F version available
[12] -40–140°F version available
DNR = Does not report

Output Data (ac)			Operation		Integrated Disconnects and Combiners			Mechanical			Contact
Rated power (W)	Nominal output voltage	Rated output current	CEC-weighted efficiency (%)	Ambient temperature range (ºF)	DC disconnect standard	AC disconnect standard	Fused combiner standard	Cooling method	Dimensions H x W x D (in.)	Weight (lbs.)	Website
4,000	208/240/277	16.7	96	-31–140	yes	no	no	passive	28.7 x 15.8 x 8.5	69	growatt-america.com
5,000	208/240/277	21	96.5	-31–140	yes	no	no	passive	28.7 x 15.8 x 8.5	69	
6,000	208/240/277	25	96.5	-31–140	yes	no	no	passive	28.7 x 15.8 x 8.5	71	
7,000	208/240/277	29	97	-31–140	yes	no	no	passive	28.7 x 15.8 x 8.5	71	
7,600	208/240/277	31.7	97	-31–140	yes	no	no	passive	28.7 x 15.8 x 8.5	71	
8,000	208/240	33.5	97.5	-31–140	yes	no	no	passive	27.3 x 14 x 8.3	66	
9,000	208/240	37.5	97.5	-31–140	yes	no	no	passive	27.3 x 14 x 8.3	66	
10,000	208/240	42	97.5	-31–140	yes	no	no	passive	27.3 x 14 x 8.3	66	
3,300/3,800	208/240	15.9	99	-22–140	option	no	no	passive	22.4 x 15.8 x 6.3	40	solar.huawei.com
4,300/5,000	208/240	20.9	99	-22–140	option	no	no	passive	22.4 x 15.8 x 6.3	40	
6,600/7,600	208/240	31.7	99	-22–140	option	no	no	passive	22.4 x 15.8 x 6.3	40	
7,800/9,000	208/240	37.5	99	-22–140	option	no	no	passive	25.6 x 17.5 x 6.3	51	
8,700/10,000	208/240	41.7	99	-22–140	option	no	no	passive	25.6 x 17.5 x 6.3	51	
9,900/11,400	208/240	47.5	99	-22–140	option	no	no	passive	25.6 x 17.5 x 6.3	51	
2,000	208/240	9.7/8.3	96.5	-13–140	option	no	option	passive	31.9 x 14.5 x 8.6[8]	45[8]	kaco-newenergy.com
3,000	208/240	14.5/12.5	96.5	-13–140	option	no	option	passive	31.9 x 14.5 x 8.6[8]	48[8]	
4,000	208/240	19.2/16.7	96.5	-13–140	option	no	option	passive	31.9 x 14.5 x 8.6[8]	48[8]	
4,600/5,000	208/240	22/20	96.5	-13–140	option	no	option	passive	31.9 x 14.5 x 8.6[8]	48[8]	
7,600	240	32	96.5	-4–122	yes	no	yes	active	24.5 x 19.3 x 8	63	pikaenergy.com
3,000	208/240	14.5/12.5	96/96.5	-13–140	yes	no	no	passive	28.5 x 21.1 x 7.8	57	sma-america.com
3,330/3,800	208/240	16	96.5	-13–140	yes	no	no	passive	28.5 x 21.1 x 7.8	57	
5,000	208/240	24	96.5/97	-13–140	yes	no	no	passive	28.5 x 21.1 x 7.8	57	
5,200/6,000	208/240	25	96.5/97	-13–140	yes	no	no	passive	28.5 x 21.1 x 7.8	57	
6,660/7,000	208/240	32/29.2	96.5/97	-13–140	yes	no	no	active	28.5 x 21.1 x 7.8	57	
6,660/7,680	208/240	32	96.5/97	-13–140	yes	no	no	active	28.5 x 21.1 x 7.8	57	
3,000	240	12.5	99	-13–140[11]	yes	yes	no	passive	17.7 x 14.6 x 6.8	22	solaredge.us
3,300/3,800	208/240	16	99	-13–140[11]	yes	yes	no	passive	17.7 x 14.6 x 6.8	22	
5,000	240	21	99	-13–140[11]	yes	yes	no	passive	17.7 x 14.6 x 6.8	25	
5,000/6,000	208/240	24/25	99	-13–140[11]	yes	yes	no	passive	17.7 x 14.6 x 6.8	26	
7,600	240	32	99	-13–140[11]	yes	yes	no	passive	17.7 x 14.6 x 6.8	26	
10,000	240	42	99	-13–140[11]	yes	yes	no	passive	21.3 x 14.6 x 7.3	39	
3,000	240	12.5	97.5	-13–140[12]	yes	yes	no	passive	30.5 x 12.5 x 7.2	51	
3,800	240	16	98	-13–140[12]	yes	yes	no	passive	30.5 x 12.5 x 7.2	51	
5,400/5,450	208/240	24/21	97/98	-13–140[12]	yes	yes	no	passive	30.5 x 12.5 x 7.2	55	
6,000	240	25	97.5	-13–140 [2]	yes	yes	no	passive	30.5 x 12.5 x 7.2	55	
7,600	240	32	97.5	-13–140[12]	yes	yes	no	active	30.5 x 12.5 x 10.5	55	
9,980/10,000	208/240	48/42	97/97.5	-13–140[12]	yes	yes	no	active	30.5 x 12.5 x 10.5	88	
11,400	240	47.5	97.5	-13–140[12]	yes	yes	no	active	30.5 x 12.5 x 10.5	88	
3,328/3,800	208/240	16	97.5	-13–122	yes	no	yes	passive	17.5 x 15.8 x 8.5	43	solectria.com
5,000/5,200	208/240	24	97.5	-13–122	yes	no	yes	passive	26.8 x 15.8 x 8.5	65	
6,600	208/240	32	97.5	-13–122	yes	no	yes	passive	26.8 x 15.8 x 8.5	65	
6,656/7,600	208/240	32	97.5	-13–122	yes	no	yes	passive	26.8 x 15.8 x 8.5	65	

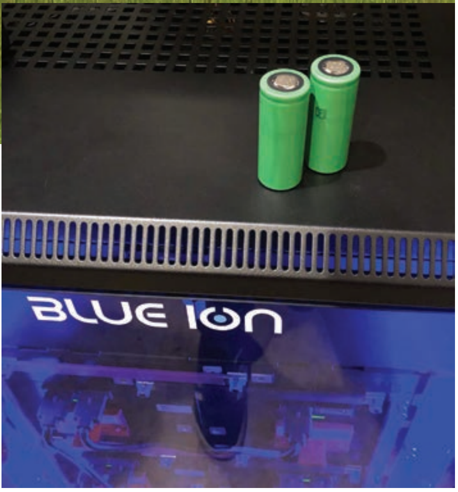


Advertiser *Index*

PROJECTS System Profiles

Ten Mile Farm

Joe Schwartz, *SolarPro*



Courtesy Joe Schwartz (2)

Overview

DESIGN: Joe Schwartz, publisher, *SolarPro*, solarprofessional.com

INSTALLATION: Joe Schwartz, *SolarPro*; True South Solar, truesouthsolar.net; Haase Energy Systems, 530.527.8989

DATE COMMISSIONED: Original system installed in 2005, upgraded in 2015 and 2017

LOCATION: Ashland, OR, 42°N

SOLAR RESOURCE: 4.9 kWh/m^2/day

ASHRAE DESIGN TEMPS: 97°F 2% average high, 17.6°F extreme minimum

ARRAY CAPACITY: 6.8 kWdc

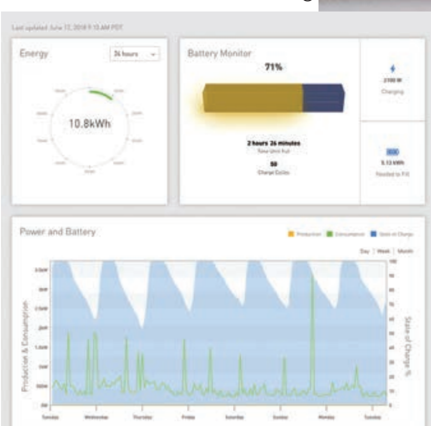
ANNUAL AC PRODUCTION: 8,200 kWh (potential)

Established in 2015, Ten Mile Farm is a side project of *SolarPro* publisher Joe Schwartz. The off-grid farm sits at an elevation of 4,600 feet. It borders the 86,744-acre Cascade-Siskiyou National Monument, which spans the intersection of the Cascade and Siskiyou mountain ranges in southwestern Oregon and northwestern California. Like many off-grid homesteads, Schwartz's PV system has evolved as energy requirements and solar technology have changed over the 15 years he has been developing the 50-acre property.

Schwartz designed and installed the core system in 2005. It included two pole mounts, each with six 175 W Sharp PV modules, two OutBack Power VFX3648 inverter/chargers and two OutBack MX60 charge controllers. All of the original system equipment has performed reliably and is still in use. The original bank of eight 6 V Discover AGM batteries (18.7 kWh total rated capacity at C20) operated for 11 years. The farm's increased electrical load, including water pumping for irrigation, led to system upgrades. In 2016, Schwartz added 1.3 kW of SunPower modules to the roof of the site's power room. In 2017, he contracted True South Solar to install a 3.45 kW SunPower array, regulated by a 600 Vdc Morningstar controller, on an agricultural building located 320 feet from the system's power room. He also worked with his friends at Haase Energy Systems to install a 14 kW Kohler LPG backup generator.

PROJECTS

Courtesy Shawn Schreiner



In the fall of 2017, Schwartz upgraded the site's energy storage to a lithium-ion system designed by Blue Planet Energy. The Blue Ion 2.0 battery consists of eight lithium iron phosphate (LiFePO4) modules manufactured by Murata (formerly Sony). Each module is made up of 224 individual 3.45 V, 9.375 Wh cells. Under its ETL listing to UL 9540, the Blue Ion 2.0 battery management unit is approved for continuous operation at charge and discharge currents up to 160 A continuous, 200 A for 30 minutes, and 220 A for 5 minutes. This makes it a good fit for systems with array capacities and inverter/charger systems of about 8 kW. Integrators can parallel multiple Blue Ion 2.0 units for capacities of up to 450 kW.

Many lithium-ion energy storage systems allow for a depth of discharge (DOD) of < 99% without any meaningful impact on cycle life. For example, the Blue Ion 2.0 system has a warranty for 8,000 cycles or 15 years at 100% DOD. The ability to fully utilize battery capacity can have significant impacts on off-grid system design, including the required storage capacity, as well as on variables such as array-to-storage capacity ratios, and backup generator capacity and projected annual run-times.

The longevity of lead acid batteries directly relates to several variables, including how deeply a bank discharges and how regularly it receives a full saturation charge at regulation voltage. In contrast, a lithium-ion battery does not require or benefit from recharging to 100% capacity, and its cycle life actually increases at lower charge voltages. This leads to interesting shifts in off-grid system operation. Heavy loading in the morning before the sun is on the array, for instance, is not a concern. In addition, routinely operating the system at a partial state of charge does not negatively affect battery longevity, which informs strategies to bridge periods of low solar insolation and charging in off-grid applications.

"During my 20-plus years working in the solar industry, there have been continual advancements in equipment for off-grid residential applications, including robust sine wave inverters, high-voltage MPPT dc charge controllers, industrial high-capacity lead-acid batteries and web-based system control and monitoring. As manufacturing scales and prices decline, lithium-ion battery systems have the potential to fundamentally impact the way off-grid systems are designed and operated."
—Joe Schwartz, SolarPro

Equipment Specifications

MODULES: 12 Sharp NT-R5E1U, 175 W STC, ±10%, 4.95 Imp, 35.4 Vmp, 5.55 Isc, 44.4 Voc; four SunPower E20-327, 327 W STC, +5/-0 W, 5.98 Imp, 54.7 Vmp, 6.46 Isc, 64.9 Voc; 10 SunPower X21-345-COM, 345 W STC, +5/-3%, 6.02 Imp, 57.3 Vmp, 6.39 Isc, 68.2 Voc

INVERTERS: 120/240 Vac off-grid service; two OutBack Power VFX3648, 7.2 kWac–rated continuous output; OutBack Power X240 balancing autotransformer; OutBack Power PS2DC system integration panel

CHARGE CONTROLLERS: Morningstar Tristar 600V, 60 A, 600 Vdc maximum input; two OutBack Power MX60, 60 A, 150 Vdc maximum input

ENERGY STORAGE: Blue Planet Energy Blue Ion 2.0 B12-16-18U, LiFePO4 lithium-ion chemistry, 16 kWh usable storage capacity (< 99% depth of discharge), 9 kW rated continuous power, 48 Vdc nominal, 8,000-cycle or 15-year warranty at 70% of rated capacity

GENERATOR: Kohler 14RESA, 14 kWac rated, 120/240 Vac output, LPG fuel

ARRAY 1: Two pole mounts; six Sharp NT-R5E1U modules per mount configured in two 3-module source circuits (525 W, 4.95 Imp, 106.2 Vmp, 5.55 Isc, 133.2 Voc); 1,050 W per mount, 2,100 W total

ARRAY 2: Roof mount, four SunPower E20-327 modules configured in two 2-module source circuits (654 W, 5.98 Imp, 109.4 Vmp, 6.46 Isc, 129.8 Voc), 1,308 W total

ARRAY 3: Roof mount, 10 SunPower X21-345-COM modules configured in two 5-module source circuits (1,725 W, 6.02 Imp, 286.5 Vmp, 6.39 Isc, 341 Voc), 3,450 W total

SYSTEM MONITORING: Blue Planet Energy, eGauge and OutBack Power web-based monitoring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