A Benchmark Tool for PV Generation:
How Much Less than Expected? And Why?

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ABSTRACT

While photovoltaic (PV) systems have proven to be a reliable technology, it is very common that small PV systems (20 kW or less) generate less energy than initially predicted. This paper presents a methodology whereby causes of these discrepancies are identified and quantified. Causes for discrepancies are broken into six "derating" categories:

- Capacity
- Tilt and Orientation
- Shading
- Equipment Performance
- Equipment Failure
- Basic Operation

The analysis procedure requires a short visit to the PV site (typically 2-3 hours for two people) where inspectors document system parameters and install sensors to monitor details of performance over a short period of time. Across the approximately 200 systems analyzed, average systems are generating 80-90% of predicted, baseline generation. While all six derating factors come into play, shading seems to be the largest – and most common – cause for lower-than-expected PV generation.

Introduction

Solar electricity generation from photovoltaic (PV) systems is generally very reliable; PV modules last for decades, there are no moving parts, and sunlight is converted directly to electricity. The amount of electricity generated by PV is also easy to predict; simple tools such as NREL's PVWatts™ are accurate and seem to be accepted by the industry.

After evaluating hundreds of smaller PV systems (usually 20 kW or less), the author has seen generation values that are consistently lower than expected by owners, program sponsors, or installers of the PV systems. Typically utilities, contractors, or designers use valid tools (such as PVWatts) to predict PV generation – but models are only as good as the information entered into them.

Originally developed as a commission tool for PV systems, the quantitative method presented here compares measured performance of PV systems to a benchmark (ideal or expected generation). The method has also been used by utility program managers and evaluators to gauge the accuracy of program predictions and to assess how installed PV systems are performing several years after installation.

The method involves a two-hour site visit (during a sunny day) where inspectors:

- Document PV module make, model and number in each array;
- Measure tilt and orientation of each array;
- Trace sun-path diagrams to evaluate shading of collectors;
- Document inverter make, model, and other balance of system parameters.

Inspectors also install sensors to measure:

- Irradiance on each array;
- Module temperatures;
- AC energy generated by the system;
- Where possible, DC energy generated by the system.

These measured values are recorded by a data logger for a short period of time (20-60 minutes). The findings from the site visit – both the system parameters and performance data – are fed into modeling tools based on PVWatts. The procedure begins with the benchmark generation value (the "ideal" or expected generation based on specifications). The tool then steps through a series of "derating factors" which are based on differences between specifications and observed or measured parameters. The six derating factors are associated with:

- Capacity
- Collector Tilt and Orientation
- Shading
- Equipment Performance
- Equipment Failure
- Basic Operation

At each step, the procedure calculates the amount of baseline generation lost (or sometimes gained) when as-built systems do not match specifications. This procedure can provide benefits to utilities or PV program managers looking to assess performance of installed systems – or a representative sample of systems – more accurately. While the most accurate way to assess PV generation is ongoing metering of each system, this procedure can be used to highlight specific reasons that measured performance differs from expectations. Knowledge of these reasons can provide more accurate generation predictions and – hopefully – higher overall generation from PV systems.

Site Visit Procedures

For best results, weather conditions during a site visit should be sunny. While inspections during cold weather are possible, cold conditions make some of the fine work more challenging. Low sun, shading, and short days make winter inspections more challenging as well. Regardless of the season, all collectors in each array must be exposed to identical sun conditions during the test period. If portions of an array are shaded, the calculated derating values will not be valid.

Site visits typically involve two inspectors who are on site for approximately two hours. One inspector focuses on the collector information and sensors; the other focuses on inverter documentation and electric energy measurements.

At the Collectors

Analysis of the collectors typically begins with the inspector making a sketch of the system noting the location of each array. For each array, the inspector records the make, model, and number of modules. This sometimes requires a borescope to view module labels when modules are mounted close to a roof. The inspector will record the dimensions of the modules and measure the tilt (from horizontal) and azimuth (compass direction) of each array. The inspector also takes photos of each array.

Shading analyses are done at each array using a Solar Pathfinder tool. Using the Solar Pathfinder, the inspector traces the shade horizon around the collectors on a sun path diagram and takes a digital photo. These digital photos are later put into Solar Pathfinder Assistant software to more quantitatively predict the effects of shading. The number of sun path diagrams traced for each array varies depending on the size and layout. For an array with virtually no shading, a single trace is adequate. For a long, ground-mounted array, traces are typically taken on each end and in the center. For roof-mounted arrays, a trace at each corner is the most common practice.

Figure 1. At left, an inspector measures collector tilt angle. At right, a sun path diagram shows the shade horizon.

After initial shading analysis and collector documentation, the inspector places a pyranometer near each array at the exact tilt and orientation of the array. Often the pyranometer is attached (temporarily) to the frame of a module so there is no shading of PV cells. In addition, the inspector attaches a low-mass temperature sensor to the back of one or more modules in each array. The instruments are connected to a data logger; insolation and module temperatures measurements are taken every five seconds throughout the short monitoring period.

Near the Inverters

At the inverters, an inspector records make, model, and number of each inverter. To record PV energy generated, the inspector installs current transducer(s) (CTs) and voltage sense wires on the output from the inverter(s). Exact placement of these sensors vary; typical locations are AC disconnects or junction boxes.

Current transducers and voltage sense wires are connected to watt-hour transducers. Total AC energy generated each minute is recorded by the data logging system. PV generation – along with module temperatures and insolation – are typically monitored for 20-60 minutes.

Derating Analyses

The purpose of the derating analysis is to compare predicted annual PV system generation to the benchmark (previously expected or "ideal" annual generation). Any differences between the predicted generation and the benchmark generation are attributed to one of the six derating factors described below. While the derating factors express energy loss associated with a particular element, the values themselves are expressed as the fraction (or percentage) of energy that is *not* compromised by that element. For example, if shade cast on a PV array blocks 5% of solar energy over the course of a year, the "shading derating factor" is approximately 95%. It may be useful to consider derating factors as similar to efficiency values.

Capacity

The capacity derating value is very straight-forward. If inspectors find installed PV capacity (at standard test conditions, STC) to be different from the benchmark, the derating factor is simply the ratio of installed capacity to benchmark capacity. If the benchmark includes a 10kW PV system and inspectors find collector capacity is only 9.8kW, the capacity derating is 98%. This translates into a 2% decrease in predicted annual generation.

Tilt and Orientation

It's quite common for inspectors to find that tilt and orientation of installed collectors do not match the benchmark specifications. Inspectors use PVWatts to predict annual generation from each array at both (A) the verified tilt and orientation and (B) the benchmark tilt and orientation. The ratio of these generation values (A/B) is the tilt and orientation derating factor.

Shading

In the author's experience, it is very rare for PV generation predictions to include effects of shading. It is almost as rare that there are absolutely no shading effects on PV collectors. Even relatively shade-free sites often experience *some* shade at certain times of day or periods in the year. Inspectors use Solar Pathfinder Assistant software – which uses PVWatts as its calculation engine (Solar Pathfinder 2008) – to calculate: (A) predicted annual generation with the recorded shading from the site and (B) annual generation with benchmark assumptions for shading (typically no shading). The ratio of the two (A/B) is the shading derating factor.

Equipment Performance

The equipment performance derating factor accounts for the operational efficiencies of all system components. This includes performance of the modules themselves (including effects from capacity variability, dirty collectors, module mismatch, system age, etc.), losses associated with wiring and connections, and inverter efficiency. The equipment performance derating factor compares measured generation to expected generation based on baseline specifications.

Inspectors use short-term test results to calculate this derating value. Baseline DC and AC energy generation for the system are calculated under conditions measured during the field testing (i.e. measured module temperatures and incident irradiance conditions). The effects of insolation are direct and linear. The module temperature effect used in the calculations (and in PVWatts software) is a 0.5% reduction in module efficiency per degree above 25°C (NREL 2010). Baseline DC generation is calculated as:

$$P_{DC,baseline}[W] = \frac{I\left[W/m^2\right]}{1000\,W/m^2} \times \left(1 - 0.005\left(T_{mod}[°C] - 25°C\right)\right) \times PV\_Cap[W] \times 87.75\%$$

where:

$P_{DC,baseline}$	is baseline DC power generation [Watts] accounting for insolation and temperature effects
I	is insolation incident upon the array(s) [W/m²]
T_{mod}	is module temperature [°C]
PV_Cap	is PV system rated capacity at STC [Watts]
87.75%	is the default derating accounting for DC energy losses (this can be

adjusted to match baseline assumptions).

Baseline AC power is simply:

$$P_{AC,baseline}[W] = P_{DC,baseline}[W] \times \text{Inverter Efficiency}$$

Inverter efficiency is taken from manufacturer literature (a 95% default efficiency is used in some instances). Over the short monitoring period, power values are calculated every five seconds and integrated to calculate DC and AC energy generated over the period. The equipment derating factor is calculated as the ratio of measured AC energy to calculated baseline AC energy over the monitored period.

$$\text{Equipment Performance Derating} = \frac{E_{AC,measured}[Wh]}{E_{AC,baseline}[Wh]}$$

If DC energy can be measured separately from AC energy, separate derating factors can be assigned to DC system components and the inverter. However, safely accessing DC wiring to install monitoring equipment is difficult in many situations.

Equipment Failure

The last two derating values relate to operation and maintenance of the PV system. While PV collectors last for decades, inverters typically do not. When inverters fail, this failure often goes unnoticed by system owners and operators. This derating value accounts for the equipment failure – and subsequent failure of operators to make repairs.

If all inverters (and all other components) are operating, the equipment failure derating is 100%. If all inverters have failed, the derating is 0%. When one of several inverters has failed, inspectors typically calculate the derating factor as the ratio of operational inverter capacity to the total inverter capacity (e.g. if a system with four identical inverters has one that is not functioning, the derating factor is 75%).

Basic Operation

In assessing hundreds of smaller PV systems over the past 15 years, the author has seen several systems not operating for a confounding reason: they are switched off. Reasons for this are usually unknown, and owners of systems are unaware that their systems are not operating. Systems that are turned on and are operating have a basic operation derating factor of 100%; systems turned off have a value of 0%.

In assessing newer systems, it is rare to find systems turned off; in systems that have been installed for four years or more, inspectors have found approximately 5% of systems turned off (the large majority of these are residential systems smaller than 10 kW).

Overall Derating Factor

The product of the six derating factors described above is the overall derating factor. This overall derating, when multiplied by the annual baseline generation prediction, will yield the revised annual generation value based on the inspections and monitoring.

Example

The hypothetical example depicted here demonstrates how derating factors are calculated and applied. The specifications of this hypothetical PV system are shown in Table 1.

Table 1. Specifications for the example system.

Location	Albany, NY
System Capacity	10 kW
Collector Orientation	South
Collector Tilt	30°
Inverters	6-kW (x2), 95% eff.
Baseline Generation	12,773 kWh/year

When inspectors visited this site, they found the PV array facing southwest (azimuth 240°) at a tilt of 20°. By inspecting labels on several modules, the total PV capacity was found to be 10,200 Watts (10.2 kW) – slightly larger than the capacity listed. Inspectors recorded shading values and performed short-term monitoring for a 45-minute period.

With the data, the capacity derating factor was calculated first – simply the ratio of installed to baseline PV capacity, or 102%. The derating factor larger than 100% implies that more generation is likely than expected from original specifications.

Using PVWatts software[1], inspectors then quantified the effect of tilt and orientation. A system facing at 240° azimuth with tilt of 20° will generate 9.1% less than a system facing due south at a tilt of 30° (as specified); this equates to a tilt and orientation derating factor of 90.9%.

Like most PV generation estimates, the designers (or people who created the baseline generation estimate) assumed there would be no shade present when making their prediction. While there is little shade at the site, sun path traces and Solar Pathfinder Assistant software predicted that this system would generate 6% less than a system with no shade at all; this translates into a shading derating factor of 94%.

During the 45-minute monitoring period, the PV system generated 3890 Watt-hours (Wh) of AC energy. During this period, the average insolation incident upon the collectors was 700 W/m^2 and the average module temperature was 45°C. Using the calculations presented above (in "Equipment Performance"), the benchmark system would be expected to generate 4018 Wh under these conditions as shown below.

These values can be duplicated by using the equations above, but this calculation has been simplified to make an example. During an actual evaluation, insolation and module temperatures would not remain constant for an entire monitoring period. Baseline energy values are actually calculated at each logging interval (typically 5 seconds). The resulting AC baseline energy values are summed for the entire monitoring period and compared to total measured AC energy. In this example, the ratio of the two is 96.8%; this is the equipment performance derating factor.

As all components of the system (including both inverters) were functioning, the equipment failure derating value is 100%. Because the system was turned "on" and operating, the basic operation derating was also 100%.

Table 2 shows the summary of this analysis. After the inspection and analysis, inspectors predict that the system will generate 84.4% of the baseline value, or 10,776 kWh per year.

Table 2. Summary of example derating analyses and predicted generation.

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[1] This calculation can easily be repeated using the free, on-line PV Watts tool.
http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/

Baseline Generation		12,773 kWh/yr
Derating Factor	Value	Associated Energy Loss (Gain) [kWh/yr]
Capacity	102%	(255)
Tilt & Oreintation	90.9%	1,186
Shading	94%	711
Equipment Performance	96.8%	356
Equipment Failure	100%	0
Basic Operation	100%	0
Overall	84.4%	1,997
Net Predicted Generation		10,776 kWh/yr

Overall Findings

Photovoltaics have a reputation for being a reliable, plug-and-play technology with little required in the way of operation and maintenance. This is largely true, but the author has found that initial predictions of performance are usually optimistic. The derating factors presented here account for most of the discrepancies found between predicted and actual generation.

Among all systems inspected, shading appears to be the largest factor. While there are some "ideal" sites with no shading whatsoever, most residential and small commercial systems are subject to a 5-10% reduction in generation because of shading (i.e. shading derating factors of 90-95%). Some sites have shading derating factors as low as 60% -- losing 40% of possible generation because of shading.

In older systems (systems that have been installed for 4 years or more) the equipment failure and basic operation derating values come into play much more frequently. Both of these are approximately 95% for older systems; in new systems, it is very rare to see such failures. Older systems also have lower equipment performance deratings; some losses in performance should be expected over time.

On the whole, after surveying approximately 200 projects for varying clients, overall derating factors for smaller PV systems (up to 20 kW) average 80-90%. By accounting for some of these simple derating parameters, PV designers, system owners, or program sponsors may certainly improve the accuracy of baseline PV generation estimates. It is not at all difficult to accurately record collector tilt, orientation, and system capacity. Shading analyses might require an additional 10-30 minutes at the site. These parameters can certainly be recorded more accurately by installers; it may also be appropriate for sponsors to inspect a portion of installed systems.

Procedure Limitations

The procedure described here makes several assumptions, and certainly the most accurate way to assess PV system performance is to continuously monitor generation. There are a growing number of products available to monitor PV generation, and cost of such systems may be coming down. Even with monitored PV performance, however, this procedure is able to identify – and quantify – factors which cause systems to generate less (or sometimes more) than expected.

One very practical limitation of the procedure is ability to document all necessary parameters of a system. At times, inspectors are not equipped to access arrays on very tall buildings (where scaffolding or lifts would be needed). At other times, there is not safe, practical access to system wiring and energy and power measurements cannot be made. These hurdles can typically be overcome by coordination with system owners and/or installers.

Another limitation of the procedure relates to capacity; inspectors do not verify the capacity of each and every module in an array; rather they inspect a small sample (usually near the edge of arrays where labels are visible). While it is rare that an array would be made up of modules of different power ratings (but with the same appearance and dimensions), it is possible.

Perhaps the weakest part of the analysis procedure is with respect to shading. Shading part of a PV module or string will affect the performance of the whole string and – to some degree – the entire system (Deline 2009; Woyte 2003). While maximum power point tracking protocols (MPPTs) will typically adjust system voltage to minimize effects of shading, it's not possible – with this procedure – to quantify the effects that partial shading will have on the entire system. In addition, Solar Pathfinder Assistant software does not accurately account for diffuse radiation. While PVs exposed to diffuse radiation can generate some energy, Solar Pathfinder software assumes shaded systems produce no energy (Solar Pathfinder 2008).

This derating procedure also captures only a snapshot of system performance. System components – especially inverters – are rated for efficiency at a specific capacities. At lower than rated operating capacities, efficiencies will change slightly. It is recommended that this procedure be performed under sunny conditions; at lower capacities from low-light conditions (e.g. overcast, early or late in the day), the discrepancy between rated and actual efficiency may be more pronounced.

Finally, the author has compared annual generation predicted using this procedure to measured generation from several systems (where generation has been monitored over a year or more). While the measured values and predicted values are generally close, there has not yet been a rigorous comparison. The main challenge in making such comparisons is weather. Weather variations can obviously cause substantial differences between predicted and actual PV generation. With systems that have been monitored in some detail, there has not yet been adequate local weather data to allow for meaningful comparisons to predictions. Efforts to make more meaningful comparisons are ongoing.

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