REDUCING RISK, INCREASING LIFECYCLE VALUE: OPTIMIZING THE PHOTOVOLTAIC PLANT DESIGN AND DEVELOPMENT PROCESS

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Report Abstract

In response to the explosive growth of solar photovoltaic (PV) systems, a wide range of standards and best practices are currently being revised or created, including those germane to plant design and specification. As electric utilities engage in greater PV asset ownership, it will be increasingly important to clarify optimal development approaches. Utilities are likely to seek more than basic requirements on the quality and life-cycle economics of PV power plants in order to satisfy internal due diligence, and for investor-owned utilities to meet regulatory mandates, particularly for rate-based PV investments. Unifying life-cycle processes and procedures that result in consensus best practices can produce benefits for both utilities and the industry at-large, including reduced risk and transaction costs, in addition to increased safety and reliability.

This paper highlights the ambiguity in existing design and development processes along the PV value chain, illustrates how standards revisions currently underway could impact the status quo, and provides suggestions for future activities. It also identifies remaining gaps and explores some key areas that utilities can consider for optimizing the procurement, design, and operation of utility-scale PV systems.

Introduction

Global PV installations—comprising residential, non-residential, and utility-scale systems—have grown exponentially over the last decade, surging from 1.7 GW of cumulative capacity in 2006 to an estimated 240 GW in 2015.[1] Within the U.S., one of the world's hottest markets, cumulative capacity increased from 105 MW in 2006[2] to an estimated 25 GW in 2015.[3] Utility-scale plants—often denoted as greater than 1-MW in nameplate capacity—currently account for more than 70% of the U.S.'s PV capacity. Furthermore, they are anticipated to account for roughly 70% of future global PV capacity installed in the 2016-2020 timeframe.[4] If accurate, some 65,500 MW of new utility-scale installations would be deployed globally every year through 2020.[5] The recent extension of the U.S. Investment Tax Credit for solar is expected to increase that value further, incentivizing an additional 15,000 MW of U.S. utility-scale PV over previous forecasts through 2020.[6] Given the trajectory of solar pricing, technology advancements, and regulatory/policy considerations, the variable resource will become an increasing part of electric utility portfolios.

PV's growth rate has outpaced standards and best practices development. What constitutes as "best practices" for designing, developing, and operating utility PV power plants is still debatable. Important benefits of having up-to-date, agreed upon standards and best practices for PV assets include shortening the learning curve, increasing business efficiency, and increasing confidence in PV as a safe, reliable, and affordable asset.

Solar generating facilities are a relatively unknown commodity for the vast majority of electric utilities. There is a gap in technical knowledge and experience pertaining to solar power systems compared to conventional fossil and nuclear power plants using rotating equipment. As a result, utilities are often unfamiliar with issues germane to the procurement, design/construction, commissioning,

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This white paper was prepared by Nicholas Lenssen of NKL Energy Consulting, and Michael Bolen and Nadav Enbar of the Electric Power Research Institute.

[1] Bloomberg New Energy Finance, "PV Market Outlook Q4 2009: Survival at What Cost?" December 23, 2009; "Q4 2015 PV Market Outlook," November 9, 2015.

[2] GTM Research, "U.S. Solar Market Insight: 2013 Year-in-Review," March 2014.

[3] GTM Research, "U.S. Solar Market Insight: Q3 2015," December 2015.

[4] GTM Research, in Trimark Associates, Inc., "Best Practices for Effective Solar Power Resources," Folsom, CA, November 5, 2015.

[5] GTM Research, "Global PV Demand Outlook, 2015–2020," June 2015.

[6] GTM Research, "Q4 2015 Solar Executive Briefing," January 2016.

operations and maintenance (O&M), and decommissioning of PV arrays.

These issues are not always simple or clear. For example, when soliciting bids for building a PV plant, various responses may not use the same definitions for important metrics such as availability or performance ratio; different climatic data may be utilized to model energy production; or varying assumptions may be relied upon to calculate energy output over time. Making apples-to-apples comparisons across bids requires consistency, transparency, and proper definition of the right parameters upfront—all gaps that standards and best practices can fill.

Likewise, module suppliers often describe their technologies' performance based on standard testing conditions (STC). But while useful for the laboratory, STC fails to capture the actual ambient conditions in which solar modules will operate. How bidders interpret the way in which modules and their performance are characterized can also impact the relative ranking of bids. This is particularly true given the different operating characteristics of crystalline silicon (c-Si) and thin film (e.g., cadmium telluride [CdTe] and copper indium gallium diselenide [CIGS]) PV technologies. For instance, operating temperature, low-light performance (e.g., at sunrise and sunset), and location-specific spectra (e.g., more UV and blue light in higher elevations) affect module technology-type differently.

The complexity of PV plant design is augmented by the on-going, often rapid changes in available technology and design practices. For example, the rise in operating voltage on the DC side of PV plants—from 600 V to 1,000 V, and more recently 1,500 V—has led to broader design changes available to optimize a plant's capital expense. The target for plant developers continues to move, making it challenging to accept past practices as guidance for future efforts.

The explosive deployment of PV installations has spurred activity among standards development organizations. Pushed by industry need, these organizations are both updating existing standards and creating new ones in an effort to reduce uncertainty as well as introduce greater efficiency and consistency to the design, installation, and management of PV plants. For example, The International Electrotechnical Commission's (IEC) PV technical committee has published more than 70 standards, and as of this writing, nearly 80 projects are underway to update or develop additional standards.[7]

Development of standards and specifications are time consuming and often lags behind the needs of industry. These efforts are making headway; at a minimum, openly discussing common issues is a form of progress. There remain areas along the PV supply chain that have yet to be fully addressed by standards-writing organizations, as discussed later in this report.

Efforts are also proceeding to create an international certificate program that would allow PV plants to be compared with others in terms of their compliance with standards. Known as IEC System for Certification to Standards Relating to Equipment for Use in Renewable Energy Applications, or IECRE, the certification aims to provide greater certainty to financiers, plant owners, and potential plant owners in evaluating the design and implementation phases of a PV plant. The effort is intended to serve as a means to encourage improved PV system quality and performance, with the ancillary

Research Methods

Findings in this paper are based on a review of existing and in-process standards work, as well as 28 in-depth interviews with a range of PV developers, equipment suppliers, utilities, independent engineers, and others (see Table 1). When asked about various aspects of the plant specification process, interviewed experts often repeated the mantra, "it's an art, not a science," underscoring the need for greater transparency and clarity around a range of important system development guidelines.

Respondent Type	Respondents
Utility	9
Developer	3
Integrated Supplier / Developer	2
O&M Provider	2
Independent Engineer	4
Others*	8
Total	**28**

Table 1. Make-up of interview respondents
Source EPRI

**Note: Others include National Laboratories, Standards Organizations, and Financiers*

[7] The International Electrotechnical Commission (IEC) is the leading global organization that publishes consensus-based international standards and manages conformity assessment systems for electric and electronic products, systems, and services, collectively known as *electrotechnology*. Details for open IEC projects on PV can be found at http://www.iec.ch/dyn/www/f?p=103:23:0::::FSP_ORG_ID,FSP_LANG_ID:1276,25.

goals of increasing investor and owner confidence in the asset to lower existing risk premiums.

It is an open question as to whether ongoing standards and certification activities are sufficient to meet electric utility needs, or whether they can serve as foundational building blocks for utilities to use in developing best practices for their own utility-scale PV plant development and ownership pursuits. The solar industry aspires to establish "gold" standards and best practices, akin to those currently used for rate-based conventional generation plants; however, many PV standards have the words "minimum requirements" in their titles and it is not clear how many PV plants are being operated in compliance with the many existing standards currently available. This paper highlights the ambiguity in existing processes along the PV plant value chain, explores how standards revisions currently underway could impact the *status quo*, and provides suggestions for future EPRI and utility involvement in standards and best practice development. It also identifies remaining gaps and explores some key areas that utilities can consider for optimizing the procurement, design, and operation of PV plants.

Examining the PV *Status Quo*: Room for Improvement across the Value Chain

The rapid growth of solar PV globally has created growing pains, including quality, performance, and industry standardization challenges. These issues have surfaced along the entire PV value chain, from modules and balance of plant equipment, through design and plant performance prediction, construction, commissioning, operation & maintenance, and decommissioning. What follows is an exploration of the range of issues over a PV plant's life cycle that could benefit from well-accepted, agreed upon processes and procedures—from design and equipment selection, through commissioning, and maintenance. Specific areas examined include equipment quality, project design and system performance modeling, plant monitoring, EPC issues and plant commissioning, and long-term O&M Strategy.

Equipment Quality

Ensuring equipment quality—and warranty value—remains an area of concern for utilities, developers, and project owners. For some, this concern stems from the strong growth of PV module producers outside of the historical leaders based in Germany and Japan, where the vast majority of PV modules and manufacturing equipment were produced as recently as 10 years ago. Specifically, the exponential growth in China's PV production over the past decade has led to often legitimate anxieties about the quality and durability of PV modules[8] (see Figure 1). Module price decreases have outpaced shipment quantity leading to decreased revenue, as well as to less scrupulous companies cutting corners and shipping product of inferior quality.

Meanwhile, spikes in demand, which often outpaced manufacturers'

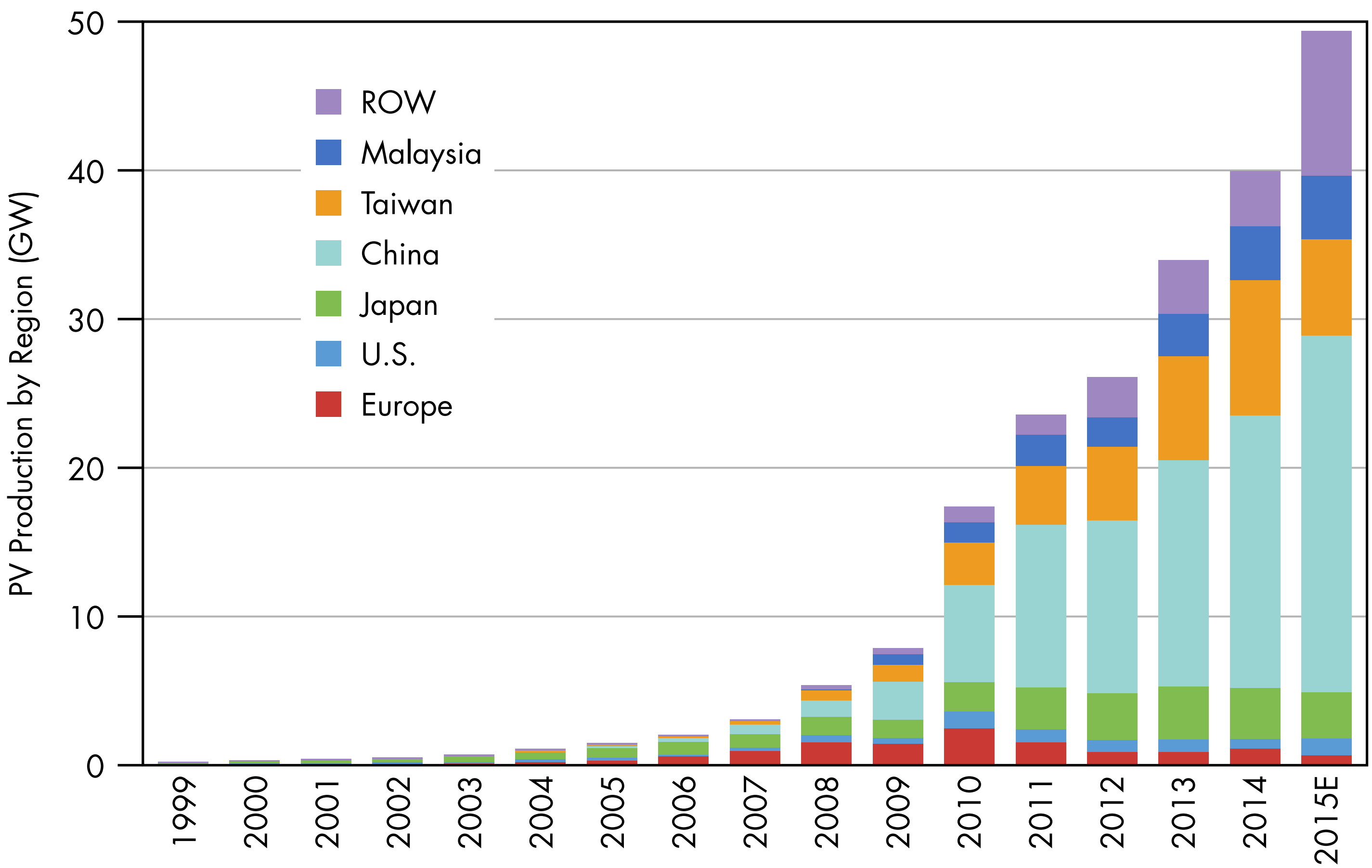

Figure 1. PV production by region/county, 2005-2015
Source: SPV Market Research

[8] Todd Woody, "Solar Industry Anxious over Defective Panels," *New York Times*. May 28, 2013, http://www.nytimes.com/2013/05/29/business/energy-environment/solar-powers-dark-side.html.

in-house production capabilities, gave rise to widespread contract manufacturing. According to one interviewed subject, modules shipped by a top tier manufacturer to a 20-MW project had origins from four different factories, with substantial differences in module quality among the shipments.

Ensuring quality control at manufacturers' sites adds another layer of complexity into equipment procurement. Selecting modules or other components to secure compliance with standards testing does not necessarily guarantee manufacturing quality and consistency of a supplier's product. Such quality assurance is still perceived as a need among companies procuring solar PV modules. Developers performing due diligence on suppliers may hire third-party, independent consulting firms to conduct factory audits for their diligence work—often at the insistence of financiers. Others may opt to buy only from companies perceived as top-tier, "bankable" module and inverter suppliers rather than take on the risk, or added cost of vetting questionable suppliers.

Equipment quality issues can also be encountered at the PV plant level. Quality control at the module manufacturer is for naught if the modules are roughly handled and broken during transport or installation (e.g., shattered glass or microcracks in c-Si cells). As another example, corrosion of steel piles used in foundations has become an issue for some PV power plants. Steel piles face galvanic corrosion underground due to contact with moisture, oxygen, and soil. Some PV plants have encountered unacceptable or unanticipated corrosion. The steel surface typically is galvanized or protected with a corrosion-resistant coating, although bare steel support has also been used. Even with corrosion protection, the application of galvanizing or coating may lack robust quality control, resulting in non-uniform coverage or local defects in the protective layer. Furthermore, steel supports have been buried in direct contact with the soil without cathodic protection, resulting in a potential corrosion problem.[9] The result could be accelerated loss of steel structure, and potentially catastrophic failure of a support (see Figure 2).

Figure 2. Below grade corrosion of steel tower
Source: Public Utilities Maintenance

Project Design and System Performance Modeling

For investors, a key *pro forma* variable is a PV power plant's lifetime energy production. Estimating PV plant energy production has room for improved consistency of methodology and application. Recent EPRI work compared expected and actual energy production from PV arrays and found a +/- 6% relative difference across five different systems,[10] in line with previous results from studies carried out by the National Renewable Energy Laboratory (NREL).[11] There are many factors that play a strong role in modeling and predicting energy output, such as differing modeling parameters and calculations, equipment tolerances and accuracies, and the PV systems themselves (e.g., size and location). Increasing accuracy and precision across models and better defining how the model can be used would allow for an easier comparison of bids for PV plants, less money being left on the table by any one party, and less perceived risk, potentially leading to lower cost of capital.

To provide additional detail, system performance modeling is commonly performed using PVsyst or System Advisor Model (SAM). Both software packages require many data inputs that can be manipulated to influence the estimated production of a specific plant, either upward (benefitting the seller) or downward (benefitting the buyer). As Soltage's Steven Goodbody argued in mid-2015:[12]

> These customizable products allow a wide variety and range of inputs, produce multi-page outputs, and do indeed create an

[9] *Corrosion of Buried Steel for PV Solar Power Plants*. EPRI, Palo Alto, CA: 2015. 3002007077.

[10] *Comparison of Predicted, Expected, and Actual PV Plant Performance*. EPRI, Palo Alto, CA: 2015. 3002006223.

[11] Rudié, et al., "System Advisor Model Performance Modeling Validation Report: Analysis of 100 Sites," *Locus Energy*. March 2014.

[12] Steven Goodbody, "The Solar Industry Needs Standards for System Production Estimates," < www.greentechmedia.com/articles/read/The-Solar-Industry-Needs-Standards-for-System-Production-Estimates > July 31, 2015.

Input	Issue
Meteorological data	Different sources of irradiance and weather data for a project can result in substantially different production estimates that are not comparable across reviewed bids
PV module degradation	Location-specific environmental conditions (e.g., climate) make rule-of-thumb degradation rates inappropriate and differently impact the materials in a module
Module operating temperature	Increasing operating temperature reduces module power output. Assumed temperatures throughout the year will impact energy predictions.
Inverter clipping	Models likely underestimate clipping due to the use of hourly time segments
Snow	Country or regional derating by snow is influenced by module clearance heights and tilt angles
Soiling	Soiling value in models is at the discretion of the model user, thus allowing non-consistent values in bids on the same plant. Impacts project economics for if/when panels are washed.
Shading and low-light response	Module type (e.g., silicon vs. thin-film) and use of tracking (e.g., fixed-tilt vs. tracking) influence energy output through assumptions on shading and low-light response.
Transformer and wiring losses	Rather than use generic assumptions, estimated losses from DC and AC equipment need to be based on actual equipment proposed and include both operational and continuous parasitic losses.

Table 2. Modeling inputs for forecasted production that can lead to non-comparable production estimates
Source: EPRI

impression of accuracy. But we should question the meaning of "accurate" when two modelers, using the same program but with differing assumptions, can produce results differing by 10 percent or more.

Nearly all of those interviewed for this research effort concurred that the inputs for PV plant modeling, shown in Table 2, are inconsistently applied across the industry. The succeeding bullet points provide greater insight into the factors that remain in contention.

- **Meteorological data**: Given the myriad sources for meteorological data, it remains unclear which data are most applicable for a specific project. The dataset closest to a site, even if it is irrigation monitoring system weather data?[13] The dataset with the highest quality of instrumentation used to collect the data, if not from a standardized source? The dataset from the closest Typical Meteorological Year (TMY) source or satellite-based data? The dataset that combines land-based and satellite data? The difference between land-based TMY3 data and satellite data such as NREL's Solar Power Prospector on its own can produce swings of +/-3% from actual plant performance, according to an established developer.[14]
- **Module operating temperature**: A typical silicon module outputs 0.45% less power per degree Celsius above 25, and conversely, power increases in cold environments. In desert environments, modules may operate at temperatures near 90°C, which equates to a 30% decrease in power. The meteorological data set, plant layout with respect to wind loading, and module type all play a role in modeling temperature and its predicted impact on energy output. Furthermore, PVsyst and SAM use different models to account for thermal losses.
- **PV module degradation**: Rules of thumb are often used to estimate PV module degradation. The common 0.5% to 0.8% per year degradation rate has been derived from a large amount of aggregated data and work performed by NREL.[15] However, it is not appropriate to apply this number to all situations because this generalization inadequately accounts for specific situations, such as the effect of climate-specific stress and/or degradation (e.g., operating temperature, snowfall, ocean spray), a module's rate of degradation (e.g., linear, supralinear, sigmoidal), or technological improvement to module manufacturing. Additional research is needed to clearly correlate the cause-and-effect of module degradation and its associated rate. This ambiguity can create business inefficiency. For instance, some developers reportedly cite higher degradation rates than expected in an effort to secure higher escalation rates for power purchase agreement (PPA) contracts. Further complicating the matter is the impact light initially has

[13] Irrigation monitoring systems typically use lower accuracy sensors that can have a +/-10% variation in their collected meteorological data.

[14] Eric Blank, Executive Vice President, Community Energy, September 3, 2015. Personal communication.

[15] Dirk Jordan and Sarah Kurtz, "Overview of Field Experience: Degradation Rates & Lifetimes," Solar Power International, Anaheim, CA, September 14, 2015. NREL/PR-5J00-65040.

on modules. For industry standard p-type silicon modules, which represents approximately 90% of the current market, there is an initial power decrease due to a detrimental boron-oxygen complex, often called light induced degradation. Some thin films have shown the opposite effect, increasing power output after initial light flashing. Standardized module infant mortality tests (e.g., IEC 61215) measure power output before and after each test, but the method used to provide a module's "nameplate" power rating is not standardized. For the module manufacturer it makes business sense to rate at a level that minimizes underperformance warranty returns. This adds to ambiguity on how module performance rolls up to predicted PV plant performance.

- **Inverter clipping**: Models likely understate inverter clipping losses. For instance, one utility operator has found that using hourly data may miss instances during the hour when irradiance levels triggered clipping. Likewise, care needs to be taken with imputing inverter capacities into performance models as, depending on the ambient temperature of an operating plant, it might lead to over-estimating production. During initial years of plant operations clipping may mask underperformance or anomalous equipment degradation rates.
- **Snow**: Derate factors vary based on the amount of snow received in an area, the height of a system (e.g., ground mount systems affected by snow drifts or clearance to shed snow), and tilt angle (e.g., high tilt angle sheds snow quicker).
- **Soiling**: Many environmental factors affect module soiling (e.g., type of soil, environmental conditions around the plant, amount of precipitation) and if/when panel washing occurs. More case studies and understanding are needed to better predict soiling's impact. According to one developer, soiling rates are often "fought over" during negotiations over output forecasts, with each party taking the position more favorable to their financial exposure. Impacting project economics is whether and how often modules will be cleaned. Most interview respondents stated that module cleaning is simply not worth the cost; however, it is a case-by-case economic decision. TÜV Rheinland found power production was reduced by up to 25% due to soiled panels in a desert environment.[16] Another interviewed source mentioned that one of his California projects suffered a ~5% reduction in energy production when modules were not washed.
- **Shading and low-light response**: Where applicable, horizon and near-field shading impact energy production. The impacts of shading are increased across PV technologies when tracking structures are used. Shading affects PV technology differently depending on the absorber type and construction of the module, causing either a linear or step-function decrease in power output. Cell response to low-light conditions, irrespective of shading, also varies by cell technology, with some – particularly thin films – more capable of converting low-light to electric energy.
- **Transformer losses**: Losses from transformers located between inverters and production meters should be, but are not always, estimated and transparently stated (e.g., operational losses, continuous parasitic losses, and whether standard equipment or high efficiency transformers are being used).
- **Wiring losses**: AC and DC wiring losses should ideally be modeled based on actual design figures that then can be retained in the EPC negotiations process.

Recent utility rate cases and the potential impact of high solar penetration on the grid (e.g., CAISO's duck curve) highlight the importance of capacity and energy production timing. Various market or policy standards have incentivized solar deployment based predominantly on capacity targets. A holistic approach that takes into account PV's impact on existing and future generation and wires assets will likely require optimization beyond capacity.

For instance, module orientation and tracking systems are two approaches that can shift production curves from PV plants. For example, orienting the azimuth of a PV system southwest shifts peak power production of that system closer to the typical peak customer load in the afternoon, though at the sacrifice of overall energy production compared to a south-facing system. Likewise, PV plant designers can choose a PV module tilt to either favor winter (high tilt at mid- and high-latitudes) or summer (low tilt) energy production. Whether to use fixed tilt mounting systems or single-axis tracking systems, which accounted for nearly 20% of ground-mounted PV systems in 2015, and more than 60% in the U.S., [17] remains a question for project developers and owners. This is a salient example

[16] Matthias Heinze, "PV system standardization developments IEC RE, IECEE, PV QA and Qualification Plus," Solar Power International, Anaheim, CA, September 14, 2015.

[17] Eric Wesoff, "Solar Trackers Employ Vastly Different Approaches to Moving PV Panels," *Greentech Media*. November 9, 2015, www.greentechmedia.com/articles/read/Solar-Trackers-Employ-Vastly-Different-Approaches-to-Moving-PV-Panels.

of the continued complexity to come as PV plant technology and needs change over time.

PV Plant Monitoring

Another area in plant design that has yet to coalesce around accepted practices is how much to invest in plant monitoring equipment, including sufficient meteorological stations on-site that can help track ambient conditions and communication systems to transfer data to secure server locations for future analyses (e.g., enabling condition-based maintenance). Data collected has a wide range of uses, including informing plant performance and guarantees, O&M cost effectiveness, and warranty claims, among others for plant operators. Based on interview findings, experienced developers appear to be adding more monitoring equipment to their plants with each successive project and to be focusing on more components and smaller sections of the overall plant. Likewise, developers are increasing the number of met stations deployed at a project in order to better capture data to ensure plant performance is meeting contractual obligations. It remains largely unsettled, however, how to determine the appropriate amount of monitoring equipment to deploy that balances its cost-benefit.

Performance ratios, or the comparison between anticipated and recorded production, require both strong modeling and standardized methods for collecting and analyzing production data from new plants. Yet even the methods for calculating performance ratios—a component that may be used to define acceptance testing protocol and basis for setting O&M contract stipulations—can vary between different EPCs. According to an experienced utility manager, performance ratio is calculated “all over the board.” In rudimentary performance ratio calculations, only the effect of insolation on the plant’s energy output is considered. Temperature-corrected performance ratio takes into account the effect of operating temperature on energy output. Further calculation refinements are converging towards an “energy performance index” that compares expected energy against actual production. As a nomenclature note, *predicted* energy is modeled using historical weather and irradiance inputs, such as typical meteorological year (TMY) data. *Expected* energy is calculated using the same model as predicted, but inputting actual on-site measured weather and irradiance data taken during energy production. Greater variances between predicted and measured than between expected and measured are to be expected.[18]

EPC Issues and Plant Commissioning

Based on interview feedback, PV plant Engineering, Procurement, and Construction (EPC) companies’ incentives can be misaligned with those of the plant owners. Historically, EPC profit was based on the upfront capital cost to build a plant, divorced from the plant owner caring more about the plant’s cost and performance over time. A number of interview respondents related that they have discovered quality issues resulting from EPC corner cutting. Misaligned incentives create situations where EPCs are encouraged to complete projects quickly and at the lowest possible cost, pass the commissioning and acceptance tests to receive final payment, then move on to successive projects. As one interviewed subject commented, if a contractor is faster at installing modules than the competition, should a greater number of microcracks in the modules’ cells be anticipated due to rougher handling?

Among cited examples of poor EPC work is a case where EPC staff bundled up bad connectors on panels and taped them off, rather than fixing the bad connectors. An operator of another project, when encountering a problem with cables, found that the test reports supposedly documenting successful installation had been copied with the same signature—and that actual tests on the system had not been completed as claimed. Only a careful review of plant data, followed by plant documentation, led to the discovery of this potentially fraudulent activity.

One utility has found that larger EPC firms tend to bring more standardization to their work, particularly firms that have strong, in-house civil engineers or ones available on commission. But the utility has also discovered that even though these firms are internally consistent in their approaches, they are not always consistent with peer EPC firms. To add to the challenge, some interview respondents found that larger firms typically do not want to bid on plants below 20 MW, as smaller, low-cost local EPC firms tend to underbid these larger companies during competitive procurement processes (e.g., higher overhead costs spread across less capacity). Then, these smaller EPC firms often employ sub-contractors who have even less standard processes in place for building projects. Given that financiers typically prefer experienced EPC firms to ensure correct construction and commissioning of projects, an apparent savings in upfront EPC costs might cause increased headaches and costs throughout the life of the project.

[18] *Comparison of Predicted, Expected, and Actual PV Plant Performance*. EPRI, Palo Alto, CA: 2015. 3002006223.

Attempts to align EPC and owner incentives are occurring. For example, one utility is taking ownership of a handful of new PV plants in 2015, and for half of the facilities, it is conducting an acceptance test at substantial completion of the project, but for the remaining plants, it plans to conduct the final acceptance test one year after commissioning. Another utility conducts its acceptance testing at commissioning, but also includes a two-year performance guarantee in its contract, effectively holding its developer responsible for contractually defined levels of plant availability. It remains unclear whether these approaches will provide sufficient confidence in plant performance over the long-term, since it is possible to mask performance problems upfront (e.g., using well over unity DC / AC ratios on inverters).

Another approach to acceptance testing comprises a capacity test and an energy test. The capacity test includes an availability test on a sunny day(s) to ensure that all major equipment is available 100% of the time (even if it is not functioning at 100% of capacity). This test is to ensure correct installation of the equipment. The second test is usually a longer-term energy test (preferably using the energy performance index), where the plant's actual energy production is compared to the project's modeled, expected energy production. Given uncertainty with model and ambient weather data monitoring equipment accuracy, expected and actual production typically end up being less than +/- 6% different. If real production falls below a minimum threshold, then contracts (and prices) are typically renegotiated.

An alternative, but expensive, method of ensuring plant performance is to pay for a wrap warranty that covers the whole plant for a set period of time. These typically are two years in length, though 10-year wrap warranties exist. In a sense, wrap warranties represent an additional cost for a plant with unknown benefits accrued to them. EPCs are often reluctant to commit to such agreements unless they are part of a vertically integrated company that supplies equipment (particularly modules) and undertakes O&M. Regardless, there remain many different approaches to how owners and financiers expect acceptance testing to occur.

Long Term O&M Strategy

PV power plants are seen by the uninitiated as requiring minimal O&M for their successful operation, with the view that they have no (or few, if tracking systems are used) moving parts. However, the O&M of PV plants is an underrated activity in terms of complexity and challenges—and still without clear answers as to what are best practices. Over 80% of PV plants installed worldwide, by capacity, have been commissioned within the last 5 years.[19] There is inadequate long-term performance data available to analyze the causal effects of various operation and maintenance schemes. This feedback loop is important for determining the right activities, frequency, and associated cost. Something akin to EPRI's Preventative Maintenance Basis Database, which provides this guidance for conventional rotating generation equipment, is needed for PV.

Lacking the clear, direct link between O&M activities and their effect has made O&M budgeting a contentious process. O&M is often viewed as a cost center rather than a value generator. As such, there is little consensus surrounding "appropriate" O&M budget levels. Developers are typically inclined to estimate lower O&M costs to increase plant valuations. O&M service providers, meanwhile, tend to embrace higher budget requirements to cover their margins and contractual uncertainties, while investors can be motivated to set O&M allocations based on individual project investment horizons and revenue prospects. These contrasting viewpoints, among others, can impact budget outcomes and potentially undermine a plant's lifecycle performance economics.

As a starting point, the PV industry would benefit from widely known and agreed upon contractual definitions. For instance, O&M contracts that include equipment availability guarantees[20] are at times based on contracts for conventional, dispatchable power plants. Given the intermittent nature of PV power plants, use of such language creates challenges for bridging the gap between plant operators and asset owners. In reviewing existing PV O&M contracts, Sandia National Laboratories found that for the term "availability," there were some 40 different definitions and methods for its calculation.[21]

[19] GTM Research, "Megawatt-scale PV O&M and Asset Management 2015–2020: Services, Markets and Competitors," November 2015.

[20] Availability or "uptime" guarantees define the percentage of time that a PV system must be fully able to produce electricity. They are typically set at 97–99% per year; however, no standard calculation method is used to determine the guarantee.

[21] *A Best Practice for Developing Availability Guarantee Language in Photovoltaic (PV) O&M Agreements*. Sandia National Laboratories, Albuquerque, NM: 2015. SAND2015-10223.

Corrective/Reactive Maintenance	
On-Site Monitoring	Non-Critical Reactive Repair**
Critical Reactive Repair* (high priority)	Warranty Enforcement
Preventative Maintenance (PM)	
Panel Cleaning	Water Drainage
Vegetation Management	Retro-Commissioning***
Wildlife Prevention	Upkeep of Data Acquisition and Monitoring Systems (e.g., electronics, sensors)
Update of Power Generation System (e.g., Inverter Servicing, BOS Inspection, Tracker Maintenance	Site Maintenance (e.g., security, road/fence repair, environmental compliance, snow removal, etc.)
Condition-base Maintenance (CBM)	
Active Monitoring – Remote and On-site Operations	Equipment Replacement (planned and unplanned)
Warranty Enforcement (planned and unplanned)	

Table 3. Major elements of PV operations and maintenance
Source: EPRI [22]

As delineated below, PV O&M approaches are typically broken out into three main categories. Table 3 provides an overview of the major tasks associated with O&M, across the three different approaches.

- **Corrective or reactive maintenance** addresses equipment repair needs and breakdowns after their occurrence and, as such, is instituted to mitigate unplanned downtime. The historical industry standard, this "break-fix" method allows for low upfront costs, but also brings with it a higher risk of component failure and accompanying higher costs on the backend.
- **Preventative maintenance** includes routine inspection and servicing of equipment—at frequencies determined by equipment type, environmental conditions, and warranty terms in an O&M services agreement—to prevent breakdowns and unnecessary production losses. This approach is becoming increasingly popular because of its perceived ability to lower the probability of unplanned PV system downtime. Still, there remains little agreement on how often even basic inspections should be done or the time intervals for completion of specific tasks.
- **Condition-based (or predictive) maintenance (CBM)** uses real-time data to anticipate failures and prioritize maintenance activities and resources. A rising number of third party integrators and turnkey providers are instituting CBM regimes to offer greater O&M efficiency. The increased efficiency, however, comes with a high upfront price tag given advanced communication and monitoring software and hardware requirements.

Likewise, PV plant owners have widely divergent views on the correct balance between on-site labor and remote analyses of operational data. Some operators are also cognizant that labor-hours spent at the plant can often be the most expensive component of O&M; by reducing them, they can free up resources that can otherwise be spent on engineering analyses and component upgrades. Yet some stakeholders emphasize "putting eyeballs on the plant" as they have found problems (including vandalism) they did not anticipate. Some utilities are even piloting efforts to use unmanned aerial systems (e.g., drones) with thermal imaging sensors to detect panel hotspots, though it's unclear whether this is a cost-effective endeavor.[23]

[22] *Budgeting for Solar PV Plant Operations and Maintenance: Practices and Pricing*. EPRI, Palo Alto, CA and Sandia National Laboratories, Albuquerque, NM: 2015. 3002006218; SAND2015-10851 R.

[23] *Utilizing Unmanned Aircraft Systems as a PV O&M Tool*. EPRI, Palo Alto, CA: 2015. 3002006216.

Canvassing PV Standards: Creation and Revision Activities

Standards provide the broad framework for any industry, including the agreed-upon definitions of terminology and minimum technical requirements stakeholders require for safety and specifications. Standards also can provide consensus best practice protocols that, for example, stipulate how a power plant's capacity should be measured. In a practical sense, standards provide a consistent, common platform and a degree of confidence that aids business transactions. They can be used, for instance, to reduce negotiating and prevent recreating common practices in bilateral contract discussions.

Given that standards are typically born from consensus, they often exclude the rigor that some parties believe are necessary. Indeed, many of the standards themselves include the words "minimum requirements" in their titles, setting an agreed upon foundation from which to build. As standards are approved and published, years can go by before they become widely adopted, if ever. Further, standards often do not prescribe how they should be implemented. Ideally, industries use standards as a springboard from which to build best practices. The PV industry is currently overhauling many of its core standards based on new learnings; best practices are being developed in parallel.

Genesis of Today's PV Module Standards

Work by the Jet Propulsion Laboratory (JPL) in the late 1970s serves as an example of how standards, specifically design qualification tests, have benefited the industry.[24] JPL executed a series of block buys of PV modules that were put under successively harsher accelerated tests. Each succeeding block buy had its test procedures modified to reflect failures that were observed in the terrestrial deployments. Module manufacturers also modified their product to reflect learnings, and an informational feedback loop was created that informed all participants.

On the fifth block of modules tested, JPL found that their test regime—which included 200 thermal cycles, 10 humidity/freeze cycles, and for the first time, hot spot testing—substantially reduced the failure rate of field deployed modules. In fact, the infant mortality rate for block IV testing regime was greater than 50%, whereas the testing regime for block V was reduced to around 1%. This early work was the basis for current module testing standards and it continues to be refined to further reduce product infant mortality.

For the PV industry, the International Electrotechnical Commission (IEC) has become the *de facto* standards development organization. It has put scores of standards in place that are the most commonly used and is currently developing many more. It is not the only standard-making body, however. ASTM International has also issued dozens of PV standards, and there are an abundance of nationally-focused organizations, including Verband der Elektrotechnik and Elektronik und Informationstechnik (VDE) in Germany; the American Society of Mechanical Engineers (ASME), Institute of Electrical and Electronics Engineers (IEEE), and National Fire Protection Association (NFPA, which produces the National Electric Code, as NFPA 70) in the United States; and Chinese and Japanese organizations as well. International standards organizations are best suited to provide guidance on common issues that transcend borders, such as PV module infant mortality testing or measuring capacity and energy of a plant. To be adopted, these standards must be usable or implementable at the local or regional levels. The national / regional standards bodies are better at guiding specific local issues, such as building codes and interconnection requirements. Table 4 provides an overview of a select number of these organization and their PV standards efforts. Additional details follow the table.

The International Electrotechnical Commission (IEC)

The IEC focuses on the preparation and publication of international standards for all electrical, electronic and related technologies. IEC membership and participation is country-based, which means that every member county, no matter how large, small or active in standards development is allowed one vote in what goes into an IEC standard.

IEC Technical Committee 82 (TC 82) covers solar PV energy systems. Created in 1981, TC 82 has published dozens of standards to help govern the PV industry in the intervening years. At the time of writing, TC 82 consisted of 38 participating countries and 11 observing county members. The committee has 73 published standards, with nearly 80 products underway to create new standards or

[24] Rosenthal, A.L., et al., "A Ten Year Review of Performance of Photovoltaic Systems." *Proceedings of 23rd IEEE Photovoltaic Specialists Conference*. 1993, Louisville, KY: IEEE, p. 1289–1291, as cited in *Photovoltaic Module Qualification Plus Testing*. National Renewable Energy Laboratory, Golden, CO: 2013. NREL/TP-5200-60950.

Standard	Title	Areas of coverage					Notes
		Equipment	Design	Construction	Commission	O&M	
IEC							
IEC 61215 Ed2.0 (published 2011)	Design qualification and type approval for crystalline silicon terrestrial PV module	x	x				Revisions in progress for 2016, will aggregate other module standards (e.g., IEC 61646 to be segregated and become IEC61215-1-2, -3, -4, -5)
IEC 61646 Ed2.0 (published 2008)	Thin-film terrestrial photovoltaic (PV) modules – Design qualification and type approval	x	x				Being updated as IEC 61215-1-2 (CdTe), 1-3 (a-Si), 1-4 (CIGS), and 1-5 (flexible, non-glass modules) for late 2016 publication
IEC 61724 Ed1.0 (published 1998)	Photovoltaic system performance monitoring – Guidelines for measurement, data exchange and analysis		x		x	x	Revisions to be published in 2016 and 2017, for measuring PV system capacity (IEC 61724-2) and energy (IEC 61724-3)
IEC 62109-1 Ed1.0 (published 2010)	Safety of power converters, inverters, combiners, controllers	x	x				Exist for individual components; new standard to be published in late 2016 on more complex combinations of devices
IEC 62446-1 Ed1.0 (published 2009)	Min. requirements for PV system documentation, commissioning tests and inspection, O&M		x	x	x	x	Updated standard to be published early 2016; to detail standardized method of calculating, and determining problems in PV system performance
IEC 62446-2 Ed1.0 (published 2009)	Grid connected photovoltaic (PV) systems – Part 2: Maintenance of PV systems					x	New standard to focus on maintenance of PV systems; target publication data in mid-2017
IEC 62446-3 Ed1.0 (published 2009)	Grid connected photovoltaic (PV) systems – Part 3: Outdoor infrared thermography of photovoltaic modules and plants		x			x	New standard to focus on diagnostic thermography of PV plant systems; target publication data in late 2016
IEC 62548 Ed1.0 (published 2013)	Design requirements for installation and safety requirements for PV		x	x	x		Focus on PV design safety requirements on DC side of system; revision focused on installation to be published late 2016
IEC 62804 Ed1.0 (published 2015)	Photovoltaic (PV) modules – Test methods for the detection of potential-induced degradation - Part 1: Crystalline silicon	x	x				Specifies tests for potential induced degradation. 62804-1 covers c-Si modules; 62804-2 to cover thin-film modules, and be published mid-2017
IEC 62892-1 (not published)	Testing of PV modules to differentiate performance in multiple climates and applications – Part 1: Requirements for testing	x	x			x	Proposed climate-specific test schedule for early 2017 publication; output of PVQAT activity
IEC 62941	Guideline for increased confidence in PV module design qualification and type approval	x	x				Published Feb. 2016; output of PVQAT activity; does not require factory audit, nor include scorecard to tier PV module suppliers
IEC PNW82-944 (not published)	Photovoltaic (PV) Systems – Availability for PV Power Stations (PVPS)				x	x	To be published 2018-2019
IECRE Certification (not published)	IEC System for Certification to Standards relating to equipment used in PV, wind, and marine energy systems	x	x	x	x	x	Goal is to have first certificate(s) issued in 2016

Standard	Title	Areas of coverage					Notes
		Equipment	Design	Construction	Commission	O&M	
ASTM	(Subcommittee E44.09 on PV)						
E772	Standard terminology for solar energy conversion	x	x				Foundation standard used for defining terms related to solar energy
E948-15	Standard test method for electrical performance of photovoltaic cells using reference cells under simulated sunlight	x	x				Methodology for testing PV cells electrical performance; WK50329 established to update this standard, with focus on temperature-dependent correction factor
E1171-15	Standard test methods for photovoltaic modules in cyclic temperature and humidity environments	x	x		x	x	Revised in 2015; refers to IEC 61215 and IEC 61646 for some specifications of testing modules
E2848-13	Standard test method for reporting photovoltaic non-concentrator system performance	x	x		x	x	Test method for conducting a capacity test; it does not account for weather or energy production over time
E2939-13	Standard practice for determining reporting conditions and expected capacity for photovoltaic non-concentrator systems				x	x	Used in conjunction with E2848 as part of acceptance test to compare expected capacity and measured capacity
WK49851	New Test Methods for Standard Test Methods for Artificial Accelerated Weathering of Materials for Solar Applications Under Simulated Sunlight	x					Proposes standard on durability testing of PV modules, with aim of providing guidelines for other standards-writing organizations (e.g., IEC, TUV-R)
E3010-15	Standard Practice for Installation, Commissioning, Operation, and Maintenance Process (ICOMP) of PV Plants		x	x	x	x	ASTM's approach in providing qualification standard for investors, in advance of IECRE
IEEE							
P1547	Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces		x		x	x	Full revision of original 2003 standard and 2014 amendment underway, includes eight sub-working groups addressing specific issues; coverage is on PV system interconnection to distributed system
ASME							
ASME-RAM-1-13	Reliability, Availability, and Maintainability of Equipment and Systems in Power Plants		x	x	x	x	Provides the requirements to establish a Reliability, Availability, and Maintainability (RAM) program for any power-generation facility
ASME-RAM-2	Reliability, Availability, and Maintainability Program Development Process for Existing Power Plants		x	x	x	x	Draft standard aimed at implementing RAM program at existing power plants. Balloting aimed for 1Q16

Table 4. Select standards covering the PV life cycle
Source: EPRI

revise existing ones,[25] an indication of the ground-swell of support in updating and expanding IEC's standards coverage.

IEC goes beyond creating standards through its Standards Management Board; it also provides conformity assessment for products, systems, and personnel via its Conformity Assessment Board (CAB). In 2013, IEC's CAB launched the IEC System for Certification to Standards Relating to Equipment for Use in Renewable Energy Applications (IECRE). IECRE aims to provide a global certificate system for PV, wind, and marine energy projects. As currently envisioned, IECRE accreditation would ensure that a common set of metrics, standards, and processes are used and followed from the inception of a project through its disposal, with the goal of decreasing overall project risk and increasing the confidence of investors and projects owners. The end result would be allowing better comparison among different plants, and overall lower cost for renewable energy, which is discussed later in this paper.

Summaries of Key IEC Standards under Revision

IEC 61215. Titled "Crystalline silicon terrestrial photovoltaic (PV) modules – Design qualification and type approval", its most recent revision was published in 2005.[26] IEC 61215 is paired with IEC 61646, which covers thin-film technologies.[27] These standards test for infant mortality of a PV module and are intended to qualify a design before the design is put into production, so, by their nature do not require an ongoing quality management system to be in place in order to initially pass the test. There is not enough information to correlate these tests to long-term reliability (i.e., they cannot calculate year-on-year degradation rate nor determine lifetime energy production). Project financiers typically require PV modules meet the application standard as part of their due diligence. However, neither IEC 61215 nor IEC 61646 suggest what the actual lifetime expectancy of modules will be, as that will also depend on their environment and the conditions under which they are operated.

These two standards are being updated and are scheduled to be replaced by a series of seven standards and test procedures under the IEC 61215 heading. For example, IEC 61646 currently covers all thin-film PV modules. Future editions will be renamed as IEC 61215-1-2, 61215-1-3, 61215-1-4, and 61215-1-5 for CdTe, a-Si, CIGS, and flexible, non-glass PV modules, respectively. Publication of these new standards is anticipated to start in 2016 and conclude in 2017. The changes underway address failures that are being seen in the field by adding more tests to the protocols, incorporating the "Quantification Plus" testing work of NREL.[28] The goal is to correlate and test as many field-observed failure modes as possible against accelerated tests, thereby reducing infant mortality and hopefully increasing module energy production. Of note, "Qualification Plus" includes accelerated tests that target infant mortality of encapsulants, backsheets, junction boxes, bypass diodes, cables, and connectors, making it applicable to all module technology types.

IEC 61724. Titled "Photovoltaic system performance monitoring - Guidelines for measurement, data exchange and analysis," its most recent revision was published in 1998.[29] However, a revision of the standard is being worked on and is scheduled for completion in early 2017. The updated IEC 61724 will include three distinct, but related, standards for guiding how to monitor a PV power plant, how to conduct a capacity test, and how to conduct an energy test—areas that are critical to gauging PV plant operations.

The monitoring standard (**IEC 61724-1**) includes various uses of plant operating data, such as identification of performance trends, comparing performance to design expectations and guarantees, localization of potential faults in a system, and comparison of PV systems at different locations. Importantly, the revised standard will also provide specific definitions for performance ratio and other metrics that often have a variety of interpretations in the industry. The proposed standard also takes into account that different sized plants require different levels of monitoring, including recording intervals and timestamp accuracy, and is likely to include three levels of precision, instead of a single set of requirements. The standard will also provide guidelines for collecting ambient environmental conditions at the plant's site. The aim is to enable sufficient collection to conduct the capacity and energy tests in IEC 61724-2 and IEC 61724-3, but also to be able to troubleshoot problems should performance not achieve design expectations.

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[25] IEC TC 82, www.iec.ch/dyn/www/f?p=103:23:0::::FSP_ORG_ID,FSP_LANG_ID:1276,25.

[26] IEC 61215 can be found at https://webstore.iec.ch/publication/4928.

[27] IEC 61646 can be found at https://webstore.iec.ch/publication/5697.

[28] *Photovoltaic Module Qualification Plus Testing*. National Renewable Energy Laboratory, Golden, CO: 2013. NREL/TP-5200-60950.

[29] IEC 61724 can be found at www.iec.ch/dyn/www/f?p=103:38:0::::FSP_LANG_ID,FSP_ORG_ID,FSP_PROJECT:25,1276,IEC%2061724%20Ed.%201.0.

The capacity test standard (**IEC 61724-2**) aims to establish a two-day minimum (potentially seven days or longer if the weather is not sunny) test to measure power output from a PV plant. The proposed method employs a correction factor to compare the plant's predicted performance (under reference conditions) to the performance expected under the measured conditions. The standard is also planning to include a methodology for how to handle PV plants with a high DC-to-AC ratio, which may otherwise produce misleading results.

The energy test standard (**IEC 61724-3**) aims to specify how to conduct long-term testing— recommended to be for 365 days—of PV systems over a full range of operating conditions and provide the documentation necessary to assess a performance guarantee for a plant's production. It also aims to ensure coverage of a host of performance issues, including response to different weather conditions and outages of the plant from hardware failure, poor maintenance procedures, plant degradation, or other problems over the course of multiple years.

The revisions to IEC 61724 have forced discussions and consensus around power and energy related metrics, such as energy availability and preferred performance metrics to use. It is hoped that this standard will begin to unify the industry, increase business efficiency, and align PV plants' expectations against actual performance.

IEC 62446. Titled "Grid connected photovoltaic systems - Minimum requirements for system documentation, commissioning tests and inspection," its most recent revision was published in 2009.[30] The standard describes a procedure for ensuring that the plant is wired correctly, but it does not attempt to verify that the output of the plant meets the design specification. IEC 62446 is being updated, with a new IEC 62446-1 focused on commissioning and inspection due to be published in early 2016. A follow-up IEC 62446-2 focused on maintenance is scheduled for mid-2017.

IEC 62804. Titled "Photovoltaic (PV) modules – Test methods for the detection of potential-induced degradation," this document specifies testing procedures to identify modules' susceptibility to potential induced degradation. Potential Induced Degradation decreases the energy output of PV modules due to anomalously high leakage current that decreases cell conversion efficiency, most often occurring at the high-voltage end of PV module strings.[31] Two new standards are to be the result, one for c-Si modules (IEC 62804-1, which was published in August 2015) and the other for thin-film modules (IEC 62804-2). These test procedures may become increasingly important given a predicted rise in 1500V inverter production and usage.[32]

IEC 62941. Titled "Guideline for increased confidence in PV module design qualification and type approval," this new technical specification had its first edition published in February 2016.[33] The catalyst for this specification came from work conducted by the International PV Quality Assurance Task Force (PVQAT). (For further information, see sidebar: *Non-Standards Organizations Support Improvements in the PV Industry*.) The specification will focus on aligning manufacturers' quality management systems with customers' needs regarding warranty, power rating, and other areas. It would be implemented as a factory inspection. However, the specification does not include a scorecard to rank PV module suppliers, which would provide both a higher hurdle for and a comparative measuring system of manufacturers.

[30] IEC 62446 can be found at www.iec.ch/dyn/www/f?p=103:38:0::::FSP_LANG_ID,FSP_ORG_ID,FSP_PROJECT:25,1276,IEC%2062446%20Ed.%201.0.

[31] *Literature Study and Risk Analysis for Potential Induced Degradation*. EPRI, Palo Alto, CA: 2014. 3002003737.

[32] GTM Research, "Q4 2015 Solar Executive Briefing," January 2016.

[33] IEC 62941 can be found at www.iec.ch/dyn/www/f?p=103:38:0::::FSP_ORG_ID,FSP_APEX_PAGE,FSP_LANG_ID,FSP_PROJECT:1276,23,25,IEC/TS%20 62941%20Ed.%201.0.

Non-Standards Organizations Support Improvements in the PV Industry

There are numerous efforts underway in the PV sector that aim to improve current practices and tools, and often end up catalyzing future activities by standards organizations to both create and update existing standards. Profiled below are four such efforts, though other organizations, such as the National Rural Electric Cooperative Association (NRECA), Solar Access to Public Capital (SAPC), Solar Electric Power Association (SEPA), and Solar Energy Industries Association (SEIA) have also contributed to these types of activities.

- **The SunSpec Alliance**, created in 2009, was an early effort to go beyond formal standards and provide best and common practices for the PV industry. The alliance has more than 70 company members. Based in California's Silicon Valley, SunSpec modeled its approach on the computing industry and internet development: open-source licensing and cooperative development. Its expectation is that this approach will lead to information models, data formats, communication protocols, system interfaces, and other artifacts that can enable PV and other distributed energy power plants to interoperate transparently with system components, software applications, financial systems, and even the grid.

  To date, SunSpec has issued seven best practice guides,[34] along with a series of specifications, software tools, and a certification process. SunSpec also aims to have its work serve as the basis for and be incorporated into standards developed by official standards organizations. SunSpec members actively participate in IEC and other standards organizations.
- **The International PV Quality Assurance Task Force (PVQAT)** works to improve PV quality and reliability standards through a three-pronged approach: a rating system to ensure durable design of PV modules, a guideline for ensuring factory quality assurance, and a system to certify PV system design, installation, and operation.[35] Launched in 2011, PVQAT aims for its work to be incorporated by international technical standards for verifying PV component and system quality and bankability. NREL is leading U.S. involvement in PVQAT.

  PVQAT is focusing not just on the design of modules, but also on the manufacturing process so as to ensure consistent quality. PVQAT has written a PV-specific version of ISO 9001 that the IEC has published as IEC 62941. PVQAT's research is also informing the work on another standard, IEC 62892-1, which will provide guidelines for climate-specific testing of PV modules in different climates and applications. PVQAT has also set up a task force to support the IECRE certification effort.
- **The Solar America Board for Codes and Standards (Solar ABCs)** is a collaborative effort that focuses on improving building codes, utility interconnection procedures, and product standards, reliability, and safety in the U.S. solar marketplace.[36] Founded in 2007, Solar ABCs has been exclusively funded by the U.S. Department of Energy (U.S. DOE), though whether the DOE will provide future funding is unclear as of January 2016. Solar ABCs has issued roughly 30 reports on specific code and standard issues, as well as three reports detailing existing gaps in PV codes and standards that merit attention.
- **The PV Performance Modeling Collaborative (PVPMC)**, though less involved in directly supporting the creation of standards, is focused on improving the accuracy and technical rigor of PV performance models and analyses.[37] Members of this collaborative support and maintain both Matlab and Python code repositories, consisting of irradiance models, PV performance algorithms and time-series data analysis tools. Spearheaded by Sandia National Laboratories, PVPMC's work aims to increase confidence in modeled PV plant output and, in turn, reduce financing costs.

[34] SunSpec best practice guides are available at http://sunspec.org/download-sunspec-best-practices.

[35] The International PV Quality Assurance Task Force homepage is www.pvqat.org/index.html.

[36] Solar ABCs homepage is www.solarabcs.org/index.html.

[37] The PV Performance Modeling Collaborative homepage is https://pvpmc.sandia.gov.

ASTM International

ASTM International develops and delivers voluntary consensus standards. Its members included more than 30,000 individuals, working via more than 140 technical standards writing committees, to create the test methods, specifications, classifications, guides and practices that support industries and governments worldwide. ASTM's PV work is mainly run through its E44.09 subcommittee. As of December 2015, ASTM had 27 active standards on PV electric power conversion and one more proposed,[38] with five of the existing standards undergoing revision.

Although ASTM has "international" in its name, the organization does not appear to hold as much credence internationally for the PV industry as it does other industries. Rather, the U.S. PV industry tends to use ASTM to produce a PV-related standard that can later be modified and incorporated by the IEC, as the IEC's process tends to be more time-consuming. This approach is unfavorable since it causes copyright issues between the organizations. Proponents of the IECRE even created a high-level ASTM standard (ASTM E3010-15) laying out standard practices for PV plant installation, commissioning, operation, and maintenance as a precursor to the IECRE effort.[39] IEC standards often point to ASTM standards for support or definitional details, as well.

ASTM E1171-15. Titled "Standard Test Methods for Photovoltaic Modules in Cyclic Temperature and Humidity Environments," its most recent revision was published in 2015.[40] E1171 is used to test PV modules ability to withstand repeated temperature cycling and high humidity. The durations of the individual environmental tests are specified by use of this test method; however, commonly used durations are 50 and 200 thermal cycles, 10 humidity-freeze cycles, and 1000 h of damp heat exposure, as specified by module qualification standards such as IEC 61215 and IEC 61646.

ASTM E2848-13. Titled "Standard test method for reporting photovoltaic non-concentrator system performance," its most recent revision was published in 2013.[41] The standard describes a test method for determining the power output of a photovoltaic system. It is to be used in documenting the completion or subsequent operation of a PV system. Essentially a capacity test, it is not intended for quantifying performance over all ranges of weather or times of year, nor for energy production.

ASTM E2939-13. Titled "Standard Practice for Determining Reporting Conditions and Expected Capacity for Photovoltaic Non-Concentrator Systems," its most recent revision was published in 2013.[42] The standard provides procedures for determining the best reporting conditions to use for defining the expected capacity of a specific photovoltaic system in a specific geographical location that is in operation under natural sunlight during a specified period of time. The expected reporting conditions are intended for comparison with the measured capacity determined by the test method in E2848 for selecting appropriate reporting conditions, including solar irradiance in the plane of the modules, ambient temperature, and wind speed, needed for the photovoltaic system capacity measurement. E2939 can be used as part of an acceptance test by comparing expected capacity and measured capacity of a plant, though many criteria, such as testing-period length and when to discard specific data, are left to users' discretion.

IEEE 1547

The IEEE 1547 interconnection standard can be adopted and used by any jurisdiction.[43] It has been the default requirement for distributed energy resources (DER) connected in most of North America's distribution system. The standard applies to all types of DER interconnected into the 60 cycle distribution grid. When the standard was issued it limited aggregate capacity to 10 MVA or less. The update that is currently in process is expected to expand the scope to any primary (MV) or secondary (LV) distribution connected system. Given the widespread deployment of PV plants interconnecting along distribution feeders, IEEE 1547's role in governing future megawatt-scale PV deployment is likely to grow.

[38] For a list of active PV standards from ASTM, go to http://www.astm.org/COMMIT/SUBCOMMIT/E4409.htm.

[39] ASTM E3010-15, Standard Practice for Installation, Commissioning, Operation, and Maintenance Process (ICOMP) of Photovoltaic Arrays, ASTM International, West Conshohocken, PA, 2013, www.astm.org/Standards/E3010.htm.

[40] ASTM E1171-15, Standard Test Methods for Photovoltaic Modules in Cyclic Temperature and Humidity Environments, ASTM International, West Conshohocken, PA, 2013, www.astm.org/Standards/E1171.htm.

[41] ASTM E2848-13, Standard Test Method for Reporting Photovoltaic Non-Concentrator System Performance, ASTM International, West Conshohocken, PA, 2013, www.astm.org/Standards/E2848.htm.

[42] ASTM E2848-13, Standard Practice for Determining Reporting Conditions and Expected Capacity for Photovoltaic Non-Concentrator Systems, ASTM International, West Conshohocken, PA, 2013, www.astm.org/cgi-bin/resolver.cgi?E2939-13.

[43] IEEE 1547's homepage is http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

Originally approved in 2003, IEEE 1547 stated that the DER shall not actively regulate voltage at the point of common coupling. However, an amendment to 1547 approved in 2014 (known as IEEE 1547a) removed that ban by stating that DER may actively participate in voltage regulation by changes in real and reactive power. State-level actions undertaken to address near-term grid reliability concerns, including updates to California Rule 21 and Hawaii Rule 14H, have taken the further step of stipulating inverter grid support requirements.[44] Another change in 1547a allows DER more flexibility in responding to voltage and frequency disturbances, including trip limits and clearance times.

Additional changes are likely in the coming year as the IEEE continues working on further modifications, including those related to voltage and frequency ride-through, voltage regulation by DER, and interoperability. Debate is underway in the 1547 working group on whether advanced inverter-based technologies, such as PVs, should be allowed to provide more services than traditional synchronous machines. Maintaining technology agnosticism has resulted in discussions around "Performance Categories" for the various technologies. In early 2016, revision efforts will commence for IEEE 1547.1, which will detail the standard test and compliance procedures for the base 1547 standard. Finding consensus on compliance has the potential to be more contentious than creating the actual technical standards, even if different levels are required for utility-scale versus distributed PV. IEEE is also beginning to take up communications and interoperability requirements under its 1547 umbrella.

The current process of updating IEEE 1547 is expected to be completed in 2016-2017 timeframe, though remaining issues to be resolved may push this timeline back. Revisions to the standard are likely to increase the inverter grid support options available for utility-scale PV systems. With 1547 stipulating minimum requirement, local interconnection agreements will remain key to stipulating site-specific obligations between DER owners and the utility.

ASME

ASME-RAM-1-13, titled "Reliability, Availability, and Maintainability of Equipment and Systems in Power Plants,"[45] is a standard that the American Society of Mechanical Engineers (ASME) published in 2013. This standard provides a high-level view of how to implement a Reliability, Availability, and Maintenance (RAM) process for power plants. RAM is a process engineering approach that has been used for some 40 years, including the electric power industry.[46] Key concepts in RAM are to identify potential failure mechanisms and make design changes to avoid them, and to monitor performance in order to enable improvements in design. In the past decade, the RAM approach has been adopted by the U.S. Department of Defense as a necessary practice for its suppliers.[47]

RAM-1-13 was conceived for use with conventional power plants, though Brian Wodka of RMF Engineering (and chair of ASME's RAM technical committee) states that it can be applied to renewable energy plants, as well.[48] The program process includes the establishment of RAM goals and requirements for design, construction and commissioning, and operations. The RAM approach is more valuable than a simple "pass/fail" methodology, as it retains flexibility for asset owners to stipulate specifications to meet their own specific requirements. In early 2016, ASME plans to ballot a more detailed, RAM-2 standard that will define tasks and how to group work in the RAM process. Although outside of the usual standards activities for PV plants, there appears to be useful guidance for PV plant developers and owners in exploring the use of the RAM process for designing future plants and maintaining existing ones.[49]

[44] *Solar PV Market Update*. Volume 15, Q3. EPRI, Palo Alto, CA: 2015. 3002005778.

[45] ASTM-RAM-1-13 can be found at www.asme.org/products/codes-standards/ram1-2013-reliability-availability.

[46] Brian Wodka, "Power Plant Reliability," *Consulting-Specifying Engineer*. June 19, 2014. www.csemag.com/single-article/power-plant-reliability/b8de98c74dcbea52c7cce9ebcb3f9d89.html.

[47] See *Department of Defense Reliability, Availability, Maintainability, and Cost Rationale Report Manual*. U.S. Department of Defense, Washington, D.C.: 2009.

[48] Brian Wodka, Senior Engineer, RMF Engineering, December 1, 2015. Personal communication.

[49] The authors acknowledge John Balfour at High Performance PV for pointing us to the use of RAM asset management principles for PV plants.

Mapping Standards onto the PV Value Chain: On-going Work, Gaps, and Challenges

In the past few years, standards organizations have responded with vigor to the global PV industry's rapid growth. However, there remain a number of areas that merit attention for the future. These gaps are typically well known to industry experts, but given the relatively slow pace—often years—that standards development can take, the PV marketplace will likely be faced with conflicting views for how to handle many of these open issues.

Bringing a number of standards efforts underway to completion has the potential to provide a stronger foundation for PV plant guidelines. EPRI has a role in helping utilities handle gaps in standards, understanding the effect of standards under development, representing utility feedback in standards development, and developing best practices. This section discusses an international effort to aggregate standards together into a plant-level certification and then provides a non-exhaustive list of smaller-scale efforts currently underway along the PV value chain.

IECRE: Bringing Efficiency and Consistency to the Design, Installation, and Management of Renewable Energy Assets

In 2013, IEC's CAB launched the IEC System for Certification to Standards Relating to Equipment for Use in Renewable Energy Applications (IECRE). IECRE is creating an asset-level, design-to-disposal certification for PV, wind, and marine energy power plants. It is a lofty goal requiring a diverse set of stakeholders (e.g., EPCs, financiers, insurers, owners, operators) to agree on the metrics, standards, and processes that need to be included and the stringency of the certification. IECRE intends to issue its first PV plant certificate in 2016.

At least two asset-level certifications already exist, both developed by independent engineering firms: VDE and DNV GL. VDE's first "Quality Tested" PV plant certificate was issued at the end 2014. The DNV GL certification (DNVGL-SE-0078) was established at the end of Q2 2015. Both are intended to certify large, utility-scale PV plants. Their certifications include normative references to international standards, such as those created by IEC, but then require other non-standardized testing and/or documentation. Further, the certificates are issued by employees of the organizations that created them. These early efforts are based on knowledge developed internally by the corporations, but the certifications' creation lacked transparency and international consensus, leading to inconsistent requirements and procedures that, anecdotally, have caused confusion, business inefficiencies, and potential conflicts of interest.

The mission of the IECRE is "to bring efficiency and consistency to the design, installation, and management of renewable energy assets"[50] via a transparent, objective, and internationally-vetted creation, issuance, and accreditation process. IECRE is developing a certification system, which is different from a standard. Most PV standards specify pass/fail testing processes. For instance, equipment vendors send their products to certified labs for testing—as defined in the standard—and approval (e.g., IEC 61215 for flat-plate silicon PV modules). A certification happens at a higher-level, requiring multiple standards be followed (e.g., at the design, procurement, construction, commission, operations, and maintenance phases), documentation and data processes be correctly handled, and an accredited auditor to review the plant and its procedures before granting the certificate.

IECRE's solar certificate is envisioned to cover the entire lifespan of a PV project, from inception to disposal; maintaining certification is likely to require approval of a project's "operational documents" at each stage of a plant's life and, perhaps, periodic audits. As of this writing, the specific content and requirements of the "operational documents" are being discussed, though there are a handful of existing IEC standards that map onto the plant lifecycle. It is likely that, at a minimum, these would be included in their respective operational documents throughout the IECRE certification process:

- System Design (e.g., IEC 62548 and/or IEC 62738)
- Planning / Procurement
  - Hardware (e.g., PV modules = IEC 61215, inverters = IEC 62109 and IEC 62891, mounting, and balance of system components = IEC 62093 and others)
  - PV Module Quality Management System (a.k.a., PV Quality Assurance = IEC 62941)
- Construction (e.g., site-specific local installation codes)
- Commissioning (e.g., IEC 62446, IEC 61829 and IEC 61724-2)
- Operations (e.g., IEC 61724)
- Maintenance (e.g., IEC 62446-2)

[50] Matthias R. Heinze, "Bankability, Independent Engineering, Securitization," presented at Intersolar, Munich, Germany, June 2015.

The construction, operations, and maintenance categories represent the biggest gaps in knowledge. More time and data points are needed to draw correlations between those activities and develop best practices and standards.

IECRE certification may be developed for any plant size, spanning the residential, commercial/industrial, and utility-scale markets. The certification stays with the plant even if ownership changes. Independent project developers, owners, and financiers are the targeted audience for certificate holders. The stakeholders affected by this certification are much broader, having implications for legal and contractual firms, service providers (e.g., independent engineering firms, O&M, asset managers), and equipment manufacturers. IECRE is inclusive to all stakeholders and encourages participation from as broad a community as possible, with particular emphasis on needs of the potential certificate holders.

IECRE also requires developing the accreditation process and training materials for auditors who will be reviewing and issuing certificates. Common processes and materials will be developed for international use, but implementation is left to each member body within each country. Currently, IECRE's solar sector has representation from 14 countries, which includes those recently deploying the majority of PV globally: China, the U.S., Japan, and India. Each member body will designate their own certifying institute(s) to carry out implementation. For instance, independent engineering firms, such as DNV GL or VDE, or safety/certification service providers, such as TÜV or UL, could be denoted as certifying bodies to issue certifications on IEC's behalf.

There are many open questions and/or gaps that are being discussed by the IECRE working groups, including:

- Strength of the certification (what metrics to include, pass/fail or graded certification)
- Applicability to existing PV plants
- Cost and value of certification (including certifying plants vs. corporations)
- Loss of certification
- Gaps and revisions in PV standards portfolio

Certificate strength. It is not readily apparent where the threshold should be set nor what metrics (i.e., safety, reliability, performance, cost) be included. Each stakeholder type has their own opinion based on their priorities. Initial interviews of stakeholders involved in the IECRE discussions indicated an approach where IECRE certification sets a minimum threshold, then testing and optimization for additional metrics would happen on a case-by-case basis as requested by the certificate requester or holder and beyond the purview of IECRE certification. It is not readily apparent how much value—compared to its cost—the certificate would hold if every plant clears a low bar, especially if additional testing is needed. Another option may be a hybrid approach of specifying certain standards that must be passed, then finding ways to distinguish the plant by going above and beyond those standards. This approach is similar to the current state of PV module testing. Manufacturers are requesting testing beyond the IEC 61215 standard, usually by requesting two times (or more) length of testing. (See page 15.) Additional alternatives for strengthening the certification requirements could include 1) setting a pass/fail bar at a very stringent level, making the certification elite and something to strive towards or 2) having a graded certificate akin to LEED certification for buildings (e.g., platinum, gold, silver, certified ratings). Any ranking scheme would require performance data be reported and collected in a database to form the basis both for determining plants that qualify for the certificate and a means for comparing plant performance. Determining where to set the certification bar will likely impact both its cost and value.

Applicability to existing plants. As currently envisioned, IECRE certification requires operational documents to be submitted throughout the PV plant's lifecycle. This approach would exclude existing PV assets. Logically though, if a plant is performing well against some agreed upon set of metrics, then that would imply the design, construction, and O&M went well. It seems reasonable to claim that current performance is predicated on past actions. Answering this question has ramifications for whether the certification needs to follow the entire cradle-to-grave process and its associated cost, or if it can be completed once a plant is operating.

Cost and value of certification. The current proposed scope of IECRE certification is daunting, covering the entire project life from inception to disposal and all major milestones in between. Each touchpoint would likely require payment. The amount of work required on both ends, auditor and auditee, dictates cost to the project, and finding the right balance will be a work-in-progress for many years to come. As an anecdotal data point, performing a utility-scale plant commissioning via IEC 62446 costs in the low hundred thousand dollars, as a rough ballpark, as actual cost depends on plant size, level of testing, and is often coupled with other work requests.

IECRE intends its certification to not increase the overall cost of a plant; however, an exact number has not been set nor targeted. There remain too many unknown variables impacting cost—such as strength of certification, wide scope of work and timeline, the certification process—that require fixed boundaries before consensus can occur. More data on certification value and cost are needed, and demonstrating the certification's value proposition is a feedback loop that will take time. As such, there is a chicken-and-egg conundrum: the certificate's value cannot be assessed without someone buying it, yet there is not enough data to guarantee value to first adopters. Further complicating the matter, many industry analysts believe PV prices will continue to fall, increasing pressure on all cost centers including certification.

In the long-term, it may be better and perhaps cheaper to certify the actual corporations and entities across the entire supply chain rather than each plant that gets built. Drawing inspiration from the automotive industry, the PV industry could employ ISO 9001-like Quality Management Principles and a Continuous Improvement Process along the entire value chain. This would ensure both the products and work are qualified against industry best practices. It would also be a seal of approval and trustworthiness for those seeking products and services within the PV industry. Furthermore, it would help address the tricky question of how certification is lost. With plant-level certification, when does a plant drop below some minimum certification threshold? For instance, if energy performance is set as a metric, is it pegged to a daily output, monthly, yearly? Who monitors and analyzes the data to revoke certification? Answers to these questions are gray areas and difficult to codify in a black-and-white standard and/or certificate.

Gaps and revisions to PV standards. There are not enough standards written to cover the entire cradle-to-grave certification, as gaps still exist in the value chain, two of which are very evident: installation and maintenance. Installation codes vary greatly around the globe and even within countries. For instance, the U.S. has over 18,000 "Authorities Having Jurisdiction" that oversee code compliance. Not every location will have up-to-date codes that include PV best practices, which leads to business inefficiency and potentially safety issues. It is an open question whether certification can require adherence to an international standard versus to a local code. A maintenance specification (IEC 62446-2) is currently being created within IEC's Technical Committee 82, though it is not due for publication until mid-2017. Also, quality management systems (e.g., IEC 62941) are beginning to be explored as applied to installation practices.

Despite these many unresolved questions, there is a strong push for IECRE to issue its first certification in 2016. This seems to be a financial decision in addition to gathering initial feedback from first adopters. Standards creation necessitates a feedback loop, requiring iterations as more information is gained. There is a role for EPRI to play in shaping this certification to ensure its members have a voice at the table and, in return, are kept abreast of standards development. EPRI can also contribute to feedback-loop data for best practices through Solar Generation Program (P193C) initiatives and projects.

In summary, IECRE could bring substantial value to the PV industry, though a number of issues remain unresolved. Table 5 offers an overview of the IECRE's strengths as well as it unsettled issues.

Strengths
International involvement from diverse stakeholders with deep expertise
IEC is a well-recognized brand within the PV industry
Business efficiency increased across the value chain due to greater transparency and familiarity, agreed upon metrics and definitions, improved process and product quality and uniformity, less one-off costs
Unresolved issues
Unknown value and cost of certification, as information feedback loop takes years
Optimizing certification metrics across diverse stakeholder participants is an intractable problem, requiring boundaries be set that will not appease everyone
Insufficient participation to date from potential certification holders

Table 5. IECRE strengths and unresolved issues

PV O&M

Owners and investors lack clear guidance on how much to invest in O&M, with part of the challenge arising from the fact that different actors in the PV value chain have varied motivations, often based on time horizon. The short-term view recognizes that every dollar spent on long-term maintenance potentially takes a dollar away from near-term revenue. Developers who plan to flip their projects to a new owner or investor within ~6 years of commissioning will tend to see O&M as a cost center, rather than a potential profit generator over the long-term. Other stakeholders might have a dif-

ferent approach for pushing specific agendas on O&M practices. A PV plant's insurance company, for example, might push operators to invest more in maintenance as a requirement to retain coverage. Likewise, there are specific tasks that need to be covered to maintain equipment warranties, particularly for inverters.

It is important to change the perception of O&M from a cost center, with a check-list of discrete activities, into a comprehensively thought-out approach to maximizing the asset's life cycle value. Currently, there is inadequate information to make direct links between O&M activities and their effect on long-term energy production. Existing PV plants are serving as testbeds to fill in this informational gap.

Over the past few years, substantial work has been completed to identify the gaps in knowledge about PV plant O&M and the initial steps to resolve them. EPRI and Sandia National Laboratories launched the PV Reliability Operations and Maintenance (PVROM) initiative in 2013, representing an early attempt at capturing field data to help inform O&M procedures and budgets.[51] Sandia National Laboratories has also led research on existing gaps in O&M standards and best practices,[52] data needs for O&M reporting,[53] and an approach and language for PV plant equipment "availability guarantees" that are typically included in O&M services agreements.[54] Meanwhile, SunSpec and NREL produced their *Best Practices in PV Systems Operations and Maintenance* report in early 2015, which aimed to provide minimum O&M requirements.[55]

A new, DOE-funded initiative, the PV O&M Collaborative Working Group (PV O&M Group), is currently being organized, the PV O&M Group aims to identify robust O&M practices that will improve plant performance and provide cost certainty. Under the auspices of NREL, Sandia National Laboratories, and SunSpec Alliance, the PV O&M Group expects to kick off its three-year effort in March 2016. Planned activities include:

- Developing standards for O&M scopes of service, contract language, and costs
- Developing additional technical specifications and calculations for availability guarantees
- Updating and refining SunSpec's and NREL's 2015 Best Practices report
- Expanding the Open Solar Performance and Reliability Clearinghouse (oSPARC) performance database to include key performance indicators and storage analysis capabilities

In addition to pursuing independent O&M research, EPRI is planning to participate in the PV O&M Group's activities through attendance, joint publications, and co-hosting workshops.

Data Collection and Archiving

Sufficient and consistently collected data—which can be archived and shared for all in the industry to compare against and improve their plants' performance—is regularly mentioned by PV industry stakeholders as an industry need. Although there are a growing number of data sources available on operating PV plants (e.g., NREL's Open PV Project,[56] SunSpec's oSPARC[57] and EPRI/Sandia National Laboratories' PVROM), there is near universal agreement that more data is needed for a variety of uses, including to provide feedback to PV plant designers.

Unfortunately, the industry has yet to agree on what data needs to be collected, where in the system it should be collected, how often, and how broadly the data should be shared. For-profit entities believe that competitive advantages can be maximized through analyzing closely held data, particularly for those companies with large operating portfolios. But better access to consistent and regularly collected data would improve each step of a PV plant's design, development, and operation, including improvement of performance models, acceptance testing, and maintenance investments. More public information would also better inform large investors that require demonstrably low-risk investments.

[51] *PV Reliability Operations Maintenance (PVROM) Database Initiative: 2013 Project Report*. EPRI, Palo Alto, CA: 2013. 3002001399.

[52] *Solar PV O&M Standards and Best Practices – Existing Gaps and Improvement Efforts*. Sandia National Laboratories, Albuquerque, NM: 2014. SAND2014-19432.

[53] *Precursor Report of Data Needs and Recommended Practices for PV Plant Availability, Operations, and Maintenance Reporting*. Sandia National Laboratories, Albuquerque, NM: 2015. SAND2015-0587.

[54] *A Best Practice for Developing Availability Guarantee Language in Photovoltaic (PV) O&M Agreements*. Sandia National Laboratories, Albuquerque, NM: 2015. SAND2015-10223.

[55] *SAPC Best Practices in PV System Operations and Maintenance, version 1.0*. Solar Access to Public Capital (SAPC) Working Group, NREL, Golden, CO: 2015. NREL/SR-6A20-63235.

[56] For more information on NREL's Open PV Project, go to https://openpv.nrel.gov/.

[57] For more information on oSPARC, go to http://sunspec.org/sunspec-osparc/.

Installation

Building codes and permitting procedures vary greatly throughout the world and often within country borders. For instance, the U.S. has over 18,000 "Authorities Having Jurisdiction" that oversee code enforcement and approval. The newness of PV and its lack of comprehensive standards often leads to inconsistencies across jurisdictions, which increases the cost of doing business across regions. It is unrealistic for an international standard to cover all possible scenarios at a local level; however, there are best practices that could help—for instance, requiring as-built drawings be kept on file.

PVQAT's proposed quality management system for module manufacturers is beginning to be extended to EPC firms, ensuring that they have quality and continuous improvement processes in place. The global demand growth for PV is leading to shortfalls in EPC staff. Each company has their own on-boarding and training processes, sometimes comprising of inadequate on-the-job-training. Anecdotally, there are stories of new hires incorrectly wiring PV plants that have led to fires and of workers sitting on PV panels and leaving unambiguous damage patterns when imaged by electroluminescence. Recognizing these issues is the first step towards developing and implementing a solution, such as the ISO 9000 family of certifications for EPCs.

A certified EPC could also benefit from PV plant certification. Under the currently envisioned IECRE certification, multiple IEC accreditor touchpoints (i.e., costs) are envisioned throughout a plant's life. Accrediting EPCs instead of plants could be a more tractable and lower cost method to increase confidence in design, construction, and commissioning. If widely adopted, it could also provide a means of identifying reputable firms in the industry.

Other Gaps

The Solar America Board for Codes and Standards (Solar ABCs) has compiled a number of smaller issues in a January 2015 brief.[58] Although most of the identified gaps relate to distributed, building-attached PV, there are some that are specific to utility-scale PV and others that target both large- and small-scale PV installations. Among those meriting attention include:

- Wind load issues for utility-scale ground mount systems. Solar ABCs states that additional research is needed to create a standard specifically addressing wind loads in utility PV plants, which are not sufficiently addressed in existing standards.
- Listing/labeling of common components used in utility-scale systems, an area that nationally recognized testing laboratories such as UL are best suited to tackle.
- End-of-life recycling of modules, which needs the development of a standard for minimal practices to be followed by plant owners at end-of-life.
- National Electric Code (NEC) specifics for utility-scale plants. The current revision of the NEC appears as if it will include a new article on large-scale solar. If approved, this gap could be closed in the U.S. by mid-2016.

An additional area for research and potential guideline/best practice creation is the approach for determining a PV plant's DC/AC ratio. Some developers reportedly push DC/AC ratios to as high as 1.7 or 1.8, which enables better production during shoulder periods by allowing for more energy to be produced during the afternoon (to coincide with typical utility summer peaks). Another result, however, is more frequent and long duration inverter clipping, particularly in hotter environments. There are concerns that an increase in clipping can potentially impact inverter life through higher operating temperatures. Concerns also surround the impact of clipping on other equipment on the DC side of the system, as the excess power production ends up being dissipated via higher temperatures throughout the module field and related equipment. Further, high DC/AC ratios may mask plant performance issues.

[58] PV Codes and Standards Gap Issues. Sherwood Associates, Inc., Boulder, CO: January 2015.

Getting Involved in PV Standards Development: EPRI and Utilities

Utilities have a unique position in terms of influencing the technologies and practices for electric generating plants. They are often either the owner of the asset themselves, or the purchaser of their output.[59] Utilities also have generations of experience with designing, building, operating and maintaining conventional power plants. This experience has led to a growth in knowledge and processes, reinforced via feedback loops back to designers that have resulted in best practices for the industry as a whole. That said, utilities have varied levels of familiarity with PV power plants and their unique design criteria, operation, and maintenance. Utility ownership of PV plants is growing year-on-year in absolute capacity terms, further increasing familiarity. There is an opportunity for utilities to map onto PV the existing processes and culture that have led to the best practices developed to govern their conventional fleets. The challenge before utilities is how to leverage their internal capabilities with external resources to maximize life cycle value, while reducing risk, for the next generation of PV power plants.

The on-going work to create updated standards and close the remaining gaps in standards are clearly valuable. But for utilities, standards, while important are not sufficient. They are foundational building blocks to use in developing best practices for utility-scale PV plants. Utilities, particularly if they are seeking to rate-base PV investments, are likely to need more than minimal requirements on the quality and life cycle economics of PV power plants to complete their own internal due diligence, and for investor-owned utilities, to meet requirements and expectations set by their regulators.

There are some discrete steps utilities can consider taking to maximize the value of large-scale PV power plants, including participation in standards and certification development work, whether independently or through EPRI. Participation has multiple benefits, such as, increasing PV plant business efficiency (e.g., well-articulated RFPs through consistent use of PV metrics, mapping best practices onto existing internal processes and/or procedures); avoiding past mistakes by learning from industry case studies and experiences that the standards are built upon; and guiding development to ensure the perspective and concerns of existing or potential PV owners are heard—which is especially pertinent to IECRE certification development. There are also steps that utilities can take in the design and development of PV plants, particularly for utility-owned assets. The content included in solar RFPs needs to be more detailed, including greater definition of terms, specification of performance model inputs, and acceptance testing procedure and criteria.

There are some other areas to explore, including actions to ensure that PV equipment used in a utility project are sufficiently vetted for product integrity. For example, requesting modules from manufacturers that employ quality management and continuous improvement processes may be considered a best practice.

Similarly, utilities can join together to create a preventative maintenance (PM) database for tracking failure modes at PV plants, such as the PMBD that EPRI manages for conventional power plants. A second O&M activity could be helping develop a standard “conduct for maintenance” of best practices for PV plant activities. Utilities have decades of experience in designing, operating, and maintaining conventional power plants, and no doubt there are processes and experience that can be translated to PV power plants. To the greatest extent possible, early involvement in standards development could reduce the learning curve for new technology integration into existing asset mix and processes.

Details on RFPs, module integrity, O&M, and the utility role in standards development follow.

Request for Proposals (RFP)

To align expectations of the EPC and eventual plant owner, and allow for apples-to-apples comparison of bids, there are some approaches utilities would well consider taking at the start of the PV design and development process. First are definitions of terms. Most standards currently being revised or published are tackling the vexing issue of defining what in the PV industry have often been ambiguous terms, among them availability, performance ratio, and reliability. Once published, utilities should follow this approach in their RFPs and require bidders to conform to their specific definitions in their submissions and, for eventual winners, in their project execution so that all parties unambiguously understand and comply with their definitions. The IEC publishes a glossary of terms, specific to the solar sector (TC 82), though some of these terms are being updated as part of the standards revisions currently underway.[60]

[59] The third alternative is direct sale of power from an Independent Power Producer (IPP) to a retail customer.

[60] IEC’s glossary for solar energy can be found at http://std.iec.ch/terms/terms.nsf/ByTC?OpenView&Count=-1&RestrictToCategory=82.

Suggestions for RFP Best Practices

- Use terminology and metrics defined in PV standards
  - Availability, Energy and Power performance indices
- Define modeled system requirements to reduce bid ambiguity
  - Meteorological data, Soiling derate
- Strive for consistency
  - Commissioning based on standards
- Consider lifecycle costs upfront
  - O&M and decommissioning

Clear definitions can be considered the foundation. The next step would be to provide as much detail as feasible on plant specifications, design, and the other factors that a comprehensive process engineering approach (or RAM) entails. Most of these issues should be decided on during the early stages of plant development and design. That allows specific details to be included in a utility RFP, where they belong, for both utility-owned assets and PPA contracted projects, and leaves less detail up for interpretation. Also, more foresight should be given to O&M when designing the plant and ensure its included in independent engineering analyses.

There are discrete, relatively simple steps that can be considered for inclusion in an RFP to provide a better apples-to-apples comparison of bids. Utilities, for example, could provide the meteorological data that bidders are required to use in their bids to ensure consistency among bids. If personnel bandwidth permits, utilities could allow bidders to submit a second proposal for the same plant using a different weather dataset, if there is sufficient justification. For example, larger developers often install and operate weather stations at intended sites for larger PV plants to collect proprietary data in advance of bidding the project.

Likewise, the calculation of soiling rates should be the same across a specific RFP, to ensure consistent bids, and potentially also direct bidders as to which model they should use in determining their projects' performance. It is important that utilities double-check the modeled performance results of prospective winning bids by re-running the model to ensure agreement with all inputs.

There are additional RFP activities where utilities could strive for greater consistency. For example, utilities often have differing definitions of guaranteed minimum/maximum energy in PPAs, according to an analysis by Black & Veatch.[61] Also lacking is detail on the definition of the base case and the method for weather-adjustments. In the same vein, developers appear to agree that utilities should provide a specific list of system requirements for plants during bids, including (but not limited to) operating parameters, telemetry (and security level), SCADA, and control system requirements. If applicable, utilities should also clearly state how curtailment and non-unity power factor will be handled in RFPs and how any potential revenue losses will be split.

The more specific the off-taker/owner is with proposal specifications, the better bidders are able to meet those requirements. This approach should also result in better visibility into bidders' abilities and relative qualifications to achieve a high-quality, ready-to-integrate plant; it would also be beneficial for ranking bidders beyond a focus on the DC side of the PV plant. Indeed, the responses to such utility requirements would likely help utilities weed out those bidders who attempt to use a relatively low price point for their initial bid that then are escalated in subsequent negotiations. On the utility side, it would also reduce potential requests by internal utility engineers for changes to plant design after contracts have been signed, which could avoid higher costs for the utility.

Including details of how acceptance testing is to be done for utility-owned assets is a priority for utility RFPs. Many utilities are already taking some good approaches to reduce risk by ensuring developers and EPC firms design and build the plant in accordance with their contractual responsibilities. Such approaches often have two steps: an initial acceptance after construction is complete, followed by a final acceptance to confirm the plant is operating to specifications after a set amount of time (often a year or more of operation). This second step often involves a performance guarantee, or related approach.

This two-step commissioning is becoming a best practice. It starts with the initial acceptance test at the end of construction, which confirms that the plant and all associated equipment are operational and meet contractual specifications. The final acceptance happens after a set time period, typically one year, of operation and data collection to identify early and/or potential problems with the plant's design, construction, or operation. This ensures PV plants are able to meet their initial and near-term commitments in terms of capac-

[61] Emily Leslie, Renewable Energy Consultant, Black & Veatch, October 14, 2015. Personal communication.

ity and energy production, and that only such contract language will lead to developers and EPC firms being held fully responsible for their work beyond initial commissioning, whether at mechanical completion or substantial completion. Although they are not yet finalized, drafts of proposed standards IEC 61724-2 (capacity testing) and IEC 61724-3 (energy testing) have the potential to be strong guides for conducting capacity and energy tests of PV plants to ensure they were designed and built according to expectations. The revised IEC 61724 standards will also be useful as a pre-requisite for purchasing an operating asset. It also appears to be central to IECRE's future certification effort.

Quality assessment activities need to be aligned with the overall size of the investment in the project. More expensive projects, with greater relative risk, or those in low insolation (i.e., low capacity factor) environments merit greater investment in quality assessment. Thus, a tiered approach of more detailed work is more appropriate than a universal approach to determining project quality.

Lastly, utilities should ensure that their RFPs include sufficient equipment to conduct plant monitoring and track long-term performance. One asset owner uses some 12,000 data points at its 35 MW PV plant, which also has six weather stations collecting ambient weather data in order to compare modeled plant output to actual production. Data collected at the plant needs to be archived and regular (weekly, monthly, quarterly, and annual) analyses on plant performance need to be carried out to discern short-falls in production and identify potential issues before they require corrective maintenance.

Improving PV Equipment: A Feedback Loop

Utilities can have a role in encouraging improved component quality and life-time performance through two approaches. First, by ensuring PV plants use modules certified via published quality standards, such as IEC 62941. Second, by providing data from utility-owned PV plants and perhaps requiring owners of other plants to provide such data as part of a PPA contract into a PV plant database, akin to the existing preventative maintenance basis database at EPRI or in existing performance-focused databases such as SunSpec's Open Solar Performance and Reliability Clearinghouse (oSPARC)[62] and NREL's Open PV Project.[63]

Module integrity is an important issue that utilities and others need to address: put simply, how much testing is enough? Although standards organizations are rewriting their recommended approaches (e.g., IEC 61215), a number of other companies have launched their own, tougher protocols to test module integrity. These include:

- **TÜV SÜD's Thresher Test**. This test extends the current IEC testing by two to four times the accelerated test durations to help identify long-term reliability and performance.[64] Environmental stresses are repeated sequentially, and the module passes only if this degradation remains within a prescribed window of the initial power rating data.
- **Atlas Material Testing Solutions' Atlas 25+**. This is a multi-dimensional durability test program designed to subject photovoltaic modules to the environmental degradation stresses which can be expected over long-term service.[65] It consists of a series of sequential tests covering UV-A and UV-B exposure, salt corrosion, humidity and thermal cycles, followed by another series of solar/thermal/humidity/freeze cycles, before a six-month or one-year field deployment.
- **Fraunhofer's PV Module Durability Initiative (PVDI)**. The PVDI is also an accelerated stress test protocol covering damp heat and thermal cycling, as well as long-term outdoor exposure.[66] Modules are subjected to accelerated stress testing intended to approach the wear-out regime for a given set of environmental conditions. The modules are rated for both performance and safety on a scale of zero to five relative to their likelihood to perform reliably with regard to the performed tests.

Such durability tests, however, may not translate into quantifying reliability as desired, as some processes that impact reliability cannot be accelerated quantitatively. Some PV experts emphasize the need to tie such durability tests to energy delivered, particularly given the additional cost extra tests involve. NREL's Sarah Kurtz, for example, points to the importance of using observations from the field to

[62] oSPARC can be found at http://sunspec.org/sunspec-osparc.

[63] The Open PV Project can be found at https://openpv.nrel.gov.

[64] For more details on the Thresher Test, see http://www.tuv-sud-psb.sg/sg-en/press-media-centre/news-archive/tuev-sued-thresher-test-for-pv-modules-enhances-investment-security.

[65] For more details on Atlas25+, see http://atlas-mts.com/services/photovoltaic-testing-services/atlas-25/.

[66] For more details on PVDI, see http://www.cse.fraunhofer.org/pv-technologies/pv-module-durability-initiative.

prioritize what additional testing should be done.[67] Factors that may impact energy output on a case-by-case basis include the type of climate in which equipment is deployed (e.g., arid, humid, tropical, coastal); inconsistencies across and/or changes to material suppliers (e.g., additives in encapsulants can impact discoloration); and manufacturing process windows (e.g., solder bond thickness within a c-Si module).

Kurtz's alternative approach to durability testing is to determine service life via a defined methodology for identifying and quantifying degradation and failure rates based on failure mechanisms and their rates, specific environment adjustment, and verified by field data. (As such, it is similar in approach to the RAM concept presented on page 19.) Such an approach needs to be combined with an audit of manufacturers' quality management systems to ensure consistency among products. Kurtz's vision is shared by PVQAT (see page 17), an effort she is among the leaders of. At least one financier is already using a variant of this approach as part of its due diligence for investments.

O&M

A central task for the utility sector is to successfully transfer O&M best practices for conventional power plant to the PV sector. This will likely involve more processes than discrete activities, given the different technology characteristics of conventional power plants and PV arrays. However, for the AC side of a PV power plant, maintenance activities are likely to be similar.

One process example is the use of a preventative maintenance (PM) database. PM databases track failure modes (and their lifespan) for power plant components; EPRI's conventional power plant Preventative Maintenance Basis Database (PMBD) contains more than 20,000 individual components, with years of data that informs the timing for PM activities—replacing parts, servicing components, or performing other maintenance tasks—before failures occur. EPRI has found that vendor-recommended maintenance is often far more frequent and intrusive than is actually required. The result from utilities following the advice of the PM database is substantial cost-savings in maintenance activities. Although utilities have far less experience operating PV plants, there is sufficient information to, at a minimum, start a utility PM database of PV plant experiences and build upon it in future years. It is imperative to determine the link between O&M activities and their effect on long-term energy production.

EPRI's Role in Standards Development

There are a number of activities EPRI can take in the near-term to assist in the development of standards guiding the PV industry, while informing its members of improved processes and procedures to consider adopting.

A near-term activity for EPRI is to continue to leverage its existing utility best practices for O&M for conventional plants and RAM-like activities for the PV sector. EPRI (and its member utilities) have decades of experience in power plant O&M, which will become increasingly important as utilities take on more ownership of PV assets. EPRI can also inform standards writing organizations while apprising PV plant operators/designers on means to improve.

EPRI also plans to become more active in the IEC standards and IECRE development. For standards, EPRI intends to represent its members as a stakeholder that is directly impacted by IEC's standards development, serving as a go-between. For IECRE's certification initiative, EPRI aims to provide the voice of utilities in the development and implementation of the certification process. EPRI will also interact with international experts on PV plant issues and keep members abreast more broadly on the status and usefulness of standards and certificates being developed, while providing recommendations to these organizations on how to close existing (and future) gaps in standards.

Active EPRI and utility activities are producing experiential data points that can inform standards and grid codes development. Included are predicted vs. expected vs. actual plant performance,[68] and monitoring best practices,etc.,[69] to inform reasonable and pertinent specifications. For example, a December 2015 EPRI paper on O&M provides potential avenues for improving investments in PV plant O&M, including labor allocation, insurance products, and new approaches in budgeting for O&M.[70] Also in 2015, EPRI

[67] Sarah Kurtz et al., "Moving Toward Quantifying Reliability – The Next Step in a Rapidly Maturing PV Industry," *42nd IEEE PVSC*. New Orleans, LA: June 2015.

[68] *Comparison of Predicted, Expected, and Actual PV Plant Performance*. EPRI, Palo Alto, CA: 2015. 3002006223.

[69] *PV Plant Performance Monitoring Guidelines*. EPRI, Palo Alto, CA: 2015. 3002006225.

[70] *Budgeting for Solar PV Plant Operations and Maintenance: Practices and Pricing*. EPRI, Palo Alto, CA and Sandia National Laboratories, Albuquerque, NM: 2015. 3002006218; SAND2015-10851 R.

launched a supplemental project to examine the issue of corrosion of buried support steel for PV plants.[71] EPRI will leverage its existing database of materials corrosion in a range of soils, and conduct new laboratory tests on soils impact on steel samples. The effort will also explore monitoring field experience at participants PV plants. An updated guideline for soil corrosion will be provided based on the research findings.

Likewise, EPRI's existing work at the Solar Technology Acceleration Center (SolarTAC) and the Southeastern Solar Research Center (SSRC) can be leveraged for informing standards writing organizations and assist in developing best practice guidelines for utilities. For instance, both sites have state-of-the-art monitoring equipment for turning capacity and energy standards into best practices. Archiving and analyzing data over the course of years would inform degradation rates of both modules and the array equipment. The SSRC is also quantifying and demonstrating the efficacy of proposed accelerated module testing.

Related to the need to increase information and data on PV plants, utilities should be aware that PV plants are not required to submit operating data to the North American Electric Reliability Council's (NERC's) Generating Availability Data System (GADS).[72] GADS archives data submitted by fossil and nuclear generating units (which is mandatory for generation units 20 MW and larger); these data are used to support equipment reliability and availability analyses and decision-making for these units. A central database of utility-scale PV plants would be a benefit to improving the industry's knowledge related to both existing plants and how to design (and procure components for) future ones. However, it remains unclear what data PV plants would submit to move this concept into reality.

PV plants can suffer from sub-par performance or failure of individual components, which would be hard to detect and report on, especially given the general variability of the resource due to climatic conditions. It is possible that NERC will eventually move forward with efforts to require PV (and wind) plants to submit data into the GADS system. Should it do so, utility views will be important to include with those of other stakeholders to ensure useful data is collected at a reasonable cost. In the meantime, additional work on defining what type of data should be collected and consolidated would be beneficial even outside of the GADS system.

[71] For more details on EPRI's Corrosion of Buried Steel project, go to www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002007077.

[72] For more details on NERC's GADS, go to www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

Conclusion and Next Steps

The PV industry has achieved tremendous growth in the past half-decade, both globally and in North America. This growth has outpaced standards and best practice development. Standards development organizations are currently revising existing standards, filling in gaps through development of new ones, and creating certifications to tie existing and future standards together. EPRI is in a unique position to participate in standards development, serve as a go-between to relay happenings back to its members, and help turn standards and specifications into best practices.

Standards organizations are working to resolve part of the dilemma created by the PV industry's fast growth by publishing a flurry of new standards or revisions in the coming years. But relying on these efforts alone is insufficient. Standards are at times set at a minimum level for recommended activities, and the industry can ill-afford to wait another year or two before taking specific actions on plants being built today or contracted for in the near-term. Furthermore, there remain significant gaps in the standards writing activities that could take years to adequately resolve.

Given the anticipated continued growth of PV installations, and the likelihood that utility PV asset ownership will increase in the future, provides the catalyst for the utility industry to be more knowledgeable with the procurement, design, development, operation and integration of PV power plants.

EPRI intends to engage with standards writing organizations at a deeper, more formal manner in 2016 and beyond. The role in helping to set standards will be two-fold: to represent utilities in standards establishment, and to provide subsequent knowledge transfer back to utilities. In particular, EPRI intends to become a participant in solar standards development organization(s), such as IEC, to ensure utility issues and concerns are considered and to gauge the usefulness and appropriateness of new products, such as IECRE certification, to its members.

Furthermore, EPRI plans to work with a range of stakeholders—including solar companies, EPCs, utilities, and other research agencies—to reduce the revised standards into actionable, best practices for specifying PV plant design, construction, and other standardized operating requirements, as well as highlight lessons learned. EPRI seeks to gather and synthesize information about unique PV design aspects from a variety of primary and secondary sources, and will support workshops and site visits to facilitate knowledge acquisition and dissemination among utilities and other stakeholders. EPRI's envisioned goal is to create "gold standard" best practices for solar assets, akin to those in place for conventional rotating generation assets.

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Appendix B. Recommended Reading

Resource Guide: Utility Solar Asset Management and Operations and Maintenance. Solar Electric Power Association, Washington, D.C. (forthcoming).

Budgeting for Solar PV Plant Operations & Maintenance: Practices and Pricing. EPRI, Palo Alto, CA and Sandia National Laboratories, Albuquerque, NM: 2015. 3002006218; SAND2015-10851 R.

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Solar Generation Program

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