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Photovoltaic Module Energy Yield Measurements: Existing Approaches and Best Practice

PHOTOVOLTAIC
POWER SYSTEMS
PROGRAMME

Report IEA-PVPS T13-11:2018

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Foreword

The International Energy Agency (IEA), founded in November 1974, is an autonomous body within the framework of the Organization for Economic Co-operation and Development (OECD) which carries out a comprehensive programme of energy co-operation among its member countries. The European Union also participates in the work of the IEA. Collaboration in research, development and demonstration of new technologies has been an important part of the Agency's Programme.

The IEA Photovoltaic Power Systems Programme (PVPS) is one of the collaborative R&D Agreements established within the IEA. Since 1993, the PVPS participants have been conducting a variety of joint projects in the application of photovoltaic conversion of solar energy into electricity.

The mission of the IEA PVPS Technology Collaboration Programme is: To enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems. The underlying assumption is that the market for PV systems is rapidly expanding to significant penetrations in grid-connected markets in an increasing number of countries, connected to both the distribution network and the central transmission network.

This strong market expansion requires the availability of and access to reliable information on the performance and sustainability of PV systems, technical and design guidelines, planning methods, financing, etc., to be shared with the various actors. In particular, the high penetration of PV into main grids requires the development of new grid and PV inverter management strategies, greater focus on solar forecasting and storage, as well as investigations of the economic and technological impact on the whole energy system. New PV business models need to be developed, as the decentralised character of photovoltaics shifts the responsibility for energy generation more into the hands of private owners, municipalities, cities and regions.

IEA PVPS Task 13 engages in focusing the international collaboration in improving the reliability of photovoltaic systems and subsystems by collecting, analyzing and disseminating information on their technical performance and failures, providing a basis for their technical assessment, and developing practical recommendations for improving their electrical and economic output.

The current members of the IEA PVPS Task 13 include:

Australia, Austria, Belgium, Canada, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, Malaysia, Netherlands, Norway, SolarPower Europe, Spain, Sweden, Switzerland, Thailand and the United States of America.

This report focusses on the measurement of modules in the field for the purpose of energy yield or performance assessments. This document should help anyone intending to start energy yield measurements of individual PV modules to obtain a technical insight into the topic, to be able to set-up his own test facility or to better understand how to interpret results measured by third parties.

The editors of the document are Gabi Friesen and Ulrike Jahn.

The report expresses, as nearly as possible, the international consensus of opinion of the Task 13 experts on the subject dealt with. Further information on the activities and results of the Task can be found at: http://www.iea-pvps.org.

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List of abbreviations

AM	Air mass
AoI	Angle of incidence
APE	Average photon energy
DHI	Diffuse horizontal irradiance
DNI	Direct normal irradiance
E	Energy output
ECT	Equivalent cell temperature
ER	Energy rating
FF	Fill factor
G	Irradiance
G_i	In-plane (plane of array) irradiance
$G_{i,d}$	In-plane diffuse irradiance
$G_{i,b}$	In-plane direct beam irradiance
G_{eff}	Effective irradiance or spectrally sensitive irradiance
G_{stc}	Reference irradiance at standard test conditions
GHI	Global horizontal irradiance
GNI	Global normal irradiance
H	Irradiation
IAM	Incident angle modifier
I_{mp}	Current at maximum power point
I_{sc}	Short circuit current
IR	Infrared
KPI	Key performance indicator
LID	Light induced degradation
MM	Spectral mismatch factor
MPP	Maximum power point
MPPT	Maximum power point tracker
MPR	Module performance ratio
P_{nom}	Nominal power
P_{max}	Power at maximum power point

P_{stc}	Power at standard test conditions
$P_{stc,stab}$	Stabilized power at standard test conditions
PID	Potential induced degradation
PLR	Performance loss rate
POA	Plane of array
PR	Performance ratio
R_s	Series resistance
R_{sc}	Resistance at short circuit current
R_{oc}	Resistance at open circuit voltage
SIF	Spectral influence factor
T_{stc}	Reference temperature at standard test conditions
T_c	Cell temperature
T_{amb}	Ambient temperature
T_{mod}	Module temperature
T_{BS}	Back sheet temperature
ΔT_{CBS}	Difference between cell and back sheet temperature
u	Uncertainty
UV	Ultraviolet
V_{mp}	Voltage at maximum power point
V_{oc}	Open circuit voltage
w	Wind speed
Y_a	PV module (array) energy yield
Y_f	Final yield
Y_r	Reference yield
Θ	Tilt angle
τ	Recording interval
γ	P_{max} temperature coefficient

Executive Summary

The monitoring of single PV modules plays an important role in the demonstration and deeper understanding of technological differences in PV module performance, lifetime and failure mechanisms.

With the growing share and relevance of PV in the market, the number of stakeholders performing outdoor measurements at module level is continuously increasing: test institutes, certification labs, PV module manufacturers, but also non-experts in the field, e.g. distributors, investors or insurance companies are publishing their results in a wide range of media, from scientific to technical journals, from risk assessment reports to purely commercial publications. The comparability of these measurements is however made difficult by the different testing approaches and missing declarations on measurement uncertainties. This is mainly due to the fact that there is no dedicated standard or recognized guideline published, covering the specific needs of PV module energy yield measurements.

The two main reference documents available today are a best practice guideline for the testing of single modules which was presented by DERLAB (European Distributed Energy Resources Laboratories) in 2012 [1] and the IEC 61724-1 Technical Standard for the monitoring of PV systems, published in 2017 [2]. The first one is limited to the definition of some testing requirements, without distinguishing between different testing purposes. It does not consider uncertainty contributions at single measurement level and gives no recommendations of how to reduce them. The second one addresses many of the missing aspects, with details on sensors, equipment accuracy, quality check and performance analysis, but without considering the special requirements of single module monitoring and benchmarking studies.

Besides the slightly different scopes, the main difference between monitoring at module or system level is that system monitoring generally does not obtain the same accuracy reachable at module level. Secondary effects related to the system configuration (e.g. inverter performance, module sampling, module selection, mismatch losses, …) and spatial variations over the system (e.g. ventilation, soiling, shading, …) are often hiding the technological differences which are the focus and reason for module level monitoring. Moreover, the system monitoring standard does not include any IV-curve measurements, which are the base of many performance, lifetime and failure studies performed at module level. On the other hand, system monitoring is including some measurements, which are not relevant for module monitoring like AC currents and voltages or other system related electrical parameters.

Small systems, designed specifically for the purpose of performance or reliability studies, could however be a good alternative if all secondary uncertainties would be reduced to a minimum and the measurements of the DC side and the meteorological parameters would be good enough to allow inter-comparisons and detailed analysis. The disadvantages of the testing of entire systems are the higher space occupation and the larger number of modules to be characterized and inspected, but, on the other hand, real system stress conditions are better simulated and a more statistically relevant number of modules is measured. New hardware solutions able to measure the IV-curves of single PV modules within a string could make this approach more attractive and affordable in the near future.

The goal of this document is to fill some of the normative gaps and to help anyone intending to start energy yield measurements of individual PV modules to obtain a technical insight into the topic, to be able to set-up his own test facility or to better understand how to interpret results measured by third parties.

The current practices for energy yield measurements of individual PV modules applied by major international research institutes and test laboratories are presented in this report. Best practice recommendations and suggestions to improve energy yield measurements are given to the reader.

A survey was conducted within the IEA PVPS Task13 consortium to assess how module energy yield measurements are performed today and how the uncertainties are calculated and reported to the end-users. Fifteen Task members with experience in PV module monitoring from over 30 test facilities installed all over the world have been interviewed. Many ISO17025 accredited test laboratories, as well as R&D institutes, have been included. The questionnaire covered all aspects, starting from general questions on the scope of testing to the test equipment, procedures, maintenance practice, data analysis and reporting.

The purposes, for which the monitoring is performed at PV module level, can be manifold:

- To assess the stability of a cell technology under specific environmental conditions and stress factors (degradation studies),
- to measure the over or under-performance with respect to a reference technology (benchmarking studies), understanding single environmental loss factors (temperature, spectrum, irradiance, wind, shadows, soiling, etc.) and
- to collect data for the validation of energy prediction models or the calibration of PV module parameters for a specific model.

It is to be mentioned that module energy yield measurements are also required for the validation of the IEC 61853 standard on energy rating [3,4,5,6], which is currently in elaboration and which aims at replacing the current power rating according to standard test conditions of modules. High precision measurements with accurately determined uncertainties are the key to be able to foster the introduction of any energy rating in the future. Further, energy yield predictions as described in the Report IEA-PVPS T13-12:2018 entitled 'Uncertainties in PV System Yield Predictions and Assessments' will profit from this.

Less frequently, outdoor measurements are performed for the purpose of module characterization, which is mostly done indoors with solar simulators, for which the measurement uncertainties are better defined and known. If characterization is performed under outdoor conditions, it is generally done using a sun-tracker and other means to control the irradiance and temperature levels. In this case the integrated energy yield is not relevant and the electrical characterization is therefore not within the scope of this document.

The different scopes give rise to different testing requirements and data analysis. The most relevant measured or calculated key performance indicators (KPI) are: Instantaneous power (P), energy output E, energy yield (Y_a), module performance ratio (MPR) and performance loss rate (PLR). The measurement accuracy of the output data depends as much on the measurement accuracy of the single components forming the measurement system, as on the conditions at the measurement system and its configuration.

This report gives an overview of the most important aspects to be considered for the set-up of a test facility, e.g. the layout of the test rack and mounting instructions for modules and sensors, as well as how to combine and configure any current/voltage measurement system, like IV-curve tracers and/or maximum power point trackers (MPPT) for PV modules in order to reduce any measurement artefacts (e.g transient or capacitive effects, MPP tracking errors, wrong loading, cable losses, …) and errors in the final determination of the KPI's due to inadeguate data recording (e.g. low sampling rates, syncronisation errors,…).

Available quality control measures, such as calibration needs, quality markers for erroneous data (e.g. temperature sensor detachment, sensor soiling, data acqusition errors, …) and maintenance practices (visual inspection, cleaning intervals, e-mail alert, …) are presented to increase the early detection of problems such as drifts, failures or malfunctions, which could further increase the measurement uncertainty.

The final goal is to achieve accurate and reliable data, also over a long time period, and higly comparable data, even with data from other test facilities mounted according to the same guidelines. A better understanding how to reduce single measurement uncertainties, by quantifying and documenting them, is therefore essential.

However, even by reducing all measurement uncertainties, an adequate inter-comparison between different PV technologies is only possible if the PV modules are selected according to well-defined sampling procedures and if the STC power and its uncertainty are known. The STC power is actually one of the main contributions to the uncertainty for the calculation of parameters Y_a and MPR. The nominal power P_{nom} as declared by the manufacturer is generally considered as the less adequate for any inter-comparison, because it can considerably differ from the real power of a PV module, its measurement uncertainty is rarely documented and it is subject to commercial marketing strategies. The most suitable value for benchmarking of products is the real STC power, with known uncertainty values and no variation after installation. The last aspect is important because, if the module is not stabilized before measuring the STC power, it can lead to misleading results. In general, the lower the measurement uncertainty and the higher the stability in the field, the higher the accuracy of the ranking is. High precision measurements and validated stabilization procedures performed by accredited test laboratories lead to highest accuracies. In general, electrical characterization and optical inspections of PV modules before installation will guarantee that no low quality, defective or damaged modules are chosen.

To understand technological differences and the over- or under-performance of one technology with respect to another under specific climatic conditions, the individual sources of loss with respect to the power under standard test conditions have to be quantified. Different approaches exist to calculate single de-rating factors which allow to select the technology with the lowest loss at specific conditions (e.g. high fraction of diffuse light, high temperatures, high angle of incidence, etc.). To calculate the losses, either a full electrical characterization of the module under controlled laboratory conditions or the monitoring of the IV-curves is needed.

It has to be mentioned that, in terms of bankability of the modules, the degradation rate is more important than the precise knowledge of the instantaneous performance given by the electrical module parameters. In the long term, the annual performance loss can have a higher impact on the life-time productivity than the electrical parameters. Much less is known on the impact of the environment on the ageing process. For this reason, many tests laboratories focus on long-term measurement campaigns and the calculation of the PLR.

Independent of the determined KPI, deviations are only meaningful if they are higher than the measurement uncertainties. There are situations, where the magnitude of measurement uncertainty is larger than the investigated environmental effect so that the result cannot be used for benchmarking or degradation studies without taking it into account. The knowledge and reduction of the uncertainties should be mandatory for anyone performing such measurements. Sometimes, a differentiation has to be done between absolute and relative measurements.

In general, the survey performed within the PVPS Task 13 expert group highlighted that the measurement accuracy and scientific detail within most test laboratories are very high. This is demonstrated by a recurrent use of high precision equipment, good measurement practice and the implementation of good quality control and maintenance practice. Nevertheless, the survey revealed some limits, which are mainly the comparability of different outdoor data and the use of these for the validation of models due to a limited harmonization or availability of measurement uncertainties for the main KPIs. The main reason for this is that compared to the measurement of the STC performance using a solar simulator, for which the measurement uncertainties have been intensively investigated and validated over the last years, in energy yield measurements the reproducibility of test conditions is not possible and the determination of the measurement uncertainty is much more complex. The uncertainty is actually site and time dependent and impacted by many factors, which are difficult to estimate and sparely described in literature.

The first step to improve the comparability of outdoor measurements is to agree on the main uncertainty contributions and to suggest a common approach for the reporting of measurement uncertainties. This document gives recommendations on how to reduce the main uncertainty contributions and how to calculate them in future projects. Major efforts should be invested in implementing and validating best practice approaches through international round robins in future.

1 Introduction

Photovoltaics (PV) continues to be a fast-growing market, with an expected growth in global installations of up to 80 GW in 2017 [7], according to SolarPower Europe, and it is on track to achieve the goal of 12 % of European electricity demand to be provided by PV by 2020. A key factor that will enable the further increase of the uptake of the technology is the reduction of PV electricity costs by increasing the lifetime output as highlighted by the Solar Europe Industry Initiative (SEII). This can be achieved by improving the reliability and service lifetime performance through constant, solid and traceable PV plant monitoring of installed systems. The same should be done also during the technology development enabling more accurate and standardized performance, energy yield and lifetime testing. This results in a further risk reduction for investors and asset owners and can provide more efficient R&D feedback to the technology providers.

The main challenge in the quest for ensuring quality operation especially for test systems is to safeguard reliability and good performance. This can be ensured by identifying and quantifying accurately the factors behind the various performance loss mechanisms, while also detecting and diagnosing potential failures at early stages or before the occurrence, through robust performance monitoring.

All this requires independent and high-quality monitoring and testing concepts, both at system and module level. With an overall designed hardware, software and sensor concept researches will be able to separate the losses and identify trends fast and repeatable, independent on the test infrastructure or location.

Through the developments in better energy yield measurements at module and system level and methods for the early fault detection methods, the improvement of preventive maintenance strategies and more reliable real-time forecasting will result in a more accurate annual energy yield and lifetime prediction. This output can reduce the gap to the target system performance operation which directly affects the levelized cost of energy (LCoE) and investment costs as the plant will operate in a healthy state for longer and loss of revenue will be minimized. Indicatively, when the energy yield measurement uncertainty could be reduced by 1 % for the annual global PV installation this improvement provides around 500 MEuros increased revenue per year.

This rectifies the effort for solid and traceable setup for R&D and industrial monitoring solutions.

2 Background Information

Chapter 2 gives an overview of the most frequent scopes for which outdoor testing of PV modules is done and explains the difference between energy yield and energy rating measurements.

2.1 Scope of Testing

The reason for testing single modules in the field are multiple and are rarely limited to a single scope. The most common ones are:

1. Measurement of the energy yield for the purpose of module benchmarking [8,9,10]. The question is raised, which technology performs better in respect to another one and under which environmental conditions. The PV module energy yield (Y_a) or module performance ratio (MPR) are the two most used performance indicators. To better understand the origin of the observed differences a scientific monitoring based on full IV curves is very often added. The typical duration of these tests is 1 year with the exigence of small data loss rates. Module energy yield measurements should not be confused with energy rating as described in chapter 2.2.
2. Measurement of medium to long term degradation rates or performance loss rates (PLR) and investigation of the degradation mechanisms under different environmental conditions [11,12,13,14,15]. In general, this type of test requires long exposure times of minimum 3 years and a monitoring of the most relevant environmental parameters.
3. Measurement of high-quality time series for the validation of existing or new energy prediction models [16,17]. Emphasis is here put on the data accuracy and good synchronization of the meteorological input parameters. Time series of 1 year are generally enough for this purpose.
4. Measurement of the module performance under variable test conditions for the scope of module characterization. The aim is to extract in the module parameters needed by specific performance models (e.g., LFM [18], SAM [19], PVSYST[20]) or the performance matrix according to the IEC 61853 standard part 1 [21]. Most of the times these measurements are done on a two-axis tracker and not on a fixed rack, due to the advantages of being faster and more accurate. The sun-tracker allows to control the angle of incidence, and irradiance and module temperature can be controlled by the mean of attenuation filters or respective temperature control units.
5. Testing and optimization of the energy yield and durability of prototypes (e.g. innovative technologies, new materials or module constructions). The focus is on highlighting differences to a reference module and to provide the results in a short time to the product developers.
6. Measurement and investigation of specific performance losses as e.g shading or soiling losses [22], thermal losses [23,24,25], or losses due to potential induced degradation (PID). Variations to the standard test facilities and test procedures are necessary to simulate the required test conditions or to monitor additional parameters. The variations can consist of e.g different shading scenarios, different back-insulations, application of external bias voltages and the monitoring of thermal distribution or leakage currents.

2.2 Energy Yield versus Energy Rating

Side by side energy yield measurements of single modules, as described in the previous chapter (see scope 1), are often wrongly named as energy rating measurements. To solve the confusion between 'Energy Rating (ER)' and 'Energy yield measurements' a short description is here given about what ER is.

The ER approach is described by the series of standards IEC 61853, which aims to establish IEC requirements for evaluating PV module performance based on power (watts), energy (watt-hours) and performance ratio. Part 1, which deals with power rating measurements of a PV module at different irradiance and temperature levels, and Part 2 for the determination of the angle of incidence (AoI) effects, spectral response, and operating temperature are public and already allow a significant reduction of the uncertainty of any energy prediction. Part 3 describing the methodology for the calculation of the energy rating and Part 4 defining the standard weather data sets covering different climatic regions are in earlier stages of development. Different authors describes how the single measurement uncertainties are propagating into the final energy yield calculations [26,27,28].

The main difference between energy yield measurements and ER is that the first is a measurement under real operating conditions over an unspecified time frame and under any climatic condition whereas the second is a pure calculation under standardized conditions. An energy yield measurement has to cover a full year to be representative, and the results are only valid for the site on which they have been measured. The measurement at the origin of any ER can be performed in a much shorter timeframe and can also be calculated for different locations. Part 1 of the IEC61853 standard dedicated to the power rating of a module, describes three approaches: procedure in natural sunlight with tracker (paragraph 8.3), procedure in sunlight without tracker (paragraph 8.4) and procedure with a solar simulator (paragraph 8.5). The approaches with a solar simulator or a sun-tracker are the most used ones, whereas the second on a fixed rack is little implemented. The main reasons for this is that the two other approaches are much better described and validated [21,29] and that the measurement uncertainty is significantly higher when measured on a fixed rack.

It has to be highlighted here that energy yield measurements are essential for the validation of the ER standard in all its parts and in particular when extending it to new technologies. High precision measurements with accurately determined uncertainties are therefore of great significance, as discussed in this document.

3 International Survey on Measurement Practices

To assess the state of the art of measurement practices, an international survey was conducted among the test laboratories of PVPS IEA TASK 13. All members performing outdoor measurements on single modules were invited to participate. The study was carried out by means of a questionnaire given to 15 members, identified within the IEA Task 13 consortium. The empty questionnaire can be found in Annex 1. All partners responded and completed the survey. Annex 2 includes a short presentation of the single test infrastructures.

The questionnaire collected detailed information about how module energy yield measurements are performed today all over the world and how the uncertainties are calculated and reported to the end-users. The questionnaire covered all aspects starting from general questions on the scope of testing, the experience of the participants, the used test equipment, test procedures, and the maintenance and data analysis approach.

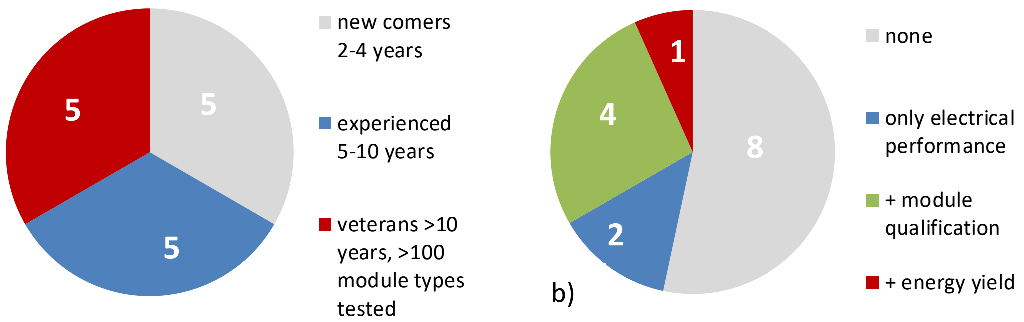


Figure 1: Experience of survey participants with module outdoor testing (a) and type of ISO 17025 accreditation (b).

As shown in Figure 1a, one-third of the 15 survey participants are veterans of the field with outdoor testing of PV modules being one of their main activities (more than 10 years of experience in the field and more than 100 module types tested), another third is performing outdoor testing for many years, but less intensively respect to the veterans (5-10 years of experience and fewer module types tested) and the remaining are 'newcomers' (2-4 years of experience and mostly smaller test facilities). Despite the survey was restricted to the IEA consortium it represents very well the state of the art of today's module outdoor testing practice within test laboratories, and the information can be taken as reference for who is implementing this type of tests. The type of the laboratories is shown in Figure 1b. Seven out of the 15 laboratories are ISO 17025 accredited test laboratories. Two are accredited only for the electrical characterization of PV modules according to one or more IEC standards (e.g., IEC 60904-x, IEC 61853-x). The others are also accredited for the full module qualification according to IEC 61215. Only one of the laboratories is actually accredited for the energy yield testing of single modules here discussed. The reason for this is the lack of a standard describing the measurement of the module energy yield of a PV module under real outdoor conditions. The accreditation is here done according to an in-house defined procedure. The eight non-accredited test laboratories are mostly universities, national research institutes and in a minor extent private companies performing measurements for commercial purposes. Except for one, the non-accredited test laboratories do not have a solar simulator in-house. For the calculation of the energy yield in kWh/Wp they have therefore to rely either on manufacturer power measurement (flasher list values), measurements performed by other test laboratories or STC power values extrapolated from outdoor data. The impact of this will be discussed in chapter 7.1.2.

Figure 2 shows the frequency of the scopes for which outdoor test are performed by the 15 partners. The scopes were already described in paragraph 2.1.

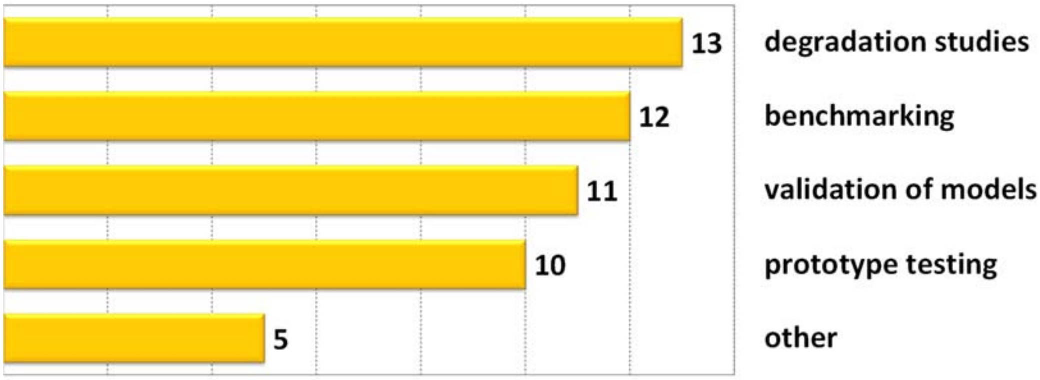


Figure 2: Survey feedback on the typical purposes for module outdoor testing within the 15 survey participants.

Many of the participants operate outdoor test facilities in different climates. The survey involved 33 test facilities comprising all relevant climatic zones: warm and tempered, arid, continental, tropical and alpine. All the key technologies, from crystalline silicon to thin film technologies are tested there. Figure 3 shows how the test facilities are distributed over the world and the different climatic zones.

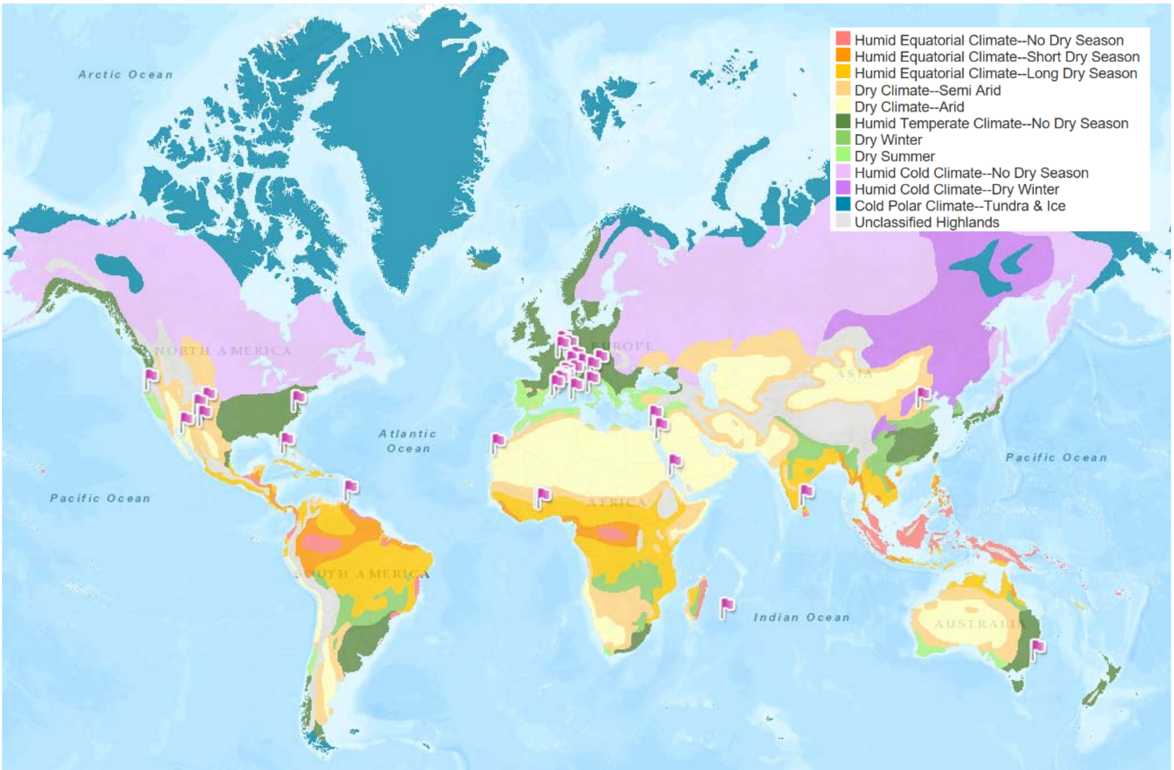


Figure 3: Climatic world map showing the distribution of the 33 outdoor test facilities (marked with flags) operated by the survey participants.

4 Test Environment and Hardware Requirements

As discussed by various authors [31,32,33] the uncertainty and reliability of medium to long term outdoor measurements is affected by many parameters. The measurement accuracy depends as much on the conditions around the measurement system as on the measurement system itself. Chapter 5 gives an overview of the most important aspects to be considered for the set-up of a test facility, and discussed the impact of individual hardware components. Best practices from the survey of international experts are presented with complete technical details and general recommendations.

4.1 Mounting Structure & Surroundings

For accurate energy yield measurement, optimal test conditions must be guaranteed throughout the year because any rejection of data will increase the uncertainty of the sum of energy delivered. This consideration leads to specific requirements for mounting structure and surrounding.

The most used mounting configuration by the survey participants is the open-rack configuration, tilted and oriented optimally (or close to) for the geographical location. For the testing of specific modules, for example building-integrated photovoltaic (BIPV) or bifacial modules, other configurations with different orientations, inclinations, or back insulations are used. One laboratory uses a 2-axis tracker for the purpose of short-term measurements.

The requirements for open-rack mounted modules will be further discussed, but many of these requirements also apply to other configurations. The impact of any deviation from the requirements should be assessed and considered when analyzing the monitoring data and the related measurement uncertainties.

The key factors discussed here are:

- Mounting rack layout
- PV module installation
- PV module shading
- Albedo
- Sensor positioning

The survey showed that the impact of the surroundings and module installations on the non-uniformity of the test field is rarely measured systematically. Most of the times it is estimated or not specified. For the irradiance, it is often assumed to be negligible or below 1%, whereas large discrepancies from 1°C to 8°C have been declared for the temperature. These values depend on what is taken into account: back side ventilation, the height of the module, the distance between modules, and module intrinsic differences. The maximum declared misalignment of the modules was of 0.5-2°, but 1/3 of the survey participants did not state any value. The survey also highlighted large differences for the heights of the modules above the ground or roof. Nine of the respondents list a module height above the ground of 20-50 cm in some cases and up to 1-3 meters in other cases. The other survey participants do not give any height specifications.

The following paragraphs give some suggestions on how test facilities could be further harmonized. Some general rules have been published by DERLAB [[1].

4.1.1 Mounting rack layout

The mounting racks for PV modules shall be tilted and oriented so the modules receive the highest yearly insolation for the geographical location. This optimal tilt angle will depend on the latitude. Various recommendations on finding the optimal tilt angle are given in literature. From http://www.solarpaneltilt.com:

- For latitude < 25°, use the latitude times 0.87. However, the minimum tilt angle shall be 10° to assure effective self-cleaning of the PV module by rainfall
- For latitude between 25° and 50°, use the latitude times 0.76 and add 3.1 degrees.
- For latitude above 50°, use a fixed tilt angle of 45°

In order to avoid measurement inconsistencies, the test rack must guarantee a coplanar installation of test modules and irradiance sensors so that all modules and sensors have the same tilt and orientation angle. Any misalignment between test modules and the reference device (irradiance sensor) will introduce measurement errors. Therefore, specific care must be taken when PV devices are installed on different mounting racks.

The misalignment of the survey participants' modules within their test fields was declared to be within 0.5-2%, and their irradiance sensors declared to be within 3% of the modules. One-third of the survey participants did not state any value.

The measurement errors due to misalignment are directly related to the cosine of the angle between the devices. Figure 4 shows this cosine error as a function of the angle of incidence (AoI) for various degrees of misalignment. It becomes apparent that misalignment should be kept to less than 0.5° to keep the irradiance difference to less than 1% during peak irradiance times (AoI < 45°). It must be noted that energy yield measurements of PV modules typically span a larger range of angles of incidence, however. For AoI > 50°, even 0.5° of misalignment will introduce measurement errors larger than 1%.

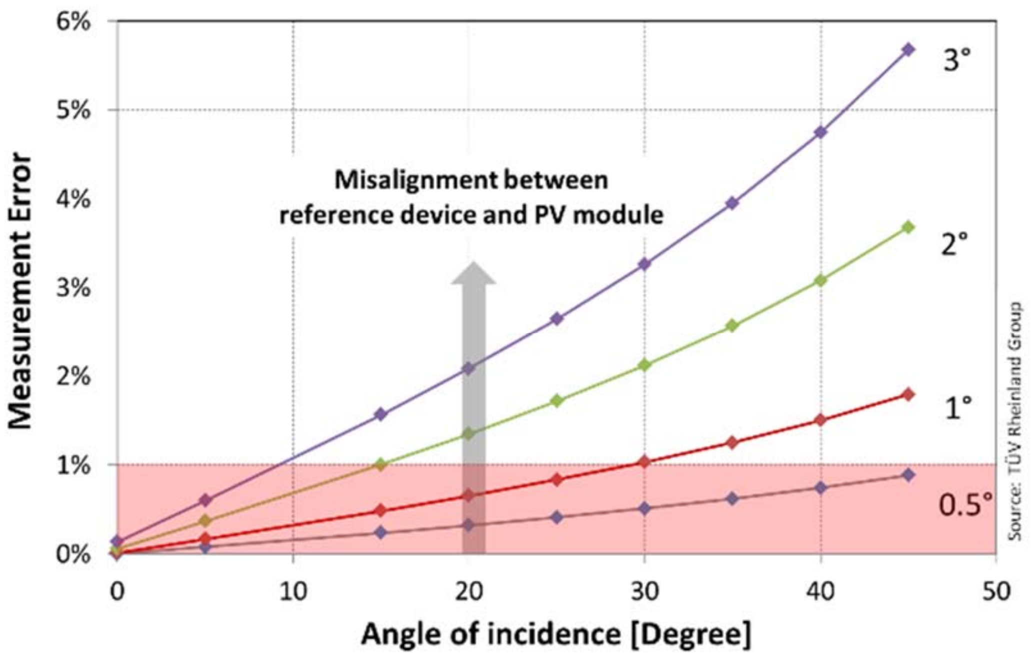


Figure 4: Measurement error caused by the misalignment of PV devices

4.1.2 PV module installation

The configuration of the PV module mounting rack can significantly affect the temperature distribution across the installed PV module. If the high-temperature rear side of the module is too close to the lower-temperature mounting rack, radiative heat exchange will typically cause module temperature gradients. In such cases, it would be difficult to find a representative location for measuring the module temperature. Therefore, an infrared image of the entire test sample shall be taken at solar irradiance >800 W/m² to identify any non-uniformities, which shall then be addressed.

For PV modules mounted on a tilted mounting rack, a temperature gradient from bottom to top is typically observed. The temperature profile highly depends on the air circulation around the test sample. In order to reduce unwanted non-uniformity effects, the test sample shall be installed at least 1 m above the ground and at least 10 cm from any other object.

Normally, the outer test samples on the left and right of a row will operate at a lower temperature due to increased forced convection by the wind, especially in locales with high wind speeds and a preferential east/west wind direction. Therefore, additional dummy modules shall be installed in these locations to reduce the environmental variability of the modules under test. Otherwise, individual test samples might be disadvantaged or favored.

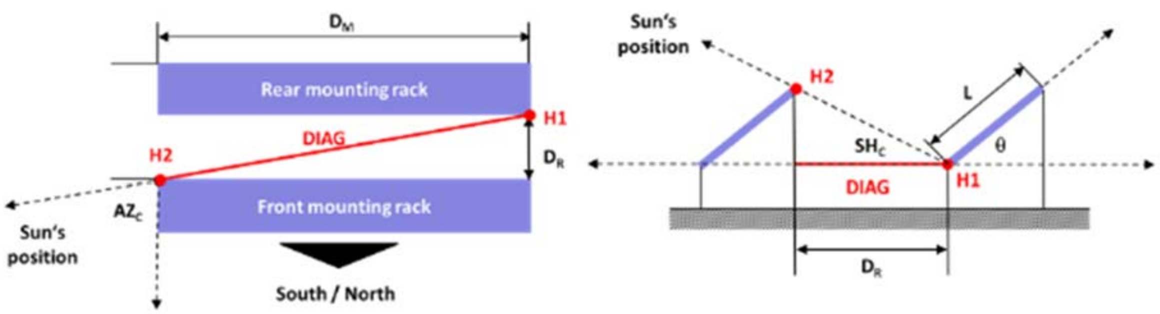
4.1.3 PV module shading

For a specific location, accurate measurement of the annual energy yield of a module requires a low number of rejected data points, or a high data availability. Primarily, this is achieved if the test modules are not subject to shading, which can be from nearby objects like buildings, trees or a fence, for example. Shading can also be caused by the elevation profile of the landscape or PV modules mounting clamps at high angles of incidence.

For general shading analysis of a test site, various shade analysis tools are commercially available that superimpose a diagram of the sun path over the course of a year on a panoramic 360-degree view of the entire site. This shows where the sun intersects the surroundings at different times of the day and year, which thus result in shading. Alternatively, shading of a site can be modeled in some computer aided design (CAD) software.

Test installations for energy yield measurement of PV modules may consist of several mounting racks. In that case, PV modules can be shaded by other modules installed in front of them. This inter-row (inter-rack) shading occurs for sun position angles less than that defined by the shading limit angles.

Figure 5 illustrates how to calculate the shading limit angles for an arrangement of two parallel mounting racks. The resulting sun azimuth and sun height angles (SA_C/SH_C) mainly depend on the rack spacing (D_R) and the rack tilt angle (θ). The closer the racks, the higher the shading effect of the front rack on PV modules installed in the rear rack.



L	**PV module length**
θ	**PV module tilt angle**
D_M	**Right-to -left distance of PV modules on mounting rack**
D_R	**Module-to-module distance between mounting racks**
H1	**Height of PV module bottom on rear mounting rack above ground**
H2	**Height of PV module top on front mounting rack above ground**
DIAG	**Length of diagonal (projection of points H1 and H2 to the ground)**
AZ_C	**Shading limit angle for sun azimuth (SA_C)**
SH_C	**Shading limit angle for sun height (SH_C)**

$$H2 = H1 + L \cdot \sin(\theta)$$

$$DIAG = \sqrt{D_R^2 + D_M^2}$$

$$SA_c = 90° - \arctan\left(\frac{D_R}{D_M}\right)$$

$$SH_c = \arctan\left(\frac{L \cdot \sin(\theta)}{\sqrt{D_M^2 + D_R^2}}\right)$$

Figure 5: Calculation of the shading limit angle for parallel arrangement of mounting racks. The shading limit coordinates are (SA_C, SH_C).

Secondary shading effects of diffuse irradiance occurring above the shading angle limit can be estimated for example with Raytracing. The calculated shading angle limit should therefore be increased by at least 5° to avoid shading losses of diffuse (especially circumsolar) irradiance.

Figure 6 illustrates the shading effect throughout the year for the following array configuration: Latitude of location: 40° N, PV module length (L): 2 m, PV module tilt angle (θ): 35°, Row spacing (D_R): 4 m, Row length (D_M): 15 m. The transfer of the so calculated shading limit angles SA_C=75.1° and SH_C=4.2° into the sun path chart of the location shows that this point lies on the sun paths of 12 October and 28 February. This means that shading will occur only during periods with lower sun heights and more southern sun azimuths, which corresponds to the period 12 October to 28 February. The shading limit angle of sun height (SH_C) must be corrected for sun azimuth angles lower than SA_c, which leads to the red shading curve in Figure 6. During the year, shading occurs for any overlap of this curve with the sun path chart, which is bordered by the summer and winter solstice. In this example, the intersection of the shading characteristic with the winter solstice (lower, inner bounding black line) leads to the result that modules are always shadow free from 8:30 AM to 15:30 PM. This defines the window out of which the data must be rejected for the purpose of our tests.

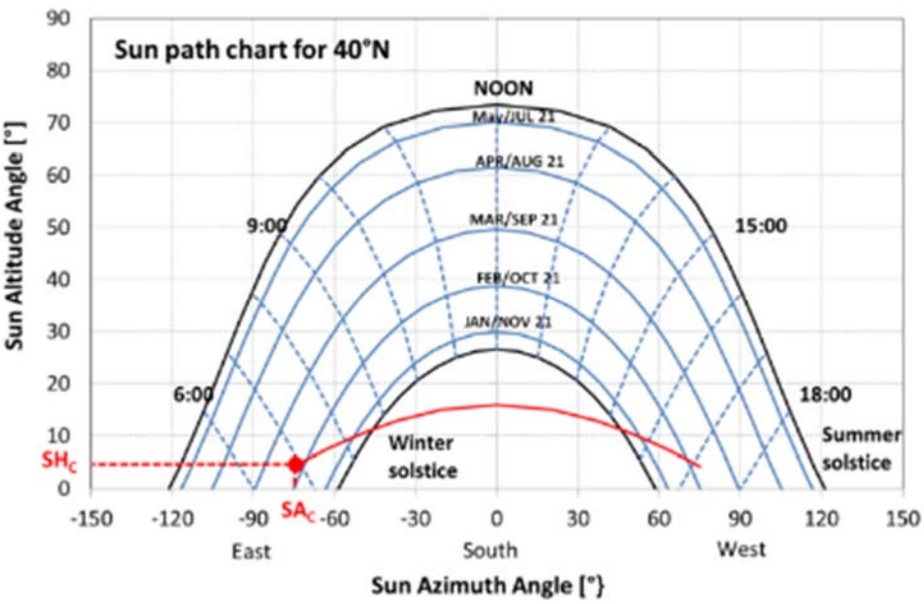


Figure 6: Example of a sun path chart for a location at 40° N. The red curve is the shading characteristic for the example given above.

4.1.4 Albedo

The total solar radiation (global radiation) reaching the modules is the sum of the direct, diffuse and reflected radiation. The diffuse radiation incident on an inclined plane is defined as the sky diffuse radiation while the reflected radiation is due to the reflection of non-atmospheric objects such as the ground). As a first approximation, the diffuse radiation can be assumed to be isotropically distributed in the hemisphere. This isotropic model underestimates diffuse irradiance on tilted surfaces. Models that are more accurate consider isotropic, circumsolar, and horizon components.

Reflected radiation t depends on the reflectivity of the surroundings (landscape, vegetation, buildings, etc.). It can be very non-uniform as different surfaces have different albedos (broadband reflectivities). The ground type as specified in the survey varies from lower albedo grass to higher albedo gravel, cement, metal and white paint, in the extreme case.

The steeper the PV modules are tilted, the less of the sky they are facing and the more reflected radiation they receive. Therefore, the albedo of the ground in the immediate surrounding is an important factor for PV module test installations. In order to minimize measurement errors introduced by reflected radiation the following recommendations should be considered:

- The ground albedo should be as uniform as possible. If needed, the ground around the mounting rack shall be covered by dark gravel.
- The installation height of the PV module above ground should be larger than 1 m.
- In the case of multiple row installations, the distance between rows should be large enough to avoid different irradiation conditions on the front and the rear mounting rack.
- Any high reflective surfaces (metallic parts, water surfaces, etc.) shall be removed, covered or painted. Care should be taken if painted, as the paint type may not reduce infrared reflections.
- In the special case of bifacial modules, the rear side albedo of the ground should be also uniform. Irradiance measurements are recommended from both sides with several locations on the back surface to detect impacts from tilt angle, height above ground and position of the test sample on the mounting rack.

4.1.5 Sensor positioning

The tolerated distance of the sensors to the test array differs significantly between the survey participants. The distances ranged from 2-35 meters for in-plane irradiance and 0.5-150 m for wind measurements. The committee recommendations are:

- Meteorological and module temperature sensor installations shall follow standards IEC 61853-2 and IEC 61724-1.
- For larger test installations or those on various mounting racks, several irradiance sensors shall be used.
- For comparative PV module performance measurements, the variability of daily solar radiation measured at different locations in the mounting rack/s shall not exceed ±1%.

More details on the meteorological sensors are given in chapter 4.3

4.2 Current and Voltage Measurements

4.2.1 Hardware solutions

The available hardware solutions for the measurement of the module power can be roughly divided into 3 categories: maximum power point trackers (MPPT), IV-tracers (IV) or IV-tracers in combination with an MPPT (IV+MPPT).

The first MPPT category includes micro-inverter based monitoring, but the lower accuracy of the internal sensors inside the inverters is usually not good enough for the purpose of energy yield inter-comparisons. In some cases, parameters are inferred from lookup tables rather than being measured. By adding a small, calibrated resistor in series to measure the current, accurate monitoring can be achieved with small bias errors. The analog-to-digital converter that is chosen should have the lowest noise and highest accuracy and stability over time and temperature. There are also DC-to-DC MPPT's with monitoring that are optimized for individual modules, but these are generally at a higher price.

The second IV-tracer category is generally combined with a static, passive load that is sized to keep the module operating around the maximum power point. An installation of a passive load brings about more realistic module temperatures and aging effects compared to the operation under open circuit or short circuit conditions [34].

The third category where IV-tracing is performed in regular intervals while the module is otherwise operated at its maximum power point is the most frequently used in the scientific community.

Figure 7 shows the outcome of the survey, where 81% of the participants stated to use IV-tracers in combination with MPPTs, while the others use IV-tracers in combination with a passive load. As most of the participants in the survey are research oriented it is not surprising that none use just an MPPT, which would limit the analysis to P_{max} and not allow for the analysis of the other parameters that can be extracted from IV-curves.

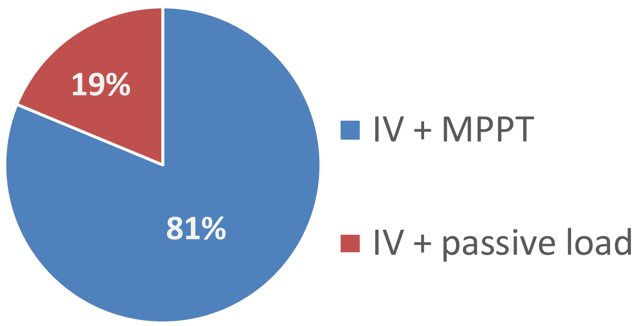


Figure 7: Hardware types implemented by the different laboratories.

The final choice of the appropriate test equipment strongly depends on the scope of the outdoor testing being performed (see chapter 2.1).

Table 1 gives an overview of the advantages and disadvantages of the three previously described approaches.

Table 1: Comparison of current and voltage measurement methods.

	(1) MPPT	(2) IV-tracer	(3) IV-tracer with MPPT
Description	Maintains the PV Module at its maximum power point (P_{max}).	Measures the current from at least open circuit to short-circuit (or vice versa)	Combination of (1) for MPPT and (2) for IV-tracing.
Pros	Simulates deployment in an array. Can integrate power production for an accurate energy yield measurement. Lower cost.	Can determine entire IV curve parameters including for example current steps near I_{SC} (mismatch) or rollover near V_{oc}. May extend into other quadrants such as V<0 and I<0 to determine other PV module characteristics. From the IV scan, all parameters for energy yield and low light behavior and thermal coefficients for any PV technology can be extracted.	User can have the flexibility to integrate the measured power for most of the duty cycle yet get the full benefit of IV curve measurements. User can see impact of different MPP tracking methods and validate impact between MPP tracking, V_{OC} or I_{SC} conditions.
Cons	No other parts of the IV curve are measured such as I_{sc} and V_{oc}. Introduces an additional uncertainty given by the tracking efficiency.	Need to decide what to do when not scanning. Algorithm needed to calculate MPP points real time and put them in to the respective V_{mp} condition real time. Whether the device is left at I_{sc}, V_{oc} or maybe last V_{mp} may affect the PV module degradation or transient behaviour. (Some modules may behave differently after experiencing V=0 or I=0 and slowly return to normal). Transients may affect energy yield calculation.	Higher cost.

The survey highlighted hardware ranging from commercial products to custom developments, from "high cost" to "low cost" solutions and from all-in-one devices (MPPT, IV-tracer and data loggers integrated into a single instrument) to self-assembled systems. Some of the producers of hardware devices for the monitoring and high-precision maximum power point tracking of individual modules include (in alphabetical order): Daystar Inc., EKO Instruments, ET Instrumente, Gantner Instruments, Höcherl & Hackl GmbH, University of Ljubljana (LPVO-MS3X16), Papendorf Software Engineering GmbH, Pordis, Stratasense and SUPSI (MPPT3000). There are other manufacturers that use a microinverter in combination with an electronic load to make these measurements, and they include: Femtogrid, PowerOne and Solaredge. Some of the aforementioned manufacturers produce devices that allow the periodic measurement of single-module IV curves from within a series string without affecting the operation of the other modules in the string.

A schematic of an example device that has IV-measurement and maximum power point tracking integrated within the same instrument is shown below. Each module is connected to its own test equipment and the test devices can be synchronized.

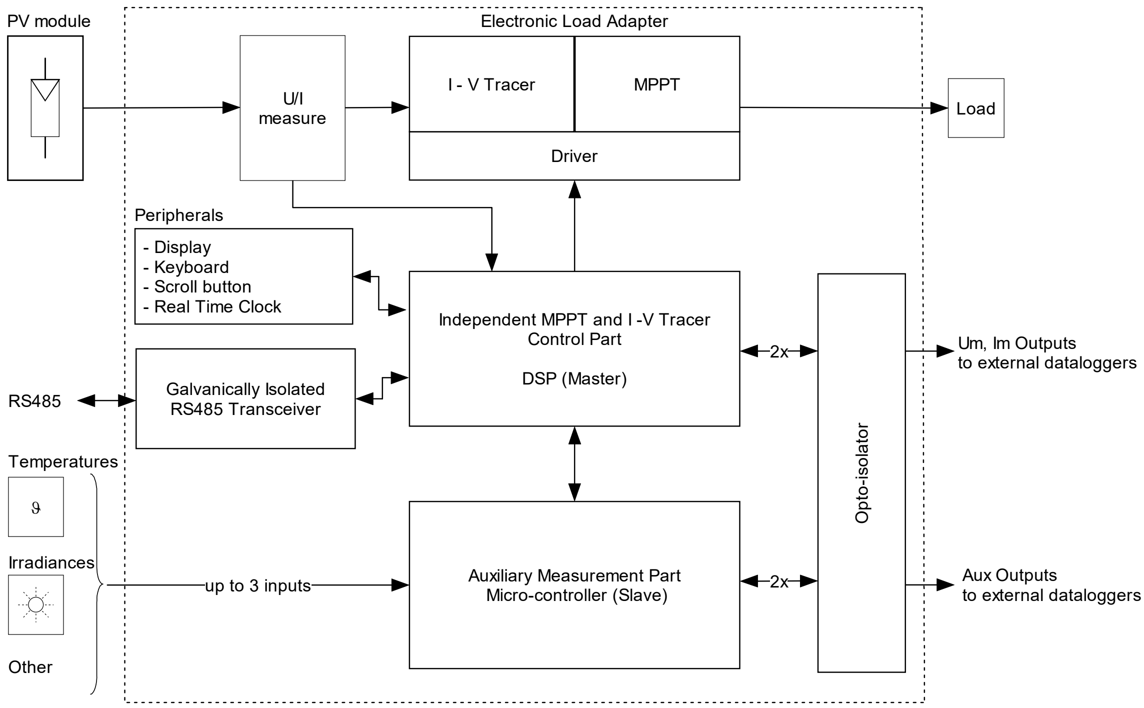


Figure 8: Schematic of an example of an all-in-one hardware solution installed at SUPSI.

Multiplexing measurements can be a cost effective and flexible way to acquire both the complete IV-curves as well as cumulative energy output of the panels. Some solutions offer for example a number of IV-tracers that can be combined with multiplexers to switch between IV-curve measurements and for example a MPPT or passive load. In Figure 9 a schematic is shown for an array of 24 panels, combined with MPPT modules. In this example an additional multiplexer is used for thermocouples that are attached to the backside of each panel. This solution requires heavy-duty relays to switch between the IV-tracer and load, and because of switching and measurement time, measured IV data will not by synchronous across all panels. However, in the case the IV-tracer can measure also the irradiance via an own pyranometer, it is still possible to have synchronized irradiance data with each IV-trace.

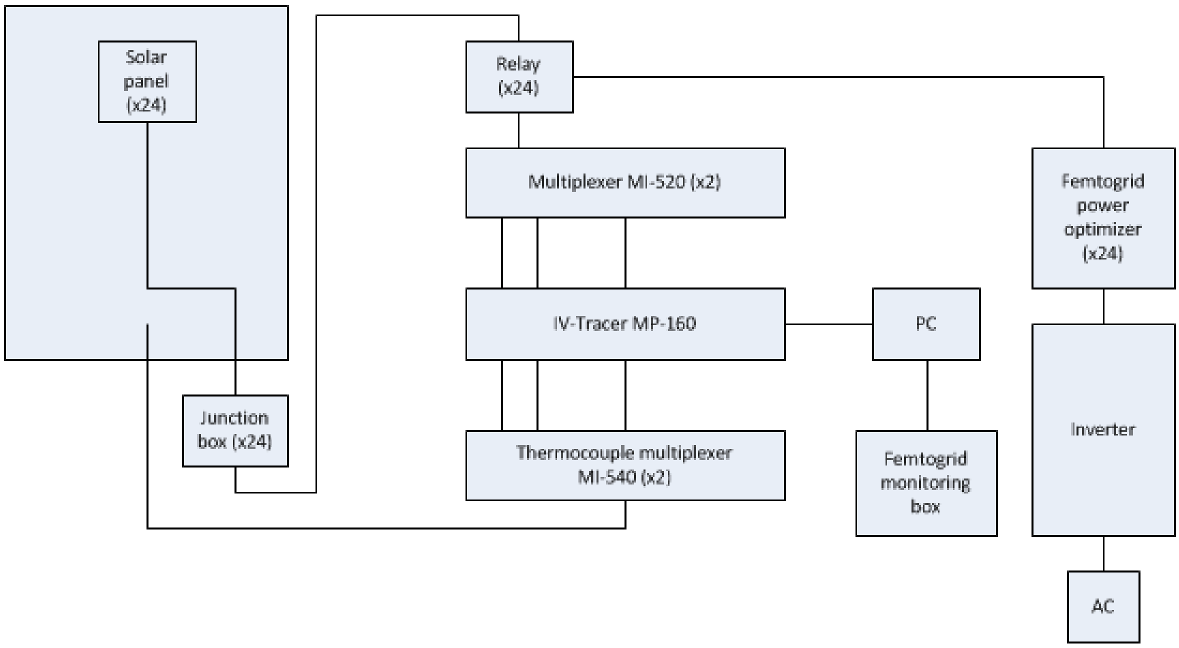


Figure 9: Example schematic of a multiplexing solution (at Utrecht University).

4.2.2 Hardware characteristics and configuration

Besides the uncertainty of the instrument, other features and technical specifications have to be taken into account when choosing and designing a new outdoor test facility. Common practices are described here followed by recommendations in chapter 4.2.3.

Hardware accuracy

According to the IEC 60904-1 standard, the voltages and currents shall be measured using instrumentation with an accuracy of ±0,2 % of the open-circuit voltage and short-circuit current. The IEC 61724-1 standard for the monitoring of photovoltaic systems states a measurement uncertainty of ±2.0% at the inverter level for a class A measurement (highest accuracy). In the case of measurements of single modules, a better accuracy than the one achieved by an inverter is generally aspired to for module characterizations. The maximum power trackers designed for this purpose (see chapter 4.2.1) generally fulfil this requirement.

Figure 10 summarizes the stated measurement uncertainties of the MPPT and/or IV-curve tracers used by the survey respondents. The uncertainties u[k=2] of the current-voltage measurements range from 0.1% to 1.5% at full scale. For half of the respondents, the measurement uncertainty was reported to be <0.2%, which is the limit required by the standard. 20% of respondents did not specify any uncertainty value for the MPPT devices. The spread in the declarations is partly due to the hardware itself, but also to stating different uncertainties.

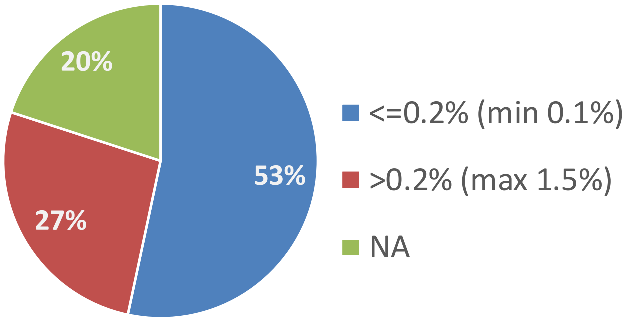


Figure 10: IV and MPPT measurement accuracy u[k=2].

To give an example, under real operating conditions the current and voltage ranges should be continuously adapted to the conditions under test (auto-ranging). Most MPPT devices have this functionality but it is not the case for all IV-tracers. This has a direct impact on the measurement accuracy, and only some uncertainty derivations take this into account.

The measurement accuracy of the hardware is, however, only one of the contributions to be considered when calculating the total uncertainty of any performance indicator. Other important contributions are the IV-tracer configuration, the MPP tracking accuracy, the sampling frequency and the synchronization of data.

IV tracer characteristics

There are a large number of different solutions available on the market to trace the IV-curve of a module, including: capacitive loads, electronic loads, bipolar power amplifiers, 4-quadrant power supplies and DC_DC converters. Overviews describing the advantages and disadvantages of different solutions can be found in the literature [35].

61% of the IV-tracers used by the institutes that responded to the survey are limited to 1 quadrant (I > 0, V > 0) for focusing on the power measurements. As shown in Figure 11, only 11% of the survey respondents have implemented a 4-quadrant measurement unit. Those units are based on more expensive, programmable, bidirectional power supplies. The number of points measured by the participants varies from a minimum of 20 to a maximum of 500 depending on the chosen hardware. The maximum power point of the IV curve is either determined via a polynomial fit of data near P_{max} or by fitting a diode model to the full curve.

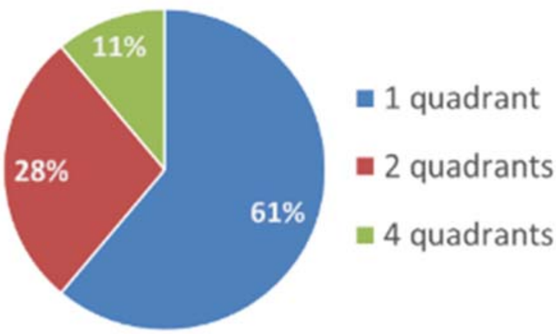


Figure 11: IV-tracer specification (1, 2 or 4 quadrant measurement).

The sweep speed of the IV-curve can have a significant impact, especially when measuring slow responding PV module technologies [30] or when measuring under fast-changing environmental conditions (e.g partly cloudy weather). *Figure 12* gives an overview of the typical sweep parameters (direction and speed).

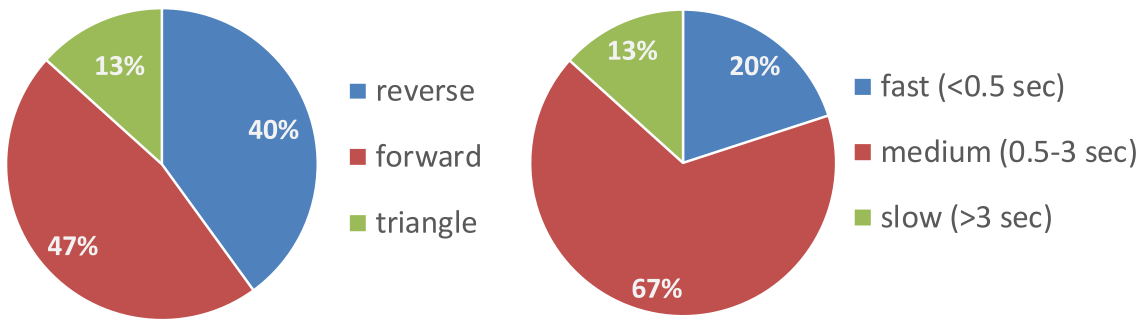


Figure 12: IV-tracer specification *(sweep speed and direction for the scanning of an IV-curve).*

67% of the respondents' instruments have sweep speeds in the range of 0.5-3 seconds, which is a good compromise for slow responding module technologies and fast changing test conditions. 13% of the instruments measure slower (> 3 seconds), requiring particular attention to irradiance stability and the review of each individual IV curve. 20% have fast sweep speeds below 0.5 sec, although this increases the risk of erroneous measurements with capacitive modules especially if swept in the reverse direction. 47% instead sweep the IV-curve in the forward direction and most adapt their sweep speed in the case of capacitive modules. 13% apply a triangular pulse; , which is particularly indicated to check for measurement artefacts due to capacitive effects or irradiance variations. For most high efficiency technologies affected by capacitive effects a good overlap of forward (I_{sc} to V_{oc}) and reverse (V_{oc} to I_{sc}) measured IV-curves is an indicator of a good measurement.

MPPT characteristics

MPPT device tracking algorithms have different accuracies, both static and dynamic, which can have a significant impact on the measurement. The static accuracy describes the tracking under stable conditions, whereas the dynamic accuracy describes the capability of the MPPT to find the maximum power point under variable conditions (e.g., fast cloud transitions). The static accuracy can also depend on the type of technology under test, which is not always stated in the datasheets. For example, it can be less efficient for modules with a low fill factor.

The survey highlighted that there is a general lack of information on the tracking accuracies, with only 3 respondents providing values. These accuracies ranged from 99-99.5% for the static accuracy and 98-99% for the dynamic accuracy. These values were either measured or taken from data sheet specifications.

Energy yield integration

The module energy yield is calculated integrating either the P_{max} values form the MPPT or the IV-tracer. As shown in *Figure 13*, nine out of fifteen survey participants rely primarily on the MPPT device, whereas the other five on the IV-tracer. A few use both for cross-checking the data, which also allows the static and dynamic tracking accuracies to be verified.

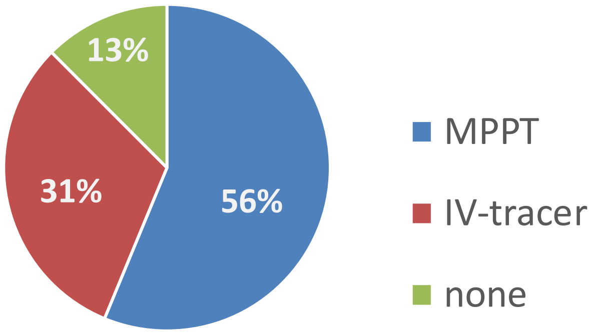


Figure 13: Hardware used for energy yield integration.

Yet, the energy yield is not measured by all participants. Two laboratories (13%) focus only on instantaneously measured IV curves. The latter are either used for: (1) the validation of performance models and the monitoring of degradation rates, or (2) the extraction of module parameters for specific models. In that case, the MPPT or passive load is only used for conditioning the module in-between traces.

Measurement synchronization

The level of synchronization between electrical, temperature, and irradiance measuring channels significantly contributes to the final accuracy of the module characterization and can even dominate the total data acquisition uncertainty. For benchmarking purposes (kWh inter comparisons), a synchronous measurement of the modules is advised.

The survey highlights, as depicted in *Figure 14*, that approximately half of the testing devices are synchronized. 15% of the MPPT's and 27% of the IV-tracers are not, but not all of these perform actually benchmarking. For 31% of the MPPT's, it is not specified. For cost reasons, 20% do not use individual IV-tracers for each PV module, but rather a single IV-tracer connected to a multiplexer, which inherently does not allow simultaneous traces. The error introduced by this procedure should be considered and included in the final uncertainty analysis.

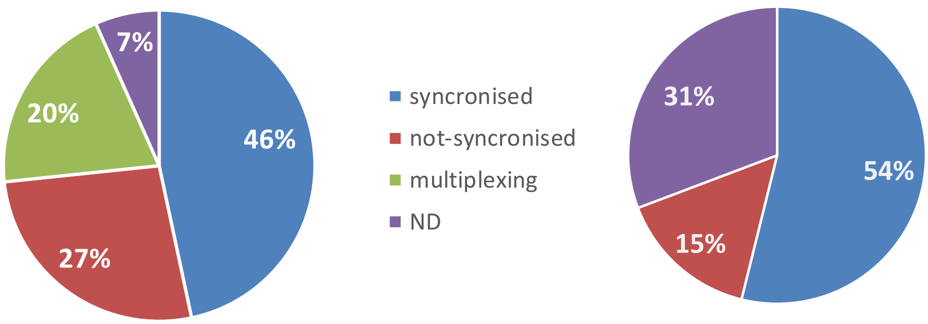


Figure 14: Synchronization between modules, with data acquired by (a) IV-tracer or (b) MPPT.

In addition to the synchronization between modules, the synchronization of the module data to the irradiance data is also very important, especially when the data are used for the validation of models or to extract module parameters. The delay between the signals should not exceed the response time of the irradiance sensor.

Figure 15 shows that 54% of the MPPT's are synchronized with the irradiance measurement, whereas the others have a delay of 2-30 sec.

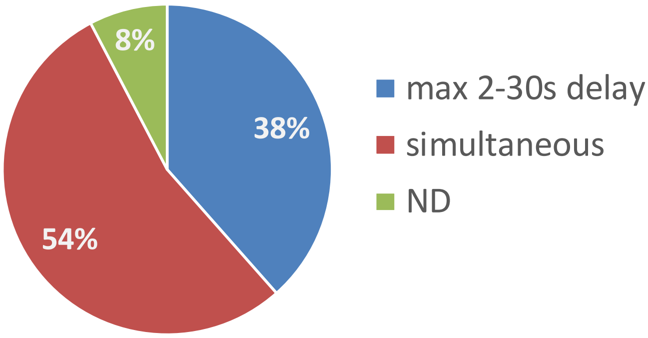


Figure 15: Synchronization of the module electrical and irradiance measurements.

As shown in *Figure 16*, different approaches are applied by the laboratories in the case of the IV measurements. 33% follow the approach of measuring the irradiance immediately before and after the IV-curve. 27% perform a single irradiance measurement just before or after the IV-curve, whereas. 20% measures the irradiance simultaneously to the current and voltage.

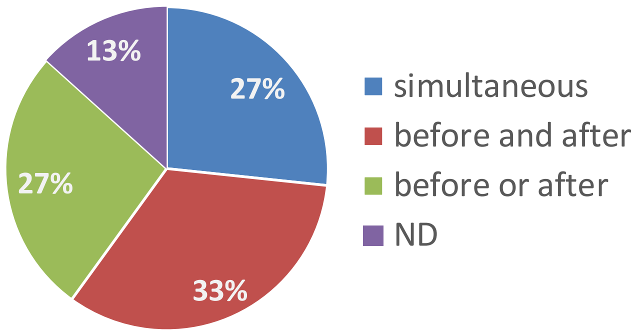


Figure 16: Approaches used for the synchronization of irradiance measurements to single IV-curves.

Sampling frequency

In addition to the data synchronization, the sampling frequency also has a significant impact on the module measurements.

The sampling frequency applied by the laboratories differs slightly depending on the hardware used. The MPPTs' frequencies range from 100 milliseconds to a maximum of 2 minutes, while the IV-tracers' are slower and range from 1 minute to 15 minutes. In the case of the MPPTs, either average or instantaneous values are stored. Higher storage frequencies below 1 minute are preferred by those doing studies of the dynamic behaviour of a module while lower frequencies of >5 minutes are limited to those only interested in the instantaneous IV-curves and not the energy yields.

The sampling frequency of the environmental parameters (irradiance and temperature) is generally equal to or higher than that of the module current/voltage measurement. These frequencies range from 100 ms to 1 minute for all parameters except the spectral irradiance data, which is generally measured with a lower frequency between 30 seconds and 15 minutes.

4.2.3 Recommendations

Summarized below are recommendations for current-voltage measurements performed with either maximum power point trackers or IV-curve tracers.

General requirements

- The general measurement requirements and accuracy of the equipment have to comply with IEC 60904-1 and IEC 61829.
- IEC 61724-1 2017 covers the main data acquisition requirements for PV systems and should be used as a reference also for PV modules.

Measurement accuracy

- Uncertainty of current and voltage data acquisition hardware should be below: I_{dc}: 0.05% and V_{dc}: 0.05%.
- Uncertainty of all calibrated shunt resistances should be below 0.1%.

DC Load

- Choose a DC Load which can control the current and voltage fast with fast settling time
- Use dedicated, zero current, voltage sensing leads (four wire connections).
- Use the same make and model DC load for PV module comparisons to eliminate any differences introduced by the hardware.
- The DC load should be in a constant temperature environment climate (e.g. air conditioned room) to limit temperature fluctuations and the resulting measurement uncertainties, and to achieve lowest thermal drift (as cabinet temperature can show delta T =30K per day).

IV scan procedure

- The parameters I_{sc}, R_{sc}, I_{mp}, V_{mp}, R_{oc} and V_{oc} should be derived from the scanned IV-curves to determine if there are any problems with the device or measurement, such as irregular curvature, scatter, or non-monotonic (not continually increasing or decreasing) behaviour.
- The scan speed, direction, settling time and resolution have to be optimized for different technologies, partly to minimize hysteresis effects (that often show up as different IV traces particularly near V_{mp}).
- The scan should take no longer than 1-2 seconds to minimize scatter in the data from variation within clouds.
- The system should be able to measure during cloud enhancement conditions (i.e., reflections off clouds near the sun) that increase the irradiance higher than clear sky values. Irradiances can briefly peak at 1800W/m^2 even in less sunny climates such as Northern Europe.
- Consider appropriate timing so transients between IV scans and MPP tracking do not impact the measurements.
- There should be at least 50 measurement points per IV scan, with a minimum of 10 sampling points per measurement point.
- The distribution of points in the IV curve may be optimized to ensure there are enough near I_{sc}, P_{max}, and V_{oc}. For example fits to I_{sc} will not be very accurate if there are very few points near I_{sc}.
- It is recommended to interpolate between data points before examining residuals. Fitting method: Cubic spline fits e.g. find points where
  $V<V_{oc}/10$ for I_{sc} : Intercept with V=0 gives Isc, slope gives $-1/R_{sc}$

V_{mp}*0.45<V<V_{mp}*0.55 for P_{max}. Maximum V*I gives P_{max},
I<I_{sc}/10 for V_{oc}: : Intercept with I=0 gives V_{oc}, slope gives -1/R_{oc}.

- Stable meteorological conditions are required before starting an IV scan.

Module bias when not being measured

- Modules should operate at their maximum power point (MPP) at all times except during IV-curve measurements. Leaving the module at I_{sc} or V_{oc} between IV curves can result in higher module temperatures due to extra heat from recombination in the cells.
- Extra care should be taken for thin film devices because module bias may cause damage to the cells and increase their degradation rate.

Maximum power point tracking

- Maximum power point (MPP) trackers may sometimes operate the module at a local maximum instead of at the MPP, so ensure that the MPP tracking algorithm is fast and accurate.
- The static and dynamic tracking accuracy (tracking efficiency) of the MPPT should be known.
- The tracking algorithms of the MPPT device should be optimized for all technologies independently of the fill factor (FF) to allow a fair comparison of the results.
- Systematic cross-checking of the MPPT data with IV-data is recommended at different environmental conditions and for different module technologies.

Data sampling and synchronization

- Eliminate or use only high quality multiplexers, many are unreliable.
- Synchronize the IV scans of all PV modules.
- The recommended interval for IV scans is 1 min, but it can change in dependence of the scope of testing.
- The data acquisition rate for environmental parameters should be in the range of 1-10 Hz, with averaging to a target sampling frequency of 1-5min.
- The data acquisition rate for IV scan parameters should be greater than 1000Hz with averaging to the target sampling frequency of the measurement points in the IV scan.
- The data acquisition rate for the environmental parameters (averaged values) should be synchronized with the IV scans.
- It is best to measure the irradiance before and after an IV trace to ensure irradiance stability during the trace. Examination of the scatter in current from I_{sc} to I_{mp} can indicate irradiance variability, but is a less direct method.

Shunts

- When external shunts are needed the typical range is 1 mΩ to 10 mΩ. They should have calibration certificates and low thermal drift characteristics.
- Calibrated shunt resistance uncertainty can reach 0.01%; the temperature coefficient should be below ±5 ppm/K (20 to 60°C).

Cables

- Four-wire connections should be made: two wires for the module power and a current measurement and two wires for a zero-current voltage measurement.
- Wires should be at least 6 mm^2 in cross sectional area for distances over 20 m. For distances less than 20 m, 4 mm^2 is sufficient for an insignificant voltage drop.

- If a four-wire connection is not made, cabling lengths should be minimized and the voltage drop should be characterized.

Connectors

- Must be standard PV module connectors (e.g., MC4) to withstand outdoor conditions and repeated reconnections without significant change in contact resistance.
- Use Y-connectors for splitting the PV module connectors into a 4-wire test configuration.
- Periodically check the connection resistance of your extension cables as it could change over time due to corrosion, dust, etc.

Fuses and overvoltage protection

- Fuses and overvoltage protection can introduce uncertainty; therefore, for optimum measurement performance, either do not use protection devices or design them so that there is minimal impact on the signals.

Checks and validation

- Quantify the voltage drop at the short-circuit condition and calculate the difference between the measured and true module I_{sc}.
- Quantify any current flow at the open-circuit condition and calculate the difference between the measured and true module V_{oc}.

Calibration:

General: regular calibration is needed for reference measurements to avoid any drift or bias.

- Calibrate the measurement equipment according to manufacturer specifications.
- Calibrate at least every two years and track the drift and bias on a quarterly basis.

4.3 Measurement of Environmental Parameters

4.3.1 In-plane irradiance

Irradiance is the measurement of solar energy input to the PV module and is, therefore, equal in importance to the electrical energy output measurement. However, irradiance is much more difficult to measure accurately and consistently, hence the need for harmonized procedures and the use of the best possible instruments.

To evaluate the overall efficiency and module performance ratio (MPR) of PV modules it is necessary to measure the global irradiance received in the plane of the modules. This is generally measured either with a pyranometer sensitive to the full spectral range or by spectrally selective reference cells. As shown in Figure 17, most of the test facilities investigated here are equipped with both types of irradiance sensors. In general, the in-plane irradiance (G_i) is measured with a minimum of two pyranometers and one or more reference cells with different spectral responses. The latter should be similar to the spectral response(s) of the test modules. The pyranometer is the primary choice for the calculation of the incoming broadband irradiance (H), whereas the reference cells are used for the correction to standard test conditions (STC) or for other data analysis purposes.

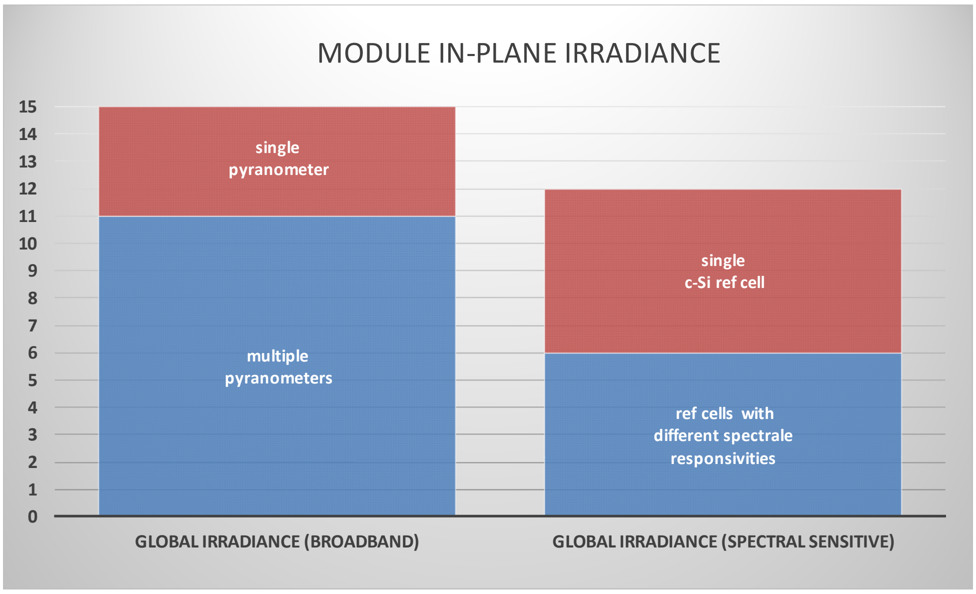


Figure 17: Type of global irradiance measurements in the plane of the array implemented at the surveyed test sites.

Commercial pyranometers available for this purpose use a black surface to absorb a broad range of the solar spectrum. This black surface is housed under glass domes to minimize convective cooling and reflective losses over a broad range of solar incidence angles. Only instruments in the highest quality class ("secondary standard" in the ISO-9060 classification) should be used in this application since lesser quality instruments are more strongly influenced by secondary factors in the operating environment such as the ambient and sky temperature [36]. Secondary standard instruments are also more stable and respond more quickly to changes in irradiance—within several seconds—though not as quickly as the near instantaneous response of a PV module or reference cell.

In addition to using a high-quality pyranometer, it is also recommended to measure in-plane irradiance with a PV reference cell that provides a signal proportional to its (temperature corrected) short-circuit current. This measurement is often referred to as the effective irradiance [*37*]. When the incident irradiance matches the AM1.5G spectrum and is normal to the receiving plane, then both the broadband and the effective irradiance values are 1000 W/m². While one can define only one ideal pyranometer, the ideal reference cell is different for every PV module: the reference should have the same angular and spectral response as the PV module under evaluation. Using a reference cell that has an angular and spectral response that is similar to the PV module under evaluation eliminates these two factors from the efficiency equation and gives a more accurate figure of the low-light performance, meta-stability or degradation. A similar response can be achieved either by using the same cell type or by adding a filter glass to a reference cell of a different type. The most common example of this is a crystalline silicon (c-Si) cell with a KG3 or KG5 filter used to approximate the spectral response of amorphous silicon (a-Si) modules. Recently, a c-Si cell with a KG1 filter was shown to be a good match for CdTe modules [*38*]. The advantage of the filtered reference cell approach is that c-Si is more stable than some of the other cell technologies. In practice, only a limited number of reference cells can be installed and maintained so there will usually be some mismatch in angular and spectral response. If needed, the angular mismatch can be quantified based on the angular response curves of both the reference cell and the module, and it can be corrected in combination with the DNI measurements. Similarly, the spectral mismatch can be quantified based on the spectral response curves and corrected in combination with spectral irradiance measurements (see chapter 7.1.3).

The short-circuit current of reference cells increases with temperature by a factor that is too large to ignore - on the order of 0.05% per °C for c-Si. For this reason, the cell must be equipped with a means of measuring its temperature, and the measurement system must make a correction based on that temperature. Higher temperatures decrease the band-gap energy of the cell material, and this improves the spectral response of the cell in the infrared region. The temperature coefficient for short-circuit current largely results from this change in spectral response multiplied by the solar spectral irradiance, so one may observe different coefficients indoors and outdoors. Because of the uncertainty in this coefficient, the uncertainty of the temperature-corrected reference cell readings will be higher when the operating temperature is further from the temperature at calibration [*39*].

The response time of reference cells is faster than that of the thermally responding pyranometers. The latter typically require 3-5 seconds to reach 95% of the value of a sudden change in irradiance whereas reference cells respond almost instantaneously. A slow response does not necessarily lead to measurement error when irradiance is integrated over time, and in fact, it can be considered an advantage since a fast-responding reference cell should be read (sampled) more frequently in order to produce an accurate integrated value [*40*]. Modern data acquisition equipment is easily capable of measuring at one sample per second, and this should be the minimum for all irradiance instruments. Fast responding instruments are very useful for detecting stable irradiance conditions, which are needed for taking accurate IV-curve measurements. Measurements from such instruments could be taken before and after an IV-curve [*25*], or the irradiance could be measured for each IV-point.

Collecting the data and refining the methods to quantify response time, temperature dependency, directional response and many other irradiance sensor characteristics are goals of the PVSENSOR project [*36*]. Many characteristics produce systematic measurement errors, and knowledge about these errors can be used both to develop correction methods and to support more sophisticated evaluation of site-specific measurement uncertainty. Further information on this topic is found in the IEA Report on uncertainties in PV System Yield Predictions [*41*].

The declarations from the 15 surveyed laboratories regarding the measurement uncertainties for global broadband irradiance varied between 1.3%- 2.5% for standard thermopile pyranometers and 5-8% for the laboratories using the SPN1 combined global and diffuse thermopile sensor. The uncertainties declared for the global irradiance measurements with spectral sensitive reference cells range from 1.8-5.0%.

Although the total irradiance received by a tilted module is a single quantity (G_i), it can be very useful to separate the amount of diffuse ($G_{i,d}$) and direct or beam irradiance ($G_{i,b}$). Since the spectral content and the angle of incidence of these two irradiance components are different, they have different influences on overall yield. The direct normal irradiance (DNI) should be measured using a first-class pyrheliometer and automated tracker. When multiplied by the cosine of the angle of incidence this gives the direct or beam irradiance in the plane ($G_{i,b}$). Note that both the slope and orientation of the module must be accurately determined for this calculation. The alternative approach, to measure $G_{i,d}$ and subtracting it from G_i is usually not recommended for determining $G_{i,b}$, since $G_{i,d}$ is more difficult to measure accurately on a tilted plane.

Measuring diffuse irradiance requires a pyranometer and a shading device to prevent direct irradiance from reaching it. The best shading device is in the form of a disk or ball, so that none of the sky is blocked, however commercial two-axis instrument trackers with shading balls are designed for horizontal diffuse measurements, not tilted. Nevertheless, if such a tracker can be adapted or custom-built to shade a tilted instrument, this is the best solution for determining the in-plane diffuse irradiance $G_{i,d}$. The other available commercial solution is to use a shading band or ring, but this introduces additional uncertainty since a correction must be made to the measurement to account for the extra portion of the sky (and in the tilted case, also ground) shaded by the ring. These correction factors were developed and validated for horizontal measurements, and using them for tilted corrections is not recommended [*42*].

Due to the difficulty, only a minority of the surveyed laboratories measure the diffuse irradiance in the plane of the array. More commonly, the diffuse irradiance is measured with a shading ring or a radiometer with an integrated diffuse irradiance measurement (SPN1 type). Figure 18 shows the other measured irradiance parameters. Most laboratories measure the diffuse irradiance on the horizontal plane (DHI). Nine laboratories measure the direct normal irradiance (DNI) with a pyrheliometer mounted on a two axis sun-tracker and are so able to calculate the diffuse irradiance. Almost all respondents measure the horizontal global irradiance, as this is one of the primary inputs for any PV yield simulation.

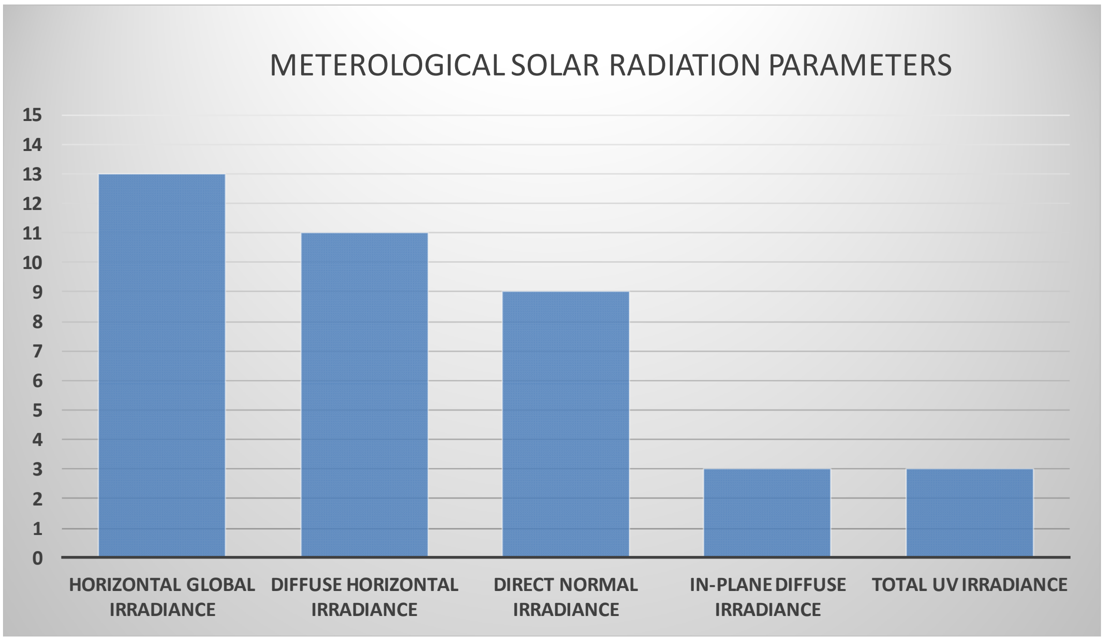


Figure 18: Type and distribution of irradiance measurements performed at the 15 interviewed laboratories.

Measurements of horizontal global and diffuse irradiance are not directly useful to evaluate the yield of a tilted module, but by using a transposition model the in-plane irradiance can be estimated and used to check data consistency. Additional lower accuracy instruments for any of the measured parameters can also serve the purpose by providing redundancy at much lower cost.

There are two additional irradiance measurement options that do not directly enter into the module performance calculation. The first is mid-infrared radiation beyond about 3000 or 4000 nm. Measured with a pyrgeometer, mid-infrared irradiance can be used for correcting thermal offset errors in pyranometer readings, thereby reducing measurement uncertainty. This measurement is also useful in cell/module operating temperature studies. The second option is ultraviolet irradiance in the range 280-315 nm (UVB) and/or 315-400 nm (UVA). Most or all of this irradiance is within the range of good pyranometers so the available energy is already included in the broadband irradiance. Very little if any is converted by PV modules to electricity because absorption in the glass and EVA is high and quantum efficiency at those wavelengths is very low. However, it can be useful for long-term studies because of the material changes that UV radiation can cause.

The best instruments are a prerequisite for high accuracy irradiance measurements, but the goal of high accuracy can only be achieved with proper installation, and maintenance. Best practices are described in multiple sources, such as [*40*,*43*,*44*]. Some important points adapted to PV performance measurement are:

- The pyranometer and reference cell slope/tilt and orientation must match that of the test modules within a small fraction of a degree.
- The tilted instruments should receive roughly the same amount of ground-reflected radiation as the modules. This is usually achieved by mounting them in close proximity and at the same height.
- If there is any risk of dew, frost or snow accumulation *and* data under those conditions needs to be evaluated, use instruments with ventilators and/or low power heaters. Ventilators can also help reduce any thermal offset which is one of several sources of error and uncertainty.
- Sensors optics must be cleaned and inspected regularly, as appropriate for local conditions *and* test schedules. In some instruments, the desiccant must also be checked and replaced periodically to prevent condensation inside the instrument.
- Calibrations must be checked regularly. If at all possible, a scheme should be implemented whereby multiple instruments are checked against each other and sent to an external calibration lab on an alternating basis.

Many of the best practices in the references are oriented toward continuous operation and should be adapted depending on the duration and conditions of a particular performance test. The following two tables summarize the irradiance parameters and their measurement alternatives.

Table 2: Required measurements.

	Position	Preferred	Alternate
G_i in-plane irradiance	Tilted	Secondary standard pyranometer	
G_{eff} spectrally sensitive 'effective' irradiance	Tilted	Reference cell(s)	
$G_{i,b}$ in-plane direct beam irradiance	Tilted	DNI * cos(Θ)	
$G_{i,d}$ in-plane diffuse irradiance	Tilted	Secondary standard pyranometer with low thermal offset installed with a with shading ball	$G_i – G_{i,b}$
DNI direct normal irradiance	Tracking	First class pyrheliometer and automated tracker	

Table 3: Additional measurements to support data consistency checks.

	Position	Preferred	Alternate
GHI global horizontal irradiance	Horizontal	Secondary standard pyranometer	Non-secondary standard pyranometer
			SPN1
DHI diffuse horizontal irradiance	Horizontal	Secondary standard pyranometer with low thermal offset installed with a with shading ball	Pyranometer with shading ring
			SPN1

4.3.2 Module temperature

With few exceptions, an increase of the module temperature above the STC value of 25°C leads to a reduction of the module's efficiency and is the largest secondary factor for loss of energy (primary effects being irradiance and shading). A correct determination of the module temperature is thus important to properly attribute losses compared to an ideal system and to determine the module temperature coefficients.

The module temperature is affected by a range of factors, such as the irradiance, wind exposure [*45*], method of operation (e.g. at MPP versus V_{oc}), the mounting structure as well as module construction (e.g., a glass-glass module shows a different temperature profile than a glass-backsheet module) [*46*].

In general, outdoor module temperature determination is done using contact measurement methods (having a temperature sensor attached to the module), non-contact methods (typically using infrared (IR) thermographic cameras) or via well-known modelled relationships using proxy measurements, such as the relationship between V_{oc} and the module temperature. An inter-comparison of the methods is given in Table 4. Contact temperature measurement methods are the most popular method within the IEC standards that relate to module power and energy determination, as they are relatively simple and cost-effective to implement.

Contact temperature measurement methods require a sensor to be in physical contact with the module's surface of interest. In general, contact temperature measurements have the sensor attached to the back surface of a module (backsheet, or glass), with the option to measure the cell temperature using custom-made modules where the temperature sensor is laminated against the cell's back surface (the latter is primarily for research purposes). The most used contact temperature sensors are Pt100 RTD (Resistance Temperature Detectors) and thermocouples [*47*], with the use of alternative methods such as digital contact sensors being investigated, [*48*,*49*] primarily to lower the cost for comparable accuracy. Generally, Pt100 sensors have the lowest uncertainty (but higher cost), and the best results are obtained by using four-wire connections. Thermocouples have typically thinner cables (and are therefore often easier to install) and the sensor itself is often cheaper than Pt100 sensors; however, they do require a cold junction. Uncertainty from the cold junction directly adds to the total measurement uncertainty, with low uncertainty cold junctions often being large and/or expensive. Digital sensors, or sensors using other principles (e.g. a negative temperature coefficient (NTC) sensor) can be read at a lower cost, but their uncertainty and traceability is not yet at the level of Pt100 or thermocouple sensors.

Most contact temperature measurements use a sensor kept in place on the backsheet[1] using epoxy glue [*47*] or tape [*50*] , often with thermally conductive paste. Since the value of interest is the cell temperature, a correction to the backsheet-measured temperature is required. The most widely used backsheet-to-cell temperature correction is given by [*46*]

$$T_c = T_{BS} + \Delta T_{CBS} * \frac{G_i}{G_{STC}}$$

where T_c is the cell temperature, T_{BS} the backsheet temperature, ΔT_{CBS} the temperature difference between the cell and backsheet at STC irradiance conditions and G_i the plane-of-array irradiance. The amount of glue used for the contact sensor may result in unexpected time delays in the measured values [*50*], and care must be employed in the choice of attachment methods, whether to use thermal paste, and how much (if any) insulation is used.

[1] Backsheet used here as generic term for back surface of a PV module.

The measurement of the open-circuit voltage is an example of a proxy or indirect method, where another variable with a well-known relationship to the quantity of interest (the cell temperature) is measured. This method has been adopted from indoor conditions (and initially on single cells) to outdoor conditions and modules, and as such assumes that the module under study has a homogeneous surface temperature. This is not always the case, as wind conditions and mounting methods can affect the intra-module temperature distribution [*23*,*24*]. The Equivalent Cell Temperature (ECT, as detailed in IEC 60904-5) is obtained by measuring the open-circuit voltage of the module and the plane-of-array irradiance, and using a one-diode model to derive the temperature form the voltage. Calibration of the model requires contact temperature measurements and measurements at different irradiances, which can affect the accuracy of the resulting values. Two-diode temperature models are also used, but add additional complexity to one-diode models.

A different type of complexity appears when using infrared (IR) thermographic cameras: as these interpret the emitted infrared radiation from the module surface, a range of factors become important, from the role and training of the operator [*51*] to the choice of standard settings, as well as camera quality. While IR thermographic cameras are improving rapidly (and decreasing in cost), they require substantive training for the operators to achieve comparable results to contact or V_{oc} methods, particularly if the value of interest is the absolute module temperature. On the other hand, IR cameras are rapidly deployable in the field, and allow temperature differences to be easily observed. For this reason, IR cameras are often used to verify that the placement of contact temperature sensors is correct, and to identify whether a module's temperature profile is homogeneous (e.g. to ensure that V_{oc} methods can be relied on). As IR cameras depend on the infrared radiation emitted from the module's surface, the best results are obtained at higher irradiances, which allow issues such as hot spots to be more easily identified [*51*,*52*]. Conversely, temperature differences are more difficult to identify at lower irradiances, and the uncertainty is higher.

For long-term outdoor energy yield measurements, the historical preference has been to use the contact method. To ensure the best results, it is actually recommended to combine it with at least another method, and to perform cross-validation of the results at regular intervals. The survey showed (see Figure 19) that the majority of test sites (8 out of 15) applies a single sensor to the module using either tape and a conductive paste or glue. Only 4 laboratories increase the number of sensors to 2-4 to get information on the non-uniformity or for redundancy checks. The stated measurement accuracies are all equal or below 1 °C.

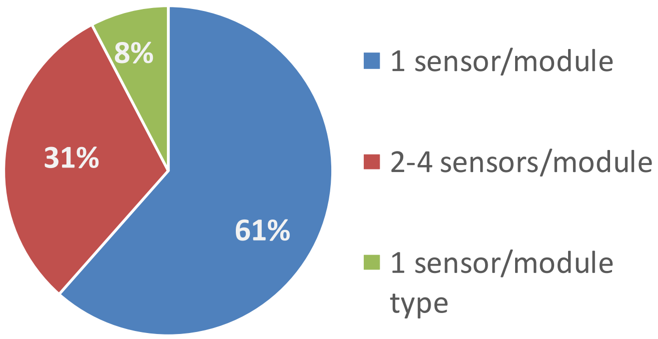


Figure 19: Number of temperature sensors applied on the back of a module.

Table 4: Comparison of main measurement methods for module temperature.

	Contact methods	**V_{oc} methods**	**IR methods**
Applicable outdoor measurement conditions	All, lowest uncertainty variation[2] over irradiance range	All, best under stable weather conditions, uncertainty increases at low irradiance	Irradiance G > 600 W/m^2 recommended [*52*,*53*] uncertainty increases at low irradiance
Standards	Included in IEC standards: 61215, 61829, 60904-5, 61724, 60891, 61853-1	Included in IEC 60904-5	Being standardized (IEC 62446-3)
Operating conditions	Module can be at any operating point	Module tested is (temporarily) at V_{oc}, remaining time at MPP, V_{oc}, I_{sc}	Module can be at any operating point
Measurements in time	Continuous measurements possible (can be used for time series analysis)	Needs either dedicated module for continuous measurements (module then at V_{oc}, and thus higher temperature), or discontinuous measurement of V_{oc} (e.g. the V_{oc} from IV-curves measured at regular intervals)	Typically snapshot measurements; repeated measurements possible using infrared sensors without continuous operator involvement
Area covered by measurement	Point-based measurement (one or more cells)	Average temperature of cells in module	Full module, no averaging (image) or average of sensor view
Resolution	< 0.01 °C	< 0.01 °C	Up to 0.01 °C, spatial resolution determined by thermographic camera: number of pixels for area covered
Uncertainty (k=1)	0.1-0.25 °C, sensor only, readout equipment can add 0.01-0.2 °C, mounting methods and reference junctions (for thermocouples) add significantly more	0.1-0.6 °C, if well calibrated on module, depends on uncertainty of contact measurement and model[3] used	0.1-1.0 °C, depending on quality (and cost of thermographic camera)
Main or most encountered	Location of sensor on module, repeatability	ECT according to IEC	Operator error: angle be-

[2] The uncertainty of contact sensors is a function of the measured temperature, but the magnitude of this uncertainty is typically lower than for either V_{oc} or IR methods.
[3] A one-diode model is used according to IEC 60904-5. Two-diode models can be more accurate, but require significantly more effort by users.

sources of error	and method of installation by operator, back surface-to-cell correction method	60904-5 requires comparison to contact temperature measurement and very sensitive to weather conditions for model coefficients: ECT calibration done under varying conditions likely to result in temperature errors	tween module and camera, emissivity correction setting, surrounding area impacts (module next to sky: large temperature difference, IR reflections from other objects)
Disadvantages	Sensor(s) installed on back surface need to have results corrected [2] to cell temperature, heat transfer from cell to back surface delayed in time (important during varying weather conditions); Sensor installation and maintenance labor intensive; Cannot measure front-side temperature (would require irradiance shield which then causes shading on module)	Determined temperature assumes homogeneous temperature profile over module surface (cannot measure ΔT over surface); Module (temporarily) not at MPP, so may affect system behavior; Measurement system may be complex for time series applications	Higher cost than alternatives; Highly sensitive to operator error; Absolute temperature measurements less accurate than alternatives

4.3.3 Meteorological data

For a deeper understanding and simulation of the module performance and stability, information about environmental parameters other than the in-plane irradiance and module temperature is needed. The bar graph in Figure 20 gives an overview of the other typically measured meteorological sensors. The assessment of spectral irradiance data is discussed separately in chapter 5.3.4..

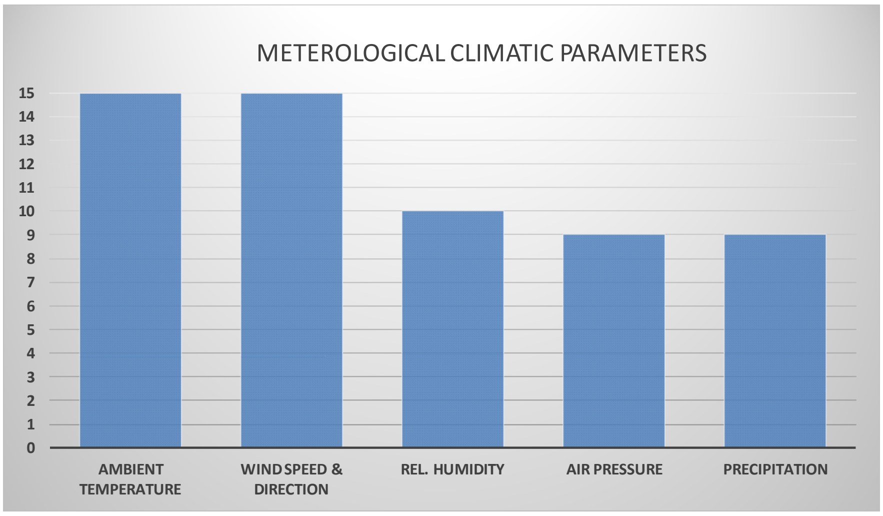


Figure 20: Environmental parameters measured by each test facility.

All test facilities of the 15 surveyed are equipped with sensors for the measurement of ambient temperature and wind conditions, 9-10 measure the relative humidity, air pressure and precipitation.

The IEC 61724-1 technical guideline [*2*] gives recommendations on how to install and operate the environmental sensors, including ones for soiling ratio and snow coverage.

4.3.4 Spectral irradiance

Even if the impact of spectral variations on PV energy yield over time is not as significant as other factors such as the total irradiance and temperature, it is however not negligible and has to be considered. There are also clearly cell technologies that are more affected than others by spectral variations [9,54,55,56,57,58,59,60,61,62]. To take into account spectral effects, the best way is to measure the spectral irradiance, but when it is not possible, simulated data can be used instead. Both approaches are described in the following.

Measured spectrum

Spectroradiometers are instruments for the measurement of spectral irradiance, i.e. the power density at every wavelength of the light received by a surface, expressed in W/m^3 in SI, or commonly in $W/m^2/nm$ or in $W/m^2/\mu m$. There are two main families of instruments: scanning spectroradiometers (or monochromators) and array detector spectroradiometers (or polychromators).

Both types have input optics, such as integrating spheres, cosine correctors or Teflon diffusers, which collect and guide light to the internal part of the instrument. In some cases, optical fibres connect optics with the instrument bench. The choice of the input optic type and material, as well as the optical fibre length and diameter affects the portion of the spectrum and the amount of radiation reaching the instrument.

Before entering the optical bench, light passes through an entrance slit that defines a clear-cut object and determines the amount of light as well as the angle of entrance. These factors are in turn directly related to the resulting spectral resolution of the instrument.

The central part of a spectroradiometer is the grating, an element that diffracts the incoming light into its spectral components. In the case of scanning spectroradiometers, the grating rotates in order to diffract one specific wavelength at a time, i.e. to allow only photons of a certain wavelength to reach the next detector element. A continuous rotation is performed in order to scan a range of wavelengths. For this reason, scanning spectroradiometers are equipped with mechanically moving parts that must be protected with stable housing, and are therefore usually heavier and more difficult to transport. In some cases, such instruments are equipped with a double monochromator, which considerably decreases the effect of stray light, thus increasing optical performance. In the case of array detector spectroradiometers, the diffraction gratings are treated in such a way that they simultaneously produce multiple images corresponding to several wavelengths. This can be obtained either with ruled gratings (parallel grooves on the grating surface) or holographic gratings (with sinusoidal index of refraction variation). Polychromatic gratings are not supposed to move. For this reason, these instruments are smaller and lighter than the ones using rotating monochromators, thus more suitable for transportation. Another difference in the two types of instruments is the acquisition time. Due to the rotation of the grating, it takes some minutes for a monochromator to scan the whole detectable spectral range. The acquisition time is much smaller, in the order of few microseconds to seconds, for a polychromator since the detection of the light is simultaneous. Consequently, polychromators are less prone to distortion in the measured spectra caused by rapidly varying meteorological conditions, such as the quick passage of a cloud.

The single (in the monochromator case) or multiple (in the polychromator case) detector elements convert the energy of the incoming portion of light into a signal intensity value with the support of a dedicated software. The detector material determines the upper wavelength limit that can be detected by the instrument. The most commonly used materials are Si and InGaAs that can detect up to 1117 nm and 1700 nm, respectively [*63*]. Other materials with lower bandgap energy can provide detection limits of 2200 nm to 2600 nm but they are much more expensive. Monochromators usually use a photomultiplier tube (PMT) as detector, while polychromators' array of pixels can consist either of a charge coupled device (CCD) or an array of photodiodes (DAD).

Different sources of noise affect the spectra measured by spectroradiometers:

- readout noise: caused by the characteristics of the internal elements and their operation;
- shot noise: associated with statistical variation in the number of photons incident on the detector;
- dark noise: associated with the thermal generation of electrons also in absence of incident light;
- fixed pattern noise: caused by variation in photo-response between neighboring pixels.

Some of the noise can be minimized by changing acquisition settings within the dedicated software or regulating external factors (ambient temperature). In other cases, noise is related to factors intrinsic to the instrument, such as the characteristics and mutual connection of the elements it is composed of, and cannot therefore be modified. For this reason, the proper setting and use of a spectroradiometer is quite complex and experience is required for validating measured spectra.

Recently, more test facilities have deployed advanced spectroradiometers. Figure 21 gives an overview of the spectroradiometers installed by the 15 test institutes. They differ in the wavelength range they are able to measure and in their orientation. Depending on the sensor type, wavelengths up to 1100, 1700 or 2500 nm are reached. In the lower wavelength range the sensors start to respond between 220 and 350 nm. Nine spectroradiometers measure the spectrum on a fixed plane of which eight on the tilted plane and one on the horizontal plane. Two are mounted on a two axis sun-tracker.

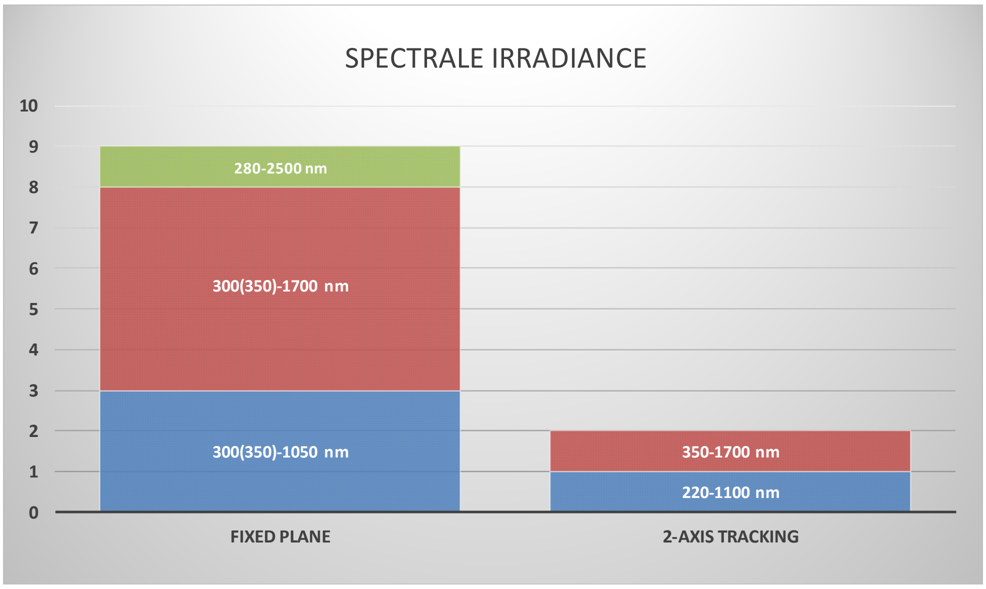


Figure 21: Feedback on spectral irradiance measurements (spectral range and installation type).

In order to overcome the above-mentioned complexity and increase mutual knowledge exchange, several inter-comparisons of spectral measurements have been organized in different parts of the world. From a historical point of view, high interest in the ultraviolet (UV) part of the solar spectrum due to its effects on human health explains the high number of inter-comparisons which focused on this spectral region [*64*,*65*,*66*,*67*,*68*,*69*,*70*,*71*,*72*]. As for spectral irradiance measurements at the Earth's surface in other spectral regions, interest has risen in the last decade, driven by the important implications for the PV sector. Therefore, some recent inter-comparison campaigns have also focused on the sensitivity regions of photovoltaic materials, such as visible and near-infrared. The main campaigns are listed in Table 5. Results generally show that differences between measurements obtained with different spectroradiometers are usually well within a ±10% range. Nevertheless, greater differences can exist in some cases, due to issues in instrument settings and management procedures as well as in measurement and calibration procedures.

Table 5: List of intercomparison campaigns of spectroradiometers for the measurement of solar spectra at spectral regions of interest for photovoltaic applications. GHI: global horizontal irradiance, DNI: direct normal irradiance. SM: single-monochromator, DM: double-monochromator, P: polychromator.

Reference	[*73*]	[*74*]	[*75*]	[*76*]	[*77*]	[*78*]
Year	not reported	1999	2013	2011	2012	2015
Place	Loughborough, UK	El Arenosillo, Spain	Golden, USA	Portici, Italy	Catania, Italy	Madrid, Spain
Measured component	GHI	GHI, DNI	GHI	GNI, DNI	GNI, DNI	GNI, DNI
Number of instruments	7	4	10	6	7	12
Spectral range (nm)	350 - 1050	400 - 700	380 - 1100	360 - 1700	360 - 1700	300-1100 300-1700
Instrument type	P	SM, DM, P	SM, DM, P	SM, P	SM, P	SM, P

Simulated spectrum

The measurement of the solar spectrum is not always possible, mainly due to the cost of spectroradiometers and the need for expertise in calibration, software set-up, operation and maintenance. For this reason, the availability of spectral data at PV plants is only available at very few locations in the world, and mainly for scientific purposes. A sound alternative is to use so called *Radiative Transfer Models* (RTM) to simulate the solar spectrum, given a set of atmospheric parameters and geographic coordinates. At the basis of these tools is the Radiative Transfer Equation (RTE) that describes the physical process of radiation transfer from space to the Earth's surface by considering the interaction of photons with the atmospheric constituents, which includes emission, scattering, absorption and reflection.

In general, RTM are classified into three main categories:

- Sophisticated rigorous models
- Parametric models
- Statistical models

The sophisticated rigorous models implement the Radiative Transfer Equation and solve it in a numerical way for each spectral wavelength using a discrete ordinate method. These models are also called *line-by-line* models, since the process of molecular absorption is treated as the sum of the contributions of the spectral lines of each gas species or aerosol constituting the atmosphere. Examples of such models are LOWTRAN [*79*], MODTRAN [*80*,*81*], SBDART [*82*], SBMOD [*83*], STREAMER [*84*], FASTCODE [*85*], UVSPEC [*86*]. RTM belonging to this family are characterized by the high accuracy of the results. On the other hand, execution time may be very high. In order to overcome this drawback, some of these models implement simplifications of the algorithm. One of the most common is the so-called *correlated K-distribution approximation*. Since the same set of values of gaseous absorption coefficients is encountered many times over a given spectral band, computation redundancy is eliminated by grouping these values. For example, the correlated k-approach of [*87*] works with 32 bands in the whole solar spectrum, and the transmittance calculation is performed only once for a given band, instead of once for each wavelength. Another important simplification is performed with the algorithm implemented in MAGIC [*88*] and SPECMAGIC [*89*]. This method makes use of *lookup tables* (LUTs), which are discrete pre-computed radiative transfer model results. Once LUTs are available, the transmittance for a given atmospheric state can be extracted from the LUTs by interpolation, thus replacing a runtime computation.

In the parametric models, the radiative transfer equation is substituted by simple parameterized expressions. These tools therefore allow a faster computation and have user-friendly interfaces while still assuring acceptable accuracy. They have appeared in the literature since the early 1980s with the aim of providing at-hand solutions for engineering applications. Examples of such models are SPCTRAL2 [*90*], SEDES [*91*], SMARTS1 [*92*] and SMARTS2 [*93*].

The statistical models treat the interaction of photons with the atmospheric constituents and surfaces as a statistical process, mainly by using the Monte Carlo technique. Once the system has been set, random photons are emitted into the medium, and after a random distance depending on the mean free path length, they are absorbed or randomly scattered until they eventually leave the domain. Interaction lengths, scattering angles and absorption rates are determined on the basis of probability density functions chosen by the user. During the whole process the photons are tracked one by one, and are counted if they exit the medium in order to obtain the spectra. Examples are MYSTIC [*94*], GRIMALDI [*95*] and BRITE [*96*].

There are other criteria to distinguish between models, e.g. wavelength range and resolution, inclusion of light polarization, geometry of the domain, license type, capacity of treating ice and water clouds, type of generated output, user interface etc. In general, none of the available models can be stated as the best one. Instead, there are models that are more suitable than others depending on the specific application and problem to solve. Numerous efforts have been made and are currently being made in order to compare the results of different RTMs, under different environmental conditions. One of the most famous is represented by the Radiation Transfer Model Intercomparison (RAMI), coordinated by the European Commission's Joint Research Center [*97*], which consists of a platform for assessing the capability, performance and agreement of RTMs under a framework of well-established rules and criteria.

5 Data Quality Control and Maintenance Practice

The reliability and accuracy of the test results depend not only on the selected hardware but also strongly on the implemented quality control measures. Especially in the case of long-term measurement campaigns - going over years - efficient data collection and hardware control is needed. It is even more challenging in the case of remote sites or extreme climates. Chapter 5 gives an overview of the implemented approaches.

5.1 Quality Markers

The survey highlighted that the level of data quality between the laboratories is generally very high and a large number of data quality markers are implemented. Figure 22 gives an overview of the typical error markers and their level of implementation within the 15 interviewed laboratories [16,31]. A case sensitive filtering of erroneous or low-quality data is so easily possible. E-mail alerts are the most commonly used tool for the notification of problems.

Figure 22: Type of data quality controls (error markers) and the number of laboratories implementing them.

5.2 Maintenance

Beside regular calibrations of the equipment, other quality control measures such as visual inspections and cleaning of the sensors is standard practice. Figure 23 shows the implementation level of different maintenance measures within the 15 survey participants as well as the frequency with which the measures are performed.

The cleaning of the modules is very site specific. Not all laboratories clean the modules regularly, but all have well-defined criteria when to clean. The IEC 61724-1 standard gives suggestions of how soiling ratios can be monitored.

Only a minority have a webcam installed. This is mostly used in the case of remote systems.

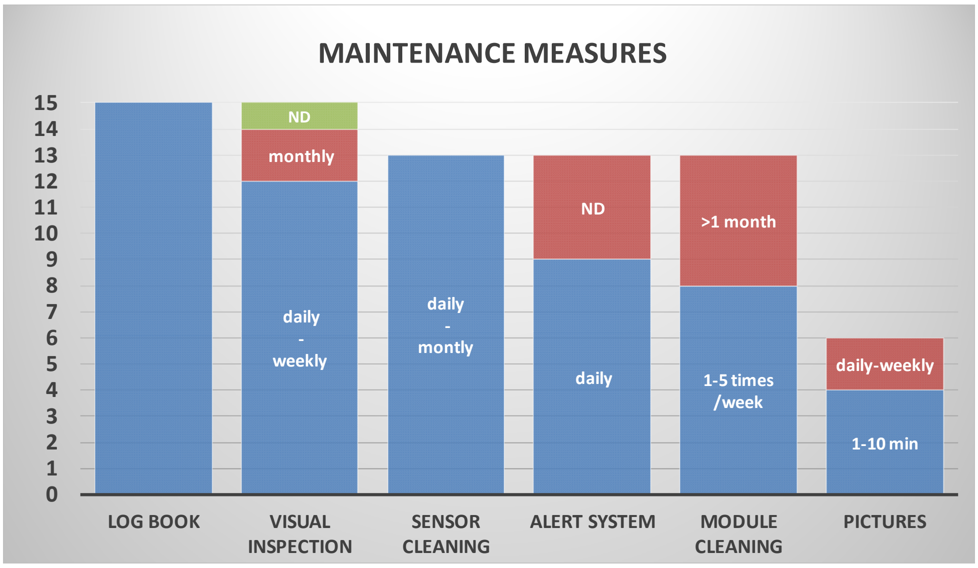


Figure 23: Feedback on type and frequency of maintenance measures implemented by the 15 laboratories.

6 Characterization of Test Modules

Chapter 6 gives an overview of how and how many PV modules are typically selected and how they are characterized before its installation on the field. All information is underpinned with figures recommendations from the survey and general recommendations.

6.1 Module Selection/Sampling

Figure 24 gives an overview of the typical number of test samples including the availability of reference modules stored in the dark and/or spare modules, and the frequency of the different approaches within the survey group. The majority (10 out of 15) exposes 2-3 modules/type, a few up to 5 modules/type and 3 out of 15 limit their tests to a single sample.

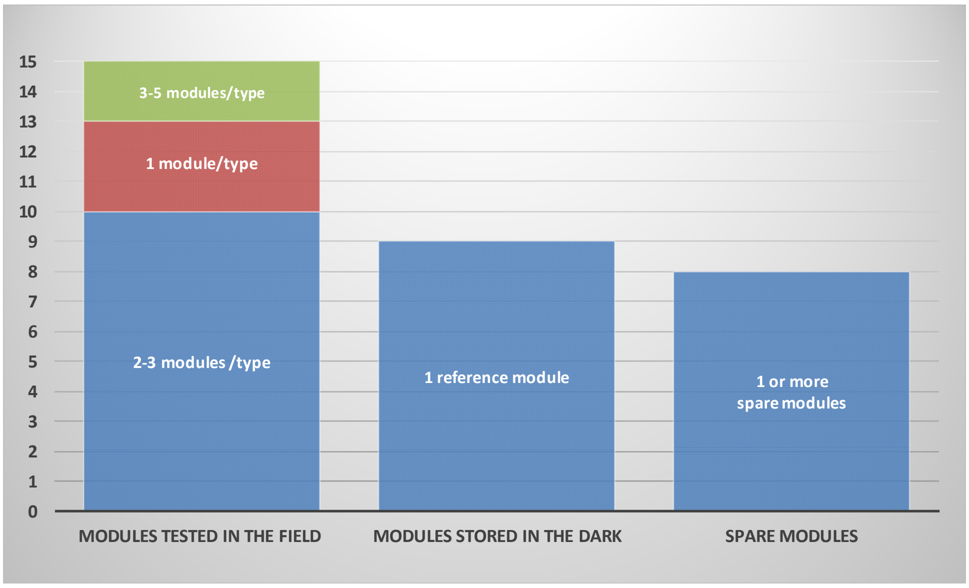


Figure 24: Availability of test modules within the 15 survey participants (sample number, reference modules, spare modules).

Even if there are no rules, it is recommended to test more than one module of the same type. Particularly in the case of long-term measurement campaigns, the availability of more than one module is of an advantage as it allows the user to do a redundancy check and to have a back-up in case of failure of a module. An exception are short measurement campaigns for the scope of module characterization or prototype testing, where 1 module is generally sufficient. The testing of a statistically relevant number of modules is generally omitted for reasons of costs and space.

The storage of an extra module in the dark as a reference device is considered to be very useful when performing regular STC control measurements. The 9 laboratories having a dark reference module also have a solar simulator in-house and are able to do performance measurements under STC conditions. The STC power of the reference modules is measured together with the outdoor exposed modules, to detect any degradation rates and to discern the effective degradation from the measurement repeatability, as obtained with the dark stored module. The others calculate the degradation rates according to one of the approaches described in chapter 7.3.

The availability of spare modules is also recommended. 8 out of 15 declares to fulfill this.

The criteria according to which the modules are selected and by whom can be of primary importance, especially in the case of benchmarking studies, where the selection can significantly influence the final result. This topic will be discussed in more detail in chapter 7.1. For the other scopes, it is generally less relevant. There are two standards cited regularly regarding the sampling approach, these are the IEC 60410 or ISO 2859-1, but depending on the purpose of the test, individual sampling procedures are sometimes more appropriate. Usually the objective is to reduce the number of samples to an acceptable range, which balances costs for testing with transferability of the results to a large number of modules. There is today no mutual agreement on how to operate for benchmark measurements.

The survey highlighted that 7 out of 15 participants declare to select their modules according to specific criteria (e.g. average manufacturer power, closest to P_{nom}). The modules are either identified through the flasher lists delivered by the manufacturers or based on own power measurements. The other 8 laboratories, which did not specify their approach, get probably the modules directly from the producers, who have their own sampling procedures, or they purchase them anonymously. In the last case, the possibility of choosing a specific module is not possible.

Any reporting should clearly state the followed approach, and the approach should be the same for all compared technologies or module types. The sampling procedure can be different depending on the scope for which the measurements are performed.

Because of the potentially high tolerances in maximum output power, as described in chapter 7.1.2, it is recommended that test samples for energy yield testing shall be randomly sampled from a production lot. A minimum of 5 samples of the power class shall be subjected to electrical stabilization in accordance with IEC 61215 and electroluminescence analysis. The sample with the smallest difference to nominal power shall be selected. In particular, c-Si test samples shall be free of cell cracks, because crack propagation during outdoor exposure may lead to increased power degradation. A pre-testing of the modules to be exposed outdoors is therefore crucial.

6.2 Pre-testing and Control Measurements

Before being installed in the field, the modules should typically undergo a quality assessment and/or a characterization. Some of the tests, in particular, the STC measurement, are repeated at the end of the measurement campaign or at regular intervals. Figure 25 gives an overview of the typically performed tests.

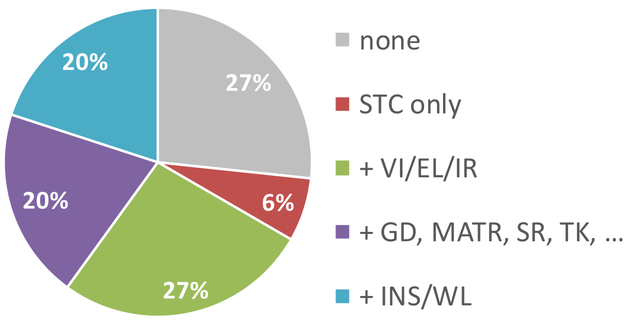


Figure 25: Frequency of indoor tests (pre-screening) performed before the outdoor exposure.

Legend: performance at (STC), visual inspection (VI), electroluminescence (EL), infrared imagining (IR), irradiance dependency (GD), temperature coefficients (TK), full matrix (MATR), spectral response (SR), insulation test (INS) and wet-leakage (WL).

73% of the asked participants measures the STC power. The STC power is a key parameter as it is used for the normalization of the module energy yield (Y_a) and the module performance ratio (MPR). The other 27% does not perform any preliminary test and relies fully on outdoor data and/or data sheet or flasher list values delivered by the module manufacturer. It is generally the case for those laboratories without a solar simulator. A few facilities send the modules to a qualified laboratory to perform the STC measurement. The origin of the STC power and its uncertainty or tolerance in case of the nominal power should always be stated.

As reported in the literature [*98*] most technologies undergo an initial degradation or rise which should be considered when performing the STC measurement. An appropriate pre-conditioning procedure should be applied especially in the case of modules coming from the factory. For some technologies a dark storage can lead to deviations also after being already exposed to the sun [*99*]. The recently published standard IEC 61215 (2016) gives clear instructions on how each technology should be stabilized to determine the STC power, both at the begin or after any stress testing. The survey highlighted that half of the participants performing own STC measurements, precondition their modules according to the existing standards [*100*] or an in-house defined procedure. The pre-conditioning is generally skipped when the module is measured immediately after the dismantling from the field or if there is the evidence that the technology is stable. A proof of the validity of the used approach should be given.

27% of the surveyed participants add a visual inspection or other optical inspection method to the STC measurement such as for example an electroluminescence and/or infrared image to identify defects. Another 20% of participants extends the electrical characterisation by performing also measurements of the temperature coefficient, the low irradiance performance, spectral response or even a full performance matrix according to IEC61853-1. Another 20% include electrical safety tests as the wet leakage and insulation test.

7 Data Analysis and Reporting

When working with long time series measured under real operating conditions, the quality of data processing is almost as important as the measurements of the data itself. Chapter 7 gives different examples of how data is analyzed for the purpose of benchmarking, investigation of performance losses, calculation of degradation rates and the comparison of measured to simulated time series. Equations, filtering approaches and typical data representations are reported considering the impact of measurement uncertainties and production tolerances .

7.1 Module Energy Yield Benchmarking

7.1.1 Energy yield assessment

The energy yield performance of a PV module is based on outdoor measurement in a certain climate over a representative period of time. The energy output is the integrated sum of maximum power values of the PV module sample ($P_{max,n}$), which are recorded in time steps τ (data recording interval given as a fraction of hour). The energy (E) is typically expressed in kWh.

$$E = \sum_{k} P_{max,k} \times \tau_k [kWh]$$

The theoretical number of data points (n_{TH}) is calculated from the hours of daylight in the data recording interval and the duration of the data recording interval (τ). The hours of daylight can be derived from the time of sunrise and sunset for each day in the data recording period.

$$n_{TH} = \sum_{Days\ of\ year} \frac{Hours\ of\ daylight}{\tau}$$

As an example, Figure 26 illustrates the change of hours of daylight during the year. Marked by a horizontal blue line, the latitude 40°N, which approximately represents the cities of New York City, Madrid and Beijing.

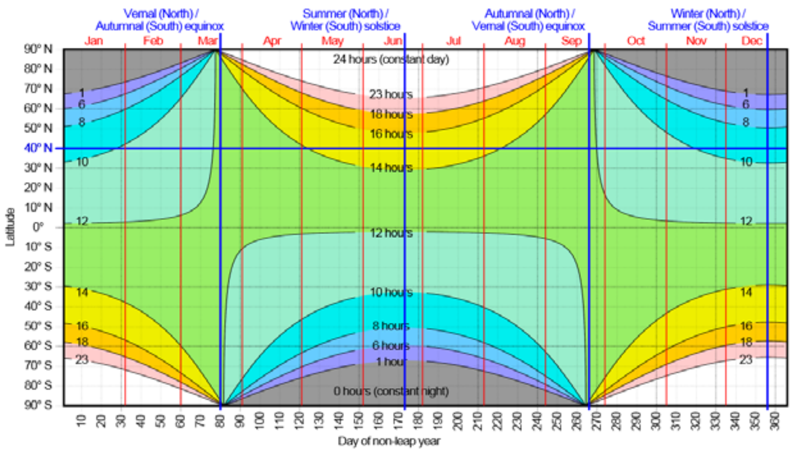


Figure 26: Contour plot of the hours of daylight as a function of latitude and day of the year, using the most accurate models described in Sunrise equation. Latitude 40° N is highlighted for reference, source (https://en.wikipedia.org/wiki/Sunrise_equation#/media/File:Hours_of_daylight_vs_latitude_vs_day_of_year_cmglee.svg).

In practice the theoretical number of data points is reduced by various effects which result in a smaller number of useful data points:

- Off-time of measurement system for meteorological parameters
- Off-time of electronic load
- Rejection of data points due to implausible recordings
- Rejection of data points due to MPP tracking failure
- Rejection of data points due to incomplete data set with the same time-stamp
- Rejection of data points due to module shading or fast fluctuation of irradiance in the test array (non-uniform irradiance due to cloud movement)
- Rejection duplicate (repetitive) data records

The data availability for the energy yield measurement is calculated as follow:

$$Data\ availability = \left(1 - \frac{Useful\ number\ of\ data\ points}{Theoretical\ number\ of\ data\ points}\right) \cdot 100\%$$

The general requirements for high quality/accurate energy yield measurements have already been discussed in the previous chapters (chapter 2.1 and 4.2). A short summary of the data requirements is given here:

- The time period of data monitoring shall cover a complete meteorological year to consider the real operating conditions at the test site.
  Note: There are situations where also a short period of energy yield measurement can be considered. For example, if the module manufacturer wants to study different materials regarding their energy yield performance (i.e. type of front glass type or specific glass coatings).
- The data recording interval τ shall be ≤60 s, which allows to detect irradiance fluctuations.
- Measurement of MPP data and meteorological measurements must be synchronized in time;
- The data availability for energy yield measurement shall be larger than 90%.

Due to the variability in weather conditions at the test site, sequential energy yield testing of different PV modules is problematic. PV module benchmarking shall be based on time synchronous energy yield measurement. The ranking of the energy yield performance can be either expressed by the “PV module (array) energy yield“(Y_a) or by the “PV module performance ratio (MPR)”:

$$Ya = \frac{Measured\ energy\ yield\ (E)}{Reference\ power\ (P_{stc})} \quad \left[\frac{kWh}{kW_P}\right]$$

$$MPR = \frac{Measured\ energy\ yield\ (E) / Reference\ power\ \ (P_{stc})}{Measured\ solar\ radiation\ (H) / Reference\ irradiance\ \ (G = 1000\frac{W}{m^2})}$$

Y_a allows the comparison of modules with different P_{stc} whereas MPR allows to compare also modules receiving different irradiances (measured at other sites, with different orientations or in different periods). The latter requires also the measurement of the incident energy or irradiation H_i, which is the integrated sum of irradiance (G_n) recorded in time steps τ (data recording interval given as a fraction of hour). The irradiation (*H*) is typically expressed in kWh/m².

$$H_i = \sum_k G_{i,k} \times \tau_k \; [kWh/m^2]$$

It is generally recommended to base the PV module benchmarking on the module performance ratio (MPR) as this parameter is independent from the data availability.

MPR=1 means that the average efficiency of the module conforms to the module efficiency at STC. Performance losses due to module temperature, low irradiance behavior, spectral/ angular effects or meta-stability will result in lower MPR values. The composition of performance losses is dependent on the climatic conditions at the location. A description of how to analyze single performance losses is given in the following sections 7.1.2-7.1.4.

7.1.2 Impact of STC power

Power labelling of PV modules

The highest uncertainty contribution is coming from the uncertainty in the STC power.

The manufacturing of PV modules is subject to various tolerances. Manufacturing tolerances can either originate from tolerances in used materials (i.e. spread of electrical characteristics of solar cells) or from the manufacturing process (i.e. quality of soldering processes). As a result, the maximum output power of production line PV modules follows a distribution curve, which makes it necessary to define various power ranges (classes). The total spread of maximum output power is documented in the data sheet of the module type. Table 6 exemplarily shows four power classes with 5 W bin widths. Such a classification is typically related to output power measurement with a pulsed solar simulator. The measurement results are generally documented in a so-called flash list.

Table 6: Sorting of PV modules into power classes.

Electrical data @STC	Power Class 1	Power Class 2	Power Class 3	Power Class 4
Nominal Power (Wp)	265	270	275	280
Watt Class Sorting (W)	0/+5	0/+5	0/+5	0/+5
Nominal Power Voltage (V)	31.1	31.2	31.4	31.9
Nominal Power Current (A)	8.53	8.66	8.76	8.78
Open Circuit Voltage (V)	38.3	38.6	38.8	39.2
Short Circuit Current (A)	9.21	9.29	9.40	9.44
Efficiency (%)	16.1	16.4	16.7	17.0

The most important parameter of a PV module is its nominal power (P_{nom}), which is expressed in Wp, 'Watt Peak'. The unit indicates that nominal power is related to the Standard Test Conditions (STC) as defined in IEC 60904-3. Two different practices can be observed to express the manufacturing tolerance:

a) <u>Plus sorting (i.e. 0/+5 W):</u> The nominal power is the minimum value of the class sorting. The output power of modules must be higher than this permissible value.

b) Plus-minus-sorting (i.e. ±3%): The nominal power is the average value of the class sorting and is usually halfway between the maximum and minimum values.

The power labelling practice of module manufacturers is not internationally harmonized. In most cases the nominal power is only referred to the flash testing, which represents only the manufacturing tolerance. However, the total power tolerance is additionally subject to the measuring uncertainty in the production line and potential electrical instability. Both are not necessarily considered in the power labelling.

When delivered to the customer the electrical output power of PV modules may not be stable, but be subject to light or temperature induced effects. The standard IEC 61215-2 published in 2016 defines a test procedure for electrical stabilization of a PV module. The PV module is subject to an irradiance cycling test with minimum 5 kWh/m² radiation each. After every cycle the output power is measured. Two successive cycles will then result in three power values (P1: initial, P2: intermediate, P3: final). From these values P_{MIN}, P_{MAX} and $P_{AVERAGE}$ are determined. The PV module is deemed to be electrically stable when the term $(P_{MAX} - P_{MIN}) / P_{AVERAGE}$ is lower than the following threshold values: 1% for c-Si PV modules, 2% for thin-film PV modules. It must be noted that the stabilization procedure may not detect slow running stabilization processes.

Choice of reference power P_{stc}

In both definitions for expressing the energy yield performance (see section 7.1.1) the choice of the reference output power has a great impact on the result. The following options are possible:

a) Nominal power P_{nom} as stated by the manufacturer
As explained before the real output power of a PV module can considerably differ from the nominal value. If $P_{stc} > P_{nom}$, a high energy yield performance of the sample will be measured, which would be a manufacturer-friendly result. This shows the need to electrically stabilize test samples prior to energy yield testing.

b) Stabilized real power $P_{stc,stab}$ as measured in accordance with IEC 61215
This reference value is the most suitable for energy yield assessment of PV modules. It assures that all test samples for comparative testing are treated equally and the impact of sampling or labelling is minimized. $P_{stc,stab}$ is the optimal parameter for benchmarking of products.

c) Actual power $P_{stc,out}$ as measured during outdoor exposure
The accuracy of scientific energy yield analysis can be increased if the actual output power at STC of the test sample is used as reference output power. This requires measurement of IV-curves and extrapolation of curves to STC by use of the standard IEC 60891. This will offer the possibility to study the metastable behavior of thin-film PV modules (i.e. initial stabilization, seasonal effects) or any output power degradation.

The reference power used for the calculations, its uncertainty and how the modules have been sampled should always be stated clearly and taken into account into the evaluation of the results (see also chapter 6.1).

Figure 27 shows an example of a ranking obtained from a 4-year-measurement campaign performed in Lugano (Switzerland). $P_{stc,stab}$ is measured with a class A solar simulator as reference value.

The graph gives the difference of MPR of different thin film modules with respect to the c-Si reference module (c-Si REF). Differences of up to ±10% were observed from one module to another. The first year is excluded from the ranking to exclude any stabilization processes.

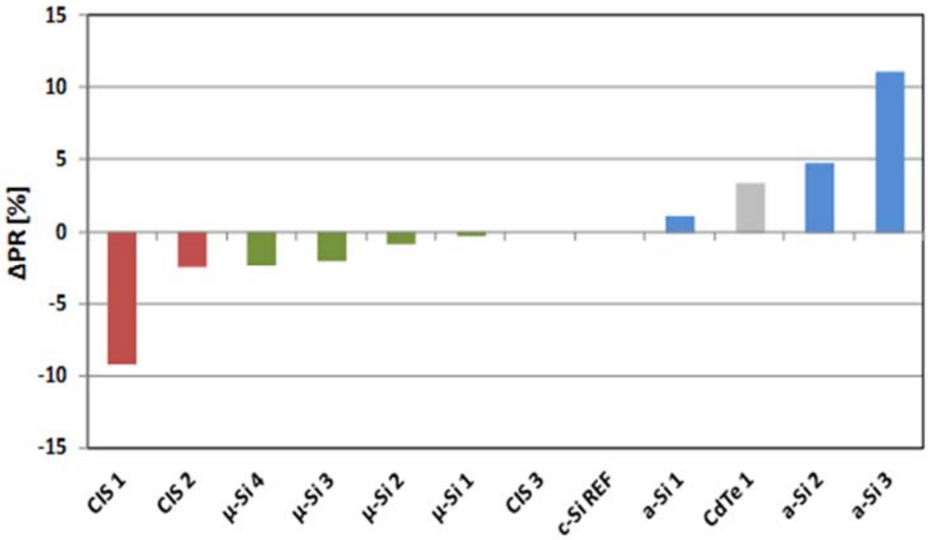


Figure 27: Thin film module ranking (2012-2014) expressed as difference of performance ratio $\Delta PR=(PR-PR_{c\text{-}Si})/PR_{c\text{-}Si}$ for 11 different thin film technologies (CIS in red, CdTe in grey, μc-Si in green and a-Si in blue).

As explained in the following sections, the differences can be correlated to different module characteristics. An example is given by the authors of [*8*].

7.1.3 Impact of temperature, irradiance, angle of incidence and spectrum

The energy yield performance of a PV module is defined by the inter-correlation of the PV module characteristics and the climatic conditions at the location. Figure 28 gives an overview of the various impacts on PV energy yield [*101*]. The major contributions are described in the following.

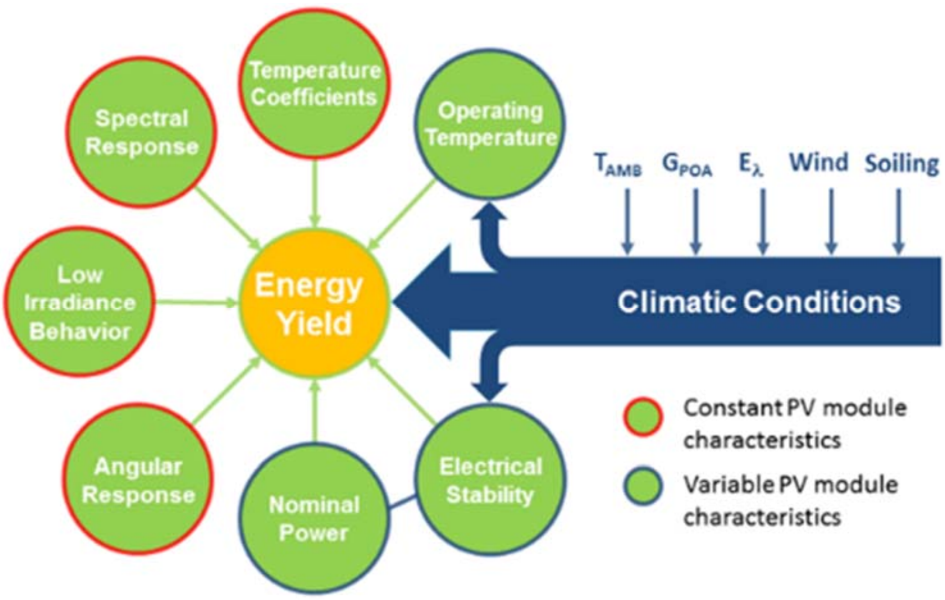


Figure 28: Factors influencing the energy yield of PV modules.

Temperature impact

On PV module level the temperature impact is described by the P_{max} temperature coefficient (TK-P_{max}), which is measured at constant irradiance (1000 W/m²) and variable module temperature (15°C to 75°C) in acc. with IEC 61853-1. Figure 29 shows the range of TK-P_{max} for various PV module types. The diagram reveals that TK-P_{max} can vary between but also within PV technologies. Lowest values are observed for CdTe modules and highest for both multi c-Si and CIGS modules.

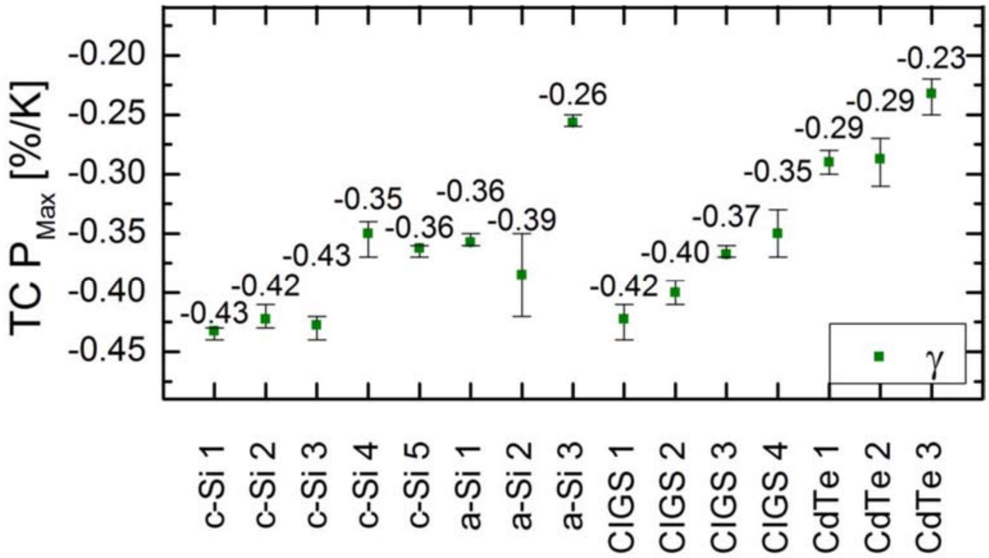


Figure 29: Temperature coefficients of various PV module types [10].

Regarding the local climate, the temperature impact is described by the module temperature, which varies during the day but can also show seasonal effects. The relevant parameter is the annual average weighted module temperature $\overline{T}_{\mathrm{mod},G}$, which is calculated in accordance with the following equation.

$$\overline{T}_{\mathrm{mod},G} = \frac{\sum (T_{\mathrm{mod}} \cdot G_i)}{\sum G_i}$$

Where T_{mod} is the module temperature and G_i is the in-plane solar irradiance. The formula assures that only module temperatures are considered, where G_i lies above a threshold value of 15 W/m². For a standard glass/backsheet construction of a multi-Si PV module $\overline{T}_{\mathrm{mod},G}$ is 30°C at Cologne (Germany) and 46°C at Tempe (Arizona). Accordingly, 7% higher temperature losses are observed in a desert climate compared to moderate climate. The difference in energy yield performance between the PV module with the best and poorest TK-P_{max} is approx. 3%.

Irradiance impact

The irradiance impact on energy yield is defined by the efficiency curve of the PV module. The efficiency curve is typically measured at constant module temperature (25°C) and variable irradiances (100 W/m² to 1100 W/m²) in accordance with IEC 61863-1. Figure 30 shows some typical normalized efficiency curves, from which low light performance losses can be directly read.

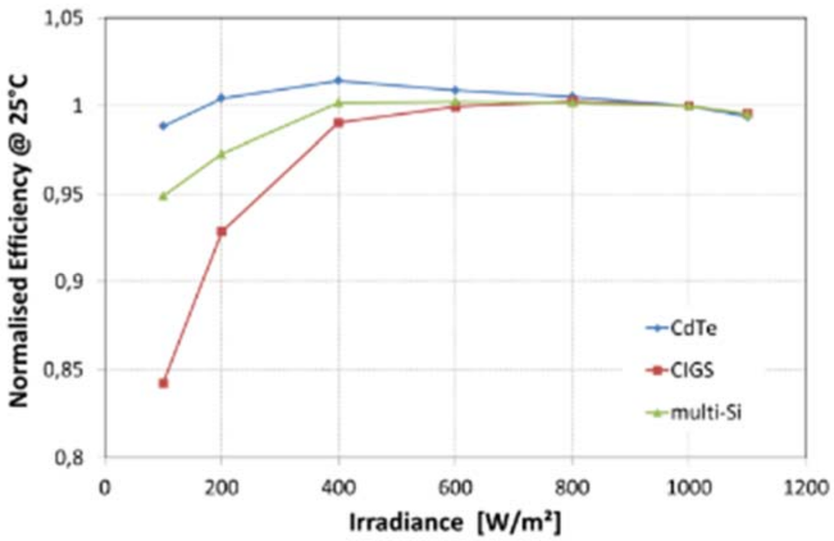


Figure 30: Efficiency curves of various PV module types.

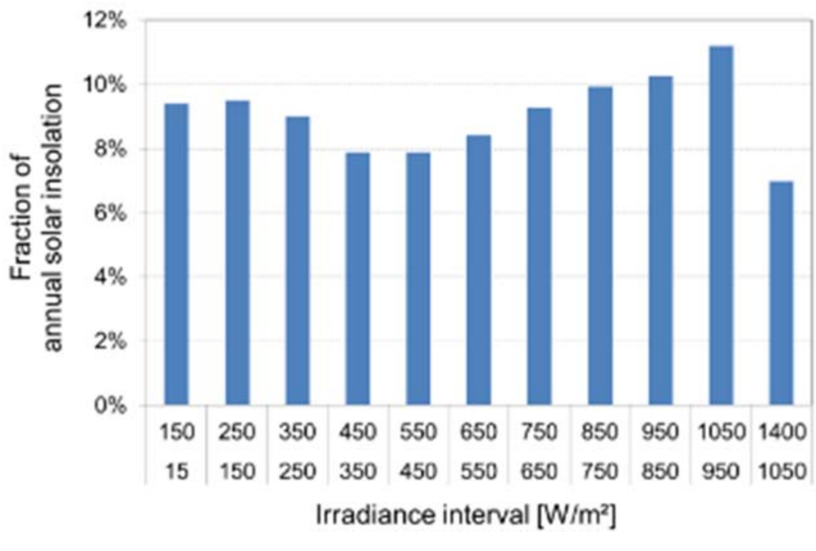


Figure 31: Classification of in-plane solar irradiance in 100 W/m² intervals in Cologne (Germany).

Related to the local climate irradiance effects are determined by the frequency distribution of in-plane solar irradiance, classified in intervals of 100 W/m2. Figure 31 shows the measured distribution curve for Cologne (Germany), which reveals that solar irradiance is nearly equally distributed. Desert locations typically show a significant shift to high irradiation, which means that differences in low light behavior of PV modules will be less noticeable.

Impact of angle of incidence

The PV module performance under varying angle of incidence (AoI) is described by its angular response curve or incident angle modifier (IAM). The IAM is measured in the angular range ±85° in accordance with IEC 61853-2. The curve describes the angular losses related to optimal cosine behavior. Figure 32 shows the angular response curves of various types of solar glass. Generally, angular losses are observed for AoI values larger than 50°. AR coatings slightly improve the angular performance [*102*].

The angular response curve of a PV module interrelates with the angular distribution of solar irradiance, classified in 10° intervals. Figure 33 shows the angular distribution for test location Cologne, where approx. 6% of solar energy is incident in the angular range AoI larger than 70°.

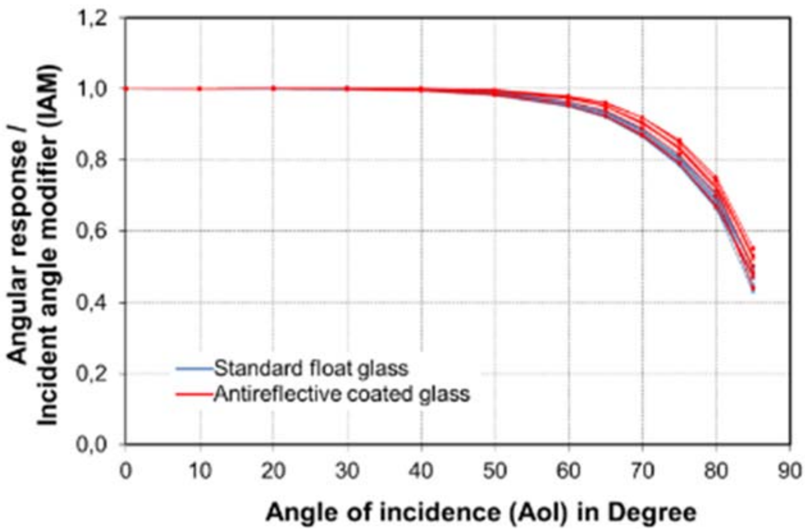


Figure 32: Angular response curves of c-Si PV modules with different types of front glass (blue: standard glass, red: anti reflective coated glass).

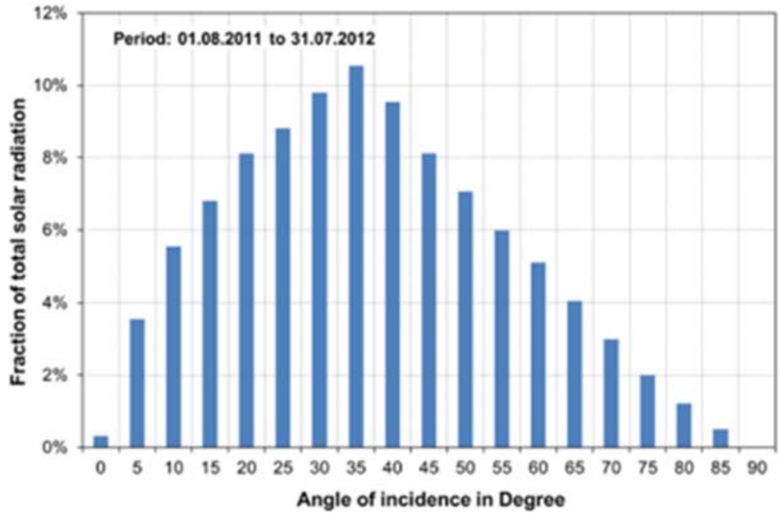


Figure 33: Classification of in-plane solar irradiance in 10° intervals of angle of incidence (Location: Cologne, Germany, south oriented 35° inclined surface)[10].

The spread of annual angular losses for different glass types range from -1.5% to -2.7%. [*103*]

Impact of spectrum

The wavelength spectrum of sunlight affects the fraction of the incident irradiance that can be absorbed by the PV device. The spectrum varies throughout the day and year due to the local conditions, including the presence of clouds, the concentration of moisture and aerosols (dust) in the atmosphere, and the atmospheric path length, which depends on the sun's angle. The extreme examples shown in Figure 34 demonstrate that spectral variations can be quite significant, however, in practice the greatest spectral differences occur at times when the total irradiance, and hence power output, is low, such as around dawn/dusk or under heavy cloud cover. As a result, the impact of spectral variations on PV energy yield over time is not as significant as other factors such as the total irradiance and temperature.

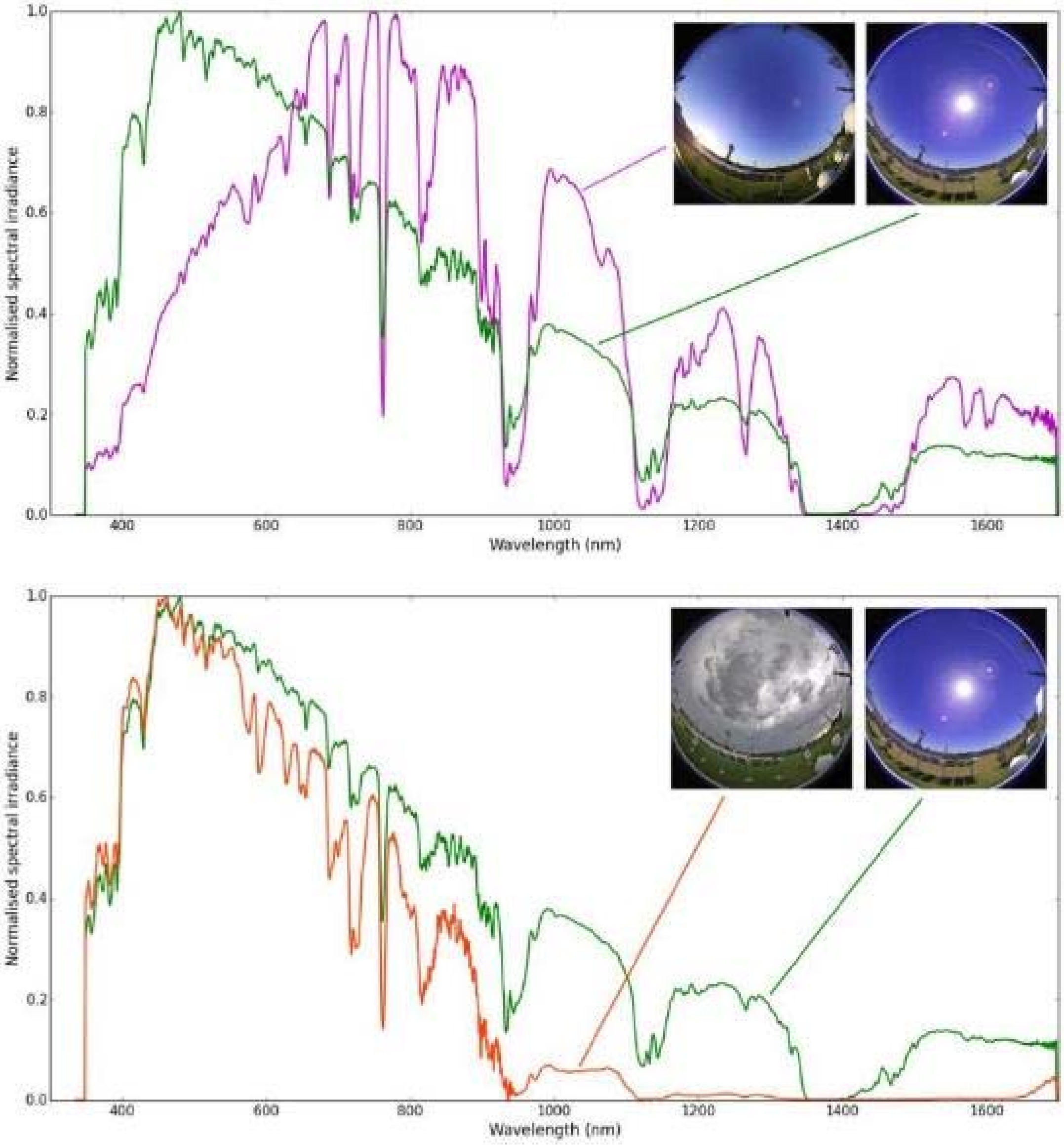


Figure 34: Global solar spectrum measured at Newcastle, Australia, comparing midday vs late afternoon on a clear day (top) and clear vs cloudy at midday (bottom). Note all spectra have been normalized to the same maximum value.

The impact of spectrum on the instantaneous PV output is equivalent to scaling the incident irradiance by a *mismatch factor*, *MM*, according to

$$MM = \frac{\int G_{ref}(\lambda)\, S_R(\lambda)\, d\lambda \int G_S(\lambda)\, S_T(\lambda)\, d\lambda}{\int G_{ref}(\lambda)\, S_T(\lambda)\, d\lambda \ \int G_S(\lambda)\, S_R(\lambda)\, d\lambda}$$

where G_{ref} is the reference spectral irradiance (usually the AM1.5 global reference [IEC60904-3]), S_R is the spectral response of the irradiance sensor, G_S is the measured spectral irradiance and S_T is the spectral response of the module (see example in Figure 35). For high quality pyranometers we can assume S_R as independent of wavelength and hence it drops out of the equation. Additionally, since spectral corrections are relatively small, it is reasonable to assume that the output power can be corrected in proportion with the irradiance.

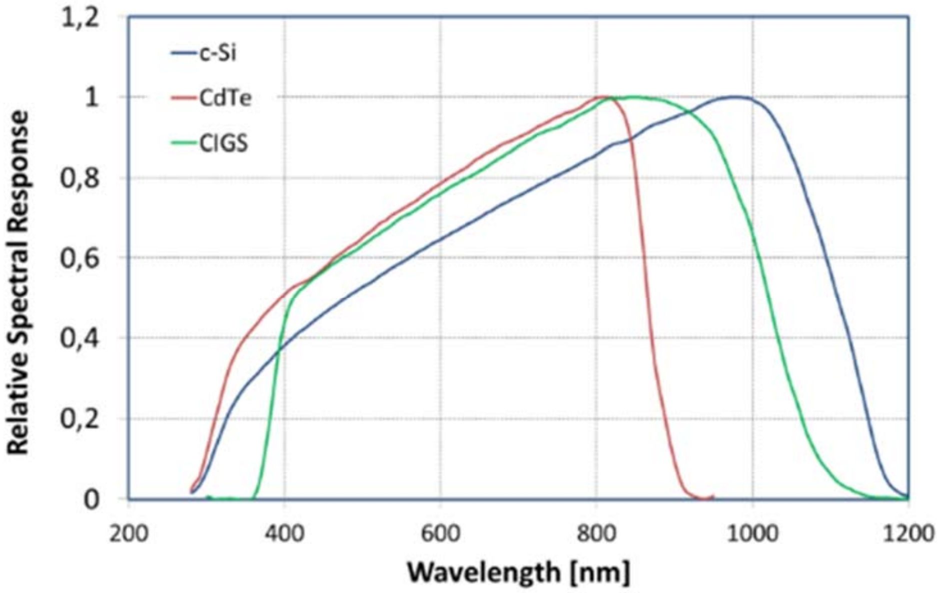


Figure 35: Spectral response of different PV technologies.

Alternatively, the spectral mismatch factor can be reasonably inferred from measurements of I_{sc} for the relevant PV modules in the field, according to

$$MM = \frac{I_{sc@meas} \cdot G_{ref}}{G_{meas} \cdot I_{sc@ref}}$$

where G_{meas} is the measured irradiance and $I_{sc\,@\,meas,\,ref}$ is the measured and reference short-circuit current values respectively.

Although an instantaneous spectral mismatch factor is useful, energy yield studies preferably address the long term effects at a given site. To quantify the impact of spectral variations on the energy yield accumulated over time, Duck and Fell [*105*] defined a *spectral impact factor (*SIF*)*, which is the irradiance-weighted mean of the observed spectral mismatch factor over a specified time period. Other spectral parameters as for example the Airmass (AM) or APE (Average Photon Energy) can be used as well [*106*]. The SIF, defined below, can be applied as a linear scale factor to the measured or calculated energy yield, to account for the difference between the effective mean local spectrum and the AM1.5 reference spectrum.

$$SIF = \frac{\sum MM\ G_i}{\sum G_i}$$

For a 33°S latitude coastal site in Australia with a good mix of clear and cloudy days, the authors observed SIF values in the range 0.95 to 1.10 for any given whole day. Seasonal effects caused variations in the SIF on clear days over a range of approximately ±0.02 around averages of approximately 1.01 for CdTe modules, 0.99 for c-Si and 0.98 for CIGS. Cloudy days were responsible for the higher values, which were typically scattered up to 1.10.

7.1.4 Calculation of derate factors

Derate factors quantify the individual sources of loss, as described in chapter 7.1.3, with respect to the power under standard test conditions.

There are many different methods reported in literature how to calculated these loss factors [*8*,*9*, *10*,*105*]. The IEC standard IEC 61724-1:2017 describes an approach for PV systems, which can easily be applied also to single PV modules. Figure 36 gives an example from the PV-KLIMA project, where the derate factors are calculated for different modules in different climates.

The estimated module performance ratio (MPR_{Calc}) is calculated according the following linear equation considering five individual derate factors.

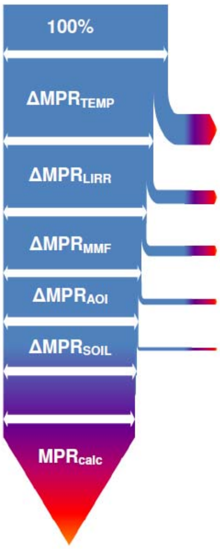
$$MPR_{calc} = 1 + \Delta MPR_{TEMP} + \Delta MPR_{LIRR} + \Delta MPR_{MMF} + \Delta MPR_{AOI} + \Delta MPR_{SOIL}$$

The mechanisms corresponding to loss terms ΔMPR for different climates from the PV module characteristics measured in the laboratory and the measured meteorological data are separated for this approach called Linear Performance Loss Analysis (LPLA). Loss mechanisms which influence the MPR of electrically stable PV modules are temperature (ΔMPR_{TEMP}), low irradiance (ΔMPR_{LIRR}), spectral effects (ΔMPR_{MMF}), angular losses (ΔMPR_{AOI}) and soiling (ΔMPR_{SOIL}).

The definition of the loss terms ΔMPR implies that losses are identified by negative numbers and gains by positive numbers. Each loss term can be computed from the irradiance weighted average of the specific performance loss term. For different PV module types operating in different climates the amount of these loss factors can be significantly different. The independency of the impact factors is assumed in order to simplify the calculations.

The amount of the individual effect is also strongly dependent on the installation conditions. The results are valid for optimal mounting situation. The influence of the individual impact factors will get higher for not optimal mounting conditions. Losses due to temperature will increase when the PV modules are mounted closely besides each other or roof integrated in a PV system. The fraction of low irradiance and thus the losses will also increase for not optimal mounting direction or tilt angles. Also an average blue shift can be expected for not optimal mounting directions leading to higher impact of spectral effects.

The difference between measured MPR and calculated MPR_{calc} was calculated respecting also the deviation of the outdoor power value to the label value. The result is independent of cell technology if the sample is electrically stable. Even though second order effects are neglected, the deviation of estimated yield based on this approach compared to the measured yield was found to be within ±3% for most of the 60 PV modules tested. The conclusion is that higher deviations are primary due to non-stable performance and non-representative $P_{max,Outdoor}$ value. The results could be further improved by isolating and optimizing the characterization of each individual influencing factor.



	c-Si 1				CdTe 1				CIGS 4			
	Cologne	Ancona	Tempe	Chennai	Cologne	Ancona	Tempe	Chennai	Cologne	Ancona	Tempe	Chennai
ΔMPR_{TEMP}	-2.3%	-3.9%	-8.9%	-9.6%	-1.5%	-3.5%	-6.7%	-6.2%	-2.9%	-4.5%	-7.7%	-7.6%
ΔMPR_{LIRR}	-1.2%	-0.8%	-0.4%	-0.5%	0.0%	+0.2%	+0.3%	+0.6%	-1.7%	-3.2%	+0.2%	-2.9%
ΔMPR_{MMF}	+1.3%	+0.5%	-0.8%	+1.6%	+2.3%	+0.9%	+1.1%	+5.3%	+1.8%	+0.7%	-0.1%	+2.8%
ΔMPR_{AOI}	-3.5%	-2.4%	-2.0%	-2.9%	-3.5%	-2.4%	-2.0%	-2.9%	-3.5%	-2.4%	-2.0%	-2.9%
ΔMPR_{SOIL}	-0.5%	-0.5%	-3.7%	-2.1%	-0.5%	-0.5%	-3.7%	-2.1%	-0.5%	-0.5%	-3.7%	-2.1%
	-6.2%	-7.2%	-15.9%	-13.5%	-3.1%	-5.4%	-11.1%	-5.3%	-6.8%	-9.9%	-13.4%	-12.7%
MPR_{calc}	**93.9%**	**92.8%**	**84.1%**	**86.5%**	**96.9%**	**94.6%**	**88.9%**	**94.7%**	**93.2%**	**90.1%**	**86.6%**	**87.3%**

Figure 36: Linear performance loss analysis for 3 modules (c-Si, CdTe, CIGS), measured at 4 locations [10].

7.2 Comparison of Module Data from Different Climates

Any benchmarking or degradation rates are strongly dependent on the meteorological and local conditions. Measurements in different climates are, therefore, important to demonstrate and better understand technological differences.

The energy yield performance of PV modules has been intensively studied in the scope of the German funded PV-KLIMA project. Comparative energy yield measurements of 15 PV modules of different type have been studied at five test locations over a period of 3 years. Each PV module was connected to an electronic load and MPP data were recorded together with solar irradiance (global tilt, global horizontal, diffuse horizontal, direct normal), in-plane spectral irradiance (wavelength range 300 nm to 1600 nm), ambient temperature, relative humidity, wind speed and wind direction. The resulting database was used for conducting a comprehensive performance loss analysis of PV modules. Table 7 shows the range of climatic conditions at the test locations. The large variation of operating conditions causes a site-dependent energy yield ranking of PV modules.

Table 7: Locations for energy yield testing operated by TÜV Rheinland within project PV-KLIMA. The average weighted module temperature is given for a standard c-Si PV module of glass/backsheet construction.

Location	**Annual Solar radiation/ Inclination angle**	**Fraction of irradiance <200 W/m²**	**Average weighted Module Temperature (> 15 W/m²)**	**Average Photon-Energy (APE)**	**Annual precipitation**
Cologne (Germany)	1195 kWh/m² 35°	19 %	30 °C	1,68 eV	774 mm

Ancona (Italy)	1556 kWh/m² 35°	12 %	34°C	1,67 eV	757 mm
Chennai (South-East India)	1861 kWh/m² 15°	9 %	45°C	1,71 eV	1197 mm
Tempe (Arizona, USA)	2360 kWh/m² 33.5°	5 %	46°C	1,68 eV	219 mm
Thuwal (Saudi Arabia)	2342 kWh/m² 25°	4 %	45°C	1,70 eV	70 mm

Principle findings for various PV technologies tested in different climates

The energy yield performance of a PV module is described by its MPR value, which is typically calculated on a monthly basis to analyze variations due to seasonal effects and for the entire year. The annual MPR value is referenced for comparing the energy yield performance of different PV modules. Figure 37 shows the results of the energy yield study performed, which was performed in the PV-KLIMA project.

The diagram reveals significant differences between the module types with best and poorest performance, which is a combination of temperature, irradiance, spectral and AoI impacts:

- Ancona (mediterranean): 12%
- Cologne (moderate): 14%
- Tempe (arid): 21%
- Chennai (tropical): 23%

As shown in Figure 36 for all PV module types, the performance difference between the test locations is attributed mainly to the temperature impact. The spread of MPR values is increasing with higher average weighted module temperature and with higher P_{max} temperature coefficient. MPR spread ranges from 5% (CdTe1) to 14% (CIGS1).

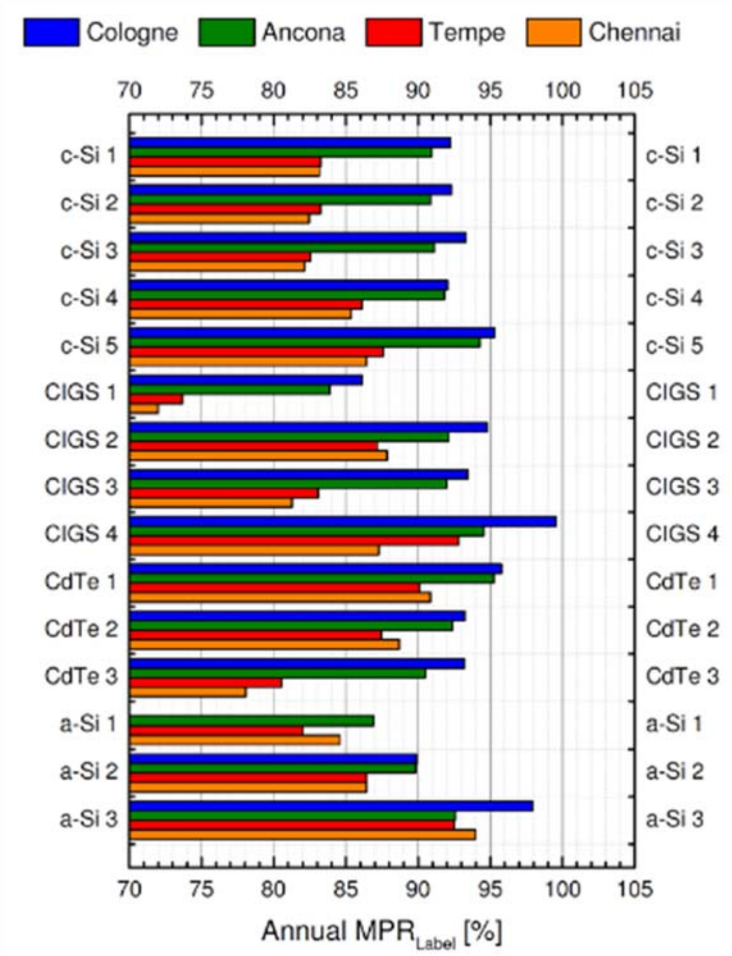


Figure 37: MPR values of different PV module types, measured at 4 locations, representing moderate, arid and tropical climate [10].

Performance figures for PV technologies tested in different climates

Another way of representing module data from different climates was presented in a former IEA Report [*107*,*108*]. The methodology requires the availability of *IV*-curves. The proposed approach is particularly useful when a large number of modules from different locations, measured during different time periods, must be compared. As all data are plotted into a single one-year plot, this approach is not applicable in case of non-reversible degradations or to investigate degradation rates.

The daily performance ratio of maximum power (PR(P_{max})) and short-circuit current (PR(I_{sc})) are used as key parameters in characterizing the performance of the modules. The basic idea behind the approach is the self-referencing approach based on the normalization of the PR(P_m) figures with PR(I_{sc}). In this way, the spread due to irradiance sensor calibration and spectral effects can be reduced, and irradiance and temperature dependencies can more easily be analyzed. Figure 38 and Figure 39 gives an example for crystalline silicon and amorphous silicon modules (a-Si, a-Si/µ-Si, a-Si/a-Si, a-Si/a-Si/a-Si) measured at 7 different locations (Norway, UK, Germany, USA, Switzerland, France and Cyprus). The normalized graphs show the typical irradiance and temperature dependencies for each technology.

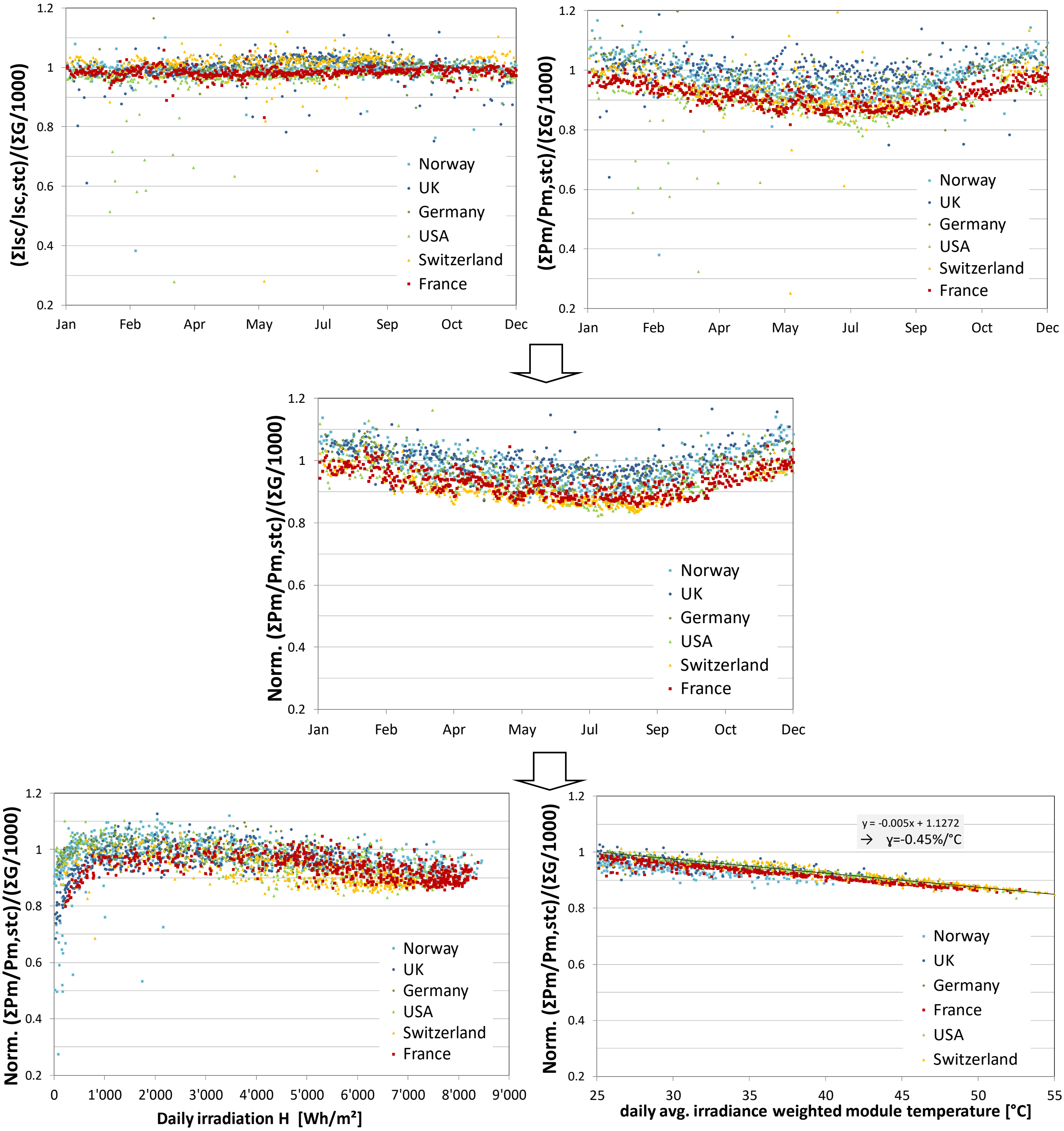


*Figure 38: Example of analysis approach with daily performance ratio PR(P_{max}) (top/right) and PR(I_{sc}) (top/left) of 6 different **c-Si modules** measured at different locations. Step 1: merge to normalized performance ratio norm. PR(P_m)and Step 2: plot in dependence of daily irradiation (bottom/left) and of average irradiance-weighted module temperature (bottom/right).*

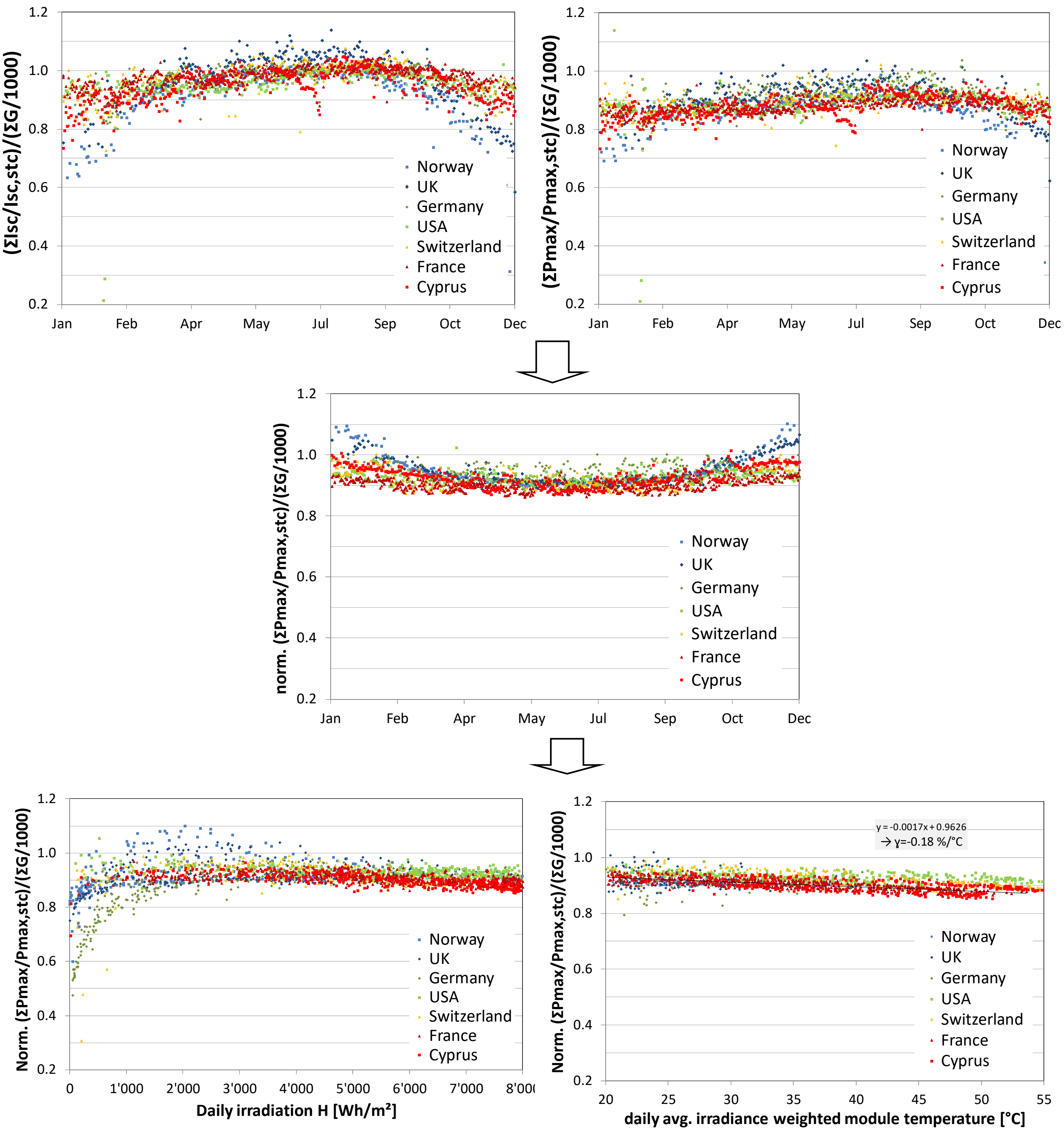


*Figure 39: Example of analysis approach with daily performance ratio PR(P_m) (top/right) and PR(I_{sc}) (top/left) of 7 different **a-Si-based silicon modules** measured at different locations. Step 1: merge to normalized performance ratio norm PR(P_m) and Step 2: plot in dependence of daily irradiation (bottom/left) and of average daylight module temperature (bottom/right).*

7.3 Module Performance Loss Rates (PLR)

7.3.1 Methodologies

This section offers an overview of the methodologies used to assess the Performance Loss Rate (PLR) of a PV module when either *IV*-curves or maximum power values are measured. Some of the methods described here were developed for PV systems [109,14,110,111,112,113] but they are fully applicable also to the module level. The topic of the assessment of PLR through indoor characterisation of PV modules at different stages of their life is not covered here.

Some technologies, especially thin-films, might show a pronounced loss of performance in the first months of operation due to stabilization processes within the PV material itself. This initial phase, characterized by a steep PLR, is followed by a more stable (long-term) performance loss behaviour. Figure 40 exemplarily compares the performance behavior of two different modules based on different PV technologies (polycrystalline-silicon and amorphous-silicon) during the first six years of operation. The initial value of performance is also displayed in order to highlight the initial loss of performance occurring in the a-Si module, which is not evident in the mc-Si module.

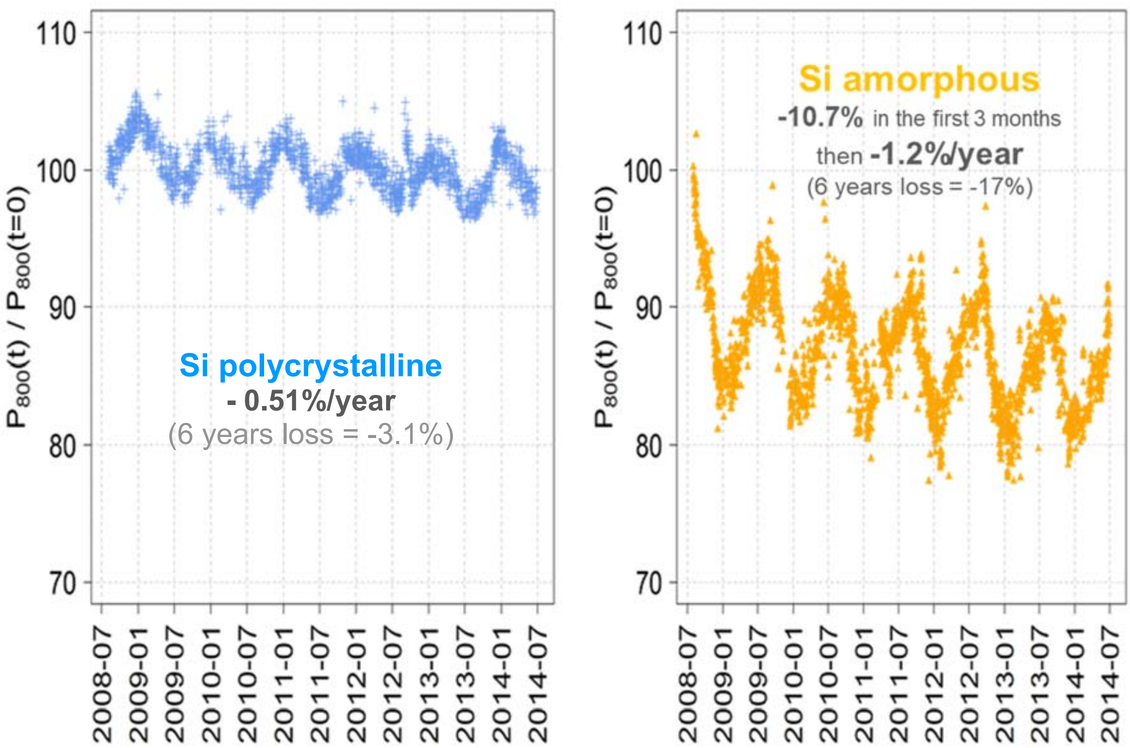


Figure 40: Performance behavior of one polycrystalline-silicon module (left) and one amorphous-silicon module (right) during the first 6 years of operation as measured by INES. Red dot: initial performance. Black dotted line: trend of the performance loss.

The methodologies presented in this section can be applied to extract both the initial and the long-term PLR.

The calculation of the PLR consists in extracting a trend from a time-series of performance indicators. In order to be effective, special care should be taken on the following issues:

- *Length of available data*: at least 3- to 5-year time-series (depending on the technology as well as on the adopted methodology) should be available to perform a reliable evaluation of PLR.

The accuracy of the several methodologies available for the calculation of PLR increases with the duration of available time-series, and the results obtained with different methodologies tend to converge to similar values [*109*,*14*].

- *Seasonality and outliers*: the accuracy of the several methodologies is strongly affected by the yearly oscillation of the performance of PV modules/systems, in a negative way. This is particularly true for crystalline-silicon products. For this reason, special care should possibly be taken in adopting appropriate filtering techniques to eliminate outliers and correction techniques to report performance values to a set of reference conditions (e.g. STC) and diminish seasonality (deterministic smoothing) [*110*,*111*,*114*]. As an alternative, statistical methods may be applied that are able to extract a trend independently from the extent of the seasonality (statistical smoothing) [*112*,*113*,*115*,*116*,*117*].

In general, the calculation of the PLR requires a performance metric, one or more filtering and correction techniques and a statistical method.

7.3.2 Performance metrics

The performance metric is an index that describes the performance of the PV module/system during a specified time range (day, week, month, year). The most common performance indexes used to calculate the PLR are: module/array Performance Ratio, module/array PVUSA, module/array DC-Power at MPP. Where possible, these indices are corrected to STC using measurements of irradiance, module temperature and sometimes spectrum.

Module/Array Performance Ratio

For PV systems, the Performance Ratio PR is defined as [*118*]:

$$PR = \frac{Yf}{Yr}$$

Where Y_f is the final yield, i.e. the generated AC-energy per kW of installed PV, and Y_r is the reference yield, i.e. the ratio of plane-of-array (POA) irradiance G_i and irradiance at STC conditions.

For the calculation of the PLR of a module the MPR as described already in chapter 6.1.1 can be used. The PR is there based on the generated DC-energy per kW of installed PV, expressed here as module/array yield Y_a rather than on Y_f.

$$MPR = \frac{Ya}{Yr}$$

The advantage of MPR method is the normalization to the irradiance. However, the strong temperature dependence reflects on the strong seasonality of the MPR metric.

Module/Array PVUSA

The PVUSA (Photovoltaics for Utility Scale Applications) metric was developed by NREL in the 1990s [*119*] as a methodology to evaluate the performance of PV modules/systems under Performance Test Conditions (PTC): normal irradiance of 1000 W/m^2, ambient temperature of 20 °C, wind speed of 1 m/s. The method performs a best-fit correlation between measured module/system power at MPP (P_{max}) and measured plane-of-array irradiance (G_i), wind speed (w) and ambient temperature (T_{amb}) according to the following parametrized equation:

$$Pmax = Gi(a + b \cdot Gi + c \cdot w + d \cdot Tamb)$$

The parameters *a*, *b*, *c*, *d* are then used to estimate the power at PTC conditions. This method involves a higher number of variables than module/array performance ratio method, but is expected to work better especially because it takes the temperature and wind cooling effects into account.

DC-Power at MPP

The DC-Power at MPP is the simplest parameter that can be used for the calculation of PLR. However, it is strongly affected by irradiance, temperature and spectral effects. For this reason, this parameter is always used coupled with filtering and correction techniques, as described in the next section.

7.3.3 Filtering and correction techniques

The adoption of techniques to eliminate outliers and attenuate the performance seasonality strongly influences the accuracy of the results, especially when no smoothing is performed on the time series of performance values (see next section). The most appropriate set of filters and corrections cannot be generalized, but depends on the specific case. For example, if the PV module/system and the irradiance sensor are far away from each other, values of performance corresponding to the situation where the two elements register different irradiance levels (especially where short-distance obstacles are present) should be discharged [*120*]. An appropriate way in doing so is to discharge instant values of PR exceeding the limits $\underline{PR} \pm n \cdot \sigma$, where $\underline{PR}$ is the average or mode of PR in a defined period, σ the standard deviation, while *n* is selected according to the desired higher or lower power of the filter. The previous condition can be applied provided that the values are reasonably distributed according to a Gaussian distribution. Another possible filter is related to the performance metric selected. For example, it is demonstrated that the PVUSA metric is more accurate when calculated under POA irradiance levels higher than 800 W/m^2 [*121*].

The most common correction applied to DC-Power measured at MPP concerns the irradiance and the temperature effects:

$$P_{corr} = P \cdot \frac{G_{STC}}{G} \cdot \frac{1}{1 + \gamma(T_c - T_{STC})}$$

where γ is the temperature coefficient in power (%/°C), while G_{STC} and T_{STC} are the irradiance and module temperature at STC conditions. The cell temperature, when not measured, can be calculated with one of the formulas available in literature [*122*]. An additional correction can be applied in order to account for the spectral effects [*109*], i.e. in order to report values of DC-power to conditions of solar irradiance spectrum as for the reference AM1.5 spectrum [*124*]. In fact, when spectral data are available (either measured or simulated as described in Section 3.2.4), spectral correction contributes to the decrease of uncertainty in the linear regression for the estimation of PLR, especially for crystalline-silicon based technologies, as shown in Figure 41. In this example the PLR is calculated with a linear regression on a 3-year series of DC-Power form 24 different PV systems installed in Bolzano (North-East Italy). The uncertainty of the linear regressions obtained by applying different sets of filtering and correction techniques is compared.

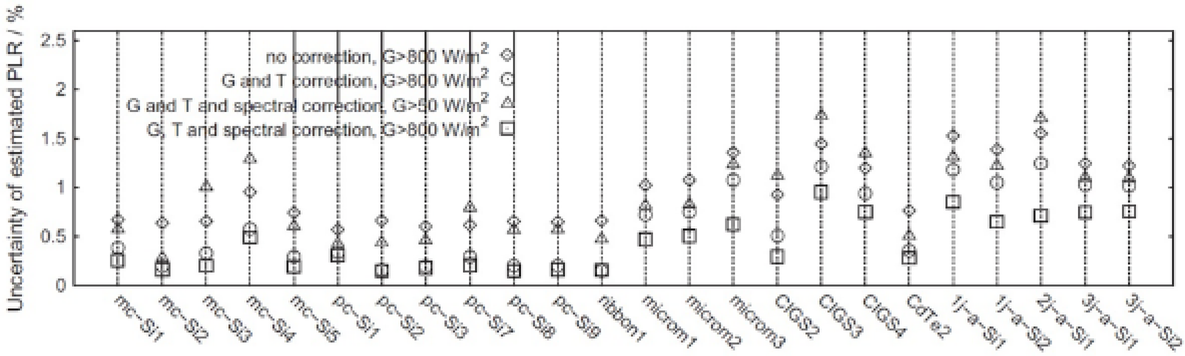


Figure 41: Regression uncertainty for the calculation of PLR using a linear regression of 3-years series of monthly DC-Power using different filtering and correction techniques.

When *IV*-curves are measured outdoors, they are corrected according to the standard IEC 60891 [*125*] in order to extract the main parameters (I_{sc}, V_{oc}, FF and P_{max}) at STC conditions. An example of *IV*-curve correction to STC conditions is shown in Figure 42. Figure 43 shows the time series of STC-corrected *IV*-curve parameters for one PV technology [*13*].

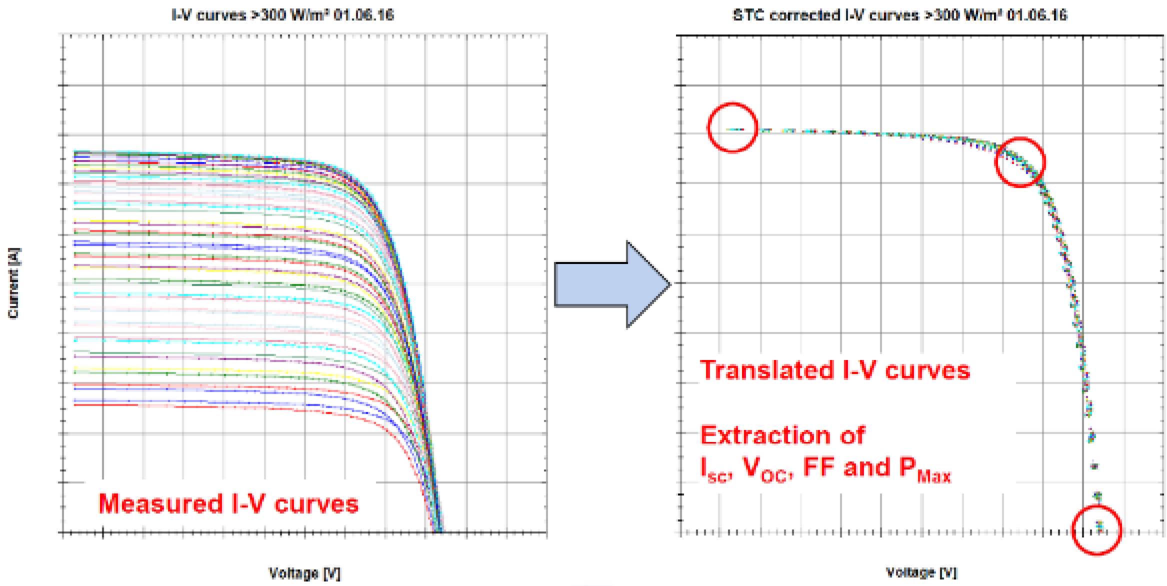


Figure 42: Correction of measured IV-curves to STC conditions, according to IEC 60981.

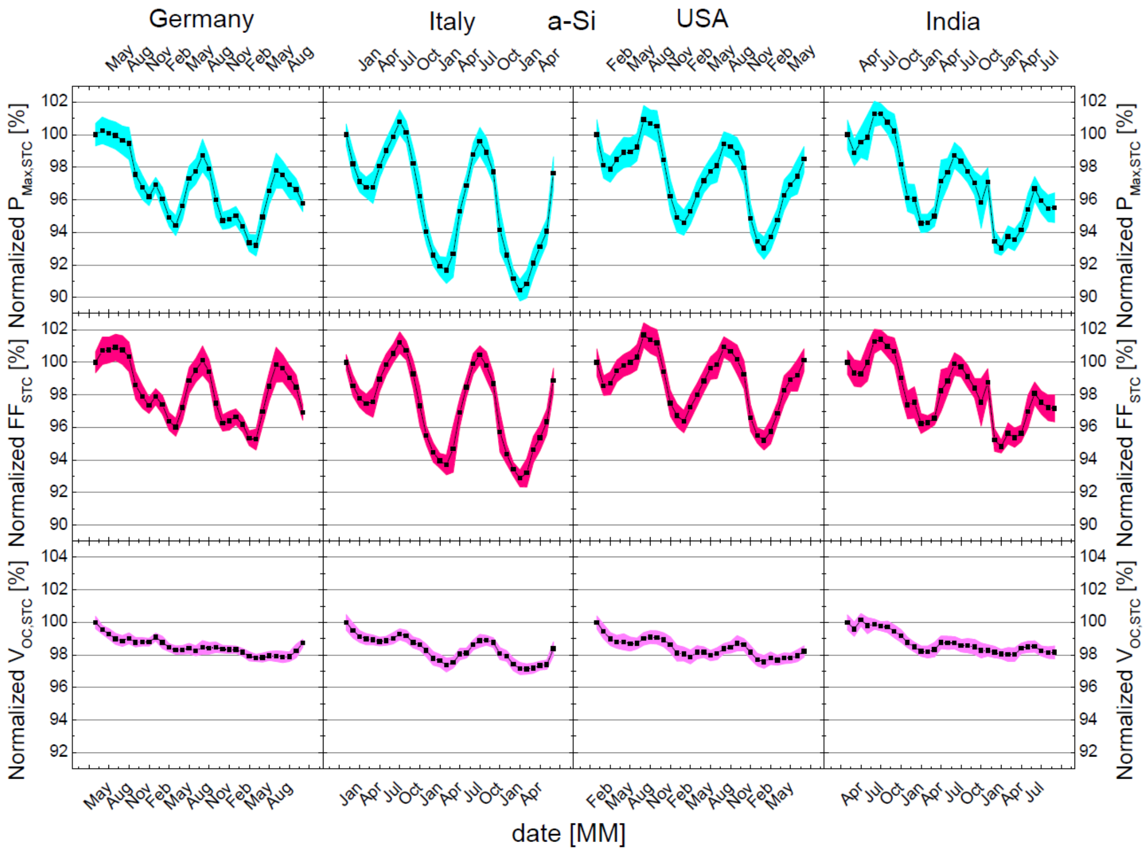


Figure 43: Time-series of some IV-curve parameters (P_{max}, FF, V_{oc}) corrected to STC condition according to IEC 60981. The displayed values refer one amorphous-silicon sample.

7.3.4 Statistical techniques

Once a time-series of performance index is available, one or more statistical techniques are needed to extract a trend and calculate the PLR. The following are proposed in literature and described in the following:

- Linear regression
- Simple- or dual-periodicity fit
- Classical time series decomposition (CSD)
- Seasonal trend decomposition using logical regression (LOESS)

Another statistical technique that is found in literature is the autoregressive integrated moving average (ARIMA) [*123*].

Linear regression

Linear regression is the simplest method to fit the time series of monthly values of performance metric. In general, this technique can be applied to the whole series of data but in some cases, where the initial performance loss (lasting until up to around six months of operation) is evident, two different linear regressions can be applied for the initial and the following period. Linear regression can be expressed as:

$$X = a \cdot t + b$$

Where *X* is the generic performance metric, *t* the progressive number of time-span (day, month etc.), while *a* and *b* are the regression coefficients. PLR is therefore calculated as:

$$PLR = \frac{12 \cdot a}{b}$$

The latter is also referred to as *relative PLR*. In the literature, another definition is used where the PLR is calculated as *12*a*, thus corresponding to an *absolute PLR*. Special care should therefore be taken in which of the two definitions is used, since in some cases, the formula defining PLR is not reported and misunderstanding might rise.

Figure 44 shows the linear regression applied to a crystalline-silicon and a thin film system and to three different performance metrics: PR, PVUSA and DC-Power corrected for irradiance, temperature and spectral effects [*109*].

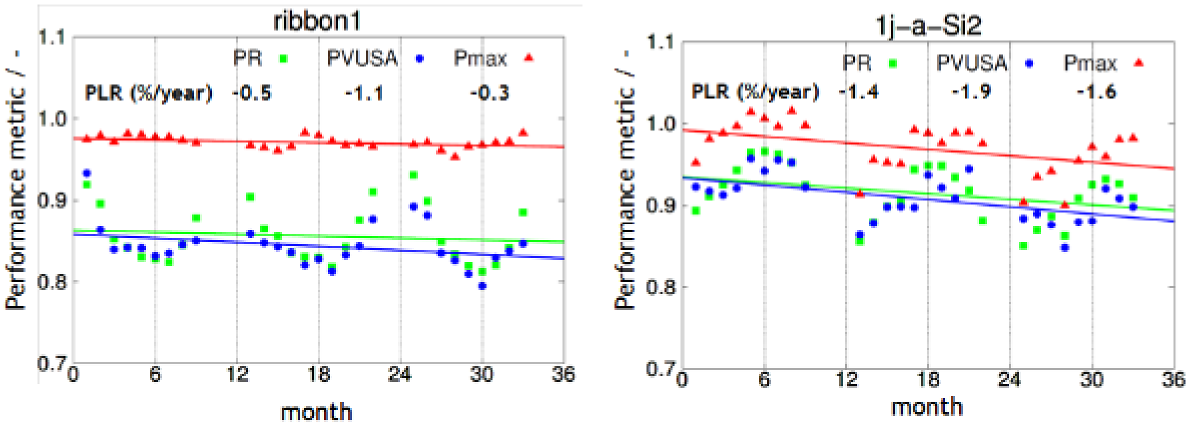


Figure 44: Linear regression of a 3-year time series of monthly PR, PVUSA and DC-Power corrected for irradiance, temperature and spectral effects to STC.

Simple- or dual-periodicity fit

In order to better fit the time-series of performance metrics the simple- or dual- periodicity fit can be applied, especially when the seasonality is evident and it is not possible to obtain a satisfactory correction of them. The time-series is fitted to seasonal functions that include a linear long term trend defined as:

Simple periodicity fit: $X = A_0 \sin\left(2\pi\frac{t}{T} - \tau\right) + at + b$

Dual periodicity fit: $X = A_0 \sin\left(2\pi\frac{t}{T} - \tau_1\right) + A_1 \sin\left(2\pi\frac{t}{2T} - \tau_1\right) + at + b$

where *X* is the generic performance metric, A_0 and A_1 the amplitude of the seasonal oscillations, *t* the time variable (days, or month), *T* the respective periodicity (12 for monthly values and 365.25 for daily values), τ the time offset of the seasonal behavior, *a* the long-term linear trend and *b* is the offset of the data. The coefficients *a* and *b* are then combined in the equation for the calculation of the PLR. The simple or double periodicity differ not only in the complexity, but also in the fact that the dual periodicity fit better captures differences between autumn and spring behaviors. A possible extension of this idea is a Fourier-like expansion with a linear decline.Figure45 (a) and Figure 45 (b) an example of application of both methods on a 66-months time series of monthly values of Performance Ratio for a 4 kWp system in Bolzano.

Classical time series decomposition (CSD)

For a classical time series decomposition, the trend is computed using a symmetrical moving average over 12 month:

$$X_{mov}(t) = \frac{1}{2}\left(\frac{1}{12}\sum_{t-6}^{t+5} X(t) + \frac{1}{12}\sum_{t-5}^{t+6} X(t)\right)$$

where *X* is the generic performance metric and *t* the time variable (days, or month).

This way, the reduction of seasonality is obtained as a mathematical smoothing rather than correcting the values of performance metrics. As before, a linear regression is then applied to the smoothed time series to compute the value of PLR. As the moving average starts only 6 months into the data there is no information on the trend of the remainder in the first and the last six months. Figure 45 (c) shows an example of application of both methods on a 66-months' time series of monthly values of Performance Ratio for a 4 kWp system in Bolzano.

Seasonal trend decomposition using logical regression (LOESS)

This technique described in [126] combines the seasonal trend decomposition and the LOESS method for estimating nonlinear relationships. It can be considered similar to the previous method, with the additional feature that here various internal regression loops are used to find a trend component also for the first and last months in the time series (those missing when using CSD). On the other hand, its complexity is higher than before. As for the previous methods, a linear regression is then applied to the smoothed time series to compute the value of PLR. Figure 45 (d) shows an example of application of this method on a 66-months time series of monthly values of Performance Ratio for a 4 kWp system in Bolzano.

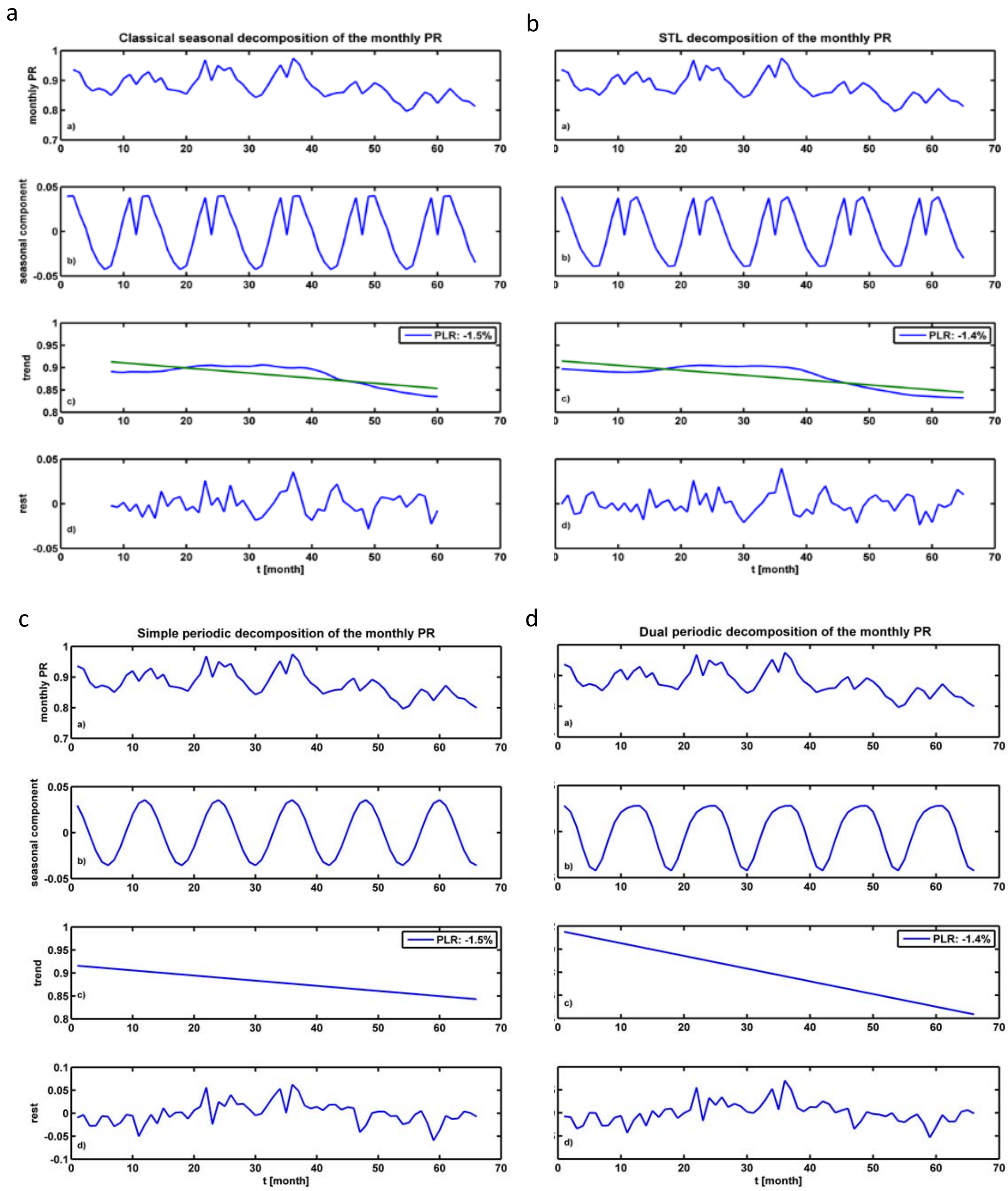


Figure 45: Examples of different statistical techniques applied of 66 monthly values of Performance Ratio for a PV system in Bolzano. (a) Simple periodicity fit, (b) dual-periodicity filt, (c) Classical time series decomposition, (d) Seasonal trend decomposition using logical regression. For each figure, from top: original time-series of monthly PR, seasonal component, long-term trend, remainder.

8 Measurement Uncertainty Analysis

The survey highlighted that there is a lack of harmonization and availability of uncertainty estimates for outdoor module performance or yield testing. Only 7 out of 15 laboratories declare an uncertainty budget. Six labs estimate the uncertainty of the instantaneous power measurement P_{max} and five of those six labs also report uncertainties for the aggregate values of E, H and MPR. Except for one, all of the other labs base their calculations on the GUM standard [*136*]. Only 2 labs published their approach [31,16]. The declared uncertainties vary from 1-2% for energy (E), from 1.5-4.1% for the incoming irradiation and from 4-6% for the MPR.

Chapter 8 gives some general rules which can be applied for the calculation of the measurement uncertainty and lists the single contributions for P_{stc}, H, E and the typically derived performance indicators Y_a, MPR. A description of how to determine the uncertainty in PLR of PV systems is given in the work of Belluardo and is summarized in the IEA Report [27]. The approach can be applied in the same way for the calculation of the PLR of PV modules.

8.1 Introduction

As already described in chapter 7.1.1, the energy output E is the measured power integrated over time. The two typically derived performance indicators are the specific module yield Y_a, and the module performance ratio MPR.

$$Ya = \frac{E}{P_{stc}}$$

$$MPR = \frac{E/P_{stc}}{Hi/1000}$$

These parameters depend on the measurement of the STC power P_{stc} and the solar irradiation H_i, which is the measured incident irradiance G_i integrated over time.

In contrast to P_{stc}, the values for E, Y_a and MPR are not unique since the reference conditions for the module energy are not uniquely specified. These values require that the module and incident energy be monitored and that the uncertainties associated with measuring those parameters be evaluated. The instantaneous power production of the test module changes depending upon the ambient temperature, the wind conditions, the spectrum of the irradiance, the percentage of diffuse irradiance, the angle of incidence, and the total irradiance. These operating conditions, which vary on daily and seasonal cycles, can be tracked and reported but cannot be normalized to a specific set of reference conditions.

The uncertainty analysis for the key performance indicators E, Y_a and MPR assumes that the quality control and maintenance practices discussed in chapter 5 are followed. Otherwise, additional uncertainties should be included. The analysis typically neglects any meta-stability and assumes the samples are in a stabilized state. If this is not the case, minor to significant variations in the specific energy yield and module performance ratio are possible because of light induced degradation and thermal annealing in amorphous silicon [*98*], due to the initial light induced degradation in crystalline Si [*137*] and due to other meta-stabilities in CdTe or CIGS [*138*,*139*]. It is also assumed that all sites mount the modules exactly the same way, especially with respect to the distance above the ground, so that thermal and albedo differences are minimized as per the guidance in section 4.1. For well-designed test sites, the modules should not be shaded except near sunrise and sunset. The measured irradiance is assumed to be the average irradiance on the test area even though albedo and shading can make the irradiance non-uniform. The current versus voltage and maximum power measurements should be conducted in accordance with the guidance provided in section 4.2. Furthermore, parameters such as dust accumulation and degradation also affect the energy yield. The effect of these operating parameters on Y_a and MPR has to be considered in the analysis.

8.2 Methodologies for Uncertainty Analysis

The ISO guide covering the expression of uncertainty in measurements [*136*] is a set of internationally accepted documents that standardizes uncertainty analysis for all measurement process and is required to be followed by all ISO 17025 accredited test labs. Following the ISO Guide, the expanded uncertainty U in the parameter X can be expressed as:

$$U_X = k \sqrt{\sum \left(\frac{s_i u_i}{k_i}\right)^2}$$

where k is the coverage factor. Typically, a k equal to 2 is used because it defines an uncertainty interval having approximately a 95% level of confidence. The expanded uncertainty is a combination of Type A and Type B uncertainties. Type A uncertainties are evaluated using statistical methods (e.g, a standard deviation of independent measurements). Some uncertainty components like the spectral mismatch factor can be evaluated using Monte Carlo methods as described in the GUM. Type B uncertainties cover all other error sources and may include manufacturer specifications, calibration results, and experimental or judgment information. The GUM supplement JCGM 101:2008 "Evaluation of measurement data - Supplement 1 to the "Guide to the expression of uncertainty in measurement - Propagation of distributions using a Monte Carlo method" describes how to use Monte-Carlo techniques.

Referring again to the above equation, the standard uncertainty component u_i of parameter X has a coverage factor k_i. The distribution of the uncertainty component is typically Gaussian if derived using statistical methods, such as a standard deviation, or if provided by a calibration lab that uses a coverage factor of 2. Uncertainties can also have a rectangular distribution where the probability is the same for the entire uncertainty interval. For rectangular distributions, k_i equal to $\sqrt{3}$ is used. To simplify the evaluation process, the uncertainties will all be expressed as a percentage. This approach results in the sensitivity s_i being unity and so saves the researcher from having to take the partial derivative of the parameter of interest with respect to all of the other parameters to obtain s_i. Uncertainty components that cannot be expressed as a product such as those relating to temperature or spectral corrections are treated separately and their component is combined with other uncertainty components in the equation above.

8.3 Single Uncertainty Contributions

8.3.1 Uncertainty in STC power U_{Pstc}

The procedure for calculating the uncertainty in the maximum power output at standard test conditions P_{stc} has been established through multiple international inter-comparisons among calibration labs with corresponding ISO compliant uncertainty analysis [*140*,*141*]. This uncertainty is very important because it is used in determining the uncertainty of the specific energy yield Y_a, and the module performance ratio MPR. Together with the uncertainty of the irradiance measurement it is actually the largest contributor.

The uncertainty in P_{stc} can be determined by a calibration of the module from a calibration lab. In this case U_{Pstc} is the 95% confidence limit uncertainty value quoted by the calibration lab which typically is ±1.3 to ±3%. If U_{Pstc} is obtained from the data sheet of a module that has passed the IEC module qualification test then ±5% is a more typical uncertainty.

If U_{Pstc} is evaluated by the researcher then the uncertainties of the various components including the reference cell uncertainty, IV system measurement uncertainty, spatial non-uniformity, spectral error, temperature error, contacting error, meta-stability error should be included [*146*,*147*,*148*,*149*,*99*,*150*,*151*,*152*,*16*,*26*]. There can be differences in P_{stc} when measured indoors under a solar simulator versus outdoors under natural sunlight. The natural sunlight can be under prevailing conditions or carefully controlled conditions like the procedures followed at NREL, ASU, Sandia and ESTI where the irradiance, temperature and spectral conditions are restricted to be near standard test conditions [*150*,*151*,*153*] .

8.3.2 Uncertainty in irradiance U_G and irradiation U_H

The uncertainty U_G in the irradiance G measured with an irradiance sensor includes error sources related to the incident angle, direct to diffuse ratio, air temperature, ground reflections, and other factors discussed in detail in [27]. The uncertainty in the broadband irradiance measured with reference cells or pyranometers has also been discussed in section 4.3.1 and evaluated by numerous groups [*154*,*155*,*156*,*157*, *158*,*159*]. The ASTM standard "Standard Guide for Evaluating Uncertainty in Calibration and Field Measurements of Broadband Irradiance with Pyranometers and Pyrheliometers" [*160*], gives guidance on applying the ISO GUM to state of the art pyranometer calibrations. Examples are given for grouping the data into morning and afternoon and then into 2 degree wide bins as a function of zenith angle. This binning allows correcting the observation of any leveling error or other time of day dependence, in addition providing data for evaluating a time of day dependent uncertainty. The uncertainty in the measurement of G_i using a single sensor depends strongly on the calibration procedure of the detector. For example, an uncertainty with a 95% confidence can exceed 8% when a single sensor is calibrated indoors using a thermal detector without spectral corrections [*161*,*162*,*163*]. Outdoor calibration uncertainties can be as low as 1% for an encapsulated silicon detector with temperature corrections [*164*] or more typically in the 3% range for a state-of-the-art pyranometer [*155*,*154*].

Based on this the 95% confidence interval uncertainty in irradiation H can be calculated as follow:

$$U_H = 2\sqrt{\left(\frac{U_G}{2}\right)^2}$$

8.3.3 Uncertainty in power U_{Pmax}

There have been numerous documents estimating the uncertainty in the measured power U_{Pmax} under natural sunlight [*146*,*149*,*99*,*148*,*151*]. A typical uncertainty estimate for modules is given by [*16*]. If the PV energy is not corrected for irradiance, temperature, spectral or incident angle sources of variation, the uncertainty in E is dominated by the uncertainty in the equipment used to measure the PV module power (U_{mpp}). These uncertainties include maximum power point tracking errors, capacitive effects, resistance losses in the case of 2-wire connection of PV modules, not-optimal measurement ranges and other hardware associated errors discussed earlier.

The 95% confidence interval uncertainty in P_{max} can be calculated as follow:

$$U_{Pmax} = 2\sqrt{\left(\frac{U_{mpp}}{2}\right)^2}$$

8.3.4 Uncertainty in key performance indicators U_E, U_{Ya} and U_{MPR}

The determination of the uncertainty of the key performance indicators requires consideration of the full test facility. Non-uniformity effects and alignment errors have to be taken into account.

The first difficulty lies in the determination of the average irradiance in the mounting rack area, which can be affected by the albedo and near shading. The module current is reduced for non-uniform light compared to uniform light of the same irradiance [*142*]. This adjustment can be captured in the uncertainty analysis at the module by including an error component to the measured PV energy [*143*,*144*,*145*]. Also the thermal non-uniformities due to variable ventilation and thermal convection effects have to be considered. By following the recommendations in chapter 4 most of the errors due to non-uniformities (U_U) can be limited to the uncertainties listed in *Table 8*.

The misalignment of the irradiance sensor with the test plane as well as the misalignment of the modules in between each other is taken into account in the uncertainty (U_A).

The determination of the time intervals between the data points and the points to include or reject can have also a significant impact on the accuracy of the integrated KPI [*165*,*166*,*167*]. Assuming that the recommendations of chapter 7.1.1 for the data recording interval and data availability are followed, the error relating to the integration of the power over time can be considered to be negligible and the uncertainty in energy is equal to the one in power. If this is not the case an additional error source related to the integration time has to be added. Moreover, if the maximum power and solar irradiance are not measured at the same time then the uncertainty due to the light fluctuations and the synchronisation of the data adds to the uncertainty of MPR U_{MPR}. These two time related uncertainties (U_T) should, however, be minimized.

Considering all listed contributions the 95% confidence interval uncertainty in E, Y_a and MPR can be calculated as follow:

$$U_E = 2\sqrt{\left(\frac{U_{Pmax}}{2}\right)^2 + \left(\frac{U_T}{2}\right)^2 + \left(\frac{U_A}{2}\right)^2 + \left(\frac{U_U}{2}\right)^2}$$

$$U_{Y_a} = 2\sqrt{\left(\frac{U_E}{2}\right)^2 + \left(\frac{U_{P_{stc}}}{2}\right)^2 + \left(\frac{U_T}{2}\right)^2 + \left(\frac{U_A}{2}\right)^2 + \left(\frac{U_U}{2}\right)^2}$$

$$U_{MPR} = 2\sqrt{\left(\frac{U_{P_{stc}}}{2}\right)^2 + \left(\frac{U_E}{2}\right)^2 + \left(\frac{U_H}{2}\right)^2 + \left(\frac{U_T}{2}\right)^2 + \left(\frac{U_A}{2}\right)^2 + \left(\frac{U_U}{2}\right)^2}$$

Table 8 summarizes the dominant error sources for the single uncertainties with typical values.

As already discussed, the calculated uncertainties are also a function of the time period under consideration. The integrated quantities for a specific year, month, day or hour will have different uncertainties. The time period should therefore always be stated along with the uncertainty number.

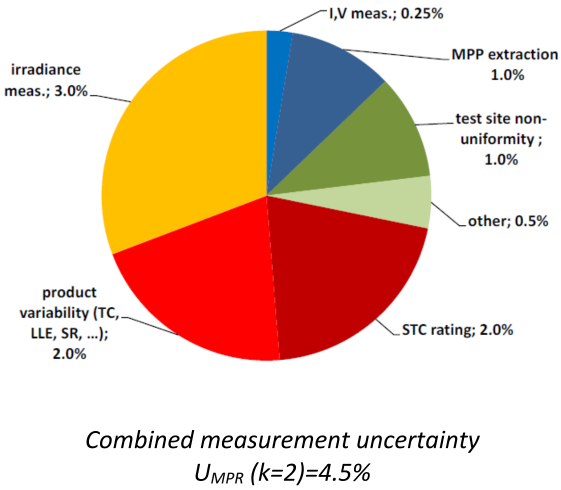
Table 8: Dominant error sources in U_{Pstc}, U_G, U_H, U_{Pmax}, U_E, U_{Ya}, U_{MPR}. Legend: U_{PP} maximum power point errors, U_T error due to time, U_A error due to alignment, U_u error due to uniformity.

Error Source	**Value**	***k***	**Comment**
STC Power: U_{Pstc}			
module calibration	1.3-3%	2	accredited laboratory accuracy
	> 3%	2	STC correction of outdoor data
data sheet value (in alternative to module calibration)	> 3%	2	manufacturer tolerance (incl. meas. uncertainty)
Irradiance/irradiation: U_G, U_H			
sensor calibration	1.0 – 5%	2	matched reference cell with T corrections
	2-8%	2	typical pyranometer calibration
calibration drift (%/year)	0.5 – 1%	2	soiling effects, sensor change
Module performance: U_{Pmax}, U_E, U_{Ya}, U_{MPR}			
Power, U_{mpp}			
current/voltage measurement	0.05 - 0.1%	2	data acquisition error
	1%	2	error due to non-optimal measurement range selection
maximum power	0.1 – 1.5%	2	error in maximum power point tracking, Equipment temperature error
over expected T range (-10 to 30 °C)	0.0 – 1.0%	2	calibrate at 22 °C but use over much wider range.
resistance losses	0-50%	2	2-*vs.*4-wire measurement
capacitive effects	0-50%	2	module technology and sweep speed dependent
Time, U_T			
synchronization	0-1%	2	simultaneous or separate measurement of power and solar irradiance. Stable or variable sky conditions
Alignment, U_A			
module/sensors and module/module	0 - 5%	2	depends on average angle of incidence. 0.5 degree alignment error on a 60° incidence angle is 1.5%
Uniformity, U_U			
irradiance	1%	2	single module, large area, albedo, …
temperature	1-4°C	2	single module, large area, wind , mounting, …

8.4 Relative Uncertainties

The difference in *MPR* or Y_a of two modules when measured side by side under the same irradiance conditions are known as ΔMPR or respectively ΔY_a and are used for module benchmarking. In the case of relative measurements many of the uncertainties listed in *Table 8* can be ignored. In particular, the highest contribution due to the irradiance measurement can be fully neglected. The modules of a test facility are measured with the same hardware and the STC power is usually determined by the same laboratory so that some typical offset errors like for example the one due to the reference cell calibration used to set the irradiance of the solar simulator, can be set to zero. This drastically reduces the combined uncertainty.

Figure 46 shows an example of how the uncertainties are changing form MPR to ΔMPR. The before negligible test site-non uniformity is getting dominant in respect to the other measurement uncertainties.



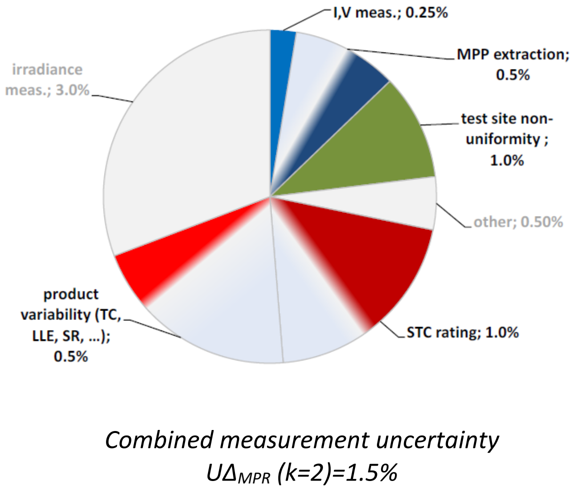


Figure 46: Single contributions in the combined measurement uncertainty of MPR and ΔMPR.

9 Summary and Conclusions

The survey performed within the PVPS Task 13 consortium highlighted that the measurement accuracy and scientific detail of the test infrastructures are generally very high, as demonstrated by a recurrent use of:

- High precision equipment (e.g. IV curve based monitoring, high precision maximum power point trackers, secondary standard pyranometers, spectrum radiometers, etc.)
- Good measurement practice (avoidance of major measurement artifacts such as capacitive effects, use of adequate sampling rates, etc.)
- Good quality control and maintenance practice (e.g. use of quality markers, e-mail alerts, regular calibration, etc.).

Despite of this, the survey revealed also some limits, which are mainly the comparability of different outdoor data and the use of these for the validation of models due to a limited harmonization of how data are reported. The survey also shows that an estimation of the final measurement uncertainty is often rough or even missing.

The main criticalities have been identified as a lack in:

- Common approach for the determination of the combined uncertainty for the three main performance indicators E, Ya, and MPR.
- Availability of a reference list containing all possible contributing uncertainties to be taken into account in any uncertainty calculation (e.g. MPP tracking accuracy, thermal non-uniformity, albedo, difference between back of module and cell temperature, etc.).
- Harmonization in the reporting of benchmarking results (missing information on description of testing procedure, module sampling procedures, uncertainty of reference STC power, etc.).
- Inter-laboratory measurement campaigns.

The main reason for these shortcomings is given by the fact that the reproducibility of outdoor test conditions is almost impossible by nature. The determination of the measurement uncertainty of outdoor measurements is therefore much more complex than for measurements at STC. The uncertainty is actually site and time dependent and is influenced by many factors, which are difficult to estimate and sparely described in literature.

Due to the pressure of having more accurate STC performance data available, in the past, a significant effort was put on international level to increase the comparability of the STC measurements, leading today to a comparability within accredited test laboratories of below ±1%. This was mainly achieved by:

- Sharing of know-how on single uncertainty contributions.
- Harmonizing the uncertainty calculations.
- Performing blind round robins to assess a major confidence in the declared uncertainties.

To likewise improve the comparability of energy yield measurements, the first step is to agree on the main uncertainty contributions and to suggest a common approach for the reporting of measurement uncertainties. The second step is to circulate reference modules within test laboratories to assess progress. Viable solutions would have to be identified to achieve reliable results in acceptable time frames.

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Annex 1: Empty Questionnaire

Questionnaire on Module Energy Yield measurements in different climates

INTRODUCTION

PV modules are currently priced according to their power output measured under standard test conditions (STC). The end-user, however, is more interested in the energy produced by a PV module and its lifetime under real operating conditions, as this directly influences the time for return on investment. A change in PV metrics from a power rating system towards an energy based rating will in future further enhance the competitiveness of different PV technologies, supporting the development of new innovative and cost effective technologies. A new energy rating standard for PV modules, which should partially overcome this problem is currently under preparation at IEC level [IEC 61853], but it requires still some effort to be finalized and validated before it can be adopted by industry and it misses the consideration of module lifetime.

Energy yield measurements of PV modules at different climatic locations plays an important role in the validation of the IEC 61853 energy rating standard, and in the demonstration and deeper understanding of module performance and lifetime. Reliable and accurate long term measurements under real operating conditions are not only crucial for the validation of different energy prediction models, but also for the definition of new accelerate aging procedures which should allow to extend the climate specific energy rating to a lifelong energy rating with a lifetime prediction.

To achieve this goals, high quality data are urgently needed, but there is currently no standard available on how these measurements should be performed. A high uncertainty in module rankings, energy-yield and lifetime predictions, based on inaccurate measurements or insufficient validation studies, leads to a higher financial risk. Not clearly stated uncertainties can lead to misleading risk assumptions which can damage the PV market.

SCOPE

The aim of this questionnaire is to collect detailed information about how module energy yield measurements are performed today all over the world and how the uncertainties are calculated and reported to the end-user. Based on this inputs the questions will be raised about what is needed to improve the comparability of data measured under different climates and how measurements and facilities could be harmonized.

The outputs of the survey will be a:

- **Public report** on 'Long-term Photovoltaic Module Outdoor Energy Yield Measurements - existing approaches and equipment'

The data collected in this survey will be treated confidentially and published only in anonymous way and after approval of the concerned partners!

INSTRUCTIONS

Please fill in the form by considering that,

- if you are running more test facilities consider only the best/most representative case or fill in two or more surveys
- multiple choice is allowed
- if you can’t answer with a unique number specify a typical value and/or a range
- where appropriate use NA (information not available) or ND (information not defined)
- add comments where you think it is useful
- add any documents/pictures you think can be useful for a better understanding
- add the most important references (own but also from third parties)

GENERAL INFORMATION

Company/Institute:

Contact person: **Email:**

1. BACKGROUND INFORMATION

1.1 What is the scope of your outdoor measurements?	☐ module energy yield benchmarking (kWh/kW inter-comparison)
	☐ module degradation studies
	☐ validation of energy prediction models
	☐ optimization of module prototypes
	☐ power rating accord. IEC61853-1 (8.4 procedure in sunlight without tracker)
	☐ other, list other scopes ______
1.2 What is the focus of your tests?	☐ research oriented
	☐ consumer/investor oriented (publication of manufacturer names)
	☐ industry oriented (proprietary data)
1.3 How many years of experience do you have with outdoor testing and how many different module types did you tested ?	
1.4 What is the typical duration of your tests?	☐ short term (<6 months)
	☐ medium term (6-24 months)
	☐ long term (>2 year)
1.5 Do you test modules in different climates?	☐ no
	☐ yes, specify type of climates according Köppen climate classification https://en.wikipedia.org/wiki/K%C3%B6ppen_climate_classification
1.6 Is your laboratory ISO 17025 accredited?	☐ no
	☐ yes, for STC power measurements
	☐ yes, for power measurements accord. IEC61853 part1
	☐ yes, for module qualification accord. IEC61215/61646
	☐ yes, for energy yield measurements [1]

[1] *by crossing **YES** you mean that the test is within the scopes of your accreditation and that it is audited. A written procedure inclusive of measurement uncertainty and a validation is available.*

2. TEST SAMPLES (SAMPLING/CHARACTERIZATION)

2.1 What is the minimum/typical number of modules you test per type?	
2.2 Do you follow a sampling procedure? [2] *(e.g. based on visual inspection, flasher lists, electrical performance, random sampling, ….)*	☐ no ☐ yes, _____________
2.3 Do you have a reference module stored in the dark?	☐ no ☐ yes
2.4 Do you typically have spare modules?	☐ no ☐ yes
2.5 Do you characterize the modules before installation in the field? (e.g. Pm@STC, IEC61853, EL, …)	☐ no (comment on this) ☐ yes, specify tests
2.6 Do you perform any stabilization before the characterization or installation in the field?	☐ no (comment on this) ☐ yes, specify stabilization procedure
2.7 Do you perform intermediate measurements? *(e.g control of the STC power, IR, EL, etc.)*	☐ no ☐ yes, specify tests
2.8 Do you perform final measurements? *(e.g control of the STC power, IR, EL, etc.)*	☐ no ☐ yes, specify tests
2.9 Do you perform any stabilization before the inter-mediate or final measurements?	☐ no (comment on this) ☐ yes, specify

[2] *Describe it in detail how you do it. Sampling procedures are important to:*

- *exclude outliers or malfunctioning modules*
- *test a module which is representative (consideration of production tolerance)*
- *define the number of modules and the criteria according which they are selected*

Other comments:

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3. DESCRIPTION OF TEST EQUIPMENT (MODULE I/V MEASUREMENT)

Equipment: *manufacturer/name*		
Methodology:	☐ only MPPT (e.g. power optimizer)	
	☐ only I-V	
	☐ MPPT with I-V	
Load:	active load	☐ MPP
	passive load	☐ fixed load (resistor)
		☐ Voc
		☐ other ______
I-V tracer specifications and data processing [3]:	quadrants	☐1 ☐2 ☐3 ☐4
	synchronized I/V data	☐ yes ☐ no
	I auto-range	☐ yes ☐ no
	V auto-range	☐ yes ☐ no
	accuracy full scale V meas.	
	accuracy full scale I meas.	
	typical I-V sweep time	
	Sweep time for capacitive modules?	☐ no distinction is made. The same sweep time is used for all modules
		☐ the sweep time is optimized to avoid capacitive effects.
	default I-V sweep direction	☐ Isc→Voc ☐ Voc→Isc ☐ Isc↔Voc
	I-V points	
	default sampling frequency interval between 2 I-V curves	
	type of extrapolation of I-V parameters (linear fit, polynomial fit, …)	Isc
		Voc
		Pmax
	When you are testing more modules in parallel, are the data synchronized?	☐ yes (individual sync. I-V tracers)
		☐ no (individual not sync. I-V tracers) max delay ________
		☐ no (multiplexing), max delay ________

[3] *ignore if selected methodology 'only MPPT'*

MPP tracker specifications and data processing [4]:	MPP tracking algorithm		
	static tracking efficiency		
	dynamic tracking efficiency		
	I auto-range	☐ yes ☐ no	
	V auto-range	☐ yes ☐ no	
	accuracy V measurement		
	accuracy I measurement		
	typical stored Im, Vm values	☐ instantaneous values	rate: _________
		☐ average of ________	rate: _________
	synchronization module data	☐ yes	
		☐ no, max delay module data ________	
Synchronization of irradiance measurement:	synchronization with I-V tracer data [3]	☐ simultaneous I, V, G measurement	
		☐ single meas. before or after I-V curve max delay _________	
		☐ single meas. before and after I-V curve max delay _________	
		☐ other, specify ______________	
	synchronization with MPPT data [4]	☐ yes ☐ no, max delay __________	
kWh integration:	calculated from I-V data	☐ yes ☐ no	
	calculated from MPPT data	☐ yes ☐ no	
	energy counter	☐ yes, accuracy _____________ ☐ no	
Calibration procedure:	default interval		
	calibration by	☐ ISO17025 accred. laboratory	
		☐ other, specify:	
Hardware operating conditions: *Conditions in which the accuracy of test equipment is guaranteed*	temperature interval		
	type of control and climatization for hot or humid climates		

[4] *ignore if selected methodology 'only I-V'*

Other comments:

___

___

___

4. DESCRIPTION OF IN-PLANE/TILTED IRRADIANCE SENSORS

	Description (manufacturer, sensor model, optional heating/ventilation unit, diffuse ring etc.)	Sampling rate	Accuracy [k=2]	n°
Pyranometers: *minimum number of sensors for each test facility*				
Reference cells: **Specify type of cell**				
Reference irradiance used for the calculation of PR:				
calibration procedure: **(interval, traceability chain, etc.)**				

Other comments:

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5. DESCRIPTION OF MODULE TEMPERATURE SENSORS

	Description
Sensor type:	☐ PT100/PT1000 ☐ RTD ☐ other ____________
Number/module:	
Positioning:	
Fixing (tape, silicone, ..):	
Measurement accuracy:	

Other comments:

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6. DESCRIPTION OF METEOROLOGICAL SENSORS

	Description (sensor model)	Sampling rate	Accuracy	n°
Global horizontal irradiance:				
Diffuse horizontal irradiance:				
Direct normal irradiance:				
UV radiometer:				
Albedo				
Ambient temperature:				
Wind speed:				
Wind direction:				
Air relative humidity:				
Barometric pressure:				
Precipitation:				
Other:				

Other comments:

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7. DESCRIPTION OF SPECTRUM RADIOMETER

	Description
Manufacturer/name:	
Sensor type/types:	
Wavelength range:	
Entrance optic:	
Positioning:	☐ tilted ☐ horizontal
Measurement interval	
Stored data	☐ raw data ☐ APE ☐ MM factor (for modules) ☐ other ______________
Calibration procedure: (interval, traceability chain, etc.)	

Other comments:

____

____

____

8. DESCRIPTION OF TEST STAND

Orientation:	☐ close to optimum	
	☐ variable over year	
	☐ façade or roof mounted option	
Mounting types:	☐ standard open-rack	
	☐ BIPV solutions	
	☐ bifacial	
Ground:	Type of ground/albedo	
	Do you consider a min. distance from ground?	☐ no
		☐ yes, specify __________
Uniformity of test site: *Specify with a number or comment on each point.* *Add NA if you have no idea about.*	Estimated misalignment between modules?	
	Estimated misalignment between modules and sensors alignment?	
	Estimated irradiance non-uniformity?	
	Estimated thermal non-uniformity? *differences can occur due to obstacles or differences in surrounding, etc*	
Sensor positioning:	max. distance between module and irradiance sensor	
	min. number of in-plane irradiance sensors?	
	max distance of wind sensor from test field	
Cabling:	4-wire connection	☐ yes ☐ no
	other cable losses?	☐ no ☐ yes, specify _________________

Other comments:

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9. MAINTENANCE

9.1 Do you have an alert system for the detection of malfunctions?	☐ no
	☐ yes interval:
9.2 Do you perform regular visual inspections? *e.g. module breakage, soiling, temperature sensors,....*	☐ no
	☐ yes interval: specify type of controls:
9.3 Do you clean your modules?	☐ no
	☐ yes, interval ____________
	☐ yes, criterium ____________
9.4 Do you clean your irradiance sensors?	☐ no
	☐ yes, interval ____________
	☐ yes, criterium: ____________________
9.5 Do you save pictures of your test facility (web-cam)	☐ no
	☐ yes, interval ____________
9.6 Do you have a log book (anomalies, repairs, replacements, snow, ...)	☐ no
	☐ yes

Other comments:

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10. DATA PROCESSING

10.1 Do you perform any automatic plausibility check of your data and mark erroneous/bad data?	☐ no
	yes, ☐ missing data ☐ out of range ☐ disconnected module ☐ anomalous peaks ☐ noisy signal ☐ shadowed module ☐ snow detection ☐ partial or total detachment of temperature sensor ☐ bad I-V curve, specify _________ ☐ _____________ ☐ ______________
10.2 Do you perform any redundancy analysis? e.g multiple sensors/modules	☐ no
	yes, we check for… ☐ drift of irradiance signal (degradation or soiling of sensors) ☐ drift of module signal (degradation or soiling of modules or problems in data acquisition) ☐ other ______________
10.3 Do you correct the measured power to verify the stability over time?	☐ no
	☐ yes, describe how or reference:
10.4 What STC power do you use to calculate kWh/kW?	☐ name plate
	☐ indoor measured STC power
	☐ outdoor measured STC power (sun-tracker)
	☐ outdoor measured STC power (fixed rack) Describe your approach and the uncertainty u[k=2] of the extracted STC power?

10.5 What other instantaneous data are calculated?	☐ air mass AM ☐ angle of incidence AOI ☐ average photon energy APE ☐ _______________
10.6 What daily aggregate data are you calculating?	☐ energy E [kWh]
	☐ irradiation H [kWh/m²]
	☐ performance ratio PR [-]
	☐ min,max,avg module temp. [°C] (within time interval)
	☐ min,max,avg ambient temp. [°C] (within time interval)
	☐ min,max,avg wind speed [m/s] (within time interval)
	☐ 24 hrs min,max,avg module temperature [°C]
	☐ 24 hours min,max,avg ambient temperature [°C]
	☐ 24 hours min,max,avg wind speed [m/s]
	☐ irradiance weighted module temperature Tmod,w [-]
	☐ UV (sepcify)
	☐ rainfall [mm]
	☐ other
10.7 Do you classify your meteo data according day types?	☐ no
	☐ yes, describe day types and how they are determined
10.8 What other aggregate data are you calculating?	☐ monthly ☐ annual ☐ total
10.9 Do you exclude early morning or afternoon data? *data are not considered for the calculation of daily aggregates as kWh*	☐ no
	☐ yes specify criterium:
10.10 Do you apply any other filter when calculating aggregate values?	☐ no
	☐ yes, explain your approach:

Other comments:

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11. UNCERTAINTY CALCULATIONS

11.1 Do you state the uncertainty for the instantaneous values? *e.g Im, Vm, Pm, Isc, Voc, G, T, ….)*	☐ no	
	☐ yes	
11.2 Do you have an estimation of the uncertainty for the aggregate values? *e.g E, H, PR, …*	☐ no	
	☐ yes	
11.3 What is the typical uncertainty for a c-Si module measured for 1 year on your test facility expressed as expanded uncertainty (k=2)	E [kWh] ± x%	
	H [kWh/m2] ± x%	
	PR [-] ± x%	
11.4 Is the uncertainty calculation done according to the ISO GUM standard?	☐ yes	
	☐ no, specify approach __________	
11.5 Do you have a reference document/sheet describing your uncertainty calculation procedure?	☐ no	
	☐ yes, specify a REF if available	
11.6 Can you share it within IEA Task 13?	☐ yes ☐ no	

Other comments:

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12. REPORTING

12.1 Do you have a standard format for energy yield reporting?	☐ no
	yes, it includes…. ☐ description of test site (AZ, EL, mounting) ☐ description of test procedure ☐ description of calculations ☐ description of test devices ☐ additional test reports of modules (characterization) ☐ meteorological data ☐ kWh/kW ranking ☐ monthly, annual and total energy output and performance ratio ☐ measurement uncertainties of outdoor data ☐ degradation rates ☐ data loss expressed in ___________ ☐ ________________ ☐ _______________
12.2 How do you calculate degradation rates? [5]	
12.3 How do you report the results for meta-stable technologies as e.g amorphous silicon? [5]	
12.4 How do you consider the impact of low irradiance? [5]	
12.5 How do you consider the impact of temperature? [5]	
12.6 How do you consider the impact of spectral irradiance? [5]	

[5] Add either a REF or an example (figure + description) of how you represent your data.

12.7 How do you compare test results from different climates? [5]	
12. 8 Do you add other information to your report? *e.g translation to other climates, theoretical values, energy lables, …*	

Other comments:

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13. MODELING

13.1 Do you compare measured with modeled data?	☐ no ☐ yes
13.2 What model do you use? *(A reference describing your model is here sufficient)*	
13.3 What module input parameters are needed? *(STC values or I-V curve, temperature coefficient, full Matrix, ….)*	
13.4 What input data do you need for the validation of your model?	☐ global in-plane irradiance (pyranometer) ☐ global horizontal irradiance ☐ direct normal irradiance or diffuse irradiance ☐ spectral irradiance ☐ wind speed ☐ ambient temperature ☐ back of module temperature ☐ full I-V curve ☐ Pm value ☐ Im and Vm value ☐ Isc value ☐ Voc value ☐ other ________________
13.5 What resolution of data do you need for your model?	

Other comments:

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14. MONITORING

14.1 Are you interested to share own monitoring data of single modules within IEA TASK 13?	☐ yes ☐ no
14.2 What time resolved data could you share?	☐ global in-plane irradiance (pyranometer) ☐ global horizontal irradiance ☐ direct normal irradiance ☐ diffuse horizontal irradiance ☐ spectral irradiance ☐ wind speed ☐ ambient temperature ☐ back of module temperature ☐ full I-V curve ☐ Pm value ☐ Im and Vm value ☐ Isc value ☐ Voc value ☐ AM, AOI ☐ APE ☐ irradiance stability
14.3 What time re-solution has your data ?	
14.4 Do you need additional testing of your modules accord. IEC 61853?	☐ yes ☐ no

Other comments:

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Annex 2: Test Facility Sheets

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

Responsible institution
AIT Austrian Institute of Technology
Giefinggasse 4
1210 Vienna, Austria

www.ait.ac.at/en/research-fields/photovoltaics/

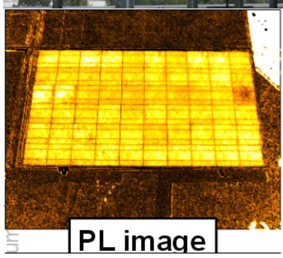
AUSTRIAN INSTITUTE OF TECHNOLOGY

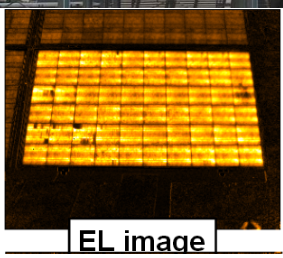
Location infrastructure/s:	Vienna, Austria

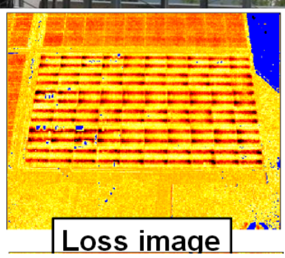
Presentation:

AIT operates an outdoor laboratory infrastructure on a measurement platform. AIT's laboratory facilities are accredited after ISO/IEC 17025, and the international high-quality IECEE CBTL scheme as well, offering tests e.g. after the standards IEC 61215, IEC 61853 and IEC 61730. The AIT outdoor-measurement platform of AIT offers short term and long term evaluation of PV-strings or PV-modules. Special interest is on the topics of (a) initial degradation and (b) degradation mechanisms as PID. Further evaluations include (c) precise power output and (d) energy yield evaluation. Degradation mechanisms are probed by means of electrical measurement as well as electro-optical (electroluminescence or lock-in-thermography) or optical methods (UV-fluorescence or IR-thermography). The platform offers continental climate in the Pannonian low land. Special set-ups or module designs can be included.

Pictures:







Technical Details:

The measurements includes : power measurement, energy yield evaluation, NMOT (5 sec interval), environmental parameters, spectro-radiometers (300 nm -1600 nm, 1min interval), cloud camera (1min interval), wind 2D speed, irradiance, PID-setup, IV-measurement or fixed load point, 1-axial and 2-axial trackers.

2 Selected References:

[1] R. Ebner, B. Kubicek, G. Újvári, S. Novalin, M. Rennhofer, M. Halwachs: "Optical Characterization of Different Thin Film Module Technologies"; International Journal of Photoenergy, Article ID 159458, p. 1 – 12 (2015).

[2] M. Knausz, G. Oreski, G. Eder, Y. Voronko, B. Duscher, T. Koch, G. Pinter, K. Berger: "Degradation of photovoltaic backsheets: Comparison of the aging induced changes on module and component level"; J. APPL. POLYM. SCI. Vol. 132(24), p. 42093 - 42100 (2015)

Short Presentation
Outdoor Module Test Facilities

Responsible institution
CEA at INES
73375 Le Bourget-du-Lac – FRANCE
http://www.cea.fr/english/Pages/research-areas/renewable-energies.aspx
www.durasol.fr

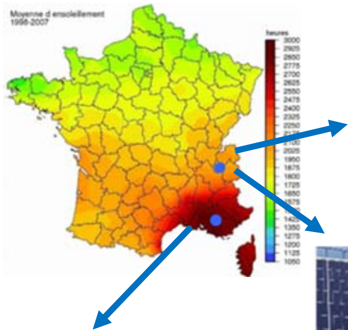
Location infrastructure/s:	73375 Le Bourget-du-Lac, 13115 Saint-Paul-lez-Durance - FRANCE

Presentation:

The PV module performance is being studied by CEA (Alternative Energy and Atomic Energy Commission) since 1983 under real operating conditions and different climates (Mediterranean at Cadarache, Alpine at Pic de Bures Mount and Semi-continental at INES). Within these platforms, CEA operates more than 200 outdoor channels for individual modules monitoring with IV curve tracer.

Around 400 modules have been studied outdoor so far for benchmarking commercial technologies on one hand, and for driving PV module innovation on the other hand, since these outdoor measurements are combined with indoor reliability and durability tests using Flash-tester, electro-luminescence, climate chambers, lock-in thermography, high voltage stress, UV stress…

Pictures:





Technical Details:

Whereas part of the channels are commercial devices with MPP tracked between 2 IV curves, other channels have been specifically developed for IV curves and Voc or fixed load between two curves. IV curves are measured automatically every 5 minutes, with irradiance and module temperature monitored every 1 minute, to allow meteorological analysis, filtering and corrections.

Example of References:

[1] "In situ monitoring of degradation processes inside PV modules of different technologies with VIM", J. Merten et al., 24th EU-PVSEC, 2009, Hambourg, Germany.

[2] "Performance Analysis of Crystalline Silicon PV Modules After 18 Months Exposure under Tropical Climate", L. Mabille, G. Razongles, L. Sicot, J. Merten, 26th EU-PVSEC, 2011, Hambourg, Germany.

Short Presentation
Outdoor Module Test Facilities

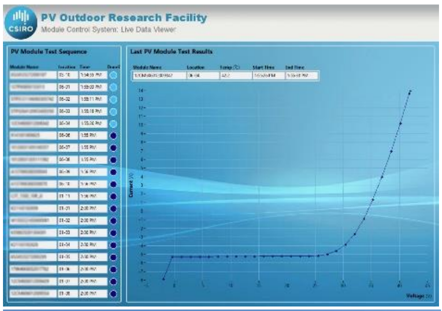
Responsible institution
PV Performance Laboratory
CSIRO Energy Centre
10 Murray Dwyer Cct, Mayfield West, NSW 2304
AUSTRALIA
www.csiro.au – www.csiro.au/energy

Location infrastructure/s:	Newcastle, New South Wales, Australia

Presentation:

CSIRO's PV Performance Laboratory is a suite of indoor and outdoor measurement facilities for research and testing the performance of solar photovoltaic cells and modules. Our cell measurement laboratory is accredited to ISO/IEC 17025 and progress toward this accreditation is underway for commercial-scale modules. Our PV Outdoor Research Facility (PVORF) has been in operation since 2013. Measurements on the facility have been used for multiple research publications as well as consumer advocacy articles, assisting companies to develop ancillary products and to inform legal proceedings.

Pictures:



Technical Details:

The PVORF hosts 60 individual north-facing test beds at 30° tilt for diagnostic testing of commercial and research scale solar PV modules. I-V curves are measured at any desired timebase, while in-between measurements the energy output is captured for use on site. The back surface temperature of each module is recorded and the modules are regularly washed to avoid soiling effects. Monitoring of the solar and weather conditions is performed with an a high accuracy ground station that is part of the global Baseline Surface Radiation Network. The solar spectrum is also measured in the range 300-1700 nm.

2 Selected References:

[1] Duck, B.C., Fell, C.J., Anderson, K.F., Sacchetta, C., Du, Y., Zhu, Y., 2018. Determining the value of cooling in photovoltaics for enhanced energy yield. *Sol. Energy* 159, 337–345. doi:10.1016/j.solener.2017.11.004

[2] Duck, B.C., Fell, C.J., 2016. Improving the Spectral Correction Function . 2016 IEEE 43rd Photovolt. Spec. Conf. 2647–2652.

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

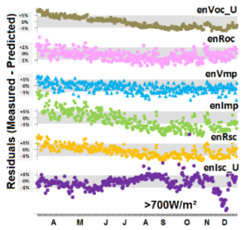
Responsible institution
PV Outdoor Monitoring Team
Contact: j.sutterlueti@gantner-instruments.com

Gantner instruments

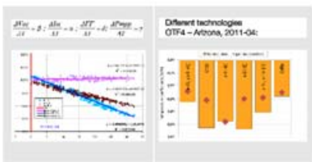
Location infrastructure/s:	Tempe, Arizona, USA and many worldwide customer installations

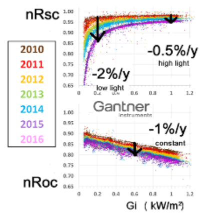
Presentation: Gantner Instruments' Outdoor Test Facility (OTF) provides all required data sets for an easy and accurate validation and technology comparison of your PV module. The OTF solution measures all parameters for energy yield, low light behaviour and thermal coefficients for any PV technology (up to 500Wp) to create track record data and bankability support. Real PV Module behaviour is essential for PV module producers, system integrators, insurance companies, banks, investors, R&D departments and others which want to understand and verify PV technology behaviour.

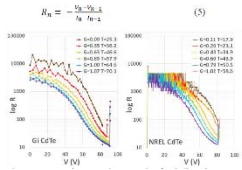
Pictures and Graphs from conference papers:



Residual analysis for 6 LFM analysis from a CIGS Module







Log Resistance-Voltage RV measurements (Gantner (left), NREL (right))

Technical Details: Analysis Functions: Energy yield parameters (PRdc, YA, YR), sun hours per year, … | PV Module performance over the day/month/year for fixed, tracked installations | Benchmarking, validate tracking benefits, Long term trends, fault finding | Thermal, low light, AOI behaviour, seasonal variation, LID effects | Spectral sensitivity | Validation of Simulation (PVSyst, PVLib) | Loss Factor Model (LFM) coefficients, Mechanistic Performance Model (MPM) coefficients

Key features - to get the characteristics of your PV Module: Measurement range: 0…60V, 0…50A, Pmax: 500W (800W max.) | 24bit resolution with 1200Vdc galvanic isolation, 50kHz sample rate | Dynamic sweep time and scan interval | Tracking modes (Mpp, Voc, Isc) | Fully synchronized scan concept | Calculation of key parameters (Isc, Rsc, Imp, Vmp, Roc, Voc) (curvature parameters for I mismatch and Rollover) | Output of Coefficient for Models (Loss Factors Model (LFM) and Mechanistic Performance Model (MPM), SAPM, ..) | Reliable software with special self-monitoring features, automatic data check, user alerts | Reliable and proven industry components and calibrated sensors | Standalone Plug & Play system for indoor/outdoor use (IP65), customized channels

Selected References:

[1] J. Sutterlüti et al.; "Characterizing PV modules under outdoor conditions: What's most important for energy yield"; Proceedings 26th EUPVSEC, (2011), pp.3608-3614.
[2] Sellner et al.; "Understanding Module Performance further: validation of the novel loss factors model and its extension to ac arrays "; 27th PVSEC Frankfurt 2012
[3] J. Sutterlueti et al: „Improved PV Performance Modelling by Combining the PV_LIB Toolbox with the Loss Factors Model (LFM)", IEEE PVSC 42, New Orleans 2015

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

Institute of Electrical Engineering,

Chinese Academy of Sciences

Responsible institution

Photovoltaic and Wind Power Systems Quality Test Center(PV Test Center)， Institute of Electrical Engineering, Chinese Academy of Sciences (IEE,CAS)
www.iee.cas.cn

Location infrastructure/s:	Gong He county, Qinghai Province, China

Presentation :

PV Test Centre of IEE is accredited with ISO 17025 by CMA and CNAS of China for performance measurement of PV cells and modules. PV Test Centre of IEE joined IEA-PVPS Task 13 group in 2009, and started the research of PV module failure characteristics, reliability and durability measurement technology under different climate conditions. The outdoor and indoor measurement data are combined to analyse PV module electrical performance, safety reliability and mechanical stress. From 2012 to 2014, PV Test Centre of IEE established an outdoor test site for PV modules (Capacity:1MW) in Qinghai province of China. 11 different modules are installed and measured for long-term performance test. In 2017, two rooftop PV module demonstration platforms in Shanghai and Xining were established for performance comparison test of PV modules under hot humid climate and plateau climate.

Pictures:





Technical Details:

The outdoor multichannel I-V test system can be used for long-term and synchronous test for different PV modules with high acquisition accuracy and maximum power point tracking. Key performance parameters (module maximum power, irradiance, module temperature), MPR and module power loss can be processed and computed automatically. The meteorological station includes sun tracker, pyrheliometer, pyranometer, UV Radiometer, temperature and humidity sensor, anemometer and barometer. I-V data and meteorological data are combined to analyse energy yield performance of different modules under typical environmental condition.

2 Selected References:

[1] Haitao Liu, Performance Ratio Measurement Method of Photovoltaic Modules under Natural Sunlight Condition, 29th CCDC, Chongqing 2017.

[2] Haitao Liu, Irradiance and Temperature Dependence Characterization of Vacuum Glass BIPV Modules, Applied Mechanics and Materials Mechanical Science and Engineering, 2014.

Short Presentation
Outdoor Module Test Facilities

Fraunhofer ISE

Responsible institution
Fraunhofer Institute for Solar Energy Systems (ISE)
Freiburg, Germany
www.ise.fraunhofer.de

Location infrastructure/s:	Freiburg (Germany), Gran Canaria (Spain), Negev desert (Israel)

Presentation:

The climatic conditions affecting solar systems vary considerably with location, resulting in different requirements for materials and components of PV modules and thermal collectors. Fraunhofer ISE operates outdoor test sites in four different climates in order to assess the performance and effects of different weathering conditions on the reliability of PV modules and thermal collectors.
The outdoor test sites are complemented by our accredited laboratories: The Fraunhofer ISE CalLab PV Modules and TestLab PV Modules offer the highest standards, precision and accuracy on the market.

Pictures:

Technical Details:

We developed a unique PV monitoring system for long-term recording of IV curves of PV modules, module temperature end environmental conditions. This system is used at our test sites and at customer sites. Modules are measured simultaneously and kept in MPP during measurement pause. Module specific and environmental data is passed through daily post-processing routines for quality control and parameter extraction and subsequently stored in a high-performance database linking samples, test sites, investigations and sensors to measured indoor and outdoor data. Data analysis and evaluation is carried out using our powerful Python framework which incorporates well-known routines and standard procedures as well as our latest findings using the advantages of scientific Python.

2 Selected References:

[1] Schill, C., Brachmann, S. & Koehl, M. Impact of soiling on IV-curves and efficiency of PV-modules. Solar Energy 112, 259–262 (2015).

[2] Koehl, M., Heck, M. Load evaluation of PV-modules for outdoor weathering under extreme climatic conditions. 4th European Weathering Symposium 2009, Budapest, Hungary, September 2009

SHORT PRESENTATION OUTDOOR MODULE TEST FACILITIES

Responsible institution
Engie Laborelec
1630 Linkebeek - Belgium
www.laborelec.be

Location infrastructure/s:	Linkebeek, Belgium and Arica, Chile (Atacama desert)

Presentation:

Engie Laborelec tests solar products in its laboratories, with the aim to better understand their behaviour, ageing and energy yield, identify and solve technical weaknesses or indicate how to improve them. An outdoor module test bench is installed since 2009, integrating various PV technologies (crystalline silicon, thin film, organic and perovskite).

In Linkebeek, Laborelec also deployed a façade integrated OPV pilot (concrete based and integrated in glass), a ground based PV infrastructure connected to a microgrid, PV + batteries systems (for B2C applications, maximizing self-consumption), as well as a monitoring platform for PV pilots installed worldwide. Laborelec also operates a test infrastructure in Chile (Atacama desert, one of the highest solar irradiance sites worldwide) including bifacial, CPV and other solar technologies.

Pictures:

Technical Details:

In the test bench, modules are accurately monitored on the DC side (1 minute average MPP data, and IV curve taken every 15 minutes), individually or in strings of 2 modules. The installation also includes modules temperature and ambient temperature sensors, one reference cell and 2 pyranometers (measuring tilted and horizontal global irradiance, and diffuse irradiance).

2 Selected References:

Short Presentation
Outdoor Module Test Facilities

Responsible institution
Research Group Energy & Automation
(KU Leuven)
https://iiw.kuleuven.be/onderzoek/eena

Location infrastructure/s:	Gent, Belgium

The Energy & Automation Research Group has performed research on photovoltaic modules and cells since 2008 for industry and academia, collaborating with Imec and EnergyVille on module energy yield characterisation in outdoor conditions, as well as indoor spectral analyses of cells.

Pictures:

Technical Details:

Indoor measurements are aimed at determining cell characteristics such as IQE/EQE with the ability to obtain angular spectral data, for reflection and absorption. Outdoor measurements are performed using a combination of high-precision in-house developed devices and commercial I-V tracers and MPP trackers, with multiple high-precision module temperature sensors available. All measurements are combined with meteorological station data and stored at high resolution (1 Hz).

2 Selected References:

[1] B. Herteleer, B. Huyck, F. Catthoor, J. Driesen and J. Cappelle, "Normalised Efficiency of Photovoltaic Systems: Going beyond the Performance Ratio", Solar Energy, vol. 157, pp. 408-418, 2017.

[2] B. Herteleer, B. Morel, B. Huyck, Cappelle, R. Appels, B. Lefevre, F. Catthoor and J. Driesen, "High Frequency Outdoor Measurements of Photovoltaic Modules Using an Innovative Measurement Set-Up," in 29th EU PVSEC, Amsterdam, 2014.

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Responsible institution
National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401-3305
www.nrel.gov

Location infrastructure/s:	Golden, Colorado

Presentation:

Since 1981 NREL has been involved in monitoring, analyzing, and modeling photovoltaic (PV) power and energy at the cell, module, and system level. We test modules and systems for long-term performance and stress them in the field and with accelerated testing equipment with the goal of finding test methods to improve PV reliability and ensure PV usage by creating international standards. Each year, the National Center for Photovoltaics (NCPV) conducts an industry PV Reliability Workshop to encourage the exchange of information about PV reliability. The Device Performance group performs current-voltage, quantum efficiency, and other measurements on a wide range of photovoltaic cell and module technologies—including commercial, developmental, and research samples—for scientists in the photovoltaic industry and at universities. The group is ISO 17025 accredited for primary reference cell calibrations, secondary reference cell calibrations, secondary module calibrations and module power over time. All measurements reported by the Device Performance group are ISO 9001 accreditation. The PV related facilities include the Outdoor Test Facility (OTF), the Solar Energy Research Facility (SERF) and the Energy Systems Integration Facility (ESIF). The OTF researchers in the NCPV study and evaluate advanced or emerging PV technologies under simulated, accelerated indoor and outdoor, and prevailing outdoor conditions.

Pictures:

Technical Details:

Equipment lists and technical details of the PV characterization equipment and test beds including: solar simulators, outdoor test beds, spectral responsivity capabilities, and technical details can be found.
Device performance web page https://www.nrel.gov/pv/device-performance.html
Reliability engineering, energy rating, standards activities at the module and system level can be found at the PV reliability and Engineering Web page https://www.nrel.gov/pv/reliability-engineering.html

Selected References:

[1] M. G. Deceglie, L. Micheli, M. Muller, "Quantifying Soiling Loss Directly from PV Yield" IEEE Journal of Photovoltaics Vol. 8 (2), 2018 pp. 547-551.

[2] K. Jordan, M. Deceglie, C. Deline, D. Jordan, "Calculating PV Degradation Rates Using Open-Source Software," SolarPro Vol. 11(2), 2018

[3] D. Jordan, C. Deline, S. Kurtz, G. Kimball, M. Anderson, "Robust PV Degradation Methodology and Application," IEEE Journal of Photovoltaics Vol. 8(2), 2018 pp. 525-531.

[4] B. Marion and B. Smith, "Photovoltaic System Derived Data for Determining the Solar Resource and for Modeling the Performance of Other Photovoltaic Systems," Solar Energy Vol. 147(1), 2017 pp. 349-357.

[5] B. Marion, "Numerical Method for Angle-of-Incidence Correction Factors for Diffuse Radiation Incident Photovoltaic Modules," Solar Energy Vol. 147(1), 2017 pp. 344-348.

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

Responsible institution
Sandia National Laboratories

https://pv.sandia.gov.

Location infrastructure/s:	Albuquerque, New Mexico USA

Presentation:

Sandia's Photovoltaic Systems Evaluation Laboratory (PSEL) has been testing solar photovoltaic energy cells, modules and systems since 1976. PSEL currently specializes in indoor and outdoor characterization and reliability assessments of PV modules and systems and hosts the New Mexico Regional Test Center and PV Lifetime project. Over 50 different PV technologies are currently under evaluation in the field including advanced module and cell technologies, bifacial PV, solar roofing, AR and anti-soiling coatings, module-level power electronics, and monitoring systems.

Pictures:

Technical Details:

- Seven-acre site with fixed tilt racking and single axis-trackers for system-level studies
- Two large dual-axis trackers that are highly configurable for multiple test configurations with IV data acquisition systems capable of measuring eight modules (tracked) outdoors simultaneously
- Comprehensive PV weather station, including spectrum
- Outdoor calibration facility for irradiance devices
- Equipment for continuous monitoring of PV system outputs on the DC & AC sides of the inverter
- Automated and mobile IV tracers for measuring module & string IV curves in the field over time
- Indoor module lab: Spire 4600 SLP flash tester, Reltron Electroluminescence unit, Dark IV, FLIR infrared characterization, Atonometrics Light Soaking Station.

2 Selected References:

[1] King, B. H., et al. (2016). Procedure to Determine Coefficients for the Sandia Array Performance Model (SAPM). Albuquerque, NM, Sandia National Laboratories. **SAND2016-5284**.

[2] King, D. L., et al. (2004). Photovoltaic Array Performance Model. Albuquerque, NM, Sandia National Laboratories. **SAND2004-3535**.

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

University of Applied Sciences and Arts
of Southern Switzerland
SUPSI

Responsible institution
PVLab (SUPSI-ISAAC)
6952 Canobbio – Switzerland
www.supsi.ch/isaac

Location infrastructure/s:	Canobbio (Lugano) - Switzerland

Presentation:

Since 1991, the monitoring and analysis of the energy yield of a PV module under real operating conditions is one of the core activities of the SUPSI PVLab. SUPSI is there comparing the performance of different products and technologies with a strong focus over the last years on building integrated modules. Since 2001 the outdoor measurements are combined with indoor performance measurements and since 2008, on request also, with several reliability tests (aging, mechanical stability and safety). Customised test stands can be developed for the investigation of special features (i.e back-insulation, coloured printings, anti-soiling, shadowing tolerance, enhanced light trapping, etc.). The laboratory is accredited ISO 17025 by SAS for the testing of PV modules.

Pictures:

Technical Details:

All measurements are performed with in-house developed, high precision, maximum power point trackers with IV-tracer capabilities (MPPT3000) and channels for the monitoring of irradiance and temperature. The measurements are combined with data form the meteo station and spectral data. A sophisticated quality control procedure with alert functions allows the highest measurement accuracy available today. Daily data processing is done automatically to determine all key performance indicators, loss factors, but also to assess day types and typical environmental parameters.

2 Selected References:

[1] S. Dittmann et al.: Energy yield measurements at SUPSI - importance of data quality control and its influence on kWh/Wp inter-comparisons, 26th EPVSEC, Hamburg, September 2011.

[2] G. Friesen et al., “A 4 year energy yield inter-comparison of thin-film modules: linking indoor to outdoor performance data”, 6th WCPEC, Kyoto 2014.

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

Responsible institution:
TÜV Rheinland Energy GmbH
Am Grauen Stein
51105 Cologne, Germany
www.tuv.com/solarenergy

TÜVRheinland®
Precisely Right.

Location infrastructure/s:	Cologne (Germany), Tempe (Arizona), Chennai (India), Thuwal (Saudi Arabia)

Presentation:

TUV Rheinland has developed this test facility under the scope of the German PV-KLIMA research project. Four systems are operated since the year 2013 at various locations covering the range of worldwide climates for PV applications: Cologne (Germany, temperate Cfb), Tempe (Arizona, desert Bwh), Chennai (India, subtropical Aw) Thuwal (Saudi Arabia, desert Bwh). Prior to outdoor installation the energy yield performance of test samples is measured in the laboratory in accordance with IEC 1853-1 and IEC 61853-2. The following services are provided:

- Energy delivery of PV modules in various climates and performance loss analysis;
- Analysis of seasonal effects, electrical stability and output power degradation;
- Long term analysis of inter-annual variability of meteorological and environmental parameters.

Pictures:


Cologne (Germany)


Chennai (India)


Tempe (Arizona)


Thuwal (Saudi Arabia)

Technical Details:

The system is capable to perform comparative energy yield measurement of up to 30 PV modules. Test samples are connected to electronic loads, which are synchronously operated in maximum power mode. Besides the energy yield measurement, I-V curves of PV modules are measured in intervals of 10 minutes. The test facility includes a meteorological station with measurement of all relevant parameters including spectral irradiance, which is measured in the wavelength range 300 nm to 1600 nm. Furthermore soiling losses are monitored.

2 Selected References:

[1] M. Schweiger, W. Herrmann, A. Gerber, U. Rau: Understanding the Energy Yield of Photovoltaic Modules in Different Climates by Linear Performance Loss Analysis of the Module Performance Ratio, IET Renewable Power Generation, doi: 10.1049/iet-rpg.2016.0682

[2] M. Schweiger, J. Bonilla, W. Herrmann, A. Gerber, U. Rau: Performance Stability of Photovoltaic Modules in Different Climates, Progress in Photovoltaics, 2017, DOI: 10.1002/pip.2904

Short Presentation Outdoor Module Test Facilities

Responsible institution
PV Technology Laboratory
1678 Nicosia- Cyprus
www.pvtechnology.ucy.ac.cy/

Location infrastructure/s:	Nicosia - Cyprus

Presentation:
The PV Technology Laboratory, founded in the year 2005, is part of the University of Cyprus and comprises of a state-of-the-art indoor and outdoor infrastructure for PV research at the level of cells/modules and systems. The outdoor facilities consist of diagnostic equipment for the measurement and monitoring at high resolution of all the important environmental and operational parameters of PV systems according to the requirements set by the IEC 61724. Currently, more than 50 PV technologies are hosted in the test site for long-term evaluation. The PV technologies are installed outdoors both at fixed and tracked mounting setups. Outdoor equipment further include grid-connected programmable inverters, module IV curve tracing, MPP trackers, along with a newly developed potential induced degradation (PID) setup for accelerated degradation tests.

Pictures:

Technical Details:

The performance of the PV systems and the prevailing meteorological conditions are recorded according to IEC 61724 and stored with the use of an advanced measurement platform. The platform comprises of meteorological and electrical sensors connected to a central data logging system that stores data at high resolution. The acquired data are automatically processed on a daily basis to determine whether or not the system is performing as expected. In addition, real-time comparisons between the measured and simulated DC power production are performed in order to identify performance losses, malfunctions and failures in PV systems.

Selected References:

[1] G. Makrides, B. Zinsser, M. Schubert, and G. E. Georghiou, "Performance loss rate of twelve photovoltaic technologies under field conditions using statistical techniques," Sol. Energy, vol. 103, no. October 2016, pp. 28–42, 2014.

[2] A. Phinikarides, G. Makrides, and G. E. Georghiou, "Estimation of annual performance loss rates of grid-connected photovoltaic systems using time series analysis and validation through indoor testing at standard test conditions," 42nd IEEE PVSC, pp. 1–5, 2015.

SHORT PRESENTATION
OUTDOOR MODULE TEST FACILITIES

Responsible institution
Copernicus Institute of Sustainable Development
(Utrecht University)
Utrecht – the Netherlands

www.uu.nl/copernicus

Universiteit Utrecht

Location infrastructure/s:	Utrecht, the Netherlands

Presentation:

Operational since 2013, the Utrecht Photovoltaic Outdoor Test facility (UPOT) is a test facility measuring the outdoor performance under real operating conditions of a large variety of commercial and prototype PV modules. In 2018, the facility will be expanded to allow for measurement of roughly fifty full size modules at the same time. The test facility is equipped with a large sensor array, including a sun tracker (with pyrheliometer and diffuse pyranometer), pyranometers for global horizontal and global in-plane irradiance, as well as a spectroradiometer for in-plane spectral irradiance. PV module measurements are performed on a high time resolution with per module IV tracing and temperature measurements. Finally, weather data is measured, and a 360-degree camera takes an image of the entire sky around the test facility.

Pictures:

Technical Details:

All measurements are performed with EKO instruments IV tracers, after the expansion the measurements will be performed by a new tool developed by Ljubljana University. Between measurements, modules are kept at MPP by Femtogrid power optimizers. The sun tracker, pyranometers and weather station are controlled via a datalogger, which is connected to a PC. The spectroradiometer and IV tracers are directly connected to the same PC. After quality control, measurements are processed and stored in a MySQL database.

2 Selected References:

[1] W.G.J.H.M. Van Sark, Atse Louwen, Arjen C. de Waal, Boudewijn Elsinga, Ruud E.I. Schropp (2012), UPOT: The Utrecht photovoltaic outdoor test facility, Proceedings of the 27th EUPVSEC, pp 3247-3249

[2] Louwen, A., de Waal, A. C., Schropp, R. E. I., Faaij, A. P. C., and van Sark, W. G. J. H. M. (2017) Comprehensive characterisation and analysis of PV module performance under real operating conditions. Prog. Photovolt: Res. Appl., 25: 218–232. doi: 10.1002/pip.2848.

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