Keep on the Sunny Side: Lessons Learned While Evaluating PV Program Impacts

Vergil Weatherford, Navigant Consulting, Inc., Asheville, NC
Eric Merkt, Navigant Consulting, Inc., Boulder, CO
Pace Goodman, Navigant Consulting, Inc., Boulder CO

ABSTRACT

Impact evaluation of large-scale photovoltaic (PV) incentive programs is important to the success of PV as a distributed generation resource—knowing the true performance of a program can help resource planners make informed decisions. In two recent PV program evaluations, the authors used a two-part approach to verifying energy production and peak demand offset consisting of: 1) a detailed field protocol for verifying system characteristics and real-time output, and 2) a batch hourly modeling framework built and implemented using the National Renewable Energy Laboratory's freely-available System Advisor Model (SAM) software. This approach allowed the evaluation team to uncover problems with the PV installations at several sites, resulting in different-from-expected output. In the case of one program, the authors found the ex-post energy production to be approximately15% greater than the ex-ante estimates. In another, there was a 2% reduction in the overall expected output. Given the scale of some PV incentive programs, these differences can have meaningful impacts on resource planning efforts. As evaluation techniques continue to improve like they have in the last 5-10 years, utilities and regulators can keep on the sunny side knowing the true production value of their investments in both commercial and residential PV incentive programs.

Introduction

For the evaluation of solar PV program impacts, the ideal data source is interval meter data providing both PV system production and end-user consumption. While access to interval meter data is improving both with modern PV inverters and with the widening adoption of Advanced Metering Infrastructure (AMI) electricity meters, its availability is far from universal. Fortunately, solar simulation modeling software and in-field data collection instrumentation have been steadily improving, giving evaluators a good alternative in the absence of interval data.

The rest of this paper outlines the approach used in two different PV impact evaluations appropriate for use when interval meter data is unavailable. The authors intend for this to serve as a guide to those conducting evaluations of PV incentive programs and to share some of the lessons learned while developing field protocols, training field technicians, modeling PV performance, and analyzing data.

The key to the authors' approach is that it combines detailed field work for a sample of sites with hourly simulation modeling for all systems. The purpose of the field visits is to verify as-installed system characteristics (azimuth, tilt, nameplate ratings, module quantities, etc.) and look for discrepancies with the as-reported characteristics. Also, the field work should catch installation errors such as voltage mismatch and unintentionally left-open circuits. Hourly modeling using typical or actual historical weather data allows evaluators to determine demand and energy savings and calculate realization rates. In-field metering with data loggers is another option for collecting interval data on PV arrays, though it increases costs of the field study significantly and will not be discussed in this paper.

Field Verification Methodology

In 2010 and 2011, the authors took part in two separate PV program evaluations, one in California and the other in New York. In both cases, field visits were an important part of the work and the authors oversaw field visits to more than 100 field sites in total. In one study, the sample size was 26% of the overall program population and in the second, it was 83%. Site visits were conducted in pairs when possible, for the sake of safety and efficiency. The vast majority of PV systems visited during the course of these two studies were roof-mounted residential systems, although a few commercial sites were included as well.

The field verification consists of the following considerations:

1. Preferential scheduling
2. System characteristics data collection (i.e. collecting data from the PV panels, inverters, wiring and general building characteristics)
3. System performance verification

Preferential Scheduling

Insolation is measured in the field by a portable pyranometer. Because of the inaccuracy of most handheld pyranometers, the sun should be at a high angle to the PV array (i.e. nearly directly overhead, not a glancing angle) at the time of the site visit. In order to facilitate this condition, the database used to make scheduling calls should include a preferential scheduling time of day (morning, midday, afternoon) based on the system azimuth. For instance, if the azimuth of the array is near due-west, an afternoon, rather than morning, site visit would be necessary so the sun is orthogonal to the array during the spot measurements. While this does make it difficult to work around certain customers' schedules, it does eliminate some measurement uncertainty.

System Characteristics Data Collection

Data collection should include all necessary solar modeling inputs, as well as contextual information. Solar model inputs typically include specifics relating to the PV panels, inverters, the system configuration (e.g. panel azimuth angles) and shading. Building or residence data, panel soiling and evidence of damage are examples of important contextual data. The following list summarizes the data collected during the verification site visits.

1. Verify that all equipment as documented in the installation invoices is still intact and document the following:
    a. Nameplate data from PV module
    b. Number of modules
    c. Nameplate data from PV inverter
    d. Number of inverters
    e. Shading analysis using a handheld electronic shading tool; files saved for later
    f. Array tilt
    g. Array azimuth
2. Note of any damage, evidence of tampering/theft/vandalism
3. Note of levels of soiling on surface
4. Note production-to-date from inverter (if available)
5. Note any other possible contributing factors to loss (or gain) in production

The authors suggest special considerations for array grouping, seasonal tilt changes and system interconnect dates when collecting solar field data.

Array Grouping and Seasonal Tilt Changes

When a PV installation is split into sections or arrays with different tilt angles or different azimuth orientations, it is necessary to model the generation of each array separately and combine the results to produce a site-level generation estimate. In some cases, PV installers will use averaged parameters for sites with multiple unique arrays, and will report the expected output of the combined system. This approach is incorrect, and can result in very different results particularly when east- and west-facing arrays are combined. In the case of some PV programs, this error may be a result of the tracking system being unable to handle multiple arrays for a single site, although the authors have also seen the problem occur even when program tracking systems are properly set up to handle multiple arrays at a given site.

While most roof-mounted PV systems are fixed, sometimes they are installed with an adjustable tilt that enables the PV system owner to adjust the array two or more times a year as the sun's declination changes. Generally this is done around the spring and fall equinoxes, but it is important to interview the system owner to determine exact dates if possible. When modeling tilt changes, it is sometimes necessary to run two or more annual models with different tilts and construct the output results piecewise from the known or estimated adjustment dates.

System Interconnect Dates

Because inverters generally track the total energy output to-date, the exact interconnection date is required in order to conduct accurate modeling. The interconnect date directly impacts the expected, or modeled, system energy generation to date, because there should be zero production up until the interconnect date.

Reported interconnect dates are sometimes inconsistent with on-site findings. During the two studies in question, there were several sources of data for interconnect dates, including inverter readouts, owner interviews, generation data, inspection documentation, and the tracking database. Inconsistent interconnect dates contribute to the overall uncertainty of modeled generation results (particularly in the first year of a program) and care must be taken to select the most appropriate interconnect date for each system.

System Performance Verification

One of the most important parts of a PV verification site visit is determining that the system output is near its expected value. There are many reasons why a PV system might not be performing as expected, but it is not always possible for the customer to notice a decline or drop in PV production. The authors developed an on-site PV production check that can be conducted with the help of some basic instruments and a simple calculation. It helps to know the characteristics of the system beforehand so that the inverter efficiency and temperature derate coefficient of the modules are on hand.

The basic process is as follows:

1. Measure panel surface temperature
2. Measure incoming solar radiation normal to the PV surface
3. Simultaneously read the instantaneous output at the inverter (may require a second person)
4. Calculate the expected output from (1), (2) and manufacturer's PV system characteristics
5. Compare expected output to actual output

Expected output calculation

The key to the onsite system output check is that the field tech can take a quick measurement, estimate system derate factors, and determine if output is reasonable given the system characteristics. The equation used in the field is as follows:

$$P_e = \frac{N \cdot W_{np} \cdot I \cdot \eta_{inv}}{1000W\,@\,STC} \cdot \left(1 + \varepsilon_T \left(T_{surf} + 25\right)\right)$$

Where:

P_e = Expected output (Watts)
N = Number of modules in the array
W_{np} = Name plate wattage of a single module Standard Testing Conditions (STC)
I = Instantaneous insolation on the plane of the array, measured by a handheld meter (Watts)
η_{inv} = Inverter efficiency[1]
ε_T = Module temperature derate factor, which is typically a negative value[1]
T_{surf} = Surface temperature (°C) of the back of a panel, taken with a surface temperature probe

The $1000W\,@\,STC$ in this equation is simply to indicate division by 1000 to normalize the insolation to Standard Testing Conditions at which the panel output is rated.

If the expected output does not match the actual output within 10%, there is likely a major issue with the array. Soiling and measurement error could be the cause for up to a 10% difference in worst-case scenarios. Further troubleshooting with a multi-meter may be required to determine the issue. A summary of the problems uncovered in these studies appears in the results section below.

Data Quality Control

Any evaluation team must take great care to ensure that the field measurements are highly accurate, consistent, and repeatable. There is always the chance for human error to affect data quality in PV verification visits, but errors can be minimized with a very detail-oriented field crew. Proper training and a requirement to repeat critical measurements multiple times improves confidence in evaluation results.

In particular, array azimuth can be especially difficult to measure consistently. It is crucial that the azimuth of the array be adjusted for magnetic declination. In the lower 48 states in the U.S.A., magnetic declination ranges from about -20 degrees up to +20 degrees depending on location, which can introduce a significant error if not accounted for. Furthermore, many compasses (including digital compasses) are sensitive to magnetic field interference, and can give erroneous results. For azimuth measurements, no less than three readings should be taken, including one on the ground (away from any potential sources of interference).

For the two studies in question, the data collected from the field went through an extensive quality control (QC) process to assure that the inputs to the model were valid and reasonable. The following list outlines the QC and data prep methodology used after the field work was complete.

1. QC and analyze the field collected data:
    a. Analyze failed spot measurements
        i. Sort out major issues (wiring, switches, interconnect, etc)
        ii. Summarize minor issues
            1. Time of spot measurement vs. azimuth

[1] The inverter efficiency and module temperature derate factor are not typically listed on the nameplate, and must be looked up in a database beforehand. The already-mentioned SAM modeling software includes a database of inverter and module characteristics which are updated with every release.

        2. Array shaded during measurement
        3. Soiling
        4. Power Factor
    iii. If no spot measurement, verify reason (e.g. roof unsafe)
  b. Check for discrepancies in reported values against verified values
    i. Equipment make/manufacturer reported incorrectly
    ii. Tilt discrepancy of >3 degrees
    iii. Azimuth discrepancy of >5 degrees
    iv. Monthly shading values off by >5%
    v. Number of arrays reported incorrectly
2. Manually verify all issues in 1(a) and 1(b) above
  a. Examine the data
    i. Refer to field forms/photos, look at notes
    ii. Refer to original install data
  b. For 2(a), track statistics for findings
  c. For 2(b), sort into:
    i. Sites without discrepancies
    ii. Sites with minor discrepancies in reported values
        1. Run model with all original installer data except contested values
        2. Determine energy verification rate
            a. Per-site
            b. For sampled population

Hourly Modeling Methodology

The authors selected the National Renewable Energy Laboratory (NREL)'s System Advisor Model (SAM) to conduct the 8760 hourly PV production modeling. It is freely available and is continually improving under a short development cycle. SAM has an advanced equipment-based modeling capability, which draws on a database of empirically determined PV and inverter characteristics in order to more accurately simulate PV system performance. SAM also has a scripting interface called SAMul (System Advisor Model User Language) which enabled the analysis team to set up batch model runs, facilitating a more coordinated modeling approach.[2]

One of the advantages of using the SAMul scripting language is that it is possible to automate batch modeling so that hundreds of PV systems can be modeled with varying system characteristics, shading profiles, and weather data. This also makes it easy to re-run the entire analysis if changes need to be made to the inputs or modeling parameters. Model outputs of hourly kilowatt-hour (kWh) production can be automatically saved to text files that in turn may be read into SAS, R, or other statistical software for analysis.

Weather Data

SAM includes access to typical weather data for locations in the U.S.A. in the Typical Meteorological Year 2 (TMY2) format[3]. If the user wishes to use actual historic data from another source to generate hourly results, the data must be converted into TMY2 format. During one evaluation in the state of

[2] https://www.nrel.gov/analysis/sam/
[3] http://rredc.nrel.gov/solar/pubs/tmy2/

California, the client asked for both peak demand and energy impacts for the program year of the evaluation. In this case, the authors downloaded actual historical hourly weather data from the California Irrigation Management Information System (CIMIS) meteorology network. The network has 120+ stations spread geographically across California in order to provide relevant meteorological data for making decisions about irrigation practices throughout the state.[4] In other areas, regional meteorological networks may exist that can provide hourly solar radiation along with other relevant data as well, and a similar conversion process could be used.

The data available at CIMIS weather stations contain most of the required inputs to the hourly solar PV model. Although the weather stations collect a wide range of data, the following list shows the variables collected that are relevant to the modeling effort:

» Total Horizontal Solar Radiation
» Dry Bulb Temperature
» Dew Point Temperature
» Relative Humidity (RH)
» Wind Speed

After downloading hourly data for all active CIMIS weather stations, the analysis team cleaned the data with the following algorithm:

1. Values outside reasonable ranges expected for the California climates were set to missing.
    a. Solar radiation values greater than 1350 W/m^2 and less than 0 were discarded
    b. Temperatures below -50 and above 150 degrees F were discarded.
    c. RH values outside the range 0-100% were discarded.
2. Data interval between observations was checked.
    a. If more than one observation occurred in one hour, the values were averaged for that hour.
    b. If observations were more than an hour apart, data was interpolated according to step 3 below in order to create 8760 continuous values.
3. Missing data was interpolated/filled (missing data represented less than 1.2 percent of the data points).
    a. Data gaps of 3 hours or less were interpolated using the spline interpolation method.[5]
    b. Data gaps of longer than 3 hours and less than 96 hours (4 days) were filled using the average of that particular hour, 2 days before and after the day in question.
    c. Data gaps of more than 4 days but less than 20 days were filled replacing the missing days with the nearest full day of data (forward or backwards).
    d. Stations with data gaps of 20 days or longer were thrown out.

Estimation of Direct and Diffuse Radiation

During the California study, all of the CIMIS data was directly input into the model without modification except solar radiation. Most PV solar models, including the SAM, require that the beam and diffuse components of solar radiation be separate inputs. Because the instrument necessary to collect beam solar radiation data separately (called a pyrheliometer) is much more expensive and difficult to maintain than a normal pyranometer, standard methods for decoupling the beam and diffuse components of the solar radiation exist. For this study, the Boland-Ridley-Lauret (BRL) model was used, which, like

[4] www.cimis.water.ca.gov
[5] The spline interpolation method is a piecewise interpolation where a polynomial is fit to a specified number of points with the minimum amount of bending.

many models, uses the standard clearness index (the ratio of total horizontal insolation to the global insolation constant) to predict the diffuse component. However, the BRL uses dynamic predictors such as solar time and altitude angle, as well as a persistence factor to more accurately decouple the diffuse component from total horizontal radiation on shorter time intervals (Ridley et Al., 2010).

In situations where actual hourly data is not available or the client does not need to know actual program-year demand impacts, daily insolation data can be used instead to normalize actual system output to-date (as recorded by the inverter) to the modeled results. This approach is described in more detail in Case Study 2 under the results section below.

Weather Station Matching

Once the weather data is cleaned, each site can be matched with the closest weather station, using a database of latitude and longitude associated with U.S.A. zip codes. The formula used to calculate distance between two points is called the "great circle formula". The distance of a site from the nearest weather station is important because solar radiation varies geographically, especially on partly cloudy days. This primarily affects peak demand impacts, as the output of the system is required on a particular hour of a particular day. The average distance from a modeled PV site to the nearest weather station was 10 miles, with a standard deviation of 7 miles.

Results

The results of the field verification and modeling efforts for each of the studies are split up into two sections. The approaches were subtly different, largely due to the differing requirements from the clients. This should be helpful to the reader as it provides some guidance for handling data collection and analysis for multiple sets of requirements.

Case Study 1: California client wants to know actual program year energy and peak demand impacts.

For this study, the authors used actual hourly insolation data as well as typical-year data, and modeled energy production during actual program year. The actual hourly weather is crucial when specific program year peak demand impacts estimates are needed.

Field Work Findings

After the fieldwork was completed, the authors compiled the results of the site visits. The field technicians uncovered a large number of discrepancies between what was reported in the tracking database and what was found onsite. The majority of the discrepancies were azimuth and tilt angle discrepancies. Table 1 summarizes the field findings.

Table 1. Comparison of Inspection Discrepancies

Issue	# of Discrepancies Found	% of Sites with Discrepancies (approx.)
Array Grouping	2	2%
Panel Miscounts	1	1%
Tilt Angle	15	17%
Azimuth	24	28%
Shading Analysis	9	10%
Wiring/Connectivity	3	3%

Array Grouping

Out of the approximately 85 sites visited, two had arrays which were incorrectly "grouped," meaning arrays with different tilts or azimuths were reported as one array. The correction resulted in a reduction of the site realization rate by around 2-3 percent in both cases.

At one site, the number of panels in each array was incorrectly reported. The total number of panels reported at the site level was correct, but the installer recorded five modules in one array and four in the other. However, the field crew counted and documented six panels in one array, and three in the other. While miscounts of this nature do not drastically affect the expected kW and kWh production for a site, they do have some effect, particularly if the azimuth or tilt values are very different for the two arrays.

Tilt and Azimuth

The tilt angle and orientation angle (azimuth) have a large effect on system performance, since they determine the panels' exposure to sunlight. For every PV system, there is a theoretical optimum tilt and azimuth to maximize production. Field crews found 15 cases where the measured tilt differed from the reported values by at least 3°. There were 24 cases where measured azimuth differed from reported values by more than 5°. Many of the azimuth discrepancies were off by more than 10°, potentially signifying that magnetic bearings were not always being converted to true bearings (magnetic declination in California ranges from 12° to 16° depending on location).

Shading Analysis

Shading factor is expressed as a percentage of total solar resource available on a monthly basis after accounting for shading. For this particular program, the installers recorded monthly shading factors using handheld shading calculators. Field crews found nine sites where their shading analysis didn't agree with the reported values by more than 5 percent on a monthly basis. Additionally, annual, quarter-hourly shading data were recorded at each array vertex for averaging and subsequent use in modeling efforts.

Wiring/Connectivity Issues

Field crews found wiring/connectivity issues at three sites that significantly impacted overall system performance. At two sites, one of the two strings of panels was not properly connected at the junction box. While the system still produced output, it was only supplying 50 percent of the power it should have. This was difficult to identify, as the inverters still displayed instantaneous output numbers, though they were significantly lower than what would be expected from that system. At a third site, the Field crews found an external junction box switch in the neutral position, and a power output reading of zero. The combination of junction box's close proximity to the ground and the external switch that could be inadvertently switched made it fairly easy for the system to be shut down.

Modeling Results

Using system characteristics provided by the installer and verified by the field study, along with built-in Typical Meteorological Year Version 2 (TMY2) weather data and actual weather data from the CIMIS stations, the authors generated three hourly output shapes for the 86 sites from the field study:

1. Using TMY2 weather
2. Using Program Year 1 (PY1) actual weather
3. Using Program Year 2 (PY2) actual weather

In order to enable a batch process of applying results from the field verification study to all sites, including those for which system characteristics data were unavailable, the authors developed an 8760 hourly verification rate shape. By setting up separate runs for each case (field-verified characteristics vs. installer-reported characteristics), the analysis team was able to generate an hourly verification rate for each of the visited/verified sites—25% of the ~300 sites in the program. By applying these hourly verification rates to the ~100 sites modeled only with the installer-provided characteristics, the authors were able to obtain 8760 verified hourly production curves for each of the 56% of sites for which site characteristics were available. In order to generate hourly data for the remainder of the sites for which detailed characteristics were not available (the remaining 44%), a typical, normalized hourly production curve was generated for each California climate zone using actual weather data, and then applied and scaled to the unknown sites (by system rated capacity) in those climate zones.

The final step in generating realistic 8760 curves was to account for the utility interconnection dates of each system. This was accomplished by setting hourly production values to zero for all hours before the installation date for the PY1 and PY2 modeled weather data. The modeled results using TMY2 data were kept as full year production for use in forecasting impacts. However, the abbreviated PY1 and PY2 production shapes were used for calculating the energy, demand, and capacity factors for those years, respectively.

At a high level, the realization rate illustrates the percentage of claimed generation that is likely to be realized, or actually produced, in a typical year. The overall realization rate for energy was around 0.98 for this particular program.

Case Study 2: New York client wants to know only energy impacts and realization rate.

For this study, the authors modeled the PV arrays using typical-year data and then normalized to total energy production to date from the inverter readouts. The normalization was based on the amount of time systems had been interconnected and the corresponding actual and typical-year total insolation over that time. This approach was much simpler than creating weather input files from raw weather data, and certainly the preferred approach when actual program-year energy and demand impacts are not necessary.

Field Work Findings

Table 1. % Installed Capacity with Various Inspection Discrepancies

Issue	Installer 1	Installer 2	Installer 3
Tilt Angle	28.5%	54.3%	N/A[1]
Azimuth	57.0%	58.4%	18.8%
Shading	26.4%	36.3%	9.4%

[1]No ex-ante tilt data for half of Installer 3's sites

Tilt and Azimuth

As shown in Table 1, discrepancies were frequent. As with case study 1, if the field technician found a tilt angle that differed by more than 3° or an azimuth that differed by more than 5° when compared to the *ex ante* value, the engineer recorded a discrepancy.

Additionally, three sites had adjustable tilt arrays, which weren't reflected in the *ex ante* program tracking data. Finally, two of the four commercial sites did not report *ex ante* tilt data, so there was no basis for verification. This was most likely a result of the tracking system/spreadsheet being unable to account for split arrays with multiple tilt values.

Shading

Installers reported *ex ante* shading factors in the program tracking data as either the annual energy (kWh) lost due to shading, or the percent of total annual energy lost due to shading. The authors brought all *ex ante* shading values to a consistent percentage basis, and compared this to the field verified annual shading percentage for each site to evaluate the accuracy of on-site shade measurements. If the *ex ante* shading percentage varied by more than 5 percent when compared to the on-site verified shading percentage, the engineer recorded a discrepancy. As shown in Table 1, discrepancies were significant.

Array Grouping

Based on the limited data provided on installation parameters, it appears that installers used average parameters for sites with multiple unique arrays and ran one site-level model for the entire system. However, the authors did not have enough data to verify that this was actually the case. This could be a result of the tracking system/spreadsheet being unable to track multiple arrays for a single site.

Wiring/Connectivity Issues

For the sites visited during this field study, the field techs did not encounter any significant issues with installation quality. Although not an installation issue, one commercial site had a large amount of cement dust coating the panels. The installer and owner were both aware of the problem, and corrective measures had been taken.

System Interconnect Dates

An "interconnected" project is a PV system that has been installed, rebated, tied to the utility grid, and is expected to be producing power. In this analysis, the interconnect date directly impacts expected (modeled) system energy production to date, so it is an important parameter that the team spent significant time verifying.

Frequently, tracked interconnect dates were inconsistent with on-site findings. There were several sources of data for interconnect dates, including inverter nameplates, owner interviews, energy production data, inspection documentation and the tracking database. Inconsistent interconnect dates contribute to the overall uncertainty of modeled production results.

Modeling Results

Initial results, calculated using SAM, indicated high realization rates. Upon investigating these results, which appeared unusually high, the authors discovered a notable difference between the SAM tool and commonly used shading measurement tools, such as the Solmetric Suneye™ and the Solar Pathfinder™.

Typically, installers calculate the percent of annual generation lost to shading directly from either the SunEye™ or other similar devices, a process which ignore all diffuse energy generation during direct beam shading. In geographic regions with an abundant solar resource, ignoring diffuse radiation during shading could have minimal impacts since direct beam radiation vastly outweighs diffuse radiation. However, in regions like New York, diffuse radiation represents a greater proportion of total available irradiance. The authors estimate that approximately 42% of available solar radiation in New York State is due to diffuse radiation. In other words, up to 42% of the energy claimed as lost due to shading may still be available to the solar PV system in the form of diffuse radiation. Calculating the realization rate using a method similar to what was likely used by installers (e.g., not considering possible gain due to diffuse radiation) results in a realization rate of 1.13 for both residential and commercial projects (Table 3). Including the possible gain due to diffuse radiation results in realization rates of 1.16 and 1.20 for residential and commercial projects. It was not possible with the available data to draw definitive conclusions regarding which shading treatment more closely matches realized electricity generation, thus both original and adjusted realization rates are shown (Table 3).

Table 3. Original and Adjusted Realization Rates by Sector

Sector	Original	Adjusted
Residential	1.16	1.13
Commercial	1.20	1.13

Conclusions

The verification of solar PV rebate program impacts is crucial to ensuring the continued success of PV as a resource for electric utilities. In the absence of metered interval data from PV systems, a bifurcated approach to verification including both field work and hourly simulation modeling can be used to determine historical energy and demand impacts as well as projected (typical year) impacts. Findings from the field verification study fed into batch hourly simulation models yield an affordable, yet thorough, evaluation methodology.

The authors have three specific recommendations for future PV verification studies that use this bifurcated approach. Certain variables that are integral to the PV modeling are subject to high degrees of measurement error, and are less repeatable. As a result of this potential error, the authors recommend rigorous on-site care and quality control for the following variables:

- Azimuth angles
- array grouping,
- seasonal tilt changes, and
- system interconnect dates.

The authors also recommend considering the solar climate, especially the potential influence of diffuse solar generation, when selecting PV energy simulation software as there are varying approaches to deal with diffuse solar generation. Lastly, the authors must emphasize the necessity to verify systems' performances on-site. In the California study there were three sites with improper wiring. The average realization rate for these sites was ~33%, and this issue would not have been uncovered without the system performance verification step.

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