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INTERNATIONAL STANDARD

colour inside

Photovoltaic system performance –
Part 1: Monitoring

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INTERNATIONAL
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INTERNATIONAL ELECTROTECHNICAL COMMISSION

PHOTOVOLTAIC SYSTEM PERFORMANCE –

Part 1: Monitoring

FOREWORD

1) The International Electrotechnical Commission (IEC) is a worldwide organization for standardization comprising all national electrotechnical committees (IEC National Committees). The object of IEC is to promote international co-operation on all questions concerning standardization in the electrical and electronic fields. To this end and in addition to other activities, IEC publishes International Standards, Technical Specifications, Technical Reports, Publicly Available Specifications (PAS) and Guides (hereafter referred to as "IEC Publication(s)"). Their preparation is entrusted to technical committees; any IEC National Committee interested in the subject dealt with may participate in this preparatory work. International, governmental and non-governmental organizations liaising with the IEC also participate in this preparation. IEC collaborates closely with the International Organization for Standardization (ISO) in accordance with conditions determined by agreement between the two organizations.

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This redline version of the official IEC Standard allows the user to identify the changes made to the previous edition IEC 61724-1:2017. A vertical bar appears in the margin wherever a change has been made. Additions are in green text, deletions are in strikethrough red text.

International Standard IEC 61724-1 has been prepared by IEC technical committee 82: Solar photovoltaic energy systems.

This second edition cancels and replaces the first edition, published in 2017. This edition constitutes a technical revision.

This edition includes the following significant technical changes with respect to the previous edition:

- Monitoring of bifacial systems is introduced.
- Irradiance sensor requirements are updated.
- Soiling measurement is updated based on new technology.
- Class C monitoring systems are eliminated.
- Various requirements, recommendations and explanatory notes are updated.

The text of this standard is based on the following documents:

FDIS	Report on voting
82/1904/FDIS	82/1925/RVD

Full information on the voting for its approval can be found in the report on voting indicated in the above table.

The language used for the development of this International Standard is English.

This document was drafted in accordance with ISO/IEC Directives, Part 2, and developed in accordance with ISO/IEC Directives, Part 1 and ISO/IEC Directives, IEC Supplement, available at www.iec.ch/members_experts/refdocs. The main document types developed by IEC are described in greater detail at www.iec.ch/standardsdev/publications.

A list of all parts in the IEC 61724 series, published under the general title *Photovoltaic system performance*, can be found on the IEC website.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under webstore.iec.ch in the data related to the specific document. At this date, the document will be

- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

IMPORTANT – The 'colour inside' logo on the cover page of this publication indicates that it contains colours which are considered to be useful for the correct understanding of its contents. Users should therefore print this document using a colour printer.

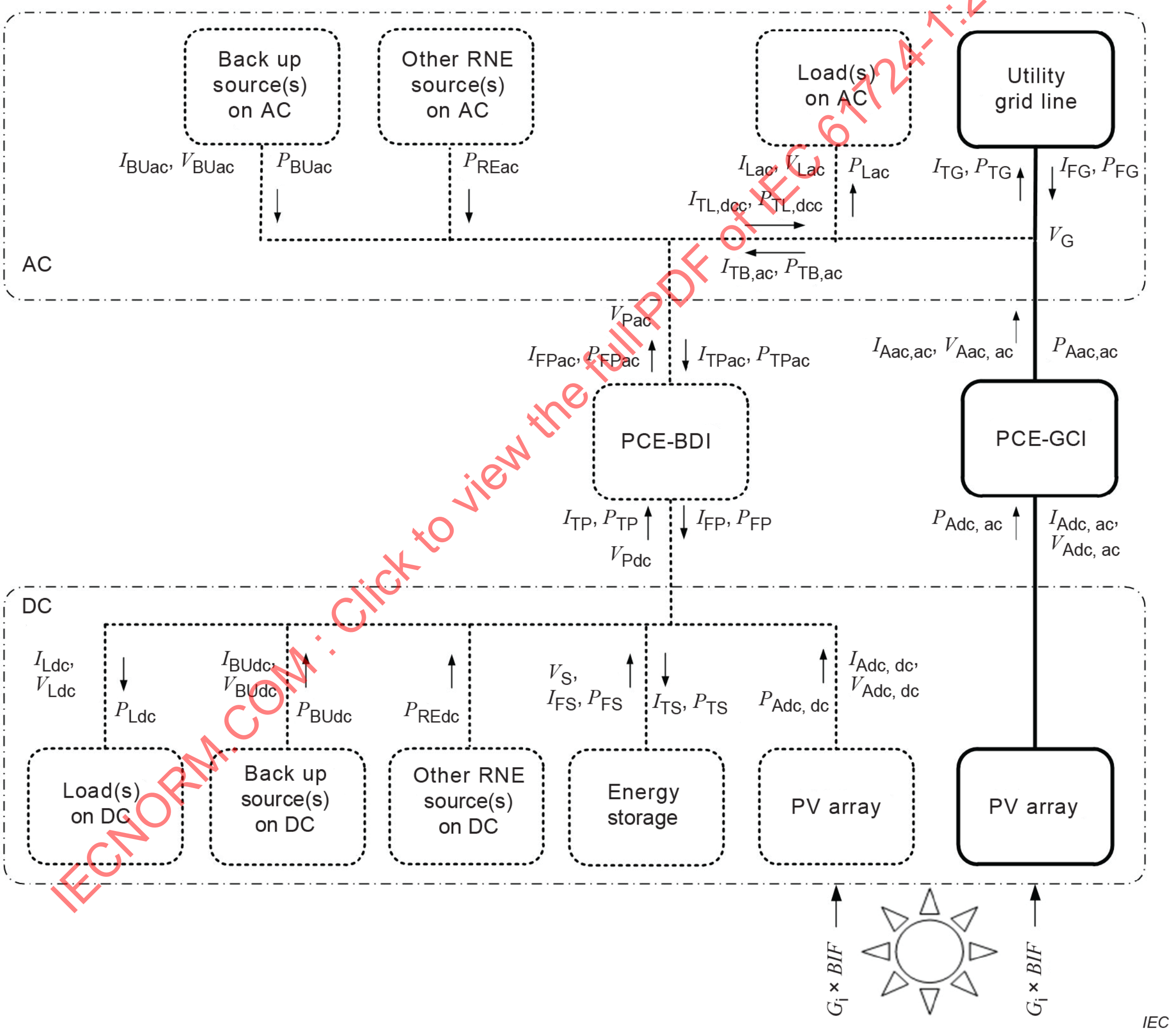
INTRODUCTION

This document defines classes of photovoltaic (PV) performance monitoring systems and serves as guidance for ~~various~~ monitoring system choices.

Figure 1 illustrates ~~possible~~ major elements comprising different PV system types.

The main clauses of this document are written for grid-connected systems without local loads, energy storage, or auxiliary sources, as shown by the bold lines in Figure 1. Annex E includes some details for systems with additional components.

The PV array may include both fixed-axis and ~~tracking~~ tracker systems and both flat-plate and concentrator systems. ~~Module-level electronics, if present, may be a component of the monitoring system.~~



Key

RNE: renewable energy

PCE: power conditioning equipment

BDI: bi-directional inverter

GCI: grid-connected inverter

Bold lines denote simple grid-connected system without local loads, energy storage, or auxiliary sources.

Figure 1 – Possible elements of PV systems

The purposes of a performance monitoring system are diverse and ~~can~~ could include ~~the following:~~

- ~~identification of performance trends in an individual PV system;~~
- ~~localization of potential faults in a PV system;~~
- ~~comparison of PV system performance to design expectations and guarantees;~~
- ~~comparison of PV systems of different configurations; and~~
- ~~comparison of PV systems at different locations.~~

comparing performance to design expectations and guarantees as well as detecting and localizing faults.

~~These diverse purposes give rise to a diverse set of requirements, and different sensors and/or analysis methods may be more or less suited depending on the specific objective. For example,~~ For comparing performance to design expectations and guarantees, the focus should be on system-level data and consistency between prediction and test methods~~, while for analysing performance trends~~.

For detecting and localizing faults there ~~may~~ should be ~~a need for~~ greater resolution at sub-levels of the system and an emphasis on measurement repeatability and correlation metrics ~~rather than absolute accuracy~~.

The monitoring system should be adapted to the PV system's size and user requirements. In general, larger ~~and more expensive~~ PV systems should have more monitoring points and higher accuracy sensors than smaller and lower-cost PV systems. ~~This document defines three classifications of monitoring system with differentiated requirements which are appropriate to a range of purposes.~~

PHOTOVOLTAIC SYSTEM PERFORMANCE –

Part 1: Monitoring

1 Scope

This part of IEC 61724 outlines terminology, equipment, and methods for performance monitoring and analysis of photovoltaic (PV) systems. ~~It addresses sensors, installation, and accuracy for monitoring equipment in addition to measured parameter data acquisition and quality checks, calculated parameters, and performance metrics.~~ It also serves as a basis for other standards which rely upon the data collected.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 60050-131, *International Electrotechnical Vocabulary (IEV) – Part 131: Circuit theory*

IEC 60904-2, *Photovoltaic devices – Part 2: Requirements for photovoltaic reference devices*

~~IEC 60904-3, *Photovoltaic devices – Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data*~~

IEC 60904-5, *Photovoltaic devices – Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open-circuit voltage method*

IEC 60904-7, *Photovoltaic devices – Part 7: Computation of the spectral mismatch correction for measurements of photovoltaic devices*

~~IEC 60904-10, *Photovoltaic devices – Part 10: Methods of linearity measurement*~~

IEC 61215 (all parts), *Terrestrial photovoltaic (PV) modules – Design qualification and type approval*

IEC 61557-12, *Electrical safety in low voltage distribution systems up to 1 000 V AC and 1 500 V DC – Equipment for testing, measuring or monitoring of protective measures – Part 12: Power metering and monitoring devices (PMD)*

IEC TS 61724-2, *Photovoltaic system performance – Part 2: Capacity evaluation method*

IEC TS 61724-3, *Photovoltaic system performance – Part 3: Energy evaluation method*

IEC TS 61836, *Solar photovoltaic energy systems – Terms, definitions and symbols*

~~IEC 62053-21, *Electricity metering equipment (a.c.) – Particular requirements – Part 21: Static meters for active energy (classes 1 and 2)*~~

IEC 62053-22, *Electricity metering equipment – Particular requirements – Part 22: Static meters for AC active energy (classes 0,1S, 0,2S and 0,5S)*

IEC 62670-3, *Photovoltaic concentrators (CPV) – Performance testing – Part 3: Performance measurements and power rating*

IEC 62817:2014, *Photovoltaic systems – Design qualification of solar trackers*

ISO/IEC Guide 98-1, *Uncertainty of measurement – Part 1: Introduction to the expression of uncertainty in measurement*

ISO/IEC Guide 98-3, *Uncertainty of measurement – Part 3: Guide to the expression of uncertainty in measurement (GUM:1995)*

ISO 9060:2018, *Solar energy – Specification and classification of instruments for measuring hemispherical solar and direct solar radiation*

ISO 9488, *Solar energy – Vocabulary*

~~ISO 9846, *Solar energy – Calibration of a pyranometer using a pyrheliometer*~~

~~ISO 9847, *Solar energy – Calibration of field pyranometers by comparison to a reference pyranometer*~~

~~WMO No. 8, *Guide to meteorological instruments and methods of observation*~~

~~ASTM G183, *Standard Practice for Field Use of Pyranometers, Pyrheliometers and UV Radiometers*~~

3 Terms and definitions

For the purposes of this document, the terms and definitions given in IEC 60050-131, IEC TS 61836, ISO 9488, and the following apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

3.1
sample
data acquired from a sensor or measuring device

3.2
sampling interval
time between samples

3.3
record
data recorded and stored ~~in data log, based on acquired samples~~

3.4
recording interval
τ
time between records

3.5
report
aggregate value based on series of records

3.6
reporting period
time between reports

3.7
front side
side of a surface which normally faces the sky

3.8
rear side
side of a surface which normally faces the ground

3.9
monofacial PV device
PV device in which only the front side is used for power generation

3.10
bifacial PV device
PV device in which both front side and rear side are used for power generation

3.11
bifaciality coefficient
φ
ratio between an I-V characteristic of the rear side and the front side of a bifacial device, typically at Standard Test Conditions (STC), unless otherwise specified

Note 1 to entry: Bifaciality coefficients include the short-circuit current bifaciality coefficient φ_{Isc}, the open-circuit voltage bifaciality coefficient φ_{Voc} and the maximum power bifaciality coefficient φ_{Pmax}.

Note 2 to entry: Bifaciality coefficients are defined in IEC TS 60904-1-2.

3.12
irradiance
G
incident flux of radiant power per unit area

Note 1 to entry: Expressed in units of W·m^{-2}.

3.13
in-plane irradiance
$\mathrm{G_i}$ or POA
sum of direct, diffuse, and ground-reflected irradiance incident upon the front side of an inclined surface parallel to the plane of the modules in the PV array, also known as plane-of-array (POA) irradiance

Note 1 to entry: Expressed in units of W·m^{-2}.

3.14
horizontal albedo
ρ_H
proportion of incident light reflected by a ground surface as measured in a horizontal plane

Note 1 to entry: It is a property of a ground surface and is a dimensionless quantity on a scale from 0 to 1.

3.15
in-plane rear-side irradiance ratio

ρ_i

ratio of the irradiance incident on the rear side of the modules in the PV array to the irradiance incident on the front side

Note 1 to entry: It is a dimensionless quantity but can exceed a value of 1 since, in addition to reflected light, diffuse and direct components of the solar resource may also be measured on the rear-side of the plane of array.

3.16
spectrally matched in-plane rear-side irradiance ratio

ρ_i^{SP}

in-plane rear-side irradiance ratio per 3.15 when both irradiance quantities are measured with a spectrally matched reference device or with the application of spectral correction factors per IEC 60904-7

3.17
spectrally matched reference device

reference device such as a PV cell or module with spectral response characteristics sufficiently close to those of the PV modules in the PV array such that spectral mismatch errors are small under the typical range of incident spectra

3.18
in-plane rear-side irradiance

$\mathrm{G_i^{rear}}$ or $\mathrm{POA^{rear}}$

sum of direct, diffuse, and ground-reflected irradiance incident on the rear side of the modules in the PV array, also known as rear-side plane-of-array irradiance

Note 1 to entry: Expressed in units of W·m^{-2}.

Note 2 to entry: (If measured via in-plane rear-side irradiance ratio): $G_i^{rear} = \rho_i \times G_i$ or $G_{i,SP}^{rear} = \rho_i^{SP} \times G_i$.

3.19
bifacial reference device

bifacial PV device, such as a cell or module, having substantially the same properties, with respect to response to front-side and rear-side irradiance, as bifacial modules to be monitored

3.20
bifacial irradiance factor

BIF

dimensionless factor that can be directly multiplied by the front-side in-plane irradiance ($\mathrm{G_i}$) to calculate the "effective" irradiance reaching a bifacial device from both the front and rear side collectively

Note 1 to entry: $BIF = (1 + \varphi_{Pmax} \times \rho_i)$ or $BIF^{sp} = (1 + \varphi_{Pmax} \times \rho_i^{SP})$. See 3.11, 3.15, 3.16.

Note 2 to entry: Rear-side POA irradiance can be measured simultaneously with front-side POA irradiance using a bifacial reference device. In that case, $BIF = G_i^{BiFi\,Ref\,Device} \div G_i$. For consistency, the front-side POA irradiance should be measured with the same or similar type of device as the bifacial reference device.

Note 3 to entry: "Effective" irradiance may include the effect of inhomogeneities in rear-side irradiance.

3.21
global horizontal irradiance

GHI

direct plus diffuse irradiance incident on the front side of a horizontal surface

Note 1 to entry: Expressed in units of W·m^{-2}.

Note 2 to entry: $GHI = DNI \cdot \cos Z + DHI$ where *Z* is the solar zenith angle.

3.22
circumsolar
immediately surrounding the solar disk

3.23
direct normal irradiance
DNI
irradiance emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5° falling on a plane surface normal to the sun's rays

~~Note 1 to entry: Some *DNI* measurement instruments have a field of view with a subtended full angle of up to 6°.~~

Note ~~2~~ 1 to entry: Expressed in units of W·m^{-2}.

Note 3 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.24
circumsolar contribution
contribution of a specific portion of the circumsolar normal irradiance to the direct normal irradiance. The circumsolar contribution refers to a specific ring-shaped angular region described by an inner and the outer angular distance from the centre of the sun (see ISO 9488)

Note 1 to entry: If the inner angle describing this angular region is the half-angle of the sun disk the circumsolar contribution is also called circumsolar ratio.

Note 2 to entry: Depending on the circumsolar irradiance measurement instrument or the solar technology involved, different wavelength ranges are included. In order to describe circumsolar irradiance correctly, the wavelength range or the spectral response of the instrument or the involved technology has to be specified.

3.25
circumsolar ratio
~~*CSR*~~
fraction of measured direct normal irradiance (*DNI*) emanating from the circumsolar region of the sky, i.e. within the angular acceptance of the *DNI* sensor but outside the solar disk

3.26
sunshape
azimuthal average radiance profile as a function of the angular distance from the centre of the sun, normalized to 1 at the centre of the sun and considering the wavelength range of shortwave radiation (see ISO 9488)

3.27
diffuse horizontal irradiance
G_d or *DHI*
global ~~horizontal~~ irradiance on the front side of a horizontal surface excluding the portion emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5°

~~Note 1 to entry: Some diffuse irradiance measurement instruments exclude a circumsolar region within a subtended full angle of up to 6°.~~

Note ~~2~~ 1 to entry: Expressed in units of W·m^{-2}.

Note 3 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.28
in-plane direct beam irradiance
$G_{i,b}$
in-plane irradiance incident upon the front side of an inclined surface parallel to the plane of the modules in the PV array emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5°~~, excluding scattering and reflections~~

Note 1 to entry: The in-plane direct beam irradiance $G_{i,b} = \cos(\theta) \times DNI$, where θ is the angle between the sun and the normal to the plane. When the plane of array is normal to the sun, $G_{i,b} = DNI$.

Note 2 to entry: Expressed in units of W·m^{-2}.

~~3.15~~
~~**in-plane diffuse irradiance**~~
~~$G_{i,d}$~~
~~in-plane irradiance excluding the direct beam irradiance~~

~~Note 1 to entry: $G_{i,d} = G_i - G_{i,b}$.~~

~~Note 2 to entry: Expressed in units of W·m^{-2}.~~

3.29
irradiation
H
irradiance integrated over a specified time interval

Note 1 to entry: Expressed in units of kW-h·m^{-2}.

3.30
standard test conditions
STC
~~reference values of~~ in-plane irradiance 1 000 W·m^{-2}, normal incidence, PV cell junction temperature 25 °C, and the reference spectral irradiance defined in IEC 60904-3

3.31
soiling ratio
SR
ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling

3.32
soiling level
SL
fractional power loss due to soiling, given by $1 - SR$

3.33
soiling rate
rate of change of soiling ratio, typically expressed in percent per day

3.34
active power
P
under periodic conditions, mean value, taken over one period, of the instantaneous product of current and voltage

Note 1 to entry: Under sinusoidal conditions, the active power is the real part of the complex power.

Note 2 to entry: Expressed in units of W.

3.35
apparent power
S
product of the rms voltage between the terminals of a two-terminal element or two-terminal circuit and the rms electric current in the element or circuit

Note 1 to entry: Under sinusoidal conditions, the apparent power is the modulus of the complex power.

Note 2 to entry: Expressed in units of VA.

3.36
power factor
λ
under periodic conditions, ratio of the absolute value of the active power P to the apparent power S:

$$\lambda = \frac{|P|}{S}$$

4 Monitoring system classification

~~The required accuracy and complexity of the monitoring system depends on the PV system size and user objectives. This document defines three classifications of monitoring systems providing varying levels of accuracy, as listed in Table 1.~~

~~The monitoring system classification shall be stated in any conformity declarations to this standard. The monitoring system classification may be referenced either by its letter code (A, B, C) or its name (high accuracy, medium accuracy, basic accuracy) as indicated in Table 1. In this document, the letter codes are used for convenience.~~

~~Class A or Class B would be most appropriate for large PV systems, such as utility-scale and large commercial installations, while Class B or Class C would be most appropriate for small systems, such as smaller commercial and residential installations. However, users of the standard may specify any classification appropriate to their application, regardless of PV system size.~~

This document defines two classifications of monitoring system, Class A and Class B.

Class A is intended for large PV systems such as utility-scale or large commercial installations.

Class B is intended for smaller systems such as rooftop or small to medium-size commercial installations.

Users of the document may specify whichever classification is most appropriate to their application, regardless of PV system size.

The monitoring system classification shall be stated in any conformity declarations to this document.

Throughout this document, some requirements are designated as applying to a particular classification. Where no designation is given, the requirements apply to ~~all~~ both classifications.

~~**Table 1 – Monitoring system classifications and suggested applications**~~

~~Typical applications~~	~~Class A High accuracy~~	~~Class B Medium accuracy~~	~~Class C Basic accuracy~~
~~Basic system performance assessment~~	~~X~~	~~X~~	~~X~~
~~Documentation of a performance guarantee~~	~~X~~	~~X~~	
~~System losses analysis~~	~~X~~	~~X~~	
~~Electricity network interaction assessment~~	~~X~~		
~~Fault localization~~	~~X~~		
~~PV technology assessment~~	~~X~~		
~~Precise PV system degradation measurement~~	~~X~~		

5 General

5.1 Measurement precision and uncertainty

~~Where requirements on measurement uncertainties are stated in the document, they refer to the combined uncertainties of the measurement sensors and any signal-conditioning electronics.~~

~~Measurement uncertainties shall apply over the typical range of values of each measured quantity indicated in the document, as well as over the typical temperature range at which the system will operate. The effect of non-linearity of the measurement within the typical range shall be included within the stated uncertainty.~~

Measurement precision refers to repeatability and resolution, which have the meanings defined in the IEC Electropedia.

Measurement uncertainty refers to accuracy and otherwise has the meaning defined in the IEC Electropedia.

Measurement uncertainties can be calculated as outlined in ISO/IEC Guide 98-1 and ISO/IEC Guide 98-3.

5.2 Calibration

~~Sensors and signal-conditioning electronics used in the monitoring system shall be calibrated prior to the start of monitoring.~~

Recalibration of sensors and signal-conditioning electronics is to be performed as ~~required~~ recommended by the manufacturer or at more frequent intervals where specified in the standard.

It is recommended to perform periodic cross-checks of each sensor against sister sensors or reference devices in order to identify out-of-calibration sensors.

5.3 Repeated elements

Depending on system size and user requirements, the monitoring system may include redundancy in sensors and/or repetition of sensor elements for different components or subsections of the full PV system. Accordingly, the measured and calculated parameters defined in this document may have multiple instances, each corresponding to a subsection or subcomponent of the PV system.

5.4 Power consumption

The parasitic power drawn by ~~tracking, monitoring, and other ancillary~~ any systems required for operation of the PV plant shall not be considered ~~a power loss of the plant, not~~ as a load supplied by the plant.

5.5 Documentation

~~Specifications of all components of the monitoring system, including sensors and signal-conditioning electronics, shall be documented.~~

~~User guides shall be provided for the monitoring system software.~~

~~All system maintenance, including cleaning of sensors, PV modules, or other soiled surfaces, shall be documented.~~

~~A log should be kept to record unusual events, component changes, sensor recalibration, changes to the data acquisition system, changes to the overall system operation, failures, faults, or accidents.~~

~~When a conformity declaration is made, documentation shall demonstrate consistency with the indicated class A, B, or C.~~

Details of all components of the monitoring system shall be documented. All system inspection and maintenance, including cleaning, shall be documented.

5.6 Inspection

~~For Class A and Class B the monitoring system should be inspected at least annually and preferably at more frequent intervals, while for Class C inspection should be per site-specific requirements. Inspection should look for damage to or displacement of exterior sensors, evidence of moisture or vermin in enclosures, loose wiring connections at sensors or within enclosures, detachment of temperature sensors, embrittlement of attachments, and other potential problems.~~

The monitoring system shall be inspected at least annually and preferably at more frequent intervals. Inspection should look for damage, deterioration, or disconnection of sensors and electrical enclosures, soiling or displacement of optical sensors, loose wiring connections, detachment of temperature sensors, embrittlement of attachments, and other potential problems.

6 Data acquisition timing and reporting

6.1 Samples, records, and reports

Figure 2 illustrates the relations between samples, records, and reports.

A sample is data acquired from a sensor or measuring device. The sampling interval is the time between samples. Samples do not need to be permanently stored.

A record is data entered into ~~a data log for~~ data storage, based on acquired samples. The recording interval, denoted by τ in this document**,** is the time between records. The recording interval should be an integer multiple of the sampling interval, and an integer number of recording intervals should fit within 1 h.

The recorded parameter value for each record is the average, maximum, minimum, sum, or other function of the samples acquired during the recording interval, as appropriate for the measured quantity. The record can also include supplementary data such as additional statistics of the samples, number of missing data points, error codes, transients, and/or other data of special interest. (For wind data records, see statement in 9.3.)

A report is an aggregate value covering multiple recording intervals. The reporting period is the time between reports. Typically the reporting period would be chosen to be days, weeks, months, or years.

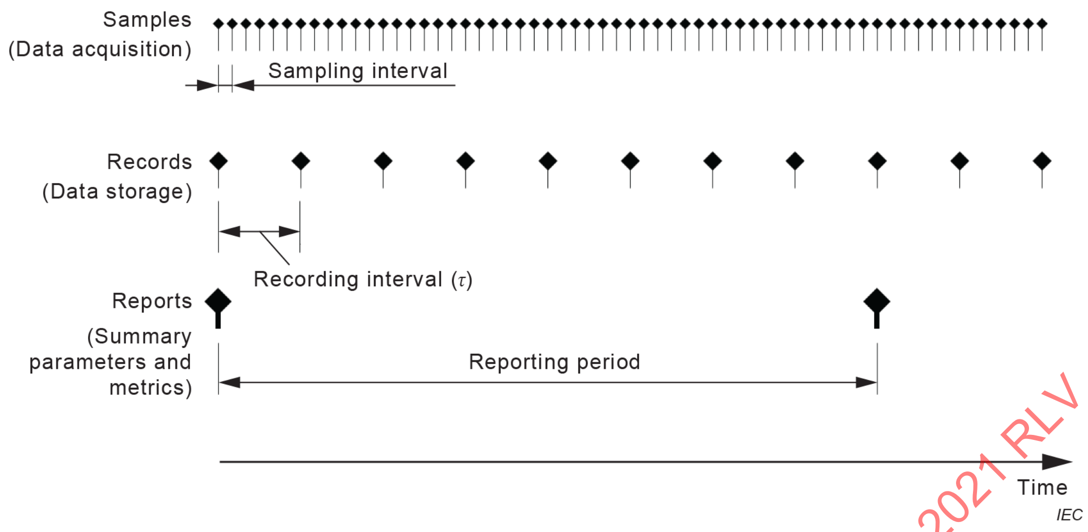


Figure 2 – Samples, records and reports

Table 1 lists maximum values for sampling intervals and recording intervals.

Further considerations relating to the sampling interval are addressed in Annex A. The maximum sampling interval for Class A is longer than the typical signal and instrument time constants for irradiance, wind and electrical output, however, the value is chosen for practicality considering common data acquisition systems.

The indicated sampling and recording interval recommendations apply to on-site ground-based measurements. For satellite-based measurement of irradiance, longer intervals of up to 1 h may be used. A ground-based instrument will require frequent samples to construct a valid time average over a recording interval, e.g. in the case of partly cloudy conditions, while satellite-based estimation uses the spatial average of many pixels in a single image as a substitute for time averaging.)

Table 1 – Sampling and recording interval requirements

	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~**Maximum sampling interval**~~			
~~For irradiance, temperature, wind*, and electrical output~~	~~3 s~~	~~1 min**~~	~~1 min**~~
~~For soiling, rain, snow, and humidity~~	~~1 min~~	~~1 min**~~	~~1 min**~~
~~**Maximum recording interval**~~	~~1 min~~	~~15 min~~	~~60 min~~

~~* See statement in 7.3.3 regarding including maximum and minimum readings in wind data records.~~

~~** The indicated sampling interval requirements for class B and class C apply to ground-based measurements, but do not apply when using satellite-based estimation of irradiance or meteorological parameters. (A ground-based instrument will require frequent samples to construct the proper average over a recording interval, e.g. in the case of partly cloudy conditions, while satellite-based estimation may derive the same average from a single image during the reporting period.)~~

	Class A High accuracy	Class B Medium accuracy
Maximum sampling interval For irradiance, temperature, wind and electrical output	5 s	1 min
Maximum recording interval	5 min (1 min – recommended)	15 min

6.2 Timestamps

Each record and each report shall include a timestamp.

Timestamp data shall include the date and time corresponding to the beginning or end of the recording interval or reporting period and the choice shall be specified.

The time should refer either to local standard time (not daylight savings time) or universal time, to avoid winter/summer time changes, and the choice of time shall be specified.

Midnight shall be treated as the start of a new day and expressed as 00:00:00.

When multiple data acquisition units are involved that each independently apply timestamps, the clocks of the units ~~shall~~ should be synchronized, preferably by an automated mechanism such as global positioning system (GPS) or network time protocol (NTP).

~~It is recommended that documentation of timestamps follow ISO 8601, *Data elements and interchange formats – Information interchange – Representation of dates and times*.~~

6.3 Parameter names

For consistency in data extraction across multiple platforms, it is recommended to use standardized parameter names. Standardized names for parameters in this document are listed in *Orange Button Taxonomy Data Definitions*.

7 ~~Measured parameters~~ Required measurements

~~7.1 General requirements~~

Table 2 lists measured parameters defined by this document and a summary of measurement requirements.

The purpose of each monitoring parameter is listed in Table 2 in order to guide the user. More details and additional requirements are provided in the subsequent referenced subclauses.

A check mark (√) in Table 2 indicates a required parameter to be measured on site, qualified by specific notes where included.

The symbol ~~"E"~~ "R" in Table 2 indicates a parameter that may be ~~estimated~~ determined based on ~~local or regional~~ remote meteorological data or satellite data, rather than by on-site measurement.

Table 2 lists the minimum number of on-site sensors where required. In many cases ~~by reference to~~ this is shown as a factor times a multiplier from Table 3. Where no number is given, only one sensor is required, although redundant sensors are typically advisable.

When multiple sensors are required, they shall be distributed throughout the PV plant at representative locations or placed at monitoring points indicated in the table where specified. If the plant includes multiple sections that have different ~~PV~~ technology types or substantially different local geography or other operation characteristics, then at least one sensor shall be placed in each such section and additional sensors shall be added, if necessary, to meet this requirement.

Empty cells in Table 2 indicate optional parameters that may be chosen for specific system requirements or to meet project specifications.

~~NOTE The most significant and direct impacts on PV performance are in-plane irradiance received by the PV array, the PV cell temperature, and shading losses due to soiling or snow. Monitoring of meteorological parameters listed in Table 3 aids in estimating some of these factors independently, provides the ability to compare to historical meteorological data for the site, and can aid in identifying system design or maintenance problems. Additional parameters listed in Table 3 aid in fault localization and assessing utility grid interactions.~~

Table 2 – Measured parameters and requirements ~~for each monitoring system class~~

~~Parameter~~	~~Symbol~~	~~Units~~	~~Monitoring purpose~~	~~Required?~~			~~Number of sensors~~
				~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~	
~~**Irradiance (see 7.3)**~~							
~~In-plane irradiance (POA)~~	~~G_i~~	~~$W{\cdot}m^{-2}$~~	~~Solar resource~~	~~√~~	~~√ or E~~	~~√ or E~~	~~Table 4 column 1~~
~~Global horizontal irradiance~~	~~*GHI*~~	~~$W{\cdot}m^{-2}$~~	~~Solar resource, connection to historical and satellite data~~	~~√~~	~~√ or E~~		~~Table 4 column 1~~
~~Direct normal irradiance~~	~~*DNI*~~	~~$W{\cdot}m^{-2}$~~	~~Solar resource, concentrator~~	~~√~~ ~~for CPV~~	~~√ or E~~ ~~for CPV~~		~~Table 4 column 1~~
~~Diffuse irradiance~~	~~G_d~~	~~$W{\cdot}m^{-2}$~~		~~√~~ ~~for CPV with < 20× concentration~~	~~√ or E~~ ~~for CPV with < 20× concentration~~		~~Table 4 column 1~~
~~Circumsolar ratio~~	~~*CSR*~~						
~~**Environmental factors (see 7.3)**~~							
~~PV module temperature~~	~~T_{mod}~~	~~°C~~	~~Determining temperature-related losses~~		~~√ or E~~		~~Table 4 column 2~~
~~Ambient air temperature~~	~~T_{amb}~~	~~°C~~	~~Connection to historical data, plus estimation of PV temperatures~~	~~√~~	~~√ or E~~	~~√ or E~~	~~Table 4 column 1~~
~~Wind speed~~		~~$m{\cdot}s^{-1}$~~	~~Estimation of PV temperatures~~	~~√~~	~~√ or E~~		~~Table 4 column 1~~
~~Wind direction~~		~~degrees~~		~~√~~			~~Table 4 column 1~~
~~Soiling ratio~~	~~*SR*~~		~~Determining soiling-related losses~~	~~√~~ ~~if soiling losses expected to be >2 %~~			~~Table 4 column 1~~
~~Rainfall~~		~~cm~~	~~Estimation of soiling losses~~	~~√~~	~~√ or E~~		~~Table 4 column 1~~
~~Snow~~			~~Estimation of snow-related losses~~				

~~Parameter~~	~~Symbol~~	~~Units~~	~~Monitoring purpose~~	~~Required?~~			~~Number of sensors~~
				~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~	
~~Humidity~~			~~Estimation of spectral variations~~				
~~Tracker system (see 7.4)~~							
~~Error in dual-axis tracker primary angle~~	$\cancel{\Delta\phi_1}$	~~degrees~~	~~Tracker system fault detection, dual-axis~~	~~√~~ ~~for CPV with >20× concentration~~			~~Table 4 column 1~~
~~Error in dual-axis tracker secondary angle~~	$\cancel{\Delta\phi_2}$	~~degrees~~		~~√~~ ~~for CPV with > 20× concentration~~			~~Table 4 column 1~~
~~Single-axis tracker tilt angle~~	$\cancel{\phi_T}$	~~degrees~~	~~Tracker system fault detection, single-axis~~	~~√~~ ~~for single-axis tracker~~			~~Table 4 column 1~~
~~Electrical output (see 7.5 and 7.6)~~							
~~Array voltage (DC)~~	$\cancel{V_A}$	~~V~~	~~Energy output, diagnostics and fault localization~~	~~√~~			~~At each inverter (optionally at each combiner box or each string)~~
~~Array current (DC)~~	$\cancel{I_A}$	~~A~~		~~√~~			
~~Array power (DC)~~	$\cancel{P_A}$	~~kW~~		~~√~~			
~~Output voltage (AC)~~	$\cancel{V_{out}}$	~~V~~	~~Energy output~~	~~√~~	~~√~~		~~At each inverter and at system level~~
~~Output current (AC)~~	$\cancel{I_{out}}$	~~A~~		~~√~~	~~√~~		
~~Output power (AC)~~	$\cancel{P_{out}}$	~~kW~~		~~√~~	~~√~~	~~√~~	
~~Output energy~~	$\cancel{E_{out}}$	~~kWh~~		~~√~~	~~√~~	~~√~~	
~~Output power factor~~	$\cancel{\lambda}$		~~Utility request compliance~~	~~√~~	~~√~~		~~At each inverter and at system level~~
~~Reduced load demand~~			~~Determine utility or load request compliance and impact on PV system performance~~	~~If applicable~~	~~If applicable~~		~~At system level~~
~~System output power factor request~~	$\cancel{\lambda_{req}}$			~~If applicable~~	~~If applicable~~		~~At system level~~

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Irradiance (see Clause 8)							
In-plane irradiance (POA)	G_i	W·m^{-2}	Solar resource	√	1 × Table 3	√	
Global horizontal irradiance	GHI	W·m^{-2}	Solar resource, connection to historical and satellite data	√	1 × Table 3	√ or R	
Horizontal albedo	ρ_H	Unitless	Solar resource, rear side	√ for bifacial, Option 1 per 8.3.3	1 × Table 3		
In-plane rear-side irradiance (POA) or spectrally matched in-plane rear-side irradiance	G_i^{rear}	W·m^{-2}		√ for bifacial, Option 2 per 8.3.3	3 × Table 3		
	$G_{i,sp}^{rear}$	W·m^{-2}					
Diffuse irradiance	G_d	W·m^{-2}	Solar resource	√ for bifacial, Option 1, per 8.3.3 (optional) √ for CPV with < 20× concentration	1 × Table 3		
Direct normal irradiance	DNI	W·m^{-2}		√ for CPV	1 × Table 3		
Circumsolar contribution, circumsolar ratio, sunshape							

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Environmental factors (see Clause 9)							
PV module temperature	T_{mod}	°C	Determining temperature-related losses	√	3 × Table 3	√	
Ambient air temperature	T_{amb}	°C	Estimation of PV temperatures, connection to prediction models	√	1 × Table 3	√ or R	
Wind speed		$m \cdot s^{-1}$		√	1 × Table 3	√ or R	
Wind direction		degrees		√	1 × Table 3		
Soiling ratio	SR		Determining soiling-related losses	√ if typical annual soiling losses without cleaning expected to be > 2 %	1 × Table 3		
Rainfall		cm	Estimation of soiling losses	√	1 × Table 3	√ or R	
Snow		cm	Estimation of snow-related losses	√ if typical annual snow losses without cleaning expected to be > 2 % and soiling measurement does not measure snow loss	1 × Table 3		
Humidity		%	Estimation of spectral variations				
Tracker system (see Clause 10)							
Single-axis tracker tilt angle	ϕ_T	degrees	Tracker system fault detection, single-axis	√ for single-axis tracker	1 × Table 3		
Dual-axis tracker error in primary angle	$\Delta\phi_1$	degrees	Tracker system fault detection, dual-axis	√ for dual-axis tracker	1 × Table 3		
Dual-axis tracker error in secondary angle	$\Delta\phi_2$	degrees					

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Electrical output (see Clause 11)							
Array voltage (DC)	V_A	V	Energy output, diagnostics and fault localization	√	At each inverter – if applicable (see 11.1)		
Array current (DC)	I_A	A		√			
Array power (DC)	P_A	kW		√			
Output voltage (AC)	V_{out}	V		√	At each inverter and at system level	√	At each inverter and at system level
Output current (AC)	I_{out}	A		√		√	
Output power (AC)	P_{out}	kW		√		√	
Output energy	E_{out}	kWh		√		√	
Output power factor	λ		Utility request compliance	√		√	
Reduced load demand			Determine utility or load request compliance and impact on PV system performance	√	At system level		
System output power factor request	λ_{req}			√	At system level		

Table 3 – ~~Relation between system size (AC) and number of sensors for specific sensors~~ Multiplier referenced in Table 2

~~System size (AC)~~	~~Number of sensors~~	
	~~Column 1~~	~~Column 2~~
~~< 5 MW~~	~~1~~	~~6~~
~~≥ 5 MW to < 40 MW~~	~~2~~	~~12~~
~~≥ 40 MW to < 100 MW~~	~~3~~	~~18~~
~~≥ 100 MW to < 200 MW~~	~~4~~	~~24~~
~~≥ 200 MW to < 300 MW~~	~~5~~	~~30~~
~~≥ 300 MW to < 500 MW~~	~~6~~	~~36~~
~~≥ 500 MW to < 750 MW~~	~~7~~	~~42~~
~~≥ 750 MW~~	~~8~~	~~48~~

System size (AC) MW	Multiplier
< 40	2
≥ 40 to < 100	3
≥ 100 to < 300	4
≥ 300 to < 500	5
≥ 500 to < 700	6
≥ 700	7, plus 1 for each additional 200 MW.

8 Irradiance

~~7.2.1 On-site irradiance measurement~~

~~7.2.1.1 General~~

~~Irradiance quantities are to be directly measured on-site when required by Table 3.~~

~~7.2.1.2 In-plane irradiance~~

~~For flat plate systems, in-plane irradiance is measured with an irradiance sensor with aperture oriented parallel to the plane of array (POA), having a field of view of at least 160° (in any plane perpendicular to the sensor aperture), mounted either on the module support structure or on another structure that is aligned parallel to the modules.~~

~~See 7.2.1.4, 7.2.1.5, and 7.2.1.7 for sensor choices and requirements.~~

~~In the case of tracked systems, the irradiance sensor shall be continuously aligned with the actual plane of array of the modules, including backtracking, if used.~~

~~For concentrator systems, see 7.2.1.8.3.~~

~~NOTE 1 The measurement of irradiance on a tracked surface can become erroneous if the tracker supporting the sensor does not track correctly. An approach to verification is to use the measured direct normal irradiance and horizontal diffuse irradiance, DNI and G_d respectively, and a transposition model to calculate the expected in-plane irradiance and then compare this with the measured value.~~

~~NOTE 2 POA irradiance can also be estimated from GHI using a decomposition and transposition model.~~

~~7.2.1.3 Global horizontal irradiance~~

~~Global horizontal irradiance (*GHI*) is measured with a horizontally oriented irradiance sensor.~~

~~See 7.2.1.4, 7.2.1.5, and 7.2.1.7 for sensor choices and requirements.~~

~~NOTE 1 Measurements of horizontal irradiance are useful for comparison to historical meteorological data and can be relevant to documentation of a performance guarantee.~~

~~NOTE 2 GHI can also be estimated from POA irradiance using a decomposition and transposition model.~~

~~7.2.1.4 Irradiance sensors~~

~~Suitable irradiance sensors include the following:~~

- ~~thermopile pyranometers;~~
- ~~PV reference devices, including reference cells and reference modules; and~~
- ~~photodiode sensors.~~

~~Thermopile pyranometers shall be classified according to ISO 9060 or WMO No. 8. Pyranometers shall be calibrated as stipulated by ISO 9846 or ISO 9847.~~

~~For class A systems, angle of incidence and temperature corrections to pyranometer measurements should be considered; see ASTM G183.~~

~~PV reference devices shall conform to IEC 60904-2 and be calibrated and maintained in accordance with procedures therein. The devices shall meet the short circuit current versus irradiance linearity requirements of IEC 60904-10. PV reference device calibration is to be performed with respect to the reference spectrum provided in IEC 60904-3.~~

~~Table 5 lists sensor choices and accuracy requirements for in-plane and global irradiance measurement, and Table 7 lists maintenance requirements for these sensors.~~

~~The sensor, signal-conditioning electronics, and data storage shall provide a range including at least 0 W·m^{-2} to 1 500 W·m^{-2} and a resolution of ≤ 1 W·m^{-2}.~~

~~NOTE Over-irradiance in the range 1 000 W·m^{-2} to 1 500 W·m^{-2} or higher can occur due to reflections from clouds under partly cloudy conditions.~~

~~Table 5 – Sensor choices and requirements for in-plane and global irradiance~~

~~Sensor Type~~	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Thermopile pyranometer~~	~~Secondary standard per ISO 9060~~ ~~or~~ ~~High quality per WMO Guide No. 8~~ ~~(Uncertainty ≤ 3 % for hourly totals)~~	~~First class per ISO 9060~~ ~~or~~ ~~Good quality per WMO Guide No. 8~~ ~~(Uncertainty ≤ 8 % for hourly totals)~~	~~Any~~
~~PV reference device~~	~~Uncertainty ≤ 3 %~~ ~~from 100 W·m^{-2} to 1 500 W·m^{-2}~~	~~Uncertainty ≤ 8 %~~ ~~from 100 W·m^{-2} to 1 500 W·m^{-2}~~	~~Any~~
~~Photodiode sensors~~	~~Not applicable~~	~~Not applicable~~	~~Any~~

~~Each irradiance sensor type has its benefits:~~

- ~~Thermopile pyranometers are insensitive to typical spectral variations and therefore measure total solar irradiance. However, this can vary from the PV-usable irradiance by 1 % to 3 % (monthly average) under typical conditions. In addition, thermopile pyranometers have long response times compared to PV devices and photodiodes.~~
- ~~Matched PV reference devices measure the PV-usable portion of the solar irradiance which correlates with the monitored PV system output. However, this may deviate from historical or meteorological measurements of irradiance, depending on instrumentation used.~~
- ~~Photodiode sensors have significantly lower cost than the other two types and are appropriate for smaller or lower cost systems, but are typically less accurate.~~

~~The angular sensitivity of the various sensors may differ from each other and from that of the PV system, becoming especially a factor when measuring global horizontal irradiance (*GHI*) in the winter or at times when the angle of incidence may be far from normal.~~

~~Thermopile pyranometers may be best for *GHI* measurement, while matched PV reference devices may be best for in-plane (POA) measurement.~~

~~7.2.1.5 Sensor locations~~

~~The location of the primary irradiance measurement sensors shall be chosen to avoid shading conditions from sunrise to sunset, if possible. If shading occurs within a half an hour of sunrise or sunset, this shall be documented.~~

~~Secondary irradiance sensors may be placed in locations that are temporarily shaded by adjacent module rows, e.g. during backtracking of a tracking system, in order to monitor this shading effect, but the performance metrics always use unshaded sensors unless explicitly noted.~~

~~The irradiance measurement sensors shall be placed so as to capture the irradiance without impact from local surroundings (shading or reflections), including nearby portions of the PV array, at all times of the year, from sunrise to sunset. When mounted near or on a building, care should be used to identify nearby vents that could discharge vapors that could condense on the sensors.~~

~~For plane-of-array measurement, for either fixed-tilt or tracking systems, irradiance sensors shall be placed at the same tilt angle as the modules, either directly on the module racking or on an extension arm maintained at the same tilt angle as the modules, avoiding shadings and reflections completely.~~

~~NOTE The measured irradiance may differ depending on the position of the sensor. For example, if the sensor is placed below a row of modules, it may show a different reading than when placed above the row of modules, since a contribution to the irradiance in a tilted plane originates from the ground or nearby features.~~

~~The local albedo should be representative of the albedo experienced by the system without the effects of adjacent module shading. If the ground covering is not a constant throughout the field, the ground covering next to the irradiance sensors shall be documented relative to what is present in the rest of the field.~~

~~7.2.1.6 Sensor alignment~~

~~Irradiance sensor angular alignment accuracy requirements are listed in Table 6.~~

~~Table 6 – Irradiance sensor alignment accuracy~~

	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Tilt angle~~	~~1°~~	~~1,5°~~	~~2°~~
~~Azimuthal angle~~	~~2°~~	~~3°~~	~~4°~~

~~The following are suggested methods of aligning the irradiance sensor to the desired angles.~~

a) ~~Tilt: Adjust the sensor mounting plate to a horizontal position, verify with a digital inclinometer, level the sensor to the plate, and secure the sensor to the plate; then adjust the mounting plate to the desired tilt angle as verified with the digital inclinometer, and tighten the plate's tilt adjustment when done.~~

b) ~~Azimuth: Using a GPS receiver, start at the sensor's location and then walk out approximately 100 m in the direction of the desired azimuth, then mark this point with an indicator such as a flag; returning to the sensor, sight along a square edge of the sensor mounting plate while adjusting the mounting plate azimuthal angle until the sight line intersects the marker previously placed with the aid of the GPS receiver; tighten the mounting plate's azimuth adjustment when done.~~

~~7.2.1.7 Sensor maintenance~~

~~Irradiance sensor maintenance requirements are listed in Table 7.~~

~~Table 7 – Irradiance sensor maintenance requirements~~

~~Item~~	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Recalibration~~	~~Once per year~~	~~Once every 2 years~~	~~As per manufacturer's requirements~~
~~Cleaning~~	~~At least once per week~~	~~Optional~~	
~~Heating to prevent accumulation of condensation and/or frozen precipitation~~	~~Required in locations where condensation and/or frozen precipitation would affect measurements on more than 7 days per year~~	~~Required in locations where condensation and/or frozen precipitation would affect measurements on more than 14 days per year~~	
~~Ventilation (for thermopile pyranometers)~~	~~Required~~	~~Optional~~	
~~Desiccant inspection and replacement (for thermopile pyranometers)~~	~~As per manufacturer's requirements~~	~~As per manufacturer's requirements~~	~~As per manufacturer's requirements~~

~~Recalibration of sensors and signal-conditioning electronics should be performed on site when possible to minimize the time that sensors are offline. If sensors are to be sent off-site for laboratory recalibration, the site should be designed with redundant sensors or else backup sensors should be used to replace those taken offline, in order to prevent interruption of monitoring.~~

~~Cleaning of irradiance sensors without cleaning the modules can result in a lowering of the measured PV system performance ratio (defined in 10.3.1). In some cases contract requirements may specify that irradiance sensors are to be maintained in the same state of cleanliness as the modules.~~

~~Night-time data should be checked to ensure accurate zero-point calibration.~~

~~NOTE It is common for pyranometers to show a small negative signal, –1 W·m⁻² to –3 W·m⁻², at night time.~~

~~7.2.1.8 Additional measurements~~

~~7.2.1.8.1 Direct normal irradiance~~

~~Direct normal irradiance (*DNI*) is measured with a pyrheliometer on a two-axis tracking stage which automatically tracks the sun.~~

~~7.2.1.8.2 Diffuse horizontal irradiance~~

~~Diffuse horizontal irradiance~~ $\cancel{G_d}$ ~~(or *DHI*) is measured with a horizontally mounted irradiance sensor with a rotating shadow band or tracked ball that blocks rays emanating directly from the solar disc.~~

8.1 Sensor types

Approaches to ground-based on-site irradiance measurement include:

- Measure total broadband hemispherical solar irradiance, independent of spectral or angular distribution. Instruments with this objective are classified as pyranometers, regardless of technology type.
- Measure matched irradiance corresponding to the PV-usable portion of the incident spectral and angular distribution. PV reference devices (reference cells and modules) are used for this objective.
- Measure spectral irradiance, from which spectrally matched irradiance can be determined. Spectroradiometers or multi-spectral instruments can be used for this objective.

Measurements can be transposed between approaches using appropriate models, with some uncertainty. If used, model-based transpositions and corrections shall be documented.

Irradiance may also be determined from remote measurements using satellite instrumentation as a supplement, or replacement (when permitted by Table 2), for ground-based on-site measurements. See 8.3.12.

The selected sensor and sensor type shall be documented.

8.2 General requirements

8.2.1 Overview

This subclause 8.2 provides general requirements applicable to most on-site irradiance measurements. Subsequent subclauses on specific irradiance measurement types may include different and/or additional requirements.

8.2.2 Sensor requirements

Sensors shall meet the requirements of Table 4 according to sensor type.

Table 4 – Irradiance sensor requirements

Sensor type	Class A system	Class B system
Pyranometer	Front side (POA and GHI): Class A per ISO 9060:2018, Spectrally flat Calibration uncertainty ≤ 2 % at 1 000 $W \cdot m^{-2}$ Range up to 1 500 $W \cdot m^{-2}$ Resolution ≤ 1 $W \cdot m^{-2}$ Rear side: Class C or better per ISO 9060:2018 Calibration uncertainty ≤ 3 % at 1 000 $W \cdot m^{-2}$ Range up to 1 500 $W \cdot m^{-2}$ Resolution ≤ 1 $W \cdot m^{-2}$	Class C or better per ISO 9060:2018 Calibration uncertainty ≤ 3 % at 1 000 $W \cdot m^{-2}$ Range up to 1 500 $W \cdot m^{-2}$ Resolution ≤ 1 $W \cdot m^{-2}$
PV reference device	Working reference device per IEC 60904-2 Calibration uncertainty ≤ 2 % at 1 000 $W \cdot m^{-2}$ Range up to 1 500 $W \cdot m^{-2}$ Resolution ≤ 1 $W \cdot m^{-2}$	Working reference device per IEC 60904-2 Calibration uncertainty ≤ 3 % at 1 000 $W \cdot m^{-2}$ Range up to 1 500 $W \cdot m^{-2}$ Resolution ≤ 1 $W \cdot m^{-2}$

Pyranometers include a wide range of instrument technologies, including but not limited to thermopile pyranometers and single- or multi-photodiode-based instruments. For front-side solar irradiance measurement in Table 4, spectrally flat means that the pyranometer's broadband irradiance measurement is negligibly affected by the spectral distribution of the incident sunlight.

8.2.3 Sensor locations

8.2.3.1 Front side

The location of front-side irradiance measurement sensors, including GHI and plane-of-array sensors, shall be chosen to be representative and to avoid shading conditions from sunrise to sunset, if possible. Shading should only occur within a half hour of sunrise or sunset and any shading shall be documented.

For front-side plane-of-array irradiance measurements, for either fixed-tilt or tracking systems, sensors shall be maintained at the same tilt and azimuth angles as the modules. This may be achieved by placing the sensors either directly on the module racking or on separate poles or extension arms with tracking, if applicable.

NOTE Optionally, additional front-side irradiance sensors may be placed in locations that are temporarily shaded by adjacent module rows, e.g. during backtracking of a tracking system, in order to monitor this shading effect, but these sensors do not satisfy the requirements of Table 2 and Table 3 and the performance metrics always use unshaded sensors, unless explicitly noted.

8.2.3.2 Rear side

The location of rear-side irradiance and/or in-plane rear-side irradiance ratio sensors shall be chosen such that they have a field of view representative of the conditions present on the rear side in the majority of the array, while minimizing shading on the modules. If the expected ground surface varies throughout the site, use an appropriate quantity of sensors and sampling methodology to capture the variations. The sensors should also be placed to capture the rear-side irradiance without impact from local surroundings other than representative shading by nearby portions of the PV array.

The sensors should be placed at the same tilt angle as the modules, directly on the module racking, by using beam or rail support structures, and positioned away from row ends, mounting piers, and other sources of localized shading or enhanced illumination phenomena such as reflections from the module racking.

A concern regarding in-plane rear-side irradiance sensors and in-plane rear-side irradiance ratio sensors is the non-uniformity of the irradiance reaching the back side of the module surface from edge to edge. It is recommended to place multiple sensors along the rear side of the racking structure to follow and measure the non-uniform illumination profile throughout the day. This allows both quantifying the non-uniformity of the rear-side irradiance and calculating an effective average of the rear-side irradiance for introduction into selected performance formulas.

NOTE The measured irradiance may differ depending on the position of the sensor, especially in the case of rear-side POA sensor measurements. For example, if the sensor is placed below a row of modules, it may show a different reading than when placed above the row of modules, since a contribution to the irradiance in a tilted plane originates from the ground or nearby features.

8.2.3.3 Horizontal albedo

The location of horizontal albedo sensors shall be chosen to be representative of the albedo at the site. The sensors should be mounted at a minimum height of 1,0 m in order to allow for a sufficient field of view of irradiance reflecting from the ground and should not be shaded by vegetation or any nearby structures, including modules and the module support structure, within a ±80 degree viewing angle. Shading by the albedo measurement device and its support structure should be minimized. If the expected ground surface varies throughout the site, use an appropriate quantity of sensors and sampling methodology to capture the variations.

8.2.4 Recalibration

Recalibration of sensors shall be conducted in a manner that minimizes downtime and sensor outages in order to prevent interruption of monitoring. Effective methods may include:

- Exchanging installed sensors with new or recalibrated units
- Performing on-site recalibration of sensors where possible
- Providing redundant sensors and alternating laboratory recalibration schedules.

For Class A systems, sensors shall be recalibrated once every 2 years, or more frequently per manufacturer recommendations.

For Class B systems, recalibrate sensors according to manufacturer recommendations.

8.2.5 Soiling mitigation

For Class A systems the effects of soiling accumulation on irradiance sensors shall be mitigated. For typical sensors and installations, weekly cleaning is required. Cleaning may be employed less frequently when local conditions allow or when technology is employed which mitigates or corrects for sensor soiling equivalently to weekly cleaning or detects soiling so that cleaning can be scheduled when needed.

8.2.6 Dew and frost mitigation

For Class A systems, the effects of dew and frost accumulation on irradiance sensors shall be mitigated for locations where dew or frost is expected during more than 2 % of annual GHI-hours.

Determination of whether an installation site requires mitigation may be performed by examining typical meteorological year data for the site, paying attention to ambient temperature and dew point. For the purposes of this assessment, dew or frost is considered expected when ambient temperature is within 1,5 °C of dew point.

Various means of mitigation, including heating and external ventilation, can be effective.Irradiance sensors shall maintain their accuracy and classification while dew and frost mitigation is applied. Heating shall not disturb the sensor's accuracy and classification. For pyranometers, effective means of ensuring accurate performance while the sensor is heated may include, but are not limited to, internal and external ventilation.

8.2.7 Inspection and maintenance

Routine inspection of sensors shall be performed to check for soiling, misalignment, and other fault conditions. For Class A systems, front-side sensors shall be inspected weekly.

Sensors shall be maintained according to manufacturer requirements. Maintenance requirements may include, for example, desiccant inspection and/or replacement, where applicable.

8.2.8 Sensor alignment

Irradiance sensors for global horizontal irradiance (GHI) shall be levelled to within 0,5°.

Irradiance sensors for plane-of-array (POA) irradiance shall be aligned with their intended plane within 0,5° of tilt and 1° of azimuth (Class A) or 1° of tilt and 2° of azimuth (Class B), with the following provisions:

- When the sensors are placed directly on the module racking, the alignment requirement is met if it can be shown that the sensors are aligned to the racking to within the stated tolerances.
- When the sensors are placed on another mounting structure independent of the modules, care shall be taken to achieve and verify alignment to within stated tolerances. If alignment cannot be achieved, the alignment error shall be measured and documented.

NOTE Sensor tilt can be measured with an inclinometer. Azimuthal alignment of plane-of-array sensors can be verified by reviewing and modelling a time series of irradiance data in clear-sky conditions.

8.3 Measurements

8.3.1 Global horizontal irradiance

Global horizontal irradiance (GHI) is measured with a horizontally oriented upwards-facing irradiance sensor or is determined from the combination of direct normal irradiance and diffuse horizontal irradiance per formula in 3.21.

8.3.2 In-plane irradiance

For flat-plate systems, in-plane irradiance is measured with an irradiance sensor with aperture oriented parallel to the plane of array (POA) mounted either on the module support structure or on another structure that is aligned parallel to the modules.

In the case of tracked systems, the irradiance sensor shall be continuously aligned with the actual plane of array of the modules, including backtracking if used.

For concentrator systems, see 8.3.9.

If any trackers are programmed to operate in a non-standard way relative to the rest of the array, these trackers should be excluded as sensor locations for the purposes of Table 2 and Table 3, but may optionally receive additional complementary sensors.

NOTE 1 The measurement of irradiance on a tracked surface can become erroneous if the tracker supporting the sensor does not track correctly. An approach to verification is to use the measured direct normal irradiance and horizontal diffuse irradiance, DNI and G_d respectively, and a transposition model to calculate the expected in-plane irradiance and then compare this with the measured value.

NOTE 2 POA irradiance can also be estimated from GHI using a decomposition and transposition model.

8.3.3 In-plane rear-side irradiance

Accurately determining the rear-side solar resource of bifacial systems is difficult. The rear-side irradiance on a PV array, as well as the spectral content of the irradiance, varies strongly spatially and temporally depending on shading patterns, details of the mounting structure, ground surface properties, and seasonal variations.

Table 2 provides two options for determining rear-side irradiance in bifacial systems:

- Option 1: Measure horizontal albedo and optionally diffuse irradiance, and use an optical model, such as a view-factor or ray-tracing model, to estimate rear-side irradiance.
- Option 2: Directly measure rear-side in-plane irradiance or, optionally, spectrally matched in-plane rear-side irradiance.

Direct measurement of rear-side in-plane irradiance is performed with an irradiance sensor with aperture oriented parallel to the plane of array (*POA*) mounted on the rear side of the module support structure. This may also be performed with a bifacial reference device (see 3.19).

8.3.4 In-plane rear-side irradiance ratio

For bifacial systems, in-plane rear-side irradiance ratio is measured by taking the ratio of the in-plane rear-side irradiance (see 8.3.3) to the in-plane irradiance (see 8.3.2).

8.3.5 Horizontal albedo

Horizontal albedo is determined by measuring the downwelling irradiance from the sky in a horizontal plane (*GHI*) and the upwelling ground-reflected irradiance in a horizontal plane and calculating the ratio of upwelling to downwelling irradiance.

See Option 1 and Option 2 in 8.3.3.

8.3.6 Direct normal irradiance

Direct normal irradiance (*DNI*) is measured with an instrument that blocks or corrects for diffuse irradiance contributions. Examples include pyrheliometers, rotating shadow band radiometers, tracked disk or ball radiometers, and others. *DNI* may be calculated from *GHI* and *DHI* per the formula in 3.23.

8.3.7 Diffuse horizontal irradiance

Diffuse horizontal irradiance G_d (or *DHI*) is measured with an instrument that blocks or corrects for direct irradiance contributions. Examples include rotating shadow band radiometers, tracked disk or ball radiometers, and others. *DHI* may be calculated from *GHI* and *DNI* per the formula in 3.27.

8.3.8 Spectrally matched irradiance

For determination of the usable solar resource, optional spectral matching of irradiance measurements for the user's specific PV modules should be considered.

Spectrally matched rear-side irradiance is particularly relevant because the spectrum of ground-reflected radiation can differ significantly from the incident solar radiation.

Methods for determining spectrally matched irradiance include:

– Measuring spectrally-matched irradiance using a spectrally matched reference device per 3.17. The residual spectral mismatch can be determined by IEC 60904-7 considering typical spectra for the application. Users should select a degree of residual spectral mismatch appropriate to their application. Identical PV technology is not necessarily required; for example, commercial monocrystalline silicon reference cells will provide beneficial spectral matching (compared to broadband measurement) for most commercial crystalline silicon PV technologies.
– Measuring broadband or non-spectrally-matched irradiance, e.g. using a pyranometer, plus performing a model-based spectral mismatch correction using environmental data such as temperature, humidity, etc.
– Measuring spectral irradiance, e.g. using a spectroradiometer or other multi-spectral instrument, from which spectral correction factors may be derived and applied to broadband irradiance data to obtain spectrally matched irradiance.

8.3.9 In-plane irradiance for concentrator systems

For concentrator systems, the total in-plane irradiance is replaced by the irradiance captured by the concentrator.

– For concentrator systems that capture only the direct beam:

  The in-plane irradiance G_i is replaced by the in-plane direct beam irradiance $G_{i,b}$:

$$G_i = G_{i,b} \tag{1}$$

– For concentrator systems that capture some diffuse light in addition to the direct beam:

  The in-plane irradiance is replaced by the effective irradiance (G_{eff}) owing to partial diffuse capture, where the fraction of diffuse light is quantified by the parameter f_d:

$$G_i \rightarrow G_{eff} = (G_{i,b} + f_d \cdot (G_i - G_{i,b})) \tag{2}$$

Determination of f_d begins by obtaining full current and voltage characteristics of a CPV module over many days with varying fractions of diffuse energy; a clear day will have little diffuse energy while a cloudy day will provide mainly diffuse energy. Analysis of a diffuse fraction for a given low and medium concentration CPV module should be based upon a large number of I-V curves where global in-plane irradiance (G_i) is above 21 W·m^{-2}.

A fundamental premise of this method is that the short-circuit current (I_{sc}) can be consistently and reliably estimated by acquiring a full trace of the current-voltage (I-V) curve for the device under test (DUT) and that the temperature coefficient for the I_{sc} parameter of the DUT has been well characterized in advance. When this premise is valid, the diffuse light capture characterization of a CPV module or receiver becomes simply a matter of determining the short-circuit current, $I_{sc,0}$ normalized to standard test conditions (STC) and then relating the as-measured $I_{sc,0}$ to this reference using an "effective irradiance" G_{eff}, such as that shown in Formula (2). One significant advantage of this approach is that compensating for the effects of solar spectrum can be accomplished by adjusting only the I_{sc} parameter.

By plotting the terms on the left-hand side of Formula (3) on the y-axis of a 2D graph and by plotting $G_{i,b}/G_i$ on the x-axis, the slope and intercept can be easily determined from the form $y = mx + b$ after performing a linear regression analysis of the I_{sc} vs. $G_{i,b}/G_i$ data.

$$\frac{1000\ \mathrm{W\cdot m^{-2}}}{G_i}\times\frac{I_{sc}}{\left[1+\alpha_{I_{sc}}\times(T_c-25\ ^{\circ}\mathrm{C})\right]}=\left(I_{sc,0}\times f_d\right)+\left(\frac{G_{i,b}}{G_i}\right)\times\left(I_{sc,0}-f_d\times I_{sc,0}\right) \quad (3)$$

where

$\alpha_{I\mathrm{sc}}$ is the temperature coefficient for I_{sc},

T_c is the cell temperature in °C,

$I_{\mathrm{sc},0}$ is the short circuit current at STC ~~(see Clause 3)~~ and 0° angle of incidence.

The term f_d then becomes:

$$f_d=\frac{b}{m+b} \quad (4)$$

One limitation to this approach that should be noted is the inherent assumption that the amount of diffuse light captured will be constant throughout the entire range of climatic conditions that are being observed. This will certainly introduce noise into the measurements, but if sampling is high enough, the linear regression analysis discussed above can provide a reasonable estimate for an average amount of diffuse capture that can be used to better define the solar resource for such concentrator PV modules.

If the results observed present a clear inflection or break in the diffuse capture response behaviour of the CPV module, the regression analysis can be split into multiple parts in a piecewise manner. This could be a likely outcome given that the nature of diffuse light is quite variable in the relative amounts of circumsolar vs. isotropic diffuse light. By treating the linear regression analysis in this fashion, one can determine the amount of diffuse capture (f_d) as a function of a specific range of the $G_{\mathrm{i,b}}/G_\mathrm{i}$ ratio.

8.3.10 Spectral irradiance for concentrator systems

For concentrator systems when a power rating according to IEC 62670-3 is to be performed, the system should include a device for determining the direct normal spectral irradiance. Refer to IEC 62670-3 for additional details.

8.3.11 Circumsolar ~~ratio~~ measurements for concentrator systems

For concentrator systems, it may be useful to measure circumsolar irradiance. Circumsolar irradiance is irradiance emanating from a region of the sky immediately surrounding the solar disk. Useful parameters to measure may include circumsolar contribution, circumsolar ratio, and sunshape. See ISO 9488.

The measured direct normal irradiance (DNI) may include circumsolar contributions due to the angular acceptance of the DNI sensor. The fraction of measured DNI which is circumsolar is defined as the circumsolar ratio.

Concentrator systems may or may not be able to capture a portion of the circumsolar irradiance, depending on their design. However, measuring circumsolar ~~ratio~~ quantities may be useful for performance characterization purposes~~; however, *CSR* measurement devices have not yet been standardized~~.

8.3.12 Satellite remote sensing of irradiance

~~When permitted by Table 3, irradiance quantities may be estimated from satellite remote sensing. Such satellite-derived irradiances are extensively used for monitoring the performance of distributed generation systems including non-instrumented class B and class C systems, in order to avoid the cost and maintenance requirements of on-site measurements.~~

~~Satellite remote sensing is an indirect approach to reliably estimate site- and time-specific surface downwelling irradiance. The approach is indirect because on-board satellite instruments measure the radiance emitted/reflected by the earth's surface through the filter of the atmosphere in a selected number of visible and infrared spectral bands; surface downwelling irradiance is inferred from these on-board satellite measurements via radiative transfer models. In-plane and other irradiance components are further modeled from the radiative transfer model output.~~

~~Satellite-derived irradiances, including global horizontal, direct normal, diffuse, and in-plane irradiances are typically available in real time from commercial services.~~

~~Important considerations when selecting satellite models are as follows:~~

- ~~satellite-derived data should be carefully selected after a review of their accuracy, e.g., by reviewing application-pertinent (localized) validations associated with the data source;~~
- ~~good satellite models can be trained locally using short-term, regionally/environmentally representative ground measurements.~~

~~NOTE 1 Satellite-derived irradiances have both advantages and disadvantages compared to on-site measured irradiances. Their main advantage is their reliability and consistency in terms of calibration and maintenance. With a single set of carefully monitored on-board sensors covering entire continents at once, satellites remove the uncertainty and cost associated with on-site maintenance, instrumentation soiling, calibration drifts and location-to-location mismatches. The main limitation of satellite irradiances versus on-site measured irradiances is their intrinsic accuracy. Unlike ground-based instruments, the accuracy of satellite models is not constant in relative terms over the entire range of irradiances, but tends to be constant in absolute terms. For the primary product of the radiative transfer models — global horizontal irradiance (GHI) – well-trained satellite models typically have an accuracy of better than 2 % at 1 000 W·m^−2^, but 20 % at 100 W·m^−2^ — i.e, a constant ~20 W·m^−2^ throughout the 100 W·m^−2^ to 1 000 W·m^−2^ range. Note that this uncertainty is not defined in absolute terms, but in relation to — hence above and beyond — the ground-based instruments against which satellite models are evaluated.~~

~~NOTE 2 The best trained satellite models can deliver an accuracy of 1 % at 1 000 W·m^−2^, and 10 % at 100 W·m^−2^ – i.e, a constant ~10 W·m^−2^ throughout the 100 W·m^−2^ to 1 000 W·m^−2^ range – relative to the instrumentation used to train them. Quantities derived from the primary radiative transfer model output GHI, including tilted in-plane irradiance, direct normal irradiance, and diffuse irradiance, have a higher uncertainty due to application of secondary models. Uncertainty for tilted, south-facing (northern hemisphere) or north-facing (southern hemisphere) in-plane irradiances is typically 1,25 times larger than for GHIs, i.e. 2,5 % at 1 000 W·m^−2^ for an untrained model, and 1,25 % for a trained model, relative to the training instrumentation. Direct normal irradiance uncertainty is of the order of 4 % at full range (1 000 W·m^−2^) for an untrained model and 2 % for a trained model, relative to the training instrumentation.~~

~~NOTE 3 If satellite-derived data have not been trained for a local area, variations in the local terrain can introduce substantial error on the order of 10 %. This is especially true in a desert with white sand, which may be difficult to distinguish from white clouds in some situations.~~

~~NOTE 4 Satellite-derived data may be less accurate for short periods but more accurate when averaged over long periods. Therefore satellite-derived data may be more appropriate, for example, for evaluating system energy production over an extended period as compared to instantaneous power production.~~

Satellite remote sensing techniques use a dual approach to measuring the total surface downwelling irradiance at the global horizontal plane. The on-board satellite instruments measure the radiance emitted or reflected by the earth's surface through the column of the atmosphere at specific visible and infrared spectral bands. The emitted radiance represents conditions where cloud cover is present, so measurements by this technique need to be framed in reference of the clear sky irradiance models. Thus, the base of satellite remote sensing uses radiative transfer models to predict the clear sky condition, then satellite measurements are applied to the clear sky as reduction in irradiance due to cloud opacity.

Operating plants considering satellite remote sensed irradiance should consider the following when comparing to on-site measured irradiances. Validated sources of satellite irradiance will have documented reliability and consistency in terms of data availability and calibration, respectively. Because satellite remote sensed irradiance sources use a single set of carefully monitored on-board sensors covering entire continents at once, data can be delivered with reduced uncertainty and cost associated with on-site maintenance, instrumentation soiling, calibration drifts and location-to-location mismatches. The accuracy benefits of satellite remote sensed data come at different temporal and spatial averaging versus on-site measurements. Satellite measurement of cloud opacity occurs at the spatial scale determined by the resolution of the measurement hardware on the satellite. For most modern satellite networks, this is approximately 0,01° by 0,01° latitude or longitude (roughly 1 km by 1 km). Thus, the representation of the irradiance condition from satellite sources reflects the average irradiance over a 0,01° by 0,01° square area. In contrast, on-site measurements reflect irradiance conditions at the surface area of the sensor, effectively a single point. This difference in measurement area leads to differences in irradiance over various time averaging periods. Additionally, the satellite image capture frequency is typically less than ground hardware data logging. As a result of both effects, satellite and ground may show greater differences in irradiance measurements on the order of 10 % to 20 % for sub-hourly to hourly periods where plant operators may be seeking analysis to diagnose plant underperformance. However, at monthly up to yearly averaging periods, satellite and ground will align on the order of < 1 % to 5 %, where plant operators may be seeking analysis to demonstrate overall plant performance.

Satellite remote sensed irradiances, including global horizontal, direct normal, diffuse, and in-plane irradiances are typically available in real time from commercial services. Long-histories of satellite measurements can be beneficial to plant operators as a reference for plant performance against long-term average/financial forecast conditions.

Important considerations when selecting satellite data are as follows:

- Satellite remote sensed irradiance data should be carefully selected after a review of accuracy and uncertainty.
- Satellite accuracy and uncertainty should be assessed against quality ground data from well-maintained sensors.
- Satellite sources should have a long history of measurement to verify accuracy across changes in satellite hardware.
- Satellite sources should provide data up to current time, also for the purpose of evaluating accuracy.
- Satellite data should be versioned; e.g. the metadata about the satellite measurements should be traceable to a repeatable model basis.
- Satellite data should provide measurements at the native satellite hardware device precision.
- The satellite remote sensed method should be specifically designed for measuring solar irradiance.

9 Environmental factors

9.1 PV module temperature

PV module temperature, T_{mod}, is measured with temperature sensors affixed to the back of ~~one or more~~ PV modules.

~~The measurement uncertainty of the temperature sensors, including signal conditioning, shall be ≤ 2 °C.~~

~~Temperature sensors shall be replaced or recalibrated as per Table 8.~~

~~Table 8 – PV module temperature sensor maintenance requirements~~

~~Item~~	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Recalibration~~	~~Once every 2 years~~	~~Per manufacturer's recommendations~~	~~Not applicable~~

For bifacial modules, rear-side temperature sensors and wiring shall obscure < 10 % of the area of any cell, and wiring should be routed in between cells when possible.

Temperature sensors shall have a measurement resolution ≤ 0,1 °C and uncertainty ± 1 °C or better.

If adhesive is used to affix the temperature sensor to the back surface of the module, the adhesive should be appropriate for prolonged outdoor use at the site conditions and should be checked to be compatible with the surface material on the rear of the module to prevent degradation by the adhesive.

Adhesive or interface material between the temperature sensor and the rear surface of the module shall be thermally conductive. The total thermal conductance of the adhesive or interface layer shall be 500 $W \cdot m^{-2} \cdot K^{-1}$ or greater, in order to keep the maximum temperature difference between the module's rear surface and the temperature sensor on the order of approximately 1 K. For example, this may be achieved using a thermally conductive adhesive with thermal conductivity greater than 0,5 $W \cdot m^{-1} \cdot K^{-1}$ in a layer not more than 1 mm thick.

See Annex B for additional recommendations on temperature sensor attachment.

Care ~~shall~~ should be taken to ensure that the temperature of the cell in front of the sensor is not substantially altered due to the presence of the sensor or other factors.

NOTE 1 Cell junction temperatures are typically 1 °C to 3 °C higher than the temperature measured on the module's rear surface, depending on the module construction. The temperature difference may be estimated, as a function of irradiance, using the thermal conductivity of the module materials.

NOTE 2 An infrared image of the front of the module may help confirm that the temperature of the cell in front of the sensor is not substantially altered by the presence of the sensor or other factors.

Module temperature varies across each module and across the array ~~and substantial differences in temperature may be observed~~. ~~For example, strong winds blowing parallel to the module surfaces may introduce a temperature difference > 5 °C. Similarly, a module may be cooler near a frame that is clamped to the rack, since the rack may act as a heat sink. Concentrator modules may show even larger variations between the outer edges of the heat sink and the heat sink that is closest to the concentrated light.~~ Temperature sensors shall be placed in representative locations to capture the range of variation and allow determination of an effective average.

~~Therefore, care shall be taken to place temperature sensors in representative locations such that the desired information is obtained. For performance monitoring, a number of temperature sensors should be distributed throughout the system so that the average temperature can be determined.~~

~~In addition, when the array consists of more than one module type or includes sections with different orientations or other attributes that can affect temperature, at least one temperature sensor is required for each module type or section type, and additional sensors, if required according to array size, are to be distributed in a representative manner amongst the different module types and section types.~~

~~Module temperature measurement may also be performed with the V_{oc}-based method described in IEC 60904-5 as an alternative to using a temperature sensor in contact with the module back surface. This may require use of an additional reference module, not connected to the PV array, for temperature measurement purposes.~~

Temperature sensors shall be replaced or recalibrated as per manufacturer's requirements.

Module temperature measurement may alternatively be performed with the V_{oc}-based method described in IEC 60904-5. This may require use of an additional reference module, not connected to the PV array, for temperature measurement. The module should be independently calibrated for this purpose. The module should be held at maximum power point in between brief V_{oc} measurements to ensure temperature is representative of the PV array. Considering the degradation of V_{oc} over time, the relation between module temperature and V_{oc} should be recalibrated at periodic intervals. If the module is not held at maximum power point, a calibrated temperature offset between maximum power point and the actual operating condition should be determined.

9.2 Ambient air temperature

~~When required by Table 3, the ambient air temperature, T_{amb}, shall be measured at locations which are representative of the array conditions by means of temperature sensors located in solar radiation shields which are ventilated to permit free passage of ambient air.~~

~~Temperature sensors and signal conditioning electronics shall together have a measurement resolution ≤ 0,1 °C and maximum uncertainty ±1 °C.~~

~~Temperature sensors should be placed at least 1 m away from the nearest PV module and in locations where they will not be affected by thermal sources or sinks, such as exhausts from inverters or equipment shelters, asphalt or roofing materials, etc.~~

~~Temperature sensors shall be replaced or recalibrated as per Table 9.~~

~~Table 9 – Ambient air temperature sensor maintenance requirements~~

~~Item~~	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Recalibration~~	~~Once every 2 years~~	~~Per manufacturer's recommendations~~	~~Not applicable~~

~~When permitted by Table 3, ambient air temperature at the site may be estimated based on local or regional meteorological data.~~

Ambient air temperature, T_{amb}, is measured by means of temperature sensors located in solar radiation shields which are ventilated to permit free passage of ambient air.

The sensors shall have a measurement resolution ≤ 0,1 °C and uncertainty ±1 °C or better.

The sensors should be placed at least 1 m away from the nearest PV module and in locations where they will not be affected by thermal sources or sinks, such as exhausts from inverters or equipment shelters, asphalt or roofing materials, etc.

The sensors shall be replaced or recalibrated as per manufacturer's requirements.

9.3 Wind speed and direction

Wind speed and wind direction are used for estimating module temperatures. They may also be used for documenting warranty claims related to wind-driven damage.

Wind speed and direction are to be measured at a height and location which are representative of the array conditions and/or the conditions assumed by any applicable performance model used for a performance guarantee of the PV installation.

In addition, wind speed and direction may also be measured at heights and locations suitable for comparison with historical or contemporaneous meteorological data.

In some cases data on wind gusts (typically gusts up to 3 s in length) may be required to compare with project design requirements. When necessary the monitoring system sampling period should be sufficiently small (e.g. ≤ ~~3~~ 5 s) and the data record should contain not only averaged but also maximum values. (See 6.1.)

Wind measurement equipment ~~shall~~ should not shade the PV system at any time of day or year and should be located at a point that is sufficiently far from obstructions.

Wind speed sensor measurement uncertainty shall be ≤ 0,5 $m{\cdot}s^{-1}$ for wind speeds ≤ 5 $m{\cdot}s^{-1}$, and ≤ 10 % of the reading for wind speeds greater than 5 $m{\cdot}s^{-1}$.

Wind direction is defined as the direction from which the wind blows, and is measured clockwise from geographical north. It shall be measured with an accuracy of 5°.

Wind sensors shall be recalibrated as per ~~Table 10~~ manufacturer's recommendations.

~~**Table 10 – Wind sensor maintenance requirements**~~

~~Item~~	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Recalibration~~	~~Per manufacturer's recommendations~~	~~Per manufacturer's recommendations~~	~~Per manufacturer's recommendations~~

9.4 Soiling ratio

~~7.3.4.1 Definition~~

~~The soiling ratio is the ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling.~~

~~7.3.4.2 Equipment~~

~~Measurement of the soiling ratio requires the following:~~

~~a) A reference PV device, designated the "soiled" device, which is allowed to accumulate soiling at the same rate as the PV array. The soiled device may be either a PV reference cell or PV module, but should preferably be a PV module that is identical to or representative of those used in the PV array to be monitored so that it will soil at the same rate. It shall be mounted in the same plane as and at the average height of the PV array, preferably with identical mounting mechanisms.~~

~~b) A reference PV device, designated the "clean" device, which is regularly cleaned so that it is kept free of soiling. The clean device may be either a PV reference cell or PV module, but shall have similar spectral and angular response to the soiled device. The effect of any differences in response should be included in the measurement uncertainty. The clean device shall be mounted close to the soiled device and co-planar to it within 0,5°. Cleaning~~

~~may be performed either manually or by an automated system and shall be done daily or at least twice per week, for Class A, or at lesser intervals if desired for Class B and Class C. The clean device should be heated to remain free of frozen precipitation if installed in areas that typically receive more than 7 days of frozen precipitation per year.~~

~~c) A measurement system for measuring the maximum power (method 1 in 7.3.4.4) and/or short-circuit current (method 2 in 7.3.4.5) of the soiled device. Maximum power may be measured using I-V curve tracing or max-power-point-tracking electronics.~~

~~d) A measurement system for measuring the short-circuit current of the clean device.~~

~~e) A measurement system for measuring the temperatures of both the soiled and clean devices using temperature sensors affixed to their rear surfaces.~~

~~For items c) and d), in between measurements, the measurement system shall not hold the module in an electrical state which may cause degradation or metastable drift of the device. Therefore, typical crystalline silicon modules should be held at open-circuit (or max power) in between measurements, to avoid hot spot generation, while typical thin film modules should be held at short circuit (or max power) in between measurements. Observe the module manufacturer's directions as needed to choose the appropriate hold state.~~

~~For tracking systems, the soiled and clean devices shall be mounted in the module plane of the tracker.~~

~~7.3.4.3 Calibration~~

~~a) Choose a reference condition of irradiance and PV device temperature, e.g. STC.~~

~~b) Determine a calibration value for the short-circuit current of the clean device at the designated reference condition. It is sufficient to use the manufacturer's datasheet values.~~

~~c) Using the clean device to measure irradiance, determine calibration values for the max power (method 1 in 7.3.4.4) and/or short-circuit current (method 2 in 7.3.4.5) of the soiled device at the reference condition as follows:~~

~~1) Completely clean the soiled device.~~

~~2) Simultaneously measure the soiled device maximum power and/or short-circuit current and temperature as well as the clean device short-circuit current and temperature.~~

~~3) Using the clean device measured short-circuit current and temperature, with the calibration data determined in step b), calculate the effective irradiance.~~

~~4) Using this calculated irradiance and the measurements for the soiled device, calculate the maximum power and/or short-circuit current of the soiled device corrected to the reference condition of irradiance and temperature.~~

~~7.3.4.4 Measurement method 1 – max power reduction due to soiling~~

~~Perform the measurement as follows:~~

~~a) Measure the short-circuit current and temperature of the clean device.~~

~~b) Measure the max power and temperature of the soiled device.~~

~~c) Calculate the effective irradiance from the values measured in a), using the calibration values determined in 7.3.4.3 b).~~

~~d) Calculate the expected max power of the soiled device at the irradiance determined in c) and the temperature measured in b), using the calibration values determined in 7.3.4.3 c).~~

~~e) Calculate the soiling ratio SR by dividing the soiled device max power measured in b) by its expected max power calculated in d).~~

~~7.3.4.5 Measurement method 2 – short-circuit current reduction due to soiling~~

~~Perform the measurement as follows:~~

~~a) Measure the short-circuit current and temperature of the clean device.~~

~~b) Measure the short-circuit current and temperature of the soiled device.~~

~~c) Calculate the effective irradiance from the values measured in a), using the calibration values determined in 7.3.4.3 b).~~

~~d) Calculate the expected short-circuit current of the soiled device at the irradiance determined in c) and the temperature measured in b), using the calibration values determined in 7.3.4.3 c).~~

~~e) Calculate the soiling ratio SR by dividing the soiled device short-circuit current measured in b) by its expected short-circuit current calculated in d).~~

~~7.3.4.6 Preferred method~~

~~Method 1 (7.3.4.4) is generally preferred because it best represents the actual power loss due to soiling, and in particular it produces more accurate results when soiling may be non-uniform across the modules, especially for typical crystalline silicon modules. Method 2 (7.3.4.5) may be used when soiling is known to be uniform across the modules or when the effects of soiling non-uniformity on the ratio of maximum power to short-circuit current are known to be small due to the construction or device physics of the module, e.g. for typical thin-film modules. Both methods may be employed simultaneously and the most appropriate value or a weighted average may be used.~~

~~7.3.4.7 Daily average value~~

~~The soiling ratio measured by the method above is an instantaneous value. Since the instantaneously measured soiling ratio tends to show a time-of-day dependence due to residual angular misalignment of the two reference devices as well as angle-dependent light scattering from soiling particles, for proper interpretation the measured soiling ratio values should be integrated to compute a daily average value.~~

~~Perform the integration by calculating the irradiance-weighted average of the measured soiling ratio values for a given day. The data may be filtered to exclude outliers and/or to limit the measured values to a specific time window that minimizes the effects of angular misalignment.~~

~~NOTE For example, when the clean and soiled devices are fixed in position (not tracking), the integration could include only times within ±2 h of solar noon. When the clean and soiled devices are installed on a tracking system, analysis could include only times when solar angle of incidence is <~35°.~~

~~7.3.4.8 Recalibration~~

~~The calibration step in 7.3.4.3 shall be repeated at least annually.~~

~~Immediately following the calibration or following any significant rainfall, the measured soiling ratio should be close to unity. Significant deviation from unity indicates a problem with the setup. This can be used as a check of the calibration, so that the calibration may be repeated if necessary.~~

Per 3.31, the soiling ratio is a property of the PV array cleanliness condition. Soiling measurement instruments approximate the true soiling ratio of the PV array by measuring the impact of soiling on a sensor surface of the instrument and assuming that the soiling condition of the PV array is the same as that of the sensor surface.

Soiling measurement instruments use various physical principles:

- One measurement approach, which has many variations, compares a pair of PV reference devices, one of which is routinely cleaned and the other of which soils naturally at the same rate as the PV array. Methods for implementing this approach are described in detail in Annex C.
- Other approaches are based on optical principles, detecting soiling particles on a collection surface according to their effect on either reflection or transmission of light.

Some of the instrument types can measure the effect of non-uniform soiling on the power loss of PV modules. Non-uniform soiling occurs when deposited soiling particles move under the influence of dew, rain, wind, and gravity, often collecting along PV module edges, especially bottom edges. This can have a disproportionate effect on power, depending on module type. See Annex C.

9.5 Rainfall

Rainfall measurements may be used to estimate the cleanliness of modules. If soiling ratio is also measured, ~~the module cleanliness is directly known~~ these data are complementary.

9.6 Snow

Snowfall measurements ~~may~~ can be used to estimate losses due to shading from snow. However, these losses ~~will~~ may also be included in measurements of soiling ratio, depending on the soiling measurement device. ~~Therefore, if soiling ratio is measured, snow measurements may be unnecessary, unless the devices used for soiling measurement are not characteristic of the array or are mounted differently or at different height.~~

9.7 Humidity

Relative humidity measurements may be used to estimate changes in incident spectrum which may affect PV module power output as well as irradiance sensor readings. Humidity data with temperature data can also be used to calculate the times of wetness due to condensation. (Alternatively, surface condensation sensors can be used to directly gather these data.)

10 Tracker system

10.1 Single-axis trackers

Measurement of the real-time tracker tilt angle ϕ_T shall be ~~measured on representative trackers~~ performed with accuracy ±1° for Class A systems. Measurement may be performed with motor or position counters or other sensors integrated into the tracker mechanism, ~~if desired, and does not require separate instrumentation~~ such as an inclinometer.

10.2 Dual-axis trackers ~~for >20x systems~~

10.2.1 Monitoring

~~For high-concentration (> 20×) systems,~~ The real-time tracker pointing errors ($\Delta\phi_1$ and $\Delta\phi_2$) ~~shall be~~ are measured on representative trackers using sensors defined and calibrated as per 7.3 of IEC 62817:2014. Selected trackers should coincide with a measurement location for DC output power (see Clause 11). Reporting of tracker pointing error data shall be per 7.4.6 of IEC 62817:2014.

10.2.2 Pointing error sensor alignment

The tracker pointing error sensor is typically mounted on the tracker such that the pointing vector of the sensor is normal to the plane of the PV system.

Initial alignment of a pointing error sensor shall be confirmed by intentionally scanning across the optimal alignment while measuring the pointing error. This may be done either by driving the tracker through the desired angle in each relevant axis or by moving the tracker ahead of the sun, stopping the tracker, and waiting for the sun to move into and out of the optimal position. The measured pointing error is plotted against the normalized system maximum power divided by direct normal irradiance (DNI). The data shall be measured under clear sky conditions with wind speeds in a range from 0,5 m·s^{-1} to 3,5 m·s^{-1}, and shall be recorded within a 1 h time period. These requirements are to minimize noise associated with variation in power output from factors other than alignment.

Ideal alignment is achieved if the pointing error is zero when the irradiance-normalized power curve is at the maximum value. No tolerance is stated here for the deviation from ideal alignment as acceptable tolerance is dependent on the given system. The width of the scan will depend upon the response of the system, but should be at most ±0,75° so that the scan is compatible with the *DNI* sensor.

The test is usually applied to an individual tracker with measurement of power generation associated only with that individual tracker, but it may be possible to plot the power generation of multiple trackers as long as all of them move together.

The plots shall be included in a test report and shall serve as indication that alignment tolerance is sufficient.

11 Electrical measurements

11.1 Inverter-level measurements

~~All electrical measurements shall have a range extending up to at least 120 % of the expected electrical output when the PV array is operating at STC or up to the maximum rating of the inverter, whichever is lower.~~

~~NOTE Electrical output can significantly exceed the expected STC value due to over-irradiance (above 1 000 W·m^{-2}) and low module temperature (below 25 °C).~~

~~Electrical measurements shall have uncertainty meeting the requirements listed in Table 11 and Table 12 for measurements corresponding to ≥ 20 % of the expected electrical output when the array is operating at STC.~~

~~Table 11 lists the requirements for inverter-level electrical measurements, including DC measurements on the PV array prior to power conversion and AC measurements following power conversion. Optionally the DC measurements may be performed at each combiner box or each string in addition to or instead of at the inverters.~~

Inverter-level electrical measurements shall meet the requirements in Table 5 if applicable for the system configuration. DC measurements may be omitted when the modules include microinverters. In Table 5 precision refers to measurement repeatability and resolution, not absolute accuracy.

Optionally, for greater fault detection capability DC measurements may be performed at sublevels of the system (e.g. strings, combiners, feeders, etc.) in addition to or instead of at the inverters.

Table 5 – Inverter-level electrical measurement requirements

~~Parameter~~	~~Measurement Uncertainty~~		
	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Input voltage (DC)~~	~~±2,0 %~~	~~n/a~~	~~n/a~~
~~Input current (DC)~~	~~±2,0 %~~	~~n/a~~	~~n/a~~
~~Input power (DC)~~	~~±2,0 %~~	~~n/a~~	~~n/a~~
~~Output voltage (AC)~~	~~±2,0 %~~	~~±3,0 %~~	~~n/a~~
~~Output current (AC)~~	~~±2,0 %~~	~~±3,0 %~~	~~n/a~~
~~Output power (AC)~~	~~±2,0 %~~	~~±3,0 %~~	~~n/a~~

Parameter	Measurement precision % of max inverter rating	
	Class A systems ~~%~~	Class B systems ~~%~~
Input voltage (DC)	±2,0	n/a
Input current (DC)	±2,0	n/a
Input power (DC)	±3,0	n/a
Output voltage (AC)	±2,0	±3,0
Output current (AC)	±2,0	±3,0
Output power (AC)	±3,0	±4,5

11.2 Plant-level measurements

~~Table 12 lists the requirements for electrical measurements at the output of the power plant, i.e. the aggregate output produced by all inverters in the system.~~

Electrical measurements at the output of the power plant shall meet the requirements of Table 6. The output of the power plant is the aggregate net output produced by the entire system.

For multi-phase systems, each phase shall be measured, or 2 of 3 phases shall be measured (two wattmeter method).

Table 6 – Plant-level AC electrical output measurement requirements

~~Parameter~~	~~Class A~~ ~~High accuracy~~	~~Class B~~ ~~Medium accuracy~~	~~Class C~~ ~~Basic accuracy~~
~~Active power and energy~~	~~Class 0,2 S~~ ~~as per IEC 62053-22~~	~~Class 0,5 S~~ ~~as per IEC 62053-22~~	~~Class 2~~ ~~per IEC 62053-21~~
~~Power factor~~	~~Class 1~~ ~~as per IEC 61557-12~~	~~Class 1~~ ~~as per IEC 61557-12~~	~~n/a~~

Parameter	Class A system	Class B system
Active power and energy	Class 0,2 S as per IEC 62053-22	Class 0,5 S as per IEC 62053-22
Power factor	Class 1 as per IEC 61557-12	Class 1 as per IEC 61557-12
Recalibration	Per manufacturer's requirements and/or local codes and contracts	Per manufacturer's requirements and/or local codes and contracts

~~7.6 External system requirements~~

For Class A, the monitoring system ~~should~~ shall document periods during which the PV system does not deliver its maximum output power to the utility grid and/or local loads as a result of external system requests or requirements, which may include, for example, system output power factor demand and system power curtailment.

12 Data processing and quality check

12.1 ~~Daylight hours~~ Night

~~Processed data for irradiance and PV-generated power should be restricted to the daylight hours of each day (sunrise to sunset, irradiance ≥ 20 W/m²) to avoid extraneous night-time data values that introduce errors in analyses, unless such errors have been demonstrated to be negligible.~~

Night-time data may contain valuable information for quality checking, such as pyranometer and other instrumentation offsets. However, processed data for irradiance, PV-generated power, and other quantities expected to be zero at night should be set to zero during night-time after quality checks are performed, to avoid extraneous values.

12.2 Quality check

12.2.1 Removing invalid readings

The measured data ~~shall~~ should be checked and filtered, either automatically or manually, to identify missing or invalid data points and filter them out of subsequent analysis. Such missing or invalid data ~~shall~~ should be documented by the monitoring system.

Recommended methods of identifying missing or invalid data points include:

- applying physically reasonable minimum and maximum limits
- applying physically reasonable limits on maximum rates of change
- applying statistical tests to identify outlying values, including comparing measurements from multiple sensors
- applying contract data to identify viable parameter boundaries for certain performance data
- noting error codes returned by sensors
- identifying and deleting redundant data entries
- identifying missing data
- identifying readings stuck at a single value for an extended time
- checking timestamps to identify gaps or duplicates in data
- checking system availability reports.

12.2.2 Treatment of missing data

Missing or invalid data may be treated in one of the following ways:

- the invalid or missing data may be replaced by values estimated from the valid data recorded before and/or after the invalid or missing data;
- the invalid or missing data may be replaced with an average value for the analyzed interval;
- the data may be treated in a manner specified in a valid contract, performance guarantee document, or other specification covering the installation;
- the analysed interval may be treated as missing or invalid.

The treatment of missing or invalid data may depend on the goal of the measurement. For example, missing or invalid data associated with inverter issues should be discarded if the goal is strictly to quantify module performance, but should be retained if the goal is to capture all aspects of plant performance and availability.

Additional recommendations and requirements for treatment of missing or invalid data are included in IEC TS 61724-2 and IEC TS 61724-3.

The specific treatment of missing or invalid data ~~shall~~ should be documented in any reports.

13 Calculated parameters

13.1 Overview

Table 7 summarizes calculated parameters which are further defined below. All quantities in the table shall be reported with respect to the reporting period (typically a day, month, or year).

Table 7 – Calculated parameters

Parameter	Symbol	Unit
Irradiation (see 13.3)		
In-plane irradiation	H_i	$kWh{\cdot}m^{-2}$
In-plane rear-side irradiation (for bifacial)	H_i^{rear}	$kWh{\cdot}m^{-2}$
Electrical energy (see 13.4)		
PV array output energy (DC)	E_A	kWh
Energy output from PV system (AC)	E_{out}	kWh
Array power rating (see 13.5)		
Array power rating (DC)	P_0	kW
Array power rating (AC)	$P_{0,AC}$	kW
Yields and yield losses (see 13.6 and 13.7)		
PV array energy yield	Y_A	$kWh{\cdot}kW^{-1}$
Final system yield	Y_f	$kWh{\cdot}kW^{-1}$
Reference yield	Y_r	$kWh{\cdot}kW^{-1}$
Array capture loss	L_C	$kWh{\cdot}kW^{-1}$
Balance of system (BOS) loss	L_{BOS}	$kWh{\cdot}kW^{-1}$
Efficiencies (Subclause 13.8)		
Array efficiency	η_A	None
System efficiency	η_f	None
BOS efficiency	η_{BOS}	None

13.2 Summations

In the formulas given below involving summation, τ_k denotes the duration of the k^{th} recording interval within a reporting period (see Clause 6), and the symbol

$$\sum_k$$

denotes summation over all recording intervals in the reporting period.

Note that in formulas involving the product of power quantities with the recording interval τ_k the power should be expressed in kW and the recording interval in hours to obtain energy in units of kWh.

13.3 Irradiation

Irradiation, also known as insolation, is the time integral of irradiance.

Each irradiation quantity H corresponding to an irradiance quantity G defined in Clause 3 is calculated by summing the irradiance as follows:

$$H = \sum_k G_k \times \tau_k \qquad (5)$$

For example, the front-side in-plane or front-side plane-of-array (POA) irradiation, H_i, is given by:

$$H_i = \sum_k G_{i,k} \times \tau_k \quad (6)$$

and rear-side in-plane or rear-side plane-of-array (POA) irradiation, H_i, is given by:

$$H_i^{rear} = \sum_k G_{i,k}^{rear} \times \tau_k \quad (7)$$

13.4 Electrical energy

13.4.1 General

Energy quantities may be calculated from the integral of their corresponding measured power parameters over the reporting period.

Alternatively, if power measurements are performed using sensors with built-in totalizers, the energy quantities may be taken directly as measurement readings from the sensors.

13.4.2 DC output energy

The PV array DC output energy is given by:

$$E_A = \sum_k P_{A,k} \times \tau_k \quad (8)$$

13.4.3 AC output energy

The AC energy output is given by:

$$E_{out} = \sum_k P_{out,k} \times \tau_k \quad (9)$$

13.5 Array power rating

13.5.1 DC power rating

The array DC power rating, P_0, is the ~~total~~ sum of the DC power output of all installed PV modules at the power rating reference condition, ~~assumed to be~~ which is either:

– standard test conditions (STC), for monofacial and bifacial modules; or

– concentrator standard test conditions (CSTC) ~~unless stated otherwise~~, for concentrator systems. P_0 is given in units of kW.

P_0 should be calculated by using data from manufacturer datasheets or module labels, or, provided that the choice is specified, using alternative data such as laboratory or on-site test data.

The definition of P_0 that is used should be specified explicitly whenever quantities that depend on P_0 are reported.

Note that the definition of P_0 ignores any rear-side contribution for bifacial modules. IEC 61215 includes provisions for measuring bifacial modules using rear-side irradiance; however, these are provided for the purpose of indoor accelerated stress testing, not performance rating.

13.5.2 AC power rating

The array AC power rating, $P_{0,AC}$, is the lesser of:

– the array DC power rating P_0, ~~or~~ and

– the sum of the inverter ratings in the system at specified operating temperature.

13.6 Yields

13.6.1 General

Yields are ratios of an energy quantity to the array power rating P_0. They indicate actual array operation relative to its rated capacity.

Yields have units of kWh·kW^{-1}, where units of kWh in the numerator describe the energy production and units of kW in the denominator describe the system power rating. The ratio of units is equivalent to hours, and the yield ratio indicates the equivalent amount of time during which the array would be required to operate at P_0 to provide the particular energy quantity measured during the reporting period.

13.6.2 PV array energy yield

The PV array energy yield Y_A is the array energy output (DC) per rated kW (DC) of installed PV array:

$$Y_A = E_A / P_0 \tag{10}$$

13.6.3 Final system yield

The final PV system yield Y_f is the net energy output of the entire PV system (AC) per rated kW (DC) of installed PV array:

$$Y_f = E_{out} / P_0 \tag{11}$$

13.6.4 Reference yield

The reference yield Y_r for a monofacial PV system can be calculated by dividing the total front-side in-plane irradiation by the module's reference plane-of-array irradiance:

$$Y_r = H_i / G_{i,ref} \tag{12}$$

where the reference plane-of-array irradiance $G_{i,ref}$ (kW·m^{-2}) is the irradiance at which P_0 is determined, usually defined under STC.

The reference yield represents the number of hours during which the solar radiation would need to be at reference irradiance levels in order to contribute the same incident solar energy as was monitored during the reporting period while the utility grid and/or local load were available.

If the reporting period is equal to one day, then Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

13.6.5 Bifacial reference yield

The reference yield Y_r^{bi} for a bifacial PV system can be calculated by taking the product of the front-side in-plane irradiation and the bifacial irradiance factor and dividing by the module's reference plane-of-array irradiance:

$$Y_r^{bi} = \sum_k (G_{i,k} \times \tau_k \times BIF_k) / G_{i,ref} \tag{13}$$

The reference yield represents the number of hours during which the solar radiation would need to be at reference irradiance levels in order to contribute the same incident solar energy as was monitored during the reporting period while the utility grid and/or local load were available.

If the reporting period is equal to one day, then Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

13.7 Yield losses

13.7.1 General

Yield losses are calculated by subtracting yields. The yield losses also have units of kWh· kW^{-1} (or h). They represent the amount of time the array would be required to operate at its rated power P_0 to provide for the respective losses during the reporting period.

13.7.2 Array capture loss

The array capture loss L_c represents the losses due to array operation, including losses in wiring and junction boxes prior to DC measurement, array temperature effects, soiling, etc., and is defined as:

$$L_C = Y_r - Y_A \tag{14}$$

13.7.3 Balance of systems (BOS) loss

The balance of systems (BOS) loss L_{BOS} represents the losses in the BOS components, including the inverter and all wiring and junction boxes not included in array capture loss, and is defined as:

$$L_{BOS} = Y_A - Y_f \tag{15}$$

13.8 Efficiencies

13.8.1 Array (DC) efficiency

The rated array efficiency is given by:

$$\eta_{A,0} = P_0 / (G_{i,ref} \times A_a) \tag{16}$$

where the overall array area A_a is the total module area, corresponding to the sum of the areas of the front surfaces of the PV modules as defined by their outer edges.

For a concentrator module, if the front surface is not coplanar, the front surface shall be projected onto an appropriate two-dimensional surface to define the area.

The mean actual array efficiency over the reporting period is defined by:

$$\eta_A = E_A / (H_i \times A_a) \tag{17}$$

13.8.2 System (AC) efficiency

The mean system efficiency over the reporting period is defined by:

$$\eta_f = E_{out} / (H_i \times A_a) \tag{18}$$

Formula (18) can also be rewritten as:

$$\eta_f = \eta_{A,0} \times PR \tag{19}$$

where

$\eta_{A,0}$ is the rated array efficiency defined in 13.8.1, and

PR is the performance ratio defined in 14.3.1.

13.8.3 BOS efficiency

The mean BOS efficiency over the reporting period is defined by:

$$\eta_{BOS} = E_{out} / E_A \tag{20}$$

14 Performance metrics

14.1 Overview

Performance metrics are listed in Table 8 and further defined in subsequent subclauses.

Table 8 – Performance metrics

Parameter	Symbol	Units
Rating-based (see 14.3)		
Performance ratio	PR	None
Annual performance ratio	PR_{annual}	None
25 °C performance ratio	$PR'_{25°C}$	None
Annual-temperature-equivalent performance ratio	$PR'_{\text{annual-eq}}$	None
~~STC temperature performance ratio~~	~~PR'_{STC}~~	~~None~~
Annual-temperature-equivalent performance ratio for bifacial systems	$PR'_{\text{annual-eq, bi}}$	None
Model-based (14.4)		
Power performance index	PPI	None
Energy performance index	EPI	None
Baseline power performance index	$BPPI$	None
Baseline energy performance index	$BEPI$	None

~~A number of metrics are defined here for quantifying system performance. These are listed in Table 14 and are further defined in the subsequent indicated sections. The most appropriate metric for a given system depends on the system design and user requirements.~~

~~Performance ratios (see 10.3) are based on the system name-plate rating, while a performance index (see 10.4) is based on a more detailed model of system performance.~~

Performance metrics in Table 8 are either rating-based (see 14.3) or model-based (see 14.4). The most appropriate metric for a given application depends on system design, user requirements, and contractual obligations. This document does not specify requirements on the metrics used.

The rating-based performance ratio metrics are relatively simple to calculate but may omit known factors that cause system power output to deviate from expectations based on the name-plate rating alone. For example, systems with high DC-to-AC ratio operate at less than the DC nameplate rating during times of high irradiance, but this is an expected attribute of the system design. Similar effects may be observed when evaluating performance ratios for tracking and/or bifacial systems. Such effects are better treated by a performance index based on a detailed system model.

~~NOTE The performance ratios compare the measured outdoor performance and the module name plate value. In this case, use of a matched reference cell calibrated according to IEC 60904 (consistently with the IEC 60904 determination of the module power rating) gives the most consistent comparison.~~

14.2 Summations

See 13.2 for an explanation of formulas given in 14.3 involving summations.

14.3 Performance ratios

14.3.1 Performance ratio

The performance ratio PR is the quotient of the system's final yield Y_{f} to its reference yield Y_{r}, and indicates the overall effect of losses on the system ~~output due to both array temperature and system component inefficiencies or failures, including balance of system components~~. (Alternatively, the performance ratio can be defined as a product of derate factors. See Annex D.) For monofacial PV systems it is defined as:

$$PR = Y_f / Y_r \tag{21}$$

$$= (E_{out} / P_0) / (H_i / G_{i,ref}) \tag{22}$$

Expanding Formula (22) gives:

$$PR = \left(\sum_k \frac{P_{out,k} \times \tau_k}{P_0} \right) \Bigg/ \left(\sum_k \frac{G_{i,k} \times \tau_k}{G_{i,ref}} \right) \tag{23}$$

Both the numerator and denominator of Formula (23) have units of kWh· kW^{-1} (or h). Moving P_0 to the denominator sum expresses both numerator and denominator in units of energy, giving PR as the ratio of measured energy to expected energy (based only on measured irradiance and neglecting other factors) over the given reporting period:

$$PR = \left(\sum_k P_{out,k} \times \tau_k \right) \Bigg/ \left(\sum_k \frac{P_0 \times G_{i,k} \times \tau_k}{G_{i,ref}} \right) \tag{24}$$

The annual performance ratio, PR_{annual}, is the performance ratio of Formula (24) evaluated for a reporting period of one year.

NOTE 1 The energy expectation expressed by the denominator of Formula (24) neglects the effect of array temperature, using the fixed value of array power rating, P_0. Therefore, the performance ratio usually decreases with increasing irradiation during a reporting period, even though energy production is increased, due to increasing PV module temperature which usually accompanies higher irradiation and results in lower efficiency. This gives a seasonal variation, with higher PR values in winter and lower values in summer. It may also give geographic variations between systems installed in different climates.

NOTE 2 Calculation of the performance ratio using GHI in place of in-plane (plane-of-array) irradiance G_i is an alternative in situations where GHI measurements are available but G_i measurements are not. In this case GHI is substituted for G_i in Formula (24), resulting in a GHI performance ratio. The GHI performance ratio would typically show high values which may even exceed unity. The values cannot necessarily be used to compare one system to another, but can be useful for tracking performance of a system over time and could also be applied to compare a system's measured, expected, and predicted performance using a performance model that is based only on GHI.

14.3.2 Temperature-corrected performance ratios

14.3.2.1 General

The seasonal variation of the performance ratio PR of Formula (24) can be significantly reduced by calculating a temperature-corrected performance ratio PR'.

NOTE While variations in average ambient temperature are the most significant factor causing seasonal variations in measured performance ratio, other factors, such as seasonally dependent shading, spectral effects, and metastabilities can also contribute to the seasonal variation of PR.

14.3.2.2 ~~STC~~ 25 °C performance ratio

The ~~STC~~ 25 °C performance ratio, ~~PR'_{STC}~~ $PR'_{25\,°C}$ is calculated by adjusting the power rating at each recording interval to compensate for differences between the actual PV module temperature and the STC reference temperature of 25 °C.

~~The value of the metric will be closer to unity than for the performance ratio calculated in Formula (22).~~

~~PR'_{STC}~~ $PR'_{25\,°C}$ is calculated by introducing a power rating temperature adjustment factor $C_{k,25\,°C}$ into Formula (24), as follows:

$$\cancel{PR'_{STC} = \left(\sum_k P_{out,k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_k \times P_0) \times G_{i,k} \times \tau_k}{G_{i,ref}}\right)}$$

$$PR'_{25\,°C} = \left(\sum_k P_{out,k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_{k,25\,°C} \times P_0) \times G_{i,k} \times \tau_k}{G_{i,ref}}\right) \quad (25)$$

where $C_{k,25°C}$ is given by:

$$C_{k,25\,°C} = 1 + \gamma \times (T_{mod,k} - 25\,°C) \quad (26)$$

Here γ is the relative maximum-power temperature coefficient (in units of $°C^{-1}$), and $T_{mod,k}$ is the module temperature (in °C) in time interval k.

With reference to Formula (26), γ is typically negative, e.g. for crystalline silicon. The measured module temperature may be used for $T_{mod,k}$ in Formula (26). However, if the monitoring objective is to compare ~~PR'_{STC}~~ $PR'_{25\,°C}$ to a target value associated with a performance guarantee, $T_{mod,k}$ should instead be estimated from the measured meteorological data with the same heat transfer model used by the simulation that set the performance guarantee value to avoid a bias error.

Note that Formulas (25) and (26) can be used to calculate performance ratio adjusted to a different reference temperature by substitution of the desired reference temperature in Formula (26) in place of 25 °C.

14.3.2.3 Annual-temperature-equivalent performance ratio

The annual-temperature-equivalent performance ratio $PR'_{annual\text{-}eq}$ is constructed to approximate the annual performance ratio PR_{annual} regardless of the duration of the reporting period. It calculates the performance ratio during the reporting period with the power rating at each recording interval adjusted to compensate for differences between the actual PV module temperature and an expected annual-average PV module temperature. While this reduces seasonal variation in the metric, it does not remove the effect of annual-average temperature losses and leaves the value of the metric comparable to the value of PR_{annual}.

$PR'_{annual\text{-}eq}$ is calculated by introducing a power rating temperature adjustment factor $C_{k,annual}$ into Formula (24), as follows:

$$\cancel{PR'_{annual-eq} = \left(\sum_k P_{out,k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_k \times P_0) \times G_{i,k} \times \tau_k}{G_{i,ref}}\right)}$$

$$PR'_{\text{annual-eq}} = \left(\sum_k P_{\text{out},k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_{k,\text{annual}} \times P_0) \times G_{i,k} \times \tau_k}{G_{i,\text{ref}}}\right) \quad (27)$$

where $C_{k,\text{annual}}$ is given by:

$$C_{k,\text{annual}} = 1 + \gamma \times (T_{\text{mod},k} - T_{\text{mod,annual-avg}}) \quad (28)$$

Here γ is the relative maximum-power temperature coefficient (in units of °C^{-1}), $T_{\text{mod},k}$ is the PV module temperature in time interval k, and $T_{\text{mod,annual-avg}}$ is an annual-average module temperature.

NOTE With reference to Formula (28), γ is typically negative, e.g. for crystalline silicon.

$T_{\text{mod,annual-avg}}$ is chosen based on historical weather data for the site and an empirical relation for the predicted module temperature as a function of ambient conditions and module construction. It should be calculated by computing an irradiance-weighted average of the predicted module temperature and then verified using the historical data for the site by confirming that the annual-equivalent performance ratio $PR'_{\text{annual-eq}}$ for the historical data (using Formulas (27) and (28)) is the same as the annual performance ratio PR_{annual} for the historical data (using Formula (24)).

The measured module temperature may be used for $T_{\text{mod},k}$ in Formula (28). However, if the monitoring objective is to compare $PR'_{\text{annual-eq}}$ to a target value associated with a performance guarantee, $T_{\text{mod},k}$ should instead be estimated from the measured meteorological data with the same heat transfer model used by the simulation that set the performance guarantee value, to avoid a bias error.

14.3.3 Bifacial performance ratios

The monofacial performance ratio formulas presented above can be transformed to bifacial performance ratio formulas by introducing the bifacial irradiance factor (BIF) to correct the measured irradiance terms.

For example, the annual temperature-equivalent performance ratio for bifacial systems, $PR'_{\text{annual-eq,bi}}$ is calculated as for the monofacial equivalent in Formula (27) by multiplying the in-plane irradiance by the bifacial irradiance factor (BIF) as follows:

$$PR'_{\text{annual-eq,bi}} = \left(\sum_k P_{\text{out},k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_{k,\text{annual}} \times P_0) \times G_{i,k} \times BIF_k \times \tau_k}{G_{i,\text{ref}}}\right) \quad (29)$$

where $C_{k,\text{annual}}$ is given by Formula (28). Just as this metric reduces seasonal variation due to temperature effects, it will also reduce seasonal variation due to changing albedo conditions (rain, snowfall, changes in vegetation, etc.).

Although only one example has been presented, note that the same correction could be applied to any other form of the performance ratio.

14.4 Performance indices

A detailed performance model may be used to predict electrical output of the PV system as a function of meteorological conditions, known attributes of the system components and materials, and the system design. The performance model attempts to capture as precisely as possible all factors that can affect electrical output.

In evaluating the system performance, particularly with respect to a performance guarantee, it is desired to compare the measured output with the predicted and expected outputs. For a given reporting period, the predicted output is the output calculated by the performance model when using historical weather data, while the expected output is the output calculated by the performance model when using measured weather data for the reporting period.

The ratio of measured output to expected output for a given reporting period defines a performance index. The performance index may be evaluated either on the basis of power, defining power performance index PPI, or on the basis of energy, defining energy performance index, EPI.

The ratio of measured output to predicted output for a given reporting period defines a baseline performance index. The baseline performance index may be evaluated either on the basis of power, defining baseline power performance index $BPPI$, or on the basis of energy, defining baseline energy performance index $BEPI$.

For evaluation of a performance guarantee, the performance model used for calculation of expected power or expected energy shall be identical to the performance model used for calculation of predicted power or predicted energy used in the performance guarantee.

Further details on the application of a performance model to evaluate the model-based performance indices are provided in IEC TS 61724-2 and IEC TS 61724-3.

15 Data filtering

15.1 Use of available data

Unless otherwise specified, the calculation of a reported parameter shall use all the available valid monitoring data during the indicated reporting period. Exceptions are given by 15.2 and 15.3.

15.2 Filtering data to specific conditions

Reported parameters may be calculated using a subset of data corresponding to a specific set of conditions, e.g. irradiance bins, temperature bins, selected portions of the day, selected sections of the power plant, etc., in order to facilitate performance analysis.

Such calculations that only use a subset of the monitoring data are to be clearly noted along with the range of conditions used for calculation.

15.3 Reduced inverter, grid, or load availability

In reports that include known periods of interrupted availability of inverters or reduced or interrupted demand availability from the utility grid or local loads, resulting in the PV system being unable to operate at maximum power, the analysis shall:

– exclude such periods, with the exclusion clearly noted; or
– include such periods without changes in analysis, but with the periods clearly noted; or
– include such periods, with the analysis performed two ways, with such periods both included (for the purpose of documenting actual results) and excluded (for the purpose of documenting a performance guarantee); or

– clearly note such periods and follow the analysis guidelines specified in an applicable contract or performance guarantee.

Annex A
(informative)

Sampling interval

A.1 General considerations

The sampling interval affects the quality of the data acquisition process in representing the true signal. In determining sampling intervals and/or filtering methods, the following factors should be considered:

- the rate of change of the parameter to be measured;
- the rate of response of the measurement transducer;
- the treatment of the sampled data (for example whether the data will be used in further calculations that involve other sampled datasets, as is the case when calculating power from sampled current and voltage measurements); and
- the ultimate use of the sampled data and the desired limit of uncertainty in representing the true signal parameter.

A.2 Time constants

In general, for rapidly changing signals, it is recommended that the sampling interval (τ_s) be less than 1/e (0,368) of the time constant of the measurement transducer, where the time-constant of a transducer is the time taken, after a step change in the measured variable, for the instrument to register 63,2 % of the step change in the measured parameter.

Alternatively, when the typical time constant of the measured parameter is longer than the time constant of the measurement transducer, the above requirement may be relaxed. In this case the sampling interval need only be less than 1/e of the measurement parameter time constant.

A.3 Aliasing error

The aliasing error is the error associated with information lost by not taking a sufficient number of sampled data points. To avoid a large aliasing error the Nyquist sampling theorem suggests that a minimum of two samples per cycle of the data bandwidth is required to reproduce the sampled data with no loss of information.

For example, the Nyquist theorem suggests that if the highest frequency in the signal to be sampled is fmax, then the minimum sampling frequency would be 2·fmax. However, this sampling frequency still does not achieve a very accurate reproduction of the original signal (average error between the reconstructed signal and the original signal is 32 % at 2·fmax) and an increase in the sampling frequency to 200·fmax is required to achieve an accuracy of 1 % in the reconstructed signal.

An alternative option is to filter the signal before sampling. This is a very effective method of reducing the maximum frequency of the signal, but filtering also results in the loss of information. This is not an issue if the ultimate use of the data is to calculate simple averages over a period of time. However if the data is to be used in a calculation involving other sampled parameters (for example the calculation of power from sampled voltage and current measurements) then analogue filtering before sampling removes fundamental elements of the time-dependent variation of the signal and can lead to the loss of accuracy in the calculated data.

A.4 Example

As an example, consider the appropriate sampling interval for measurements of irradiance. The greatest fluctuations in the signal occur under partly cloudy conditions, as the irradiance sensor is alternately shaded and unshaded. Assume a worst-case situation in which the irradiance changes significantly due to passing clouds approximately once every 30 s. In addition, assume that the primary monitoring purpose is only to determine the average irradiance over a reporting period of 1 h, rather than to recover the exact irradiance time series. In this case the time constants are of more importance than the aliasing error. Sampling the irradiance at least once every 10 s should be adequate. For this example, a Monte Carlo simulation shows that the typical sampling-related uncertainty in the average irradiance recorded over 1 h is on the order of 0,5 %. This is negligible compared to typical instrumental uncertainty.

Annex B
(informative)

Module ~~backsheet~~ temperature sensor selection and attachment

B.1 Objective

This annex provides guidelines for flat-plate PV module rear surface temperature measurement sensor selection and attachment in typical installed systems.

The sensor type and attachment method can have significant impacts on the measured temperature, leading to significant measurement errors. These errors are affected primarily by the contact between the sensor and the module's rear surface, the amount and type of insulation placed over the sensor, and the amount and type of adhesive used.

The recommendations stated in this annex are designed to minimize deviations from the ideal measurement condition while providing for secure and reliable long-term measurements.

B.2 Sensor and material selection

B.2.1 Optimal sensor types

Preference should be given to flat probes designed specifically for long-term surface measurements. Thin-film thermocouples of types T or E are generally acceptable. Small form-factor RTD and thermistor elements may be utilized provided air gaps are minimized when applying the tape overlay. However, bead thermocouples, unpackaged resistive elements, and devices encased in cylindrical probe heads should be avoided when possible.

B.2.2 Optimal tapes

To minimize errors and to weather-proof the temperature sensor, reinforcement of the sensor and sensor leads is recommended. This may be accomplished by applying an adhesive overlay or tape.

Adhesive overlays and tapes should be fabricated from materials resistant to the effects of temperature, humidity, and ultraviolet radiation. Avoid tapes not intended for use in securing sensors to surfaces – such as electrical tape, duct tape, aluminized cloth tape, foil tape, or packaging tape – as they may be structurally weak and because their adhesives tend to dry out over time or flow at elevated temperatures. Polyimide tapes (such as Kapton) are known to be susceptible to embrittlement when exposed to ultraviolet radiation and moisture in the presence of oxygen (air) and should be avoided for long-term installations. Polyester is probably the most appropriate overlay material since many backsheets are constructed of multi-layer polyester and this material holds up well against moisture, temperature, and ultraviolet light. Pressure-sensitive silicone adhesive is generally applied to polyester tapes and is recommended.

When using an overlay or tape, minimize air gaps as much as possible. Pockets of trapped air will temper the sensor response, thus negatively impacting the performance of the measurement system.

Temperature sensor readings may be affected by wind, causing temperature readings lower than the cell temperature. Application of thermally insulating tape over the sensor can be used to suppress the wind cooling effect. For this purpose, using foam resin tape with an aluminium cover layer over the temperature sensor glued to the surface of the PV module backsheet is introduced in IEC 60904-5.

B.2.3 Cyanoacrylate adhesives and backsheet integrity

The use of cyanoacrylate adhesive on module backsheets should be avoided, because it is suggested by material manufacturers that cyanoacrylate may react chemically with PET (polyethylene terephthalate) or PTFE (polytetrafluoroethylene) backsheets, potentially resulting in the degradation of the backsheet integrity and thereby affecting the PV module's long-term encapsulation performance.

B.3 Sensor attachment ~~method~~

B.3.1 Permanent versus temporary

Directions are provided for both permanent and temporary attachment.

Permanent attachment is recommended when long-term monitoring is desired and the sensor will not be removed or relocated. For instance, when including back-of-module temperature measurements within a fielded data acquisition system.

Temporary attachment is recommended when the measurement sensor will need to be relocated or removed owing to the short-term nature of the monitoring, such as during commissioning or periodic maintenance.

B.3.2 Attachment location

Select a sensor location at the centre of a cell close to the centre of the module, avoiding boundaries between cells.

For crystalline silicon modules, select the centre of the centre-most cell within the module, or, when the module is built with even numbers of rows or columns of cells, select one of the cells closest to the centre.

For thin-film modules, place the sensor within the boundary of a cell near the centre of the module, avoiding scribe lines between adjacent cells if possible.

B.3.3 ~~Sensor attachment~~ Bifacial modules

For bifacial modules, rear-side temperature sensors and wiring shall obscure < 10 % of the area of any cell, and wiring should be routed in between cells when possible.

B.3.4 Method

– Clean the module's rear surface and sensor element of oil and dust by using lint-free wipes dampened with a 70 % solution of isopropyl alcohol in distilled water. Allow all cleaned surfaces to dry completely before proceeding.

– Attach the sensor using the appropriate method:

a) Permanent (see Figure B.1):

- The adhesive should be confirmed to be compatible with the ~~backsheet~~ back surface material so as to not affect the long-term integrity of the module.
- Mix a thermally conductive epoxy as per manufacturer instructions.
- Apply the adhesive to the side of the sensor element intended to contact the module surface. Do not over-apply the adhesive; it should be as thin as possible yet fully coat the surface of the sensor element.
- Place the sensor element in the selected location. Manipulate the sensor to remove air bubbles and obtain a uniform adhesive thickness.

- Apply a polyester tape overlay to maintain the sensor position while the adhesive cures and to provide long-term protection of the sensor element. Round die-cut shapes are ideal as their lack of corners reduces the potential of delamination. If round shapes are not available, significantly round the corners of the tape using scissors.
- Allow the adhesive to cure as per the manufacturer's instructions.

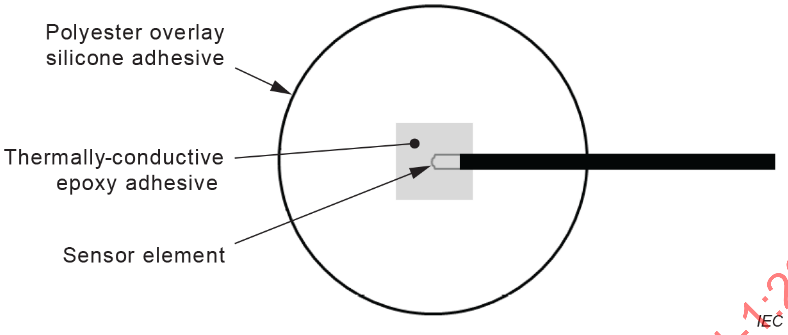


Figure B.1 – Sensor attachment, permanent

b) Temporary (see Figure B.2):

- Trim thin-film sensor encapsulation (such as tape) to within approximately 3 mm of the sensor element. Round all trimmed corners.
- Apply the sensor element to the centre of a round polyester adhesive dot or rounded polyester tape on the adhesive side. Tapes and dots fabricated with silicone adhesive are recommended. The sensor should stick to the tape.
- Place the sensor element in the selected location. Manipulate the sensor to remove air bubbles.

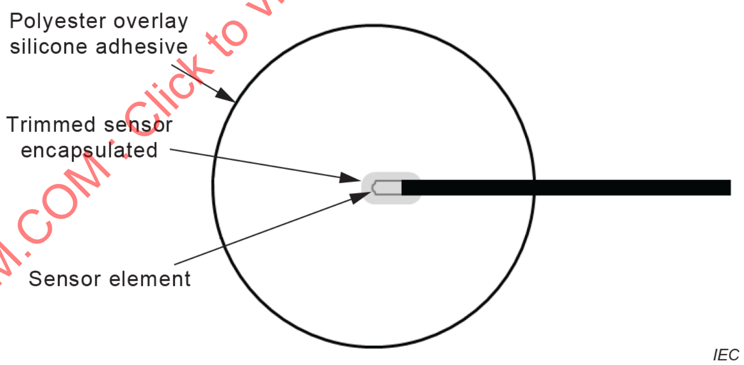


Figure B.2 – Sensor attachment, temporary

– Secure the sensor wire to the module's ~~backsheet~~ rear surface using polyester tape at 2 to 4 points to reduce strain on the sensor element. Generally, tape sections will not need to exceed approximately 2 cm wide by 5 cm in length. Use as little tape as possible to secure the lead wires (see Figure B.3).

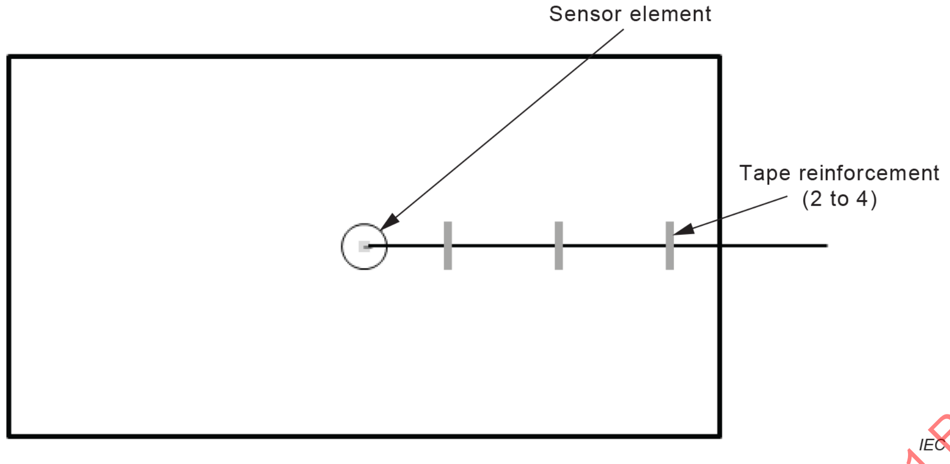


Figure B.3 – Sensor element wire strain relief

– For RTDs or thermistors, the measurement circuit may require a completion resistor. In this case select a resistor with a low temperature coefficient, e.g. ≤ 10 parts per million per °C.

Annex C
(normative)

Soiling measurement using clean and soiled PV reference device pair

C.1 Overview

This annex describes a method for measuring soiling losses by comparing two PV reference devices, one of which is allowed to soil naturally at the same rate as the modules of the PV array and the other of which is routinely cleaned and serves as a reference.

C.2 Equipment

Implementation of the method requires the following:

a) A reference PV device (either monofacial device or bifacial device), designated the "soiled" device, which is allowed to accumulate soiling at the same rate as the PV array. The soiled device may be either a PV reference cell or PV module, but should preferably be a PV module that is identical to or representative of those used in the PV array to be monitored so that it will soil at the same rate. It shall be mounted in the same plane as and at the average height of the PV array, preferably with identical mounting mechanisms.

b) A reference PV device (either monofacial device or bifacial device), designated the "clean" device, which is regularly cleaned so that it is kept free of soiling. The clean device may be either a PV reference cell or PV module, but shall have similar spectral and angular response to the soiled device. The effect of any differences in response should be included in the measurement uncertainty. The clean device shall be mounted close to the soiled device and co-planar to it within 0,5°. Cleaning may be performed either manually or by an automated system and should be done daily or at least once per week. For a bifacial device, both the front side and rear side shall be cleaned.

c) A measurement system for measuring the maximum power (method 1) and/or short-circuit current (method 2) of the soiled device. Maximum power may be measured using I-V curve tracing or max-power-point-tracking electronics.

d) A measurement system for measuring the short-circuit current of the clean device.

e) A measurement system for measuring the temperatures of both the soiled and clean devices using temperature sensors affixed to their rear surfaces.

For items c) and d), in between measurements, the measurement system shall not hold the module in an electrical state which may cause degradation or metastable drift of the device. Therefore, typical crystalline silicon modules should be held at open-circuit (or max power) in between measurements, to avoid hot spot generation, while typical thin film modules should be held at short circuit (or max power) in between measurements. Observe the module manufacturer's directions as needed to choose the appropriate hold state.

For tracking systems, the soiled and clean devices shall be mounted in the module plane of the tracker.

C.3 Normalization

a) Choose a reference condition of irradiance and PV device temperature, e.g. STC.

b) Determine a reference value for the short-circuit current of the clean device at the designated reference condition. It is sufficient to use the manufacturer's datasheet values. Additional measures may need to be considered for bifacial reference PV devices.

c) Using the clean device to measure irradiance, determine reference values for the max power (method 1) and/or short-circuit current (method 2) of the soiled device at the reference condition as follows:
   – Completely clean the soiled device.
   – Simultaneously measure the soiled device maximum power and/or short-circuit current and temperature as well as the clean device short-circuit current and temperature.
   – Using the clean device measured short-circuit current and temperature, with the reference data determined in step b), calculate the effective irradiance.
   – Using this calculated irradiance and the measurements for the soiled device, calculate the maximum power and/or short-circuit current of the soiled device corrected to the reference condition of irradiance and temperature.

C.4 Measurement method 1 – max power reduction due to soiling

Perform the measurement as follows:

a) Simultaneously (within 2 s) measure the short-circuit current and temperature of the clean device and the max power and temperature of the soiled device.
b) Calculate the effective irradiance from the values for the clean device measured in a), using the reference values determined in Clause C.3.
c) Calculate the expected max power of the soiled device at the irradiance determined in b) and the temperature measured in a), using the reference values determined in Clause C.3.
d) Calculate the soiling ratio *SR* by dividing the soiled device max power measured in a) by its expected max power calculated in c).

C.5 Measurement method 2 – short-circuit current reduction due to soiling

Perform the measurement as follows:

a) Simultaneously (within 2 s) measure the short-circuit current and temperature of the clean device and the short-circuit current and temperature of the soiled device.
b) Calculate the effective irradiance from the values for the clean device measured in a), using the reference values determined in Clause C.3.
c) Calculate the expected short-circuit current of the soiled device at the irradiance determined in b) and the temperature measured in a), using the reference values determined in Clause C.3.
d) Calculate the soiling ratio SR by dividing the soiled device short-circuit current measured in a) by its expected short-circuit current calculated in c).

C.6 Non-uniform soiling

Using a full-sized PV module with Method 1 (max power reduction, Clause C.4) yields more accurate results because it best represents the actual power loss due to soiling, and in particular it produces more accurate results when soiling is non-uniform across the modules, especially for typical crystalline silicon modules. Method 2 (short-circuit current reduction) may be adequate when soiling is assumed to be uniform across the modules or when the effects of soiling non-uniformity on the ratio of maximum power to short-circuit current are known to be small due to the construction or device physics of the module, e.g. for typical thin film modules. Both methods may be employed simultaneously and the most appropriate value or a weighted average may be used.

C.7 Daily average value

The soiling ratio measured by the method described above is an instantaneous value. The instantaneously measured soiling ratio tends to show a time-of-day dependence due to residual angular misalignment of the two reference devices as well as angle-dependent light scattering from soiling particles. In addition, the instantaneously measured values typically show noise due to irradiance fluctuations and other factors. Therefore, the instantaneously measured values shall be integrated to compute a daily average value.

Computation of daily average may be performed either by:

a) averaging the instantaneously calculated soiling ratios over a daily period, or
b) summing the measured max power and expected max power (see Clause C.4) or measured short-circuit current and expected short-circuit current (see Clause C.5) over a daily period and calculating the ratio of the of the sums of measured to expected values.

If averaging the instantaneously measured soiling ratios per choice a), the data should first be filtered to exclude low irradiance and outliers and/or to limit the measured values to a specific time window that minimizes the effects of angular misalignment. The number of data points passing the filter should be recorded as a quality metric and calculation of the daily average should only be performed when a sufficient number of data points are valid. The averaging should be irradiance-weighted. When angular misalignment between the clean and soiled devices has been limited to 0,5°, the averaging should include only times within ±2 h of solar noon, on a fixed tilt system, or all times when solar angle of incidence is < ~35°, on a tracking system. The time window can be extended if angular misalignment is reduced.

C.8 Renormalization

The normalization step in Clause C.3 shall be repeated at least annually.

Immediately following the normalization or following any significant rainfall, the measured soiling ratio should be close to unity. Significant deviation from unity indicates a problem with the setup. This can be used as a check of the normalization, so that the normalization may be repeated if necessary.

Annex D
(informative)

Derate factors

Derate factors quantify individual sources of loss with respect to the nameplate's DC power rating.

Derates may be defined as a series of multiplicative factors contributing to the performance ratio, PR, according to the relation:

$$PR = Y_f / Y_r = \prod_{k=1}^{N} DR_k \tag{D.1}$$

where the DR_k are N individual derates corresponding to different loss mechanisms, and are given by:

$$DR_k = Y_k / Y_{k-1} \tag{D.2}$$

Here Y_k is the system yield with loss mechanisms 1 through k operational, given by:

$$Y_k = Y_{k-1} - L_k \tag{D.3}$$

where L_k is the yield loss due to loss mechanism k. Y_0 corresponds to Y_r and Y_N corresponds to Y_f.

The number of derate factors may be adjusted for different purposes, depending on the system size and analysis goals.

Categorizing all losses as either array capture or BOS losses, Formula (D.1) may be written as:

$$PR = DR_{capture} \times DR_{BOS} \tag{D.4}$$

Here $DR_{capture}$ represents the combined array capture losses, given by:

$$DR_{capture} = Y_A / Y_r = (Y_r - L_C) / Y_r \tag{D.5}$$

and DR_{BOS} represents the combined BOS losses, given by:

$$DR_{BOS} = Y_f / Y_A = (Y_A - L_{BOS}) / Y_A \tag{D.6}$$

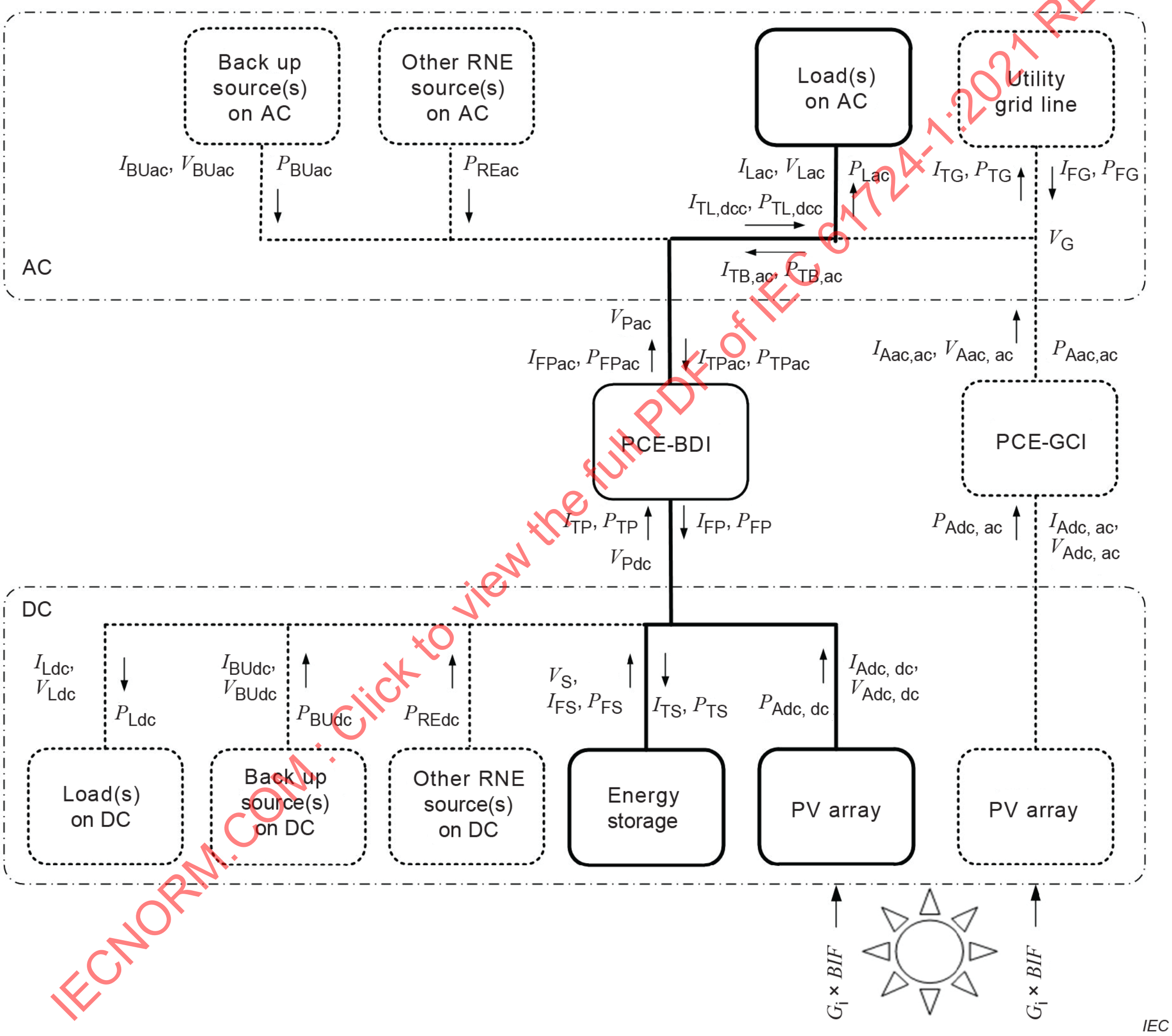
As an aid to performance diagnosis, DR_{capture} and DR_{BOS} may each be rewritten as products of derates corresponding to individual contributing loss mechanisms within the capture and BOS categories. Determination of these contributing derate factors may be done through direct measurement (for example, by measuring energies into and out of specific components of the system during the reporting period, or by measuring specific loss mechanisms such as soiling) and/or modelling (for example, by fitting a performance model to the measured data within the reporting period).

Annex E
(normative)

Systems with local loads, storage, or auxiliary sources

E.1 System types

Figure E.1 illustrates major possible elements comprising different PV system types and energy flow between the elements. Bold lines highlight a system configuration that includes local energy storage and local loads.



Key

RNE renewable energy

PCE power conditioning equipment

BDI bi-directional inverter

GCI grid-connected inverter

Figure E.1 – Energy flow between possible elements of different PV system types

For this annex, we consider the different PV system types listed in Table E.1, each including the indicated elements.

Table E.1 – Elements of different PV system types

System element	System type				
	Grid tied	**Grid tied with storage**	**Grid tied with storage and backup**	**Mini-grid**	**Micro-grid**
PV array (DC)				√	√
PV array (AC)	√	√	√	√	√
Energy storage (DC)		√	√	√	√
PCU (GCI)	√	√	√	√	√
PCU (BDI)		√	√	√	√
Utility grid line	√	√	√		√
Load(s) (DC)		√	√	√	√
Load(s) (AC)		√	√	√	√
Back-up sources (DC)			√	√	√
Other RNE sources (DC)		√		√	√
Back-up sources (AC)			√	√	√
Other RNE sources (AC)		√		√	√

E.2 Parameters and formulas

Table E.2 lists parameters and formulas for monitoring energy flow in each system type defined in this annex.

Table E.2 – Parameters and formulas for different system types

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Meteorology						
~~Plane of array irradiance (W·m^{-2})~~	$\cancel{G_{i,ref}}$	~~√~~	~~√~~	~~√~~	~~√~~	~~√~~
In-plane irradiance (W·m^{-2})	G_i	√	√	√	√	√
In-plane irradiation (kWh·m^{-2})	H_i	√	√	√	√	√
In-plane rear-side irradiance (W·m^{-2})	G_i^{rear}	√	√	√	√	√
In-plane rear-side irradiation (kWh·m^{-2})	H_i^{rear}	√	√	√	√	√
PV						
Nominal PV array power (kW) = module power at STC × no. of modules in the array	P_0	√	√	√	√	√
Nominal PV array power (kW) of DC coupling system	$P_{0,dc}$				√	√
Nominal PV array power (kW) of AC coupling system	$P_{0,ac}$		√	√	√	√
PV array area (m^2)= module area × no. of modules in the array	A_a	√	√	√	√	√
PV array area (m^2) of DC coupling system	$A_{a,dc}$				√	√
PV array area (m^2) of AC coupling system	$A_{a,ac}$		√	√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
PV array output voltage	V_{A}		√	√	√	√
PV array output voltage of DC coupling system	$V_{\mathrm{Adc,dc}}$				√	√
PV array output voltage of AC coupling system	$V_{\mathrm{adc,ac}}$		√	√	√	√
PV array output current	I_{A}		√	√	√	√
PV array output current of DC coupling system	$I_{\mathrm{Adc,dc}}$				√	√
PV array output current of AC coupling system	$I_{\mathrm{Adc,ac}}$		√	√	√	√
PV array output power	P_{A}		√	√	√	√
PV array output power of DC coupling system	$P_{\mathrm{Adc,dc}}$		√	√	√	√
PV array output power of AC coupling system	$P_{\mathrm{Adc,ac}}$		√	√	√	√
Energy storage						
Operating voltage	V_{S}		√	√	√	√
Current to storage	I_{TS}		√	√	√	√
Current from storage	I_{FS}		√	√	√	√
Power to storage	P_{TS}		√	√	√	√
Power from storage	P_{FS}		√	√	√	√
Utility grid						
Utility grid voltage	V_{U}		√	√		√
Current to utility grid	I_{TU}		√	√		√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Current from utility grid	I_{FU}		√	√		√
Power to utility grid	P_{TU}		√	√		√
Power from utility grid	P_{FU}		√	√		√
Loads on DC						
Load voltage	V_{Ldc}		√	√	√	√
Load current	I_{Ldc}		√	√	√	√
Load power	P_{Ldc}		√	√	√	√
Loads on AC						
Load voltage	V_{Lac}		√	√	√	√
Load current	I_{Lac}		√	√	√	√
Load power	P_{Lac}		√	√	√	√
Back-up source(s) on AC			√	√	√	√
Back-up AC voltage	V_{BUac}			√	√	√
Back-up AC current	I_{BUac}			√	√	√
Back-up AC power	P_{BUac}			√	√	√
Back-up source(s) on DC						
Back-up DC voltage	V_{BUdc}			√	√	√
Back-up DC current	I_{BUdc}			√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Back-up DC power	P_{BUdc}			√	√	√
Other renewable source(s) on AC						
Other RE AC voltage	V_{REac}		√	√	√	√
Other RE AC current	I_{REac}		√	√	√	√
Other RE AC power	P_{REac}		√	√	√	√
Other renewable source(s) on DC						
Other RE DC voltage	V_{REdc}		√	√	√	√
Other RE DC current	I_{REdc}		√	√	√	√
Other RE DC power	P_{REdc}		√	√	√	√
Electrical energy						
Renewable output energy per day (kWh)	$E_{RE} = E_{REdc} + E_{REac}$		√	√	√	√
(Net) energy to utility grid (kWh)	$E_{TU} = E_{TU} - E_{FU}$		√	√	√	√
(Net) energy from utility grid (kWh)	$E_{FU} = E_{FU} - E_{TU}$		√	√	√	√
Net energy to storage (kWh)	$E_{TS} = (E_{TS} - E_{FS})$		√	√	√	√
Net energy from storage (kWh)	$E_{FS} = (E_{FS} - E_{TS})$		√	√	√	√
Array output energy per day (kWh)	$E_A = E_{Adc,dc} + E_{Adc,ac}$		√	√	√	√
Energy from back-up system (kWh)	$E_{BU} = E_{BUdc} + E_{BUac}$		√	√	√	√
Energy to load (kWh)	$E_L = E_{Ldc} + E_{Lac}$		√	√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
	$E_{L} = E_{Ldc} + (E_{TL,dcc} + E_{TL,ac})$		√	√	√	√
Energy to load (kWh) from AC coupling system	$E_{TL,acc} = (E_{Aac,ac}) - E_{TB,ac}$		√	√	√	√
PV array energy yield	$Y_{A} = E_{A} / P_{0}$	√	√	√	√	√
PV array energy yield of DC coupling subsystem	$Y_{A,dc} = E_{Adc,dc} / P_{0,dc}$		√	√	√	√
PV array energy yield of AC coupling subsystem	$Y_{A,ac} = E_{Adc,ac} / P_{0,ac}$		√	√	√	√
Final system yield	(a) $Y_{f} = E_{out} / P_{0}$ (b) $Y_{f} = Y_{fac}$ (c) $Y_{f} = Y_{fdc} + Y_{fac}$	(a)	(b)	(b)	(c)	(c)
Final system yield of DC coupling subsystem	$Y_{f,dc} = Y_{fTB,dc} + Y_{fTL,dc}$				√	√
Final system yield of DC coupling subsystem to charge battery	$Y_{fTB,dc} = E_{ATB,dc} / P_{0,dc}$				√	√
Final system yield of DC coupling subsystem to load	$Y_{fTL,dc} = E_{ATL,dc} \times \eta_{BOS,dcc} / P_{0,dc}$				√	√
Final system yield of AC coupling subsystem	$Y_{f,ac} = Y_{fTB,ac} + Y_{fTL,ac}$		√	√	√	√
Final system yield of AC coupling subsystem to charge battery	$Y_{fTB,ac} = (E_{ATB,ac} \times \eta_{BOS,dcc}) / P_{0,ac}$		√	√	√	√
Final system yield of AC coupling subsystem to load	$Y_{fTL,ac} = E_{ATL,ac} / P_{0,ac}$		√	√	√	√
Direct PV energy contribution to E_{use} (kWh)	$E_{use,PV} = E_{A} \times \eta_{BOS}$ or		√	√	√	√
	$E_{use,PV} = F_{A} \times E_{use}$		√	√	√	√
Direct PV energy contribution to E_{use} (kWh) of DC coupling subsystem	$E_{use,PV,dc} = F_{A,dc} \times E_{use,dcc}$				√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Direct PV energy contribution to E_{use} (kWh) of AC coupling subsystem	$E_{use,PV,ac} = F_{A,ac} \times E_{use,ac}$		√	√	√	√
Fraction of total system input energy contributed by PV array	$F_A = E_A / E_{in}$		√	√	√	√
Fraction of total system input energy contributed by PV array of DC coupling subsystem	$F_{A,dc} = E_{Adc,dc} / E_{in,dcc}$				√	√
Fraction of total system input energy contributed by PV array of AC coupling subsystem	$F_{A,ac} = E_{Adc,ac} / E_{in,ac}$		√	√	√	√
Total system input energy (kWh)	$E_{in} = E_A + E_{BU} + E_{FU} + E_{FS} + E_{RE}$		√	√	√	√
Total system input energy of DC coupling subsystem (kWh)	(a) $E_{in,dcc} = (E_{TB,ac}) + E_{FS} + (E_{REdc} + E_{REac})$ (b) $E_{in,dcc} = (E_{TB,ac}) + (E_{BUac} + E_{BUac}) + E_{FS} + (E_{REdc} + E_{REac})$ (c) $E_{in,dcc} = (E_{Adc,dc} + E_{TB,ac}) + (E_{BUac} + E_{BUac}) + E_{FU} + E_{FS} + (E_{REdc} + E_{REac})$		(a)	(b)	(b)	(c)
Total system input energy of AC coupling subsystem (kWh)	$E_{in,ac} = E_{Adc,ac}$		√	√	√	√
Total system output energy (kWh)	$E_{use} = E_{Ldc} + E_{Lac} + E_{TU} + E_{TS}$		√	√	√	√
Total system output energy of DC coupling subsystem(kWh)	(a) $E_{use,dcc} = E_{Ldc} + (E_{TL,dcc} + E_{TL,ac}) + E_{TS}$ (b) $E_{use,dcc} = E_{Ldc} + (E_{TL,dcc} + E_{TL,ac}) + E_{TU} + E_{TS}$		(a)	(a)	(a)	(b)
Total system output energy of AC coupling subsystem (kWh)	$E_{use,ac} = E_{TL,ac} + E_{TB,ac}$		√	√	√	√
Reference yield (h·d^{-1})	$Y_r = H_i / G_{i,ref}$		√	√	√	√
Array capture losses (h·d^{-1})	$L_c = Y_r - Y_A$		√	√	√	√
Array capture losses of DC coupling subsystem (h·d^{-1})	$L_{c,dc} = Y_r - Y_{A,dc}$				√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Array capture losses of AC coupling subsystem (h·d^{-1})	$L_{c,ac} = Y_r - Y_{A,ac}$		√	√	√	√
System losses (h·d^{-1})	$L_s = Y_A - Y_f$		√	√	√	√
System losses of DC coupling subsystem (h·d^{-1})	$L_{s,dc} = Y_{A,dc} - Y_{f,dc}$				√	√
System losses of AC coupling subsystem (h·d^{-1})	$L_{s,ac} = Y_{A,ac} - Y_{f,ac}$		√	√	√	√
Performance ratio	$PR = Y_f / Y_r$	√	√	√	√	√
Performance ratio of DC coupling subsystem	$PR_{dc} = Y_{f,dc} / Y_r$		√	√	√	√
Performance ratio of AC coupling subsystem	$PR_{ac} = Y_{f,ac} / Y_r$		√	√	√	√
Mean array efficiency	$\eta_A = E_A / (H_i \times A_a)$	√	√	√	√	√
Mean array efficiency of DC coupling subsystem	$\eta_{A,dc} = E_{A,dc} / (H_{i,dc} \times A_{a,dc})$				√	√
Mean array efficiency of AC coupling subsystem	$\eta_{A,ac} = E_{A,ac} / (H_{i,ac} \times A_{a,ac})$		√	√	√	√
Overall PV plant efficiency	(a) $\eta_f = E_{out} / (H_i \times A_a)$ (b) $\eta_{tot} = E_{use,PV} / (H_i \times A_a)$	(a)	(b)	(b)	(b)	(b)
Overall PV plant efficiency of DC coupling subsystem	$\eta_{tot,dcc} = E_{use,PV,dc} / (H_{i,dc} \times A_{a,dc})$				√	√
Overall PV plant efficiency of AC coupling subsystem	$\eta_{tot,ac} = E_{use,PV,ac} / (H_{i,ac} \times A_{a,ac})$		√	√	√	√
BOS efficiency	(a) $\eta_{BOS} = E_{out} / E_A$ (b) $\eta_{BOS} = E_{use} / E_{in}$	(a)	(b)	(b)	(b)	(b)
BOS efficiency of DC coupling subsystem	$\eta_{BOS,dcc} = E_{use,dcc} / E_{in,dcc}$				√	√
BOS efficiency of AC coupling subsystem	$\eta_{BOS,ac} = E_{use,ac} / E_{in,ac}$		√	√	√	√

Bibliography

~~IEC TS 61724-2, *Photovoltaic system performance – Part 2: Capacity evaluation method*~~

~~IEC TS 61724-3, *Photovoltaic system performance – Part 3: Energy evaluation method*~~

IEC TS 60904-1-2, *Photovoltaic devices – Part 1-2: Measurement of current-voltage characteristics of bifacial photovoltaic (PV) devices*

IEC 60904-3, *Photovoltaic devices – Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data*

Orange Button Taxonomy Data Definitions, SunSpec Alliance

IEC 61724-1

Edition 2.0 2021-07

INTERNATIONAL STANDARD

NORME INTERNATIONALE

Photovoltaic system performance –
Part 1: Monitoring

Performances des systèmes photovoltaïques –
Partie 1: Surveillance

IEC 61724-1:2021-07(en-fr)

CONTENTS

INTERNATIONAL ELECTROTECHNICAL COMMISSION

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PHOTOVOLTAIC SYSTEM PERFORMANCE –

Part 1: Monitoring

FOREWORD

1) The International Electrotechnical Commission (IEC) is a worldwide organization for standardization comprising all national electrotechnical committees (IEC National Committees). The object of IEC is to promote international co-operation on all questions concerning standardization in the electrical and electronic fields. To this end and in addition to other activities, IEC publishes International Standards, Technical Specifications, Technical Reports, Publicly Available Specifications (PAS) and Guides (hereafter referred to as "IEC Publication(s)"). Their preparation is entrusted to technical committees; any IEC National Committee interested in the subject dealt with may participate in this preparatory work. International, governmental and non-governmental organizations liaising with the IEC also participate in this preparation. IEC collaborates closely with the International Organization for Standardization (ISO) in accordance with conditions determined by agreement between the two organizations.
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International Standard IEC 61724-1 has been prepared by IEC technical committee 82: Solar photovoltaic energy systems.

This second edition cancels and replaces the first edition, published in 2017. This edition constitutes a technical revision.

This edition includes the following significant technical changes with respect to the previous edition:

- Monitoring of bifacial systems is introduced.
- Irradiance sensor requirements are updated.
- Soiling measurement is updated based on new technology.
- Class C monitoring systems are eliminated.
- Various requirements, recommendations and explanatory notes are updated.

The text of this standard is based on the following documents:

FDIS	Report on voting
82/1904/FDIS	82/1925/RVD

Full information on the voting for its approval can be found in the report on voting indicated in the above table.

The language used for the development of this International Standard is English.

This document was drafted in accordance with ISO/IEC Directives, Part 2, and developed in accordance with ISO/IEC Directives, Part 1 and ISO/IEC Directives, IEC Supplement, available at www.iec.ch/members_experts/refdocs. The main document types developed by IEC are described in greater detail at www.iec.ch/standardsdev/publications.

A list of all parts in the IEC 61724 series, published under the general title *Photovoltaic system performance*, can be found on the IEC website.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under webstore.iec.ch in the data related to the specific document. At this date, the document will be

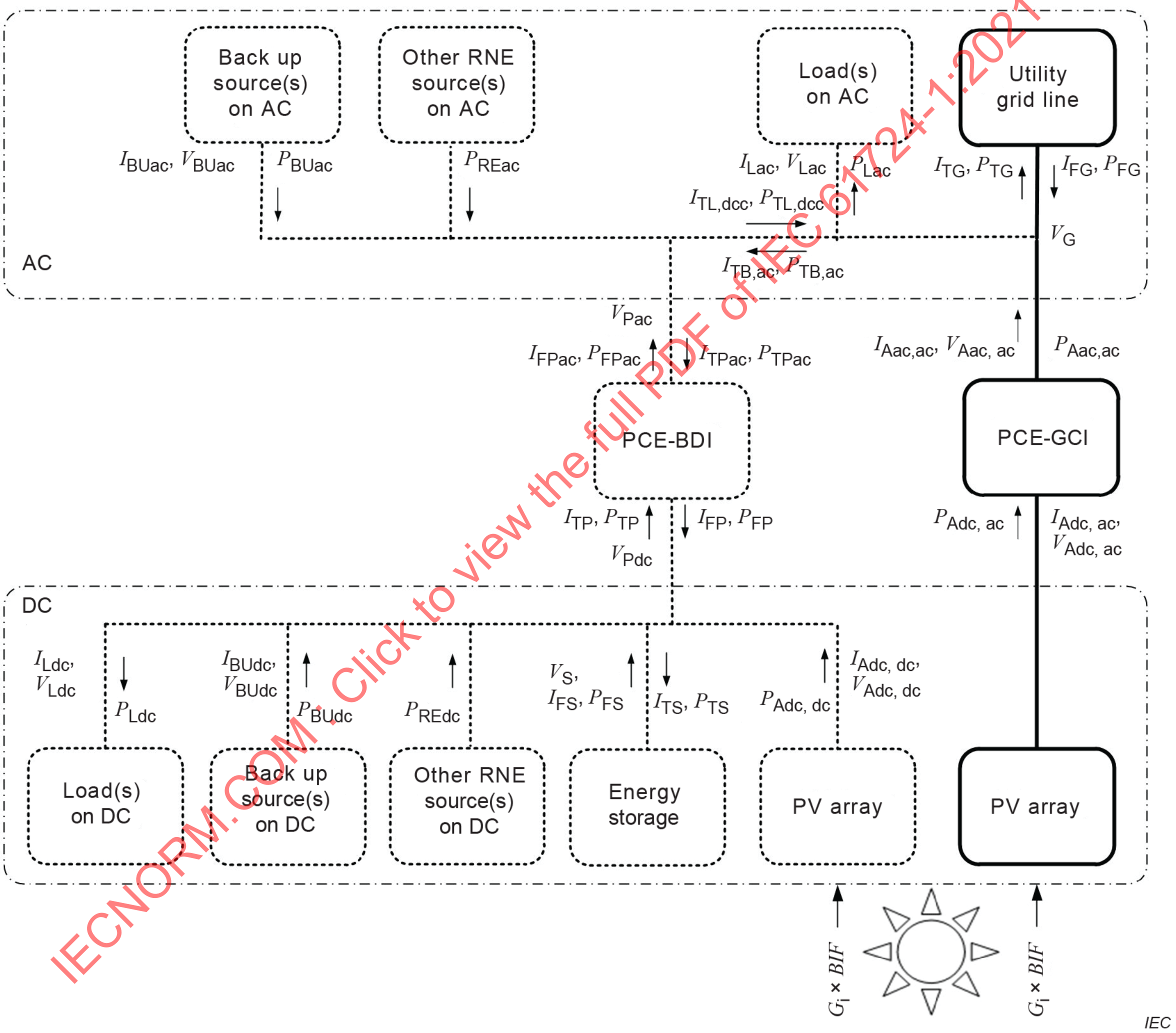
- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

INTRODUCTION

This document defines classes of photovoltaic (PV) performance monitoring systems and serves as guidance for monitoring system choices.

Figure 1 illustrates major elements comprising different PV system types. The main clauses of this document are written for grid-connected systems without local loads, energy storage, or auxiliary sources, as shown by the bold lines in Figure 1. Annex E includes some details for systems with additional components.

The PV array may include both fixed-axis and tracker systems and both flat-plate and concentrator systems.



Key

RNE: renewable energy

PCE: power conditioning equipment

BDI: bi-directional inverter

GCI: grid-connected inverter

Bold lines denote simple grid-connected system without local loads, energy storage, or auxiliary sources.

Figure 1 – Possible elements of PV systems

The purposes of a performance monitoring system are diverse and could include comparing performance to design expectations and guarantees as well as detecting and localizing faults.

For comparing performance to design expectations and guarantees, the focus should be on system-level data and consistency between prediction and test methods.

For detecting and localizing faults there should be greater resolution at sub-levels of the system and an emphasis on measurement repeatability and correlation metrics.

The monitoring system should be adapted to the PV system's size and user requirements. In general, larger PV systems should have more monitoring points and higher accuracy sensors than smaller and lower-cost PV systems.

PHOTOVOLTAIC SYSTEM PERFORMANCE –

Part 1: Monitoring

1 Scope

This part of IEC 61724 outlines terminology, equipment, and methods for performance monitoring and analysis of photovoltaic (PV) systems. It also serves as a basis for other standards which rely upon the data collected.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 60050-131, *International Electrotechnical Vocabulary (IEV) – Part 131: Circuit theory*

IEC 60904-2, *Photovoltaic devices – Part 2: Requirements for photovoltaic reference devices*

IEC 60904-5, *Photovoltaic devices – Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open-circuit voltage method*

IEC 60904-7, *Photovoltaic devices – Part 7: Computation of the spectral mismatch correction for measurements of photovoltaic devices*

IEC 61215 (all parts), *Terrestrial photovoltaic (PV) modules – Design qualification and type approval*

IEC 61557-12, *Electrical safety in low voltage distribution systems up to 1 000 V AC and 1 500 V DC – Equipment for testing, measuring or monitoring of protective measures – Part 12: Power metering and monitoring devices (PMD)*

IEC TS 61724-2, *Photovoltaic system performance – Part 2: Capacity evaluation method*

IEC TS 61724-3, *Photovoltaic system performance – Part 3: Energy evaluation method*

IEC TS 61836, *Solar photovoltaic energy systems – Terms, definitions and symbols*

IEC 62053-22, *Electricity metering equipment – Particular requirements – Part 22: Static meters for AC active energy (classes 0,1S, 0,2S and 0,5S)*

IEC 62670-3, *Photovoltaic concentrators (CPV) – Performance testing – Part 3: Performance measurements and power rating*

IEC 62817:2014, *Photovoltaic systems – Design qualification of solar trackers*

ISO/IEC Guide 98-1, *Uncertainty of measurement – Part 1: Introduction to the expression of uncertainty in measurement*

ISO/IEC Guide 98-3, *Uncertainty of measurement – Part 3: Guide to the expression of uncertainty in measurement (GUM:1995)*

ISO 9060:2018, *Solar energy – Specification and classification of instruments for measuring hemispherical solar and direct solar radiation*

ISO 9488, *Solar energy – Vocabulary*

3 Terms and definitions

For the purposes of this document, the terms and definitions given in IEC 60050-131, IEC TS 61836, ISO 9488, and the following apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

3.1
sample
data acquired from a sensor or measuring device

3.2
sampling interval
time between samples

3.3
record
data recorded and stored

3.4
recording interval
τ
time between records

3.5
report
aggregate value based on series of records

3.6
reporting period
time between reports

3.7
front side
side of a surface which normally faces the sky

3.8
rear side
side of a surface which normally faces the ground

3.9
monofacial PV device
PV device in which only the front side is used for power generation

3.10
bifacial PV device
PV device in which both front side and rear side are used for power generation

3.11
bifaciality coefficient
φ
ratio between an I-V characteristic of the rear side and the front side of a bifacial device, typically at Standard Test Conditions (STC), unless otherwise specified

Note 1 to entry: Bifaciality coefficients include the short-circuit current bifaciality coefficient φ_{Isc}, the open-circuit voltage bifaciality coefficient φ_{Voc} and the maximum power bifaciality coefficient φ_{Pmax}.

Note 2 to entry: Bifaciality coefficients are defined in IEC TS 60904-1-2.

3.12
irradiance
G
incident flux of radiant power per unit area

Note 1 to entry: Expressed in units of $\mathrm{W{\cdot}m^{-2}}$.

3.13
in-plane irradiance
$\mathrm{G_i}$ or POA
sum of direct, diffuse, and ground-reflected irradiance incident upon the front side of an inclined surface parallel to the plane of the modules in the PV array, also known as plane-of-array (POA) irradiance

Note 1 to entry: Expressed in units of $\mathrm{W{\cdot}m^{-2}}$.

3.14
horizontal albedo
ρ_H
proportion of incident light reflected by a ground surface as measured in a horizontal plane

Note 1 to entry: It is a property of a ground surface and is a dimensionless quantity on a scale from 0 to 1.

3.15
in-plane rear-side irradiance ratio
ρ_i
ratio of the irradiance incident on the rear side of the modules in the PV array to the irradiance incident on the front side

Note 1 to entry: It is a dimensionless quantity but can exceed a value of 1 since, in addition to reflected light, diffuse and direct components of the solar resource may also be measured on the rear-side of the plane of array.

3.16
spectrally matched in-plane rear-side irradiance ratio
ρ_i^{SP}
in-plane rear-side irradiance ratio per 3.15 when both irradiance quantities are measured with a spectrally matched reference device or with the application of spectral correction factors per IEC 60904-7

3.17
spectrally matched reference device
reference device such as a PV cell or module with spectral response characteristics sufficiently close to those of the PV modules in the PV array such that spectral mismatch errors are small under the typical range of incident spectra

3.18
in-plane rear-side irradiance
G_i^{rear} or POA^{rear}
sum of direct, diffuse, and ground-reflected irradiance incident on the rear side of the modules in the PV array, also known as rear-side plane-of-array irradiance

Note 1 to entry: Expressed in units of W·m^{-2}.

Note 2 to entry: (If measured via in-plane rear-side irradiance ratio): $G_i^{rear} = \rho_i \times G_i$ or $G_{i,SP}^{rear} = \rho_i^{SP} \times G_i$.

3.19
bifacial reference device
bifacial PV device, such as a cell or module, having substantially the same properties, with respect to response to front-side and rear-side irradiance, as bifacial modules to be monitored

3.20
bifacial irradiance factor
BIF
dimensionless factor that can be directly multiplied by the front-side in-plane irradiance (G_i) to calculate the “effective” irradiance reaching a bifacial device from both the front and rear side collectively

Note 1 to entry: $BIF = (1 + \varphi_{Pmax} \times \rho_i)$ or $BIF^{sp} = (1 + \varphi_{Pmax} \times \rho_i^{SP})$. See 3.11, 3.15, 3.16.

Note 2 to entry: Rear-side POA irradiance can be measured simultaneously with front-side POA irradiance using a bifacial reference device. In that case, $BIF = G_i^{BiFi\ Ref\ Device} \div G_i$. For consistency, the front-side POA irradiance should be measured with the same or similar type of device as the bifacial reference device.

Note 3 to entry: ”Effective” irradiance may include the effect of inhomogeneities in rear-side irradiance.

3.21
global horizontal irradiance
GHI
direct plus diffuse irradiance incident on the front side of a horizontal surface

Note 1 to entry: Expressed in units of W·m^{-2}.

Note 2 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.22
circumsolar
immediately surrounding the solar disk

3.23
direct normal irradiance
DNI
irradiance emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5° falling on a plane surface normal to the sun’s rays

Note 1 to entry: Expressed in units of W·m^{-2}.

Note 2 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.24
circumsolar contribution
contribution of a specific portion of the circumsolar normal irradiance to the direct normal irradiance. The circumsolar contribution refers to a specific ring-shaped angular region described by an inner and the outer angular distance from the centre of the sun (see ISO 9488)

Note 1 to entry: If the inner angle describing this angular region is the half-angle of the sun disk the circumsolar contribution is also called circumsolar ratio.

Note 2 to entry: Depending on the circumsolar irradiance measurement instrument or the solar technology involved, different wavelength ranges are included. In order to describe circumsolar irradiance correctly, the wavelength range or the spectral response of the instrument or the involved technology has to be specified.

3.25
circumsolar ratio
fraction of measured direct normal irradiance (DNI) emanating from the circumsolar region of the sky, i.e. within the angular acceptance of the DNI sensor but outside the solar disk

3.26
sunshape
azimuthal average radiance profile as a function of the angular distance from the centre of the sun, normalized to 1 at the centre of the sun and considering the wavelength range of shortwave radiation (see ISO 9488)

3.27
diffuse horizontal irradiance
$\mathrm{G_d}$ or DHI
global irradiance on the front side of a horizontal surface excluding the portion emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5°

Note 1 to entry: Expressed in units of W·m^{-2}.

Note 2 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.28
in-plane direct beam irradiance
$\mathrm{G_{i,b}}$
in-plane irradiance incident upon the front side of an inclined surface parallel to the plane of the modules in the PV array emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5°

Note 1 to entry: The in-plane direct beam irradiance $G_{i,b} = \cos(\theta) \times DNI$, where θ is the angle between the sun and the normal to the plane. When the plane of array is normal to the sun, $G_{i,b} = DNI$.

Note 2 to entry: Expressed in units of W·m^{-2}.

3.29
irradiation
H
irradiance integrated over a specified time interval

Note 1 to entry: Expressed in units of kW-h·m^{-2}.

3.30
standard test conditions
STC
in-plane irradiance 1 000 W·m^{-2}, normal incidence, PV cell junction temperature 25 °C, and the reference spectral irradiance defined in IEC 60904-3

3.31
soiling ratio
SR
ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling

3.32
soiling level
SL
fractional power loss due to soiling, given by $1 - SR$

3.33
soiling rate
rate of change of soiling ratio, typically expressed in percent per day

3.34
active power
P
under periodic conditions, mean value, taken over one period, of the instantaneous product of current and voltage

Note 1 to entry: Under sinusoidal conditions, the active power is the real part of the complex power.

Note 2 to entry: Expressed in units of W.

3.35
apparent power
S
product of the rms voltage between the terminals of a two-terminal element or two-terminal circuit and the rms electric current in the element or circuit

Note 1 to entry: Under sinusoidal conditions, the apparent power is the modulus of the complex power.

Note 2 to entry: Expressed in units of VA.

3.36
power factor
λ
under periodic conditions, ratio of the absolute value of the active power P to the apparent power S:

$$\lambda = \frac{|P|}{S}$$

4 Monitoring system classification

This document defines two classifications of monitoring system, Class A and Class B.

Class A is intended for large PV systems such as utility-scale or large commercial installations.

Class B is intended for smaller systems such as rooftop or small to medium-size commercial installations.

Users of the document may specify whichever classification is most appropriate to their application, regardless of PV system size.

The monitoring system classification shall be stated in any conformity declarations to this document.

Throughout this document, some requirements are designated as applying to a particular classification. Where no designation is given, the requirements apply to both classifications.

5 General

5.1 Measurement precision and uncertainty

Measurement precision refers to repeatability and resolution, which have the meanings defined in the IEC Electropedia.

Measurement uncertainty refers to accuracy and otherwise has the meaning defined in the IEC Electropedia.

Measurement uncertainties can be calculated as outlined in ISO/IEC Guide 98-1 and ISO/IEC Guide 98-3.

5.2 Calibration

Recalibration of sensors and signal-conditioning electronics is to be performed as recommended by the manufacturer or at more frequent intervals where specified in the standard.

It is recommended to perform periodic cross-checks of each sensor against sister sensors or reference devices in order to identify out-of-calibration sensors.

5.3 Repeated elements

Depending on system size and user requirements, the monitoring system may include redundancy in sensors and/or repetition of sensor elements for different components or subsections of the full PV system. Accordingly, the measured and calculated parameters defined in this document may have multiple instances, each corresponding to a subsection or subcomponent of the PV system.

5.4 Power consumption

The parasitic power drawn by any systems required for operation of the PV plant shall not be considered as a load supplied by the plant.

5.5 Documentation

Details of all components of the monitoring system shall be documented. All system inspection and maintenance, including cleaning, shall be documented.

5.6 Inspection

The monitoring system shall be inspected at least annually and preferably at more frequent intervals. Inspection should look for damage, deterioration, or disconnection of sensors and electrical enclosures, soiling or displacement of optical sensors, loose wiring connections, detachment of temperature sensors, embrittlement of attachments, and other potential problems.

6 Data acquisition timing and reporting

6.1 Samples, records, and reports

Figure 2 illustrates the relations between samples, records, and reports.

A sample is data acquired from a sensor or measuring device. The sampling interval is the time between samples. Samples do not need to be permanently stored.

A record is data entered into data storage, based on acquired samples. The recording interval, denoted by τ in this document, is the time between records. The recording interval should be an integer multiple of the sampling interval, and an integer number of recording intervals should fit within 1 h.

The recorded parameter value for each record is the average, maximum, minimum, sum, or other function of the samples acquired during the recording interval, as appropriate for the measured quantity. The record can also include supplementary data such as additional statistics of the samples, number of missing data points, error codes, transients, and/or other data of special interest. (For wind data records, see statement in 9.3.)

A report is an aggregate value covering multiple recording intervals. The reporting period is the time between reports. Typically the reporting period would be chosen to be days, weeks, months, or years.

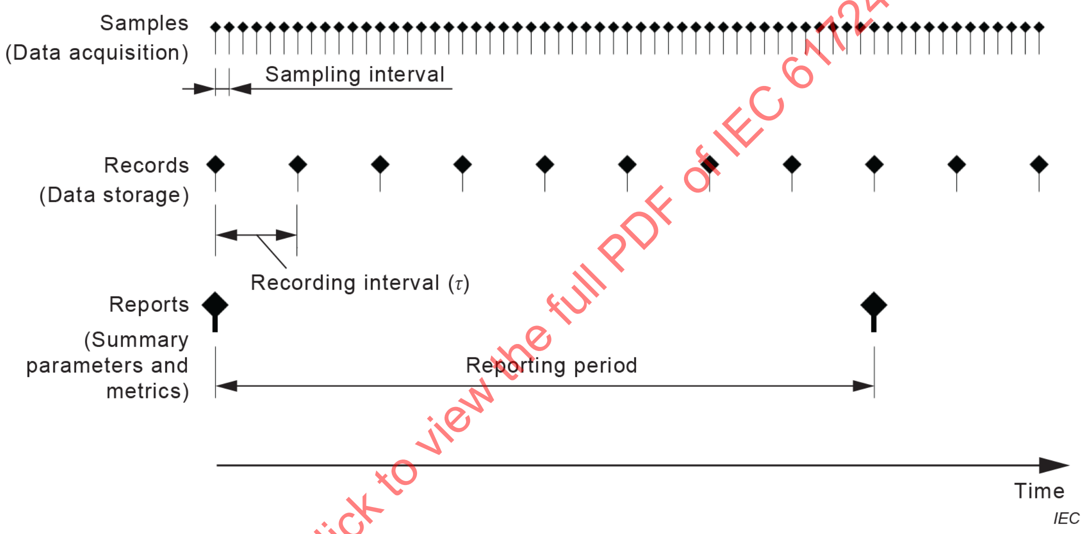


Figure 2 – Samples, records and reports

Table 1 lists maximum values for sampling intervals and recording intervals.

Further considerations relating to the sampling interval are addressed in Annex A. The maximum sampling interval for Class A is longer than the typical signal and instrument time constants for irradiance, wind and electrical output, however, the value is chosen for practicality considering common data acquisition systems.

The indicated sampling and recording interval recommendations apply to on-site ground-based measurements. For satellite-based measurement of irradiance, longer intervals of up to 1 h may be used. A ground-based instrument will require frequent samples to construct a valid time average over a recording interval, e.g. in the case of partly cloudy conditions, while satellite-based estimation uses the spatial average of many pixels in a single image as a substitute for time averaging.)

Table 1 – Sampling and recording interval requirements

	Class A **High accuracy**	**Class B** **Medium accuracy**
Maximum sampling interval For irradiance, temperature, wind and electrical output	5 s	1 min
Maximum recording interval	5 min (1 min – recommended)	15 min

6.2 Timestamps

Each record and each report shall include a timestamp.

Timestamp data shall include the date and time corresponding to the beginning or end of the recording interval or reporting period and the choice shall be specified.

The time should refer either to local standard time (not daylight savings time) or universal time, to avoid winter/summer time changes, and the choice of time shall be specified.

Midnight shall be treated as the start of a new day and expressed as 00:00:00.

When multiple data acquisition units are involved that each independently apply timestamps, the clocks of the units should be synchronized, preferably by an automated mechanism such as global positioning system (GPS) or network time protocol (NTP).

6.3 Parameter names

For consistency in data extraction across multiple platforms, it is recommended to use standardized parameter names. Standardized names for parameters in this document are listed in *Orange Button Taxonomy Data Definitions*.

7 Required measurements

Table 2 lists measured parameters defined by this document and a summary of measurement requirements.

The purpose of each monitoring parameter is listed in Table 2 in order to guide the user. More details and additional requirements are provided in the subsequent referenced subclauses.

A check mark (√) in Table 2 indicates a required parameter to be measured on site, qualified by specific notes where included.

The symbol “R” in Table 2 indicates a parameter that may be determined based on remote meteorological data or satellite data rather than by on-site measurement.

Table 2 lists the minimum number of on-site sensors where required. In many cases this is shown as a factor times a multiplier from Table 3. Where no number is given, only one sensor is required, although redundant sensors are typically advisable.

When multiple sensors are required, they shall be distributed throughout the PV plant at representative locations or placed at monitoring points indicated in the table where specified. If the plant includes multiple sections that have different technology types or substantially different local geography or other operation characteristics, then at least one sensor shall be placed in each such section and additional sensors shall be added, if necessary, to meet this requirement.

Empty cells in Table 2 indicate optional parameters that may be chosen for specific system requirements or to meet project specifications.

Table 2 – Measured parameters and requirements

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Irradiance (see Clause 8)							
In-plane irradiance (POA)	G_i	W·m^{-2}	Solar resource	√	1 × Table 3	√	
Global horizontal irradiance	GHI	W·m^{-2}	Solar resource, connection to historical and satellite data	√	1 × Table 3	√ or R	
Horizontal albedo	ρ_H	Unitless	Solar resource, rear side	√ for bifacial, Option 1 per 8.3.3	1 × Table 3		
In-plane rear-side irradiance (POA) or spectrally matched in-plane rear-side irradiance	G_i^{rear}	W·m^{-2}		√ for bifacial, Option 2 per 8.3.3	3 × Table 3		
	$G_{i,sp}^{rear}$	W·m^{-2}					
Diffuse irradiance	G_d	W·m^{-2}	Solar resource	√ for bifacial, Option 1, per 8.3.3 (optional) √ for CPV with < 20× concentration	1 × Table 3		
Direct normal irradiance	DNI	W·m^{-2}		√ for CPV	1 × Table 3		
Circumsolar contribution, circumsolar ratio, sunshape							

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Environmental factors (see Clause 9)							
PV module temperature	T_{mod}	°C	Determining temperature-related losses	√	3 × Table 3	√	
Ambient air temperature	T_{amb}	°C	Estimation of PV temperatures, connection to prediction models	√	1 × Table 3	√ or R	
Wind speed		$m \cdot s^{-1}$		√	1 × Table 3	√ or R	
Wind direction		degrees		√	1 × Table 3		
Soiling ratio	SR		Determining soiling-related losses	√ if typical annual soiling losses without cleaning expected to be > 2 %	1 × Table 3		
Rainfall		cm	Estimation of soiling losses	√	1 × Table 3	√ or R	
Snow		cm	Estimation of snow-related losses	√ if typical annual snow losses without cleaning expected to be > 2 % and soiling measurement does not measure snow loss	1 × Table 3		
Humidity		%	Estimation of spectral variations				
Tracker system (see Clause 10)							
Single-axis tracker tilt angle	ϕ_T	degrees	Tracker system fault detection, single-axis	√ for single-axis tracker	1 × Table 3		
Dual-axis tracker error in primary angle	$\Delta\phi_1$	degrees	Tracker system fault detection, dual-axis	√ for dual-axis tracker	1 × Table 3		
Dual-axis tracker error in secondary angle	$\Delta\phi_2$	degrees					

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Electrical output (see Clause 11)							
Array voltage (DC)	V_A	V	Energy output, diagnostics and fault localization	√	At each inverter – if applicable (see 11.1)		
Array current (DC)	I_A	A		√			
Array power (DC)	P_A	kW		√			
Output voltage (AC)	V_{out}	V		√	At each inverter and at system level	√	At each inverter and at system level
Output current (AC)	I_{out}	A		√		√	
Output power (AC)	P_{out}	kW		√		√	
Output energy	E_{out}	kWh		√		√	
Output power factor	λ		Utility request compliance	√		√	
Reduced load demand			Determine utility or load request compliance and impact on PV system performance	√	At system level		
System output power factor request	λ_{req}			√	At system level		

Table 3 – Multiplier referenced in Table 2

System size (AC) MW	Multiplier
< 40	2
≥ 40 to < 100	3
≥ 100 to < 300	4
≥ 300 to < 500	5
≥ 500 to < 700	6
≥ 700	7, plus 1 for each additional 200 MW.

8 Irradiance

8.1 Sensor types

Approaches to ground-based on-site irradiance measurement include:

- Measure total broadband hemispherical solar irradiance, independent of spectral or angular distribution. Instruments with this objective are classified as pyranometers, regardless of technology type.
- Measure matched irradiance corresponding to the PV-usable portion of the incident spectral and angular distribution. PV reference devices (reference cells and modules) are used for this objective.
- Measure spectral irradiance, from which spectrally matched irradiance can be determined. Spectroradiometers or multi-spectral instruments can be used for this objective.

Measurements can be transposed between approaches using appropriate models, with some uncertainty. If used, model-based transpositions and corrections shall be documented.

Irradiance may also be determined from remote measurements using satellite instrumentation as a supplement, or replacement (when permitted by Table 2), for ground-based on-site measurements. See 8.3.12.

The selected sensor and sensor type shall be documented.

8.2 General requirements

8.2.1 Overview

This subclause 8.2 provides general requirements applicable to most on-site irradiance measurements. Subsequent subclauses on specific irradiance measurement types may include different and/or additional requirements.

8.2.2 Sensor requirements

Sensors shall meet the requirements of Table 4 according to sensor type.

Table 4 – Irradiance sensor requirements

Sensor type	Class A system	Class B system
Pyranometer	Front side (POA and GHI): Class A per ISO 9060:2018, Spectrally flat Calibration uncertainty ≤ 2 % at 1 000 W·m^{-2} Range up to 1 500 W·m^{-2} Resolution ≤ 1 W·m^{-2} Rear side: Class C or better per ISO 9060:2018 Calibration uncertainty ≤ 3 % at 1 000 W·m^{-2} Range up to 1 500 W·m^{-2} Resolution ≤ 1 W·m^{-2}	Class C or better per ISO 9060:2018 Calibration uncertainty ≤ 3 % at 1 000 W·m^{-2} Range up to 1 500 W·m^{-2} Resolution ≤ 1 W·m^{-2}
PV reference device	Working reference device per IEC 60904-2 Calibration uncertainty ≤ 2 % at 1 000 W·m^{-2} Range up to 1 500 W·m^{-2} Resolution ≤ 1 W·m^{-2}	Working reference device per IEC 60904-2 Calibration uncertainty ≤ 3 % at 1 000 W·m^{-2} Range up to 1 500 W·m^{-2} Resolution ≤ 1 W·m^{-2}

Pyranometers include a wide range of instrument technologies, including but not limited to thermopile pyranometers and single- or multi-photodiode-based instruments. For front-side solar irradiance measurement in Table 4, spectrally flat means that the pyranometer's broadband irradiance measurement is negligibly affected by the spectral distribution of the incident sunlight.

8.2.3 Sensor locations

8.2.3.1 Front side

The location of front-side irradiance measurement sensors, including GHI and plane-of-array sensors, shall be chosen to be representative and to avoid shading conditions from sunrise to sunset, if possible. Shading should only occur within a half hour of sunrise or sunset and any shading shall be documented.

For front-side plane-of-array irradiance measurements, for either fixed-tilt or tracking systems, sensors shall be maintained at the same tilt and azimuth angles as the modules. This may be achieved by placing the sensors either directly on the module racking or on separate poles or extension arms with tracking, if applicable.

NOTE Optionally, additional front-side irradiance sensors may be placed in locations that are temporarily shaded by adjacent module rows, e.g. during backtracking of a tracking system, in order to monitor this shading effect, but these sensors do not satisfy the requirements of Table 2 and Table 3 and the performance metrics always use unshaded sensors, unless explicitly noted.

8.2.3.2 Rear side

The location of rear-side irradiance and/or in-plane rear-side irradiance ratio sensors shall be chosen such that they have a field of view representative of the conditions present on the rear side in the majority of the array, while minimizing shading on the modules. If the expected ground surface varies throughout the site, use an appropriate quantity of sensors and sampling methodology to capture the variations. The sensors should also be placed to capture the rear-side irradiance without impact from local surroundings other than representative shading by nearby portions of the PV array.

The sensors should be placed at the same tilt angle as the modules, directly on the module racking, by using beam or rail support structures, and positioned away from row ends, mounting piers, and other sources of localized shading or enhanced illumination phenomena such as reflections from the module racking.

A concern regarding in-plane rear-side irradiance sensors and in-plane rear-side irradiance ratio sensors is the non-uniformity of the irradiance reaching the back side of the module surface from edge to edge. It is recommended to place multiple sensors along the rear side of the racking structure to follow and measure the non-uniform illumination profile throughout the day. This allows both quantifying the non-uniformity of the rear-side irradiance and calculating an effective average of the rear-side irradiance for introduction into selected performance formulas.

NOTE The measured irradiance may differ depending on the position of the sensor, especially in the case of rear-side POA sensor measurements. For example, if the sensor is placed below a row of modules, it may show a different reading than when placed above the row of modules, since a contribution to the irradiance in a tilted plane originates from the ground or nearby features.

8.2.3.3 Horizontal albedo

The location of horizontal albedo sensors shall be chosen to be representative of the albedo at the site. The sensors should be mounted at a minimum height of 1,0 m in order to allow for a sufficient field of view of irradiance reflecting from the ground and should not be shaded by vegetation or any nearby structures, including modules and the module support structure, within a ±80 degree viewing angle. Shading by the albedo measurement device and its support structure should be minimized. If the expected ground surface varies throughout the site, use an appropriate quantity of sensors and sampling methodology to capture the variations.

8.2.4 Recalibration

Recalibration of sensors shall be conducted in a manner that minimizes downtime and sensor outages in order to prevent interruption of monitoring. Effective methods may include:

- Exchanging installed sensors with new or recalibrated units
- Performing on-site recalibration of sensors where possible
- Providing redundant sensors and alternating laboratory recalibration schedules.

For Class A systems, sensors shall be recalibrated once every 2 years, or more frequently per manufacturer recommendations.

For Class B systems, recalibrate sensors according to manufacturer recommendations.

8.2.5 Soiling mitigation

For Class A systems the effects of soiling accumulation on irradiance sensors shall be mitigated. For typical sensors and installations, weekly cleaning is required. Cleaning may be employed less frequently when local conditions allow or when technology is employed which mitigates or corrects for sensor soiling equivalently to weekly cleaning or detects soiling so that cleaning can be scheduled when needed.

8.2.6 Dew and frost mitigation

For Class A systems, the effects of dew and frost accumulation on irradiance sensors shall be mitigated for locations where dew or frost is expected during more than 2 % of annual GHI-hours.

Determination of whether an installation site requires mitigation may be performed by examining typical meteorological year data for the site, paying attention to ambient temperature and dew point. For the purposes of this assessment, dew or frost is considered expected when ambient temperature is within 1,5 °C of dew point.

Various means of mitigation, including heating and external ventilation, can be effective.Irradiance sensors shall maintain their accuracy and classification while dew and frost mitigation is applied. Heating shall not disturb the sensor's accuracy and classification. For pyranometers, effective means of ensuring accurate performance while the sensor is heated may include, but are not limited to, internal and external ventilation.

8.2.7 Inspection and maintenance

Routine inspection of sensors shall be performed to check for soiling, misalignment, and other fault conditions. For Class A systems, front-side sensors shall be inspected weekly.

Sensors shall be maintained according to manufacturer requirements. Maintenance requirements may include, for example, desiccant inspection and/or replacement, where applicable.

8.2.8 Sensor alignment

Irradiance sensors for global horizontal irradiance (GHI) shall be levelled to within 0,5°.

Irradiance sensors for plane-of-array (POA) irradiance shall be aligned with their intended plane within 0,5° of tilt and 1° of azimuth (Class A) or 1° of tilt and 2° of azimuth (Class B), with the following provisions:

- When the sensors are placed directly on the module racking, the alignment requirement is met if it can be shown that the sensors are aligned to the racking to within the stated tolerances.
- When the sensors are placed on another mounting structure independent of the modules, care shall be taken to achieve and verify alignment to within stated tolerances. If alignment cannot be achieved, the alignment error shall be measured and documented.

NOTE Sensor tilt can be measured with an inclinometer. Azimuthal alignment of plane-of-array sensors can be verified by reviewing and modelling a time series of irradiance data in clear-sky conditions.

8.3 Measurements

8.3.1 Global horizontal irradiance

Global horizontal irradiance (GHI) is measured with a horizontally oriented upwards-facing irradiance sensor or is determined from the combination of direct normal irradiance and diffuse horizontal irradiance per formula in 3.21.

8.3.2 In-plane irradiance

For flat-plate systems, in-plane irradiance is measured with an irradiance sensor with aperture oriented parallel to the plane of array (POA) mounted either on the module support structure or on another structure that is aligned parallel to the modules.

In the case of tracked systems, the irradiance sensor shall be continuously aligned with the actual plane of array of the modules, including backtracking if used.

For concentrator systems, see 8.3.9.

If any trackers are programmed to operate in a non-standard way relative to the rest of the array, these trackers should be excluded as sensor locations for the purposes of Table 2 and Table 3, but may optionally receive additional complementary sensors.

NOTE 1 The measurement of irradiance on a tracked surface can become erroneous if the tracker supporting the sensor does not track correctly. An approach to verification is to use the measured direct normal irradiance and horizontal diffuse irradiance, DNI and G_d respectively, and a transposition model to calculate the expected in-plane irradiance and then compare this with the measured value.

NOTE 2 POA irradiance can also be estimated from GHI using a decomposition and transposition model.

8.3.3 In-plane rear-side irradiance

Accurately determining the rear-side solar resource of bifacial systems is difficult. The rear-side irradiance on a PV array, as well as the spectral content of the irradiance, varies strongly spatially and temporally depending on shading patterns, details of the mounting structure, ground surface properties, and seasonal variations.

Table 2 provides two options for determining rear-side irradiance in bifacial systems:

- Option 1: Measure horizontal albedo and optionally diffuse irradiance, and use an optical model, such as a view-factor or ray-tracing model, to estimate rear-side irradiance.
- Option 2: Directly measure rear-side in-plane irradiance or, optionally, spectrally matched in-plane rear-side irradiance.

Direct measurement of rear-side in-plane irradiance is performed with an irradiance sensor with aperture oriented parallel to the plane of array (POA) mounted on the rear side of the module support structure. This may also be performed with a bifacial reference device (see 3.19).

8.3.4 In-plane rear-side irradiance ratio

For bifacial systems, in-plane rear-side irradiance ratio is measured by taking the ratio of the in-plane rear-side irradiance (see 8.3.3) to the in-plane irradiance (see 8.3.2).

8.3.5 Horizontal albedo

Horizontal albedo is determined by measuring the downwelling irradiance from the sky in a horizontal plane (GHI) and the upwelling ground-reflected irradiance in a horizontal plane and calculating the ratio of upwelling to downwelling irradiance.

See Option 1 and Option 2 in 8.3.3.

8.3.6 Direct normal irradiance

Direct normal irradiance (DNI) is measured with an instrument that blocks or corrects for diffuse irradiance contributions. Examples include pyrheliometers, rotating shadow band radiometers, tracked disk or ball radiometers, and others. DNI may be calculated from GHI and DHI per the formula in 3.23.

8.3.7 Diffuse horizontal irradiance

Diffuse horizontal irradiance G_{d} (or DHI) is measured with an instrument that blocks or corrects for direct irradiance contributions. Examples include rotating shadow band radiometers, tracked disk or ball radiometers, and others. DHI may be calculated from GHI and DNI per the formula in 3.27.

8.3.8 Spectrally matched irradiance

For determination of the usable solar resource, optional spectral matching of irradiance measurements for the user's specific PV modules should be considered.

Spectrally matched rear-side irradiance is particularly relevant because the spectrum of ground-reflected radiation can differ significantly from the incident solar radiation.

Methods for determining spectrally matched irradiance include:

- Measuring spectrally-matched irradiance using a spectrally matched reference device per 3.17. The residual spectral mismatch can be determined by IEC 60904-7 considering typical spectra for the application. Users should select a degree of residual spectral mismatch appropriate to their application. Identical PV technology is not necessarily required; for example, commercial monocrystalline silicon reference cells will provide beneficial spectral matching (compared to broadband measurement) for most commercial crystalline silicon PV technologies.
- Measuring broadband or non-spectrally-matched irradiance, e.g. using a pyranometer, plus performing a model-based spectral mismatch correction using environmental data such as temperature, humidity, etc.
- Measuring spectral irradiance, e.g. using a spectroradiometer or other multi-spectral instrument, from which spectral correction factors may be derived and applied to broadband irradiance data to obtain spectrally matched irradiance.

8.3.9 In-plane irradiance for concentrator systems

For concentrator systems, the total in-plane irradiance is replaced by the irradiance captured by the concentrator.

- For concentrator systems that capture only the direct beam:

  The in-plane irradiance G_i is replaced by the in-plane direct beam irradiance $G_\text{i,b}$:

$$G_\text{i} = G_\text{i,b} \tag{1}$$

- For concentrator systems that capture some diffuse light in addition to the direct beam:

  The in-plane irradiance is replaced by the effective irradiance (G_eff) owing to partial diffuse capture, where the fraction of diffuse light is quantified by the parameter f_d:

$$G_\text{i} \rightarrow G_\text{eff} = (G_\text{i,b} + f_\text{d} \cdot (G_\text{i} - G_\text{i,b})) \tag{2}$$

Determination of f_d begins by obtaining full current and voltage characteristics of a CPV module over many days with varying fractions of diffuse energy; a clear day will have little diffuse energy while a cloudy day will provide mainly diffuse energy. Analysis of a diffuse fraction for a given low and medium concentration CPV module should be based upon a large number of I-V curves where global in-plane irradiance (G_i) is above 21 W·m^{-2}.

A fundamental premise of this method is that the short-circuit current (I_sc) can be consistently and reliably estimated by acquiring a full trace of the current-voltage (I-V) curve for the device under test (DUT) and that the temperature coefficient for the I_sc parameter of the DUT has been well characterized in advance. When this premise is valid, the diffuse light capture characterization of a CPV module or receiver becomes simply a matter of determining the short-circuit current, $I_\text{sc,0}$ normalized to standard test conditions (STC) and then relating the as-measured $I_\text{sc,0}$ to this reference using an "effective irradiance" G_eff, such as that shown in Formula (2). One significant advantage of this approach is that compensating for the effects of solar spectrum can be accomplished by adjusting only the I_sc parameter.

By plotting the terms on the left-hand side of Formula (3) on the y-axis of a 2D graph and by plotting $G_\text{i,b}/G_\text{i}$ on the x-axis, the slope and intercept can be easily determined from the form $y = mx + b$ after performing a linear regression analysis of the I_sc vs. $G_\text{i,b}/G_\text{i}$ data.

$$\frac{1000\ \mathrm{W\cdot m^{-2}}}{G_i}\times\frac{I_{sc}}{\left[1+\alpha_{I_{sc}}\times(T_c-25\ °\mathrm{C})\right]}=\left(I_{sc,0}\times f_d\right)+\left(\frac{G_{i,b}}{G_i}\right)\times\left(I_{sc,0}-f_d\times I_{sc,0}\right) \quad (3)$$

where

α_{Isc} is the temperature coefficient for I_{sc},

T_c is the cell temperature in °C,

$I_{sc,0}$ is the short circuit current at STC and 0° angle of incidence.

The term f_d then becomes:

$$f_d=\frac{b}{m+b} \quad (4)$$

One limitation to this approach that should be noted is the inherent assumption that the amount of diffuse light captured will be constant throughout the entire range of climatic conditions that are being observed. This will certainly introduce noise into the measurements, but if sampling is high enough, the linear regression analysis discussed above can provide a reasonable estimate for an average amount of diffuse capture that can be used to better define the solar resource for such concentrator PV modules.

If the results observed present a clear inflection or break in the diffuse capture response behaviour of the CPV module, the regression analysis can be split into multiple parts in a piecewise manner. This could be a likely outcome given that the nature of diffuse light is quite variable in the relative amounts of circumsolar vs. isotropic diffuse light. By treating the linear regression analysis in this fashion, one can determine the amount of diffuse capture (f_d) as a function of a specific range of the $G_{i,b}/G_i$ ratio.

8.3.10 Spectral irradiance for concentrator systems

For concentrator systems when a power rating according to IEC 62670-3 is to be performed, the system should include a device for determining the direct normal spectral irradiance. Refer to IEC 62670-3 for additional details.

8.3.11 Circumsolar measurements for concentrator systems

For concentrator systems, it may be useful to measure circumsolar irradiance. Circumsolar irradiance is irradiance emanating from a region of the sky immediately surrounding the solar disk. Useful parameters to measure may include circumsolar contribution, circumsolar ratio, and sunshape. See ISO 9488.

The measured direct normal irradiance (DNI) may include circumsolar contributions due to the angular acceptance of the DNI sensor. The fraction of measured DNI which is circumsolar is defined as the circumsolar ratio.

Concentrator systems may or may not be able to capture a portion of the circumsolar irradiance, depending on their design. However, measuring circumsolar quantities may be useful for performance characterization purposes.

8.3.12 Satellite remote sensing of irradiance

Satellite remote sensing techniques use a dual approach to measuring the total surface downwelling irradiance at the global horizontal plane. The on-board satellite instruments measure the radiance emitted or reflected by the earth's surface through the column of the atmosphere at specific visible and infrared spectral bands. The emitted radiance represents conditions where cloud cover is present, so measurements by this technique need to be framed in reference of the clear sky irradiance models. Thus, the base of satellite remote sensing uses radiative transfer models to predict the clear sky condition, then satellite measurements are applied to the clear sky as reduction in irradiance due to cloud opacity.

Operating plants considering satellite remote sensed irradiance should consider the following when comparing to on-site measured irradiances. Validated sources of satellite irradiance will have documented reliability and consistency in terms of data availability and calibration, respectively. Because satellite remote sensed irradiance sources use a single set of carefully monitored on-board sensors covering entire continents at once, data can be delivered with reduced uncertainty and cost associated with on-site maintenance, instrumentation soiling, calibration drifts and location-to-location mismatches. The accuracy benefits of satellite remote sensed data come at different temporal and spatial averaging versus on-site measurements. Satellite measurement of cloud opacity occurs at the spatial scale determined by the resolution of the measurement hardware on the satellite. For most modern satellite networks, this is approximately 0,01° by 0,01° latitude or longitude (roughly 1 km by 1 km). Thus, the representation of the irradiance condition from satellite sources reflects the average irradiance over a 0,01° by 0,01° square area. In contrast, on-site measurements reflect irradiance conditions at the surface area of the sensor, effectively a single point. This difference in measurement area leads to differences in irradiance over various time averaging periods. Additionally, the satellite image capture frequency is typically less than ground hardware data logging. As a result of both effects, satellite and ground may show greater differences in irradiance measurements on the order of 10 % to 20 % for sub-hourly to hourly periods where plant operators may be seeking analysis to diagnose plant underperformance. However, at monthly up to yearly averaging periods, satellite and ground will align on the order of < 1 % to 5 %, where plant operators may be seeking analysis to demonstrate overall plant performance.

Satellite remote sensed irradiances, including global horizontal, direct normal, diffuse, and in-plane irradiances are typically available in real time from commercial services. Long-histories of satellite measurements can be beneficial to plant operators as a reference for plant performance against long-term average/financial forecast conditions.

Important considerations when selecting satellite data are as follows:

- Satellite remote sensed irradiance data should be carefully selected after a review of accuracy and uncertainty.
- Satellite accuracy and uncertainty should be assessed against quality ground data from well-maintained sensors.
- Satellite sources should have a long history of measurement to verify accuracy across changes in satellite hardware.
- Satellite sources should provide data up to current time, also for the purpose of evaluating accuracy.
- Satellite data should be versioned; e.g. the metadata about the satellite measurements should be traceable to a repeatable model basis.
- Satellite data should provide measurements at the native satellite hardware device precision.
- The satellite remote sensed method should be specifically designed for measuring solar irradiance.

9 Environmental factors

9.1 PV module temperature

PV module temperature, T_{mod}, is measured with temperature sensors affixed to the back of PV modules.

For bifacial modules, rear-side temperature sensors and wiring shall obscure < 10 % of the area of any cell, and wiring should be routed in between cells when possible.

Temperature sensors shall have a measurement resolution ≤ 0,1 °C and uncertainty ± 1 °C or better.

If adhesive is used to affix the temperature sensor to the back surface of the module, the adhesive should be appropriate for prolonged outdoor use at the site conditions and should be checked to be compatible with the surface material on the rear of the module to prevent degradation by the adhesive.

Adhesive or interface material between the temperature sensor and the rear surface of the module shall be thermally conductive. The total thermal conductance of the adhesive or interface layer shall be 500 $W{\cdot}m^{-2}{\cdot}K^{-1}$ or greater, in order to keep the maximum temperature difference between the module's rear surface and the temperature sensor on the order of approximately 1 K. For example, this may be achieved using a thermally conductive adhesive with thermal conductivity greater than 0,5 $W{\cdot}m^{-1}{\cdot}K^{-1}$ in a layer not more than 1 mm thick.

See Annex B for additional recommendations on temperature sensor attachment.

Care should be taken to ensure that the temperature of the cell in front of the sensor is not substantially altered due to the presence of the sensor or other factors.

NOTE 1 Cell junction temperatures are typically 1 °C to 3 °C higher than the temperature measured on the module's rear surface, depending on the module construction. The temperature difference may be estimated, as a function of irradiance, using the thermal conductivity of the module materials.

NOTE 2 An infrared image of the front of the module may help confirm that the temperature of the cell in front of the sensor is not substantially altered by the presence of the sensor or other factors.

Module temperature varies across each module and across the array. Temperature sensors shall be placed in representative locations to capture the range of variation and allow determination of an effective average.

Temperature sensors shall be replaced or recalibrated as per manufacturer's requirements.

Module temperature measurement may alternatively be performed with the V_{oc}-based method described in IEC 60904-5. This may require use of an additional reference module, not connected to the PV array, for temperature measurement. The module should be independently calibrated for this purpose. The module should be held at maximum power point in between brief V_{oc} measurements to ensure temperature is representative of the PV array. Considering the degradation of V_{oc} over time, the relation between module temperature and V_{oc} should be recalibrated at periodic intervals. If the module is not held at maximum power point, a calibrated temperature offset between maximum power point and the actual operating condition should be determined.

9.2 Ambient air temperature

Ambient air temperature, T_{amb}, is measured by means of temperature sensors located in solar radiation shields which are ventilated to permit free passage of ambient air.

The sensors shall have a measurement resolution ≤ 0,1 °C and uncertainty ±1 °C or better.

The sensors should be placed at least 1 m away from the nearest PV module and in locations where they will not be affected by thermal sources or sinks, such as exhausts from inverters or equipment shelters, asphalt or roofing materials, etc.

The sensors shall be replaced or recalibrated as per manufacturer's requirements.

9.3 Wind speed and direction

Wind speed and wind direction are used for estimating module temperatures. They may also be used for documenting warranty claims related to wind-driven damage.

Wind speed and direction are to be measured at a height and location which are representative of the array conditions and/or the conditions assumed by any applicable performance model used for a performance guarantee of the PV installation.

In addition, wind speed and direction may also be measured at heights and locations suitable for comparison with historical or contemporaneous meteorological data.

In some cases data on wind gusts (typically gusts up to 3 s in length) may be required to compare with project design requirements. When necessary the monitoring system sampling period should be sufficiently small (e.g. ≤ 5 s) and the data record should contain not only averaged but also maximum values. (See 6.1.)

Wind measurement equipment should not shade the PV system at any time of day or year and should be located at a point that is sufficiently far from obstructions.

Wind speed sensor measurement uncertainty shall be ≤ 0,5 $m \cdot s^{-1}$ for wind speeds ≤ 5 $m \cdot s^{-1}$, and ≤ 10 % of the reading for wind speeds greater than 5 $m \cdot s^{-1}$.

Wind direction is defined as the direction from which the wind blows, and is measured clockwise from geographical north. It shall be measured with an accuracy of 5°.

Wind sensors shall be recalibrated as per manufacturer's recommendations.

9.4 Soiling ratio

Per 3.31, the soiling ratio is a property of the PV array cleanliness condition. Soiling measurement instruments approximate the true soiling ratio of the PV array by measuring the impact of soiling on a sensor surface of the instrument and assuming that the soiling condition of the PV array is the same as that of the sensor surface.

Soiling measurement instruments use various physical principles:

- One measurement approach, which has many variations, compares a pair of PV reference devices, one of which is routinely cleaned and the other of which soils naturally at the same rate as the PV array. Methods for implementing this approach are described in detail in Annex C.
- Other approaches are based on optical principles, detecting soiling particles on a collection surface according to their effect on either reflection or transmission of light.

Some of the instrument types can measure the effect of non-uniform soiling on the power loss of PV modules. Non-uniform soiling occurs when deposited soiling particles move under the influence of dew, rain, wind, and gravity, often collecting along PV module edges, especially bottom edges. This can have a disproportionate effect on power, depending on module type. See Annex C.

9.5 Rainfall

Rainfall measurements may be used to estimate the cleanliness of modules. If soiling ratio is also measured, these data are complementary.

9.6 Snow

Snowfall measurements can be used to estimate losses due to shading from snow. However, these losses may also be included in measurements of soiling ratio, depending on the soiling measurement device.

9.7 Humidity

Relative humidity measurements may be used to estimate changes in incident spectrum which may affect PV module power output as well as irradiance sensor readings. Humidity data with temperature data can also be used to calculate the times of wetness due to condensation. (Alternatively, surface condensation sensors can be used to directly gather these data.)

10 Tracker system

10.1 Single-axis trackers

Measurement of the real-time tracker tilt angle ϕ_T shall be performed with accuracy ±1° for Class A systems. Measurement may be performed with motor or position counters or other sensors integrated into the tracker mechanism, such as an inclinometer.

10.2 Dual-axis trackers

10.2.1 Monitoring

The real-time tracker pointing errors ($\Delta\phi_1$ and $\Delta\phi_2$) are measured on representative trackers using sensors defined and calibrated as per 7.3 of IEC 62817:2014. Selected trackers should coincide with a measurement location for DC output power (see Clause 11). Reporting of tracker pointing error data shall be per 7.4.6 of IEC 62817:2014.

10.2.2 Pointing error sensor alignment

The tracker pointing error sensor is typically mounted on the tracker such that the pointing vector of the sensor is normal to the plane of the PV system.

Initial alignment of a pointing error sensor shall be confirmed by intentionally scanning across the optimal alignment while measuring the pointing error. This may be done either by driving the tracker through the desired angle in each relevant axis or by moving the tracker ahead of the sun, stopping the tracker, and waiting for the sun to move into and out of the optimal position. The measured pointing error is plotted against the normalized system maximum power divided by direct normal irradiance (DNI). The data shall be measured under clear sky conditions with wind speeds in a range from 0,5 m·s^{-1} to 3,5 m·s^{-1}, and shall be recorded within a 1 h time period. These requirements are to minimize noise associated with variation in power output from factors other than alignment.

Ideal alignment is achieved if the pointing error is zero when the irradiance-normalized power curve is at the maximum value. No tolerance is stated here for the deviation from ideal alignment as acceptable tolerance is dependent on the given system. The width of the scan will depend upon the response of the system, but should be at most ±0,75° so that the scan is compatible with the DNI sensor.

The test is usually applied to an individual tracker with measurement of power generation associated only with that individual tracker, but it may be possible to plot the power generation of multiple trackers as long as all of them move together.

The plots shall be included in a test report and shall serve as indication that alignment tolerance is sufficient.

11 Electrical measurements

11.1 Inverter-level measurements

Inverter-level electrical measurements shall meet the requirements in Table 5 if applicable for the system configuration. DC measurements may be omitted when the modules include microinverters. In Table 5 precision refers to measurement repeatability and resolution, not absolute accuracy.

Optionally, for greater fault detection capability DC measurements may be performed at sublevels of the system (e.g. strings, combiners, feeders, etc.) in addition to or instead of at the inverters.

Table 5 – Inverter-level electrical measurement requirements

Parameter	Measurement precision % of max inverter rating	
	Class A systems %	Class B systems %
Input voltage (DC)	±2,0	n/a
Input current (DC)	±2,0	n/a
Input power (DC)	±3,0	n/a
Output voltage (AC)	±2,0	±3,0
Output current (AC)	±2,0	±3,0
Output power (AC)	±3,0	±4,5

11.2 Plant-level measurements

Electrical measurements at the output of the power plant shall meet the requirements of Table 6. The output of the power plant is the aggregate net output produced by the entire system.

For multi-phase systems, each phase shall be measured, or 2 of 3 phases shall be measured (two wattmeter method).

Table 6 – Plant-level AC electrical output measurement requirements

Parameter	Class A system	Class B system
Active power and energy	Class 0,2 S as per IEC 62053-22	Class 0,5 S as per IEC 62053-22
Power factor	Class 1 as per IEC 61557-12	Class 1 as per IEC 61557-12
Recalibration	Per manufacturer's requirements and/or local codes and contracts	Per manufacturer's requirements and/or local codes and contracts

For Class A, the monitoring system shall document periods during which the PV system does not deliver its maximum output power to the utility grid and/or local loads as a result of external system requests or requirements, which may include, for example, system output power factor demand and system power curtailment.

12 Data processing and quality check

12.1 Night

Night-time data may contain valuable information for quality checking, such as pyranometer and other instrumentation offsets. However, processed data for irradiance, PV-generated power, and other quantities expected to be zero at night should be set to zero during night-time after quality checks are performed, to avoid extraneous values.

12.2 Quality check

12.2.1 Removing invalid readings

The measured data should be checked and filtered, either automatically or manually, to identify missing or invalid data points and filter them out of subsequent analysis. Such missing or invalid data should be documented by the monitoring system.

Recommended methods of identifying missing or invalid data points include:

- applying physically reasonable minimum and maximum limits
- applying physically reasonable limits on maximum rates of change
- applying statistical tests to identify outlying values, including comparing measurements from multiple sensors
- applying contract data to identify viable parameter boundaries for certain performance data
- noting error codes returned by sensors
- identifying and deleting redundant data entries
- identifying missing data
- identifying readings stuck at a single value for an extended time
- checking timestamps to identify gaps or duplicates in data
- checking system availability reports.

12.2.2 Treatment of missing data

Missing or invalid data may be treated in one of the following ways:

- the invalid or missing data may be replaced by values estimated from the valid data recorded before and/or after the invalid or missing data;
- the invalid or missing data may be replaced with an average value for the analyzed interval;
- the data may be treated in a manner specified in a valid contract, performance guarantee document, or other specification covering the installation;
- the analysed interval may be treated as missing or invalid.

The treatment of missing or invalid data may depend on the goal of the measurement. For example, missing or invalid data associated with inverter issues should be discarded if the goal is strictly to quantify module performance, but should be retained if the goal is to capture all aspects of plant performance and availability.

Additional recommendations and requirements for treatment of missing or invalid data are included in IEC TS 61724-2 and IEC TS 61724-3.

The specific treatment of missing or invalid data should be documented in any reports.

13 Calculated parameters

13.1 Overview

Table 7 summarizes calculated parameters which are further defined below. All quantities in the table shall be reported with respect to the reporting period (typically a day, month, or year).

Table 7 – Calculated parameters

Parameter	Symbol	Unit
Irradiation (see 13.3)		
In-plane irradiation	H_i	kWh·m^{-2}
In-plane rear-side irradiation (for bifacial)	H_i^{rear}	kWh·m^{-2}
Electrical energy (see 13.4)		
PV array output energy (DC)	E_A	kWh
Energy output from PV system (AC)	E_{out}	kWh
Array power rating (see 13.5)		
Array power rating (DC)	P_0	kW
Array power rating (AC)	$P_{0,AC}$	kW
Yields and yield losses (see 13.6 and 13.7)		
PV array energy yield	Y_A	kWh·kW^{-1}
Final system yield	Y_f	kWh·kW^{-1}
Reference yield	Y_r	kWh·kW^{-1}
Array capture loss	L_C	kWh· kW^{-1}
Balance of system (BOS) loss	L_{BOS}	kWh· kW^{-1}
Efficiencies (Subclause 13.8)		
Array efficiency	η_A	None
System efficiency	η_f	None
BOS efficiency	η_{BOS}	None

13.2 Summations

In the formulas given below involving summation, τ_k denotes the duration of the k^{th} recording interval within a reporting period (see Clause 6), and the symbol

$$\sum_k$$

denotes summation over all recording intervals in the reporting period.

Note that in formulas involving the product of power quantities with the recording interval τ_k the power should be expressed in kW and the recording interval in hours to obtain energy in units of kWh.

13.3 Irradiation

Irradiation, also known as insolation, is the time integral of irradiance.

Each irradiation quantity H corresponding to an irradiance quantity G defined in Clause 3 is calculated by summing the irradiance as follows:

$$\mathrm{H} = \sum_{k} \mathrm{G_k} \times \tau_\mathrm{k} \tag{5}$$

For example, the front-side in-plane or front-side plane-of-array (POA) irradiation, H_i, is given by:

$$\mathrm{H_i} = \sum_{k} \mathrm{G_{i,k}} \times \tau_\mathrm{k} \tag{6}$$

and rear-side in-plane or rear-side plane-of-array (POA) irradiation, H_i, is given by:

$$H_i^{rear} = \sum_{k} \mathrm{G_{i,k}^{rear}} \times \tau_k \tag{7}$$

13.4 Electrical energy

13.4.1 General

Energy quantities may be calculated from the integral of their corresponding measured power parameters over the reporting period.

Alternatively, if power measurements are performed using sensors with built-in totalizers, the energy quantities may be taken directly as measurement readings from the sensors.

13.4.2 DC output energy

The PV array DC output energy is given by:

$$E_\mathrm{A} = \sum_{k} P_{\mathrm{A},k} \times \tau_k \tag{8}$$

13.4.3 AC output energy

The AC energy output is given by:

$$E_\mathrm{out} = \sum_{k} P_{\mathrm{out},k} \times \tau_k \tag{9}$$

13.5 Array power rating

13.5.1 DC power rating

The array DC power rating, P_0, is the sum of the DC power output of all installed PV modules at the power rating reference condition, which is either:

– standard test conditions (STC), for monofacial and bifacial modules; or
– concentrator standard test conditions (CSTC), for concentrator systems. P_0 is given in units of kW.

P_0 should be calculated by using data from manufacturer datasheets or module labels, or, provided that the choice is specified, using alternative data such as laboratory or on-site test data.

The definition of P_0 that is used should be specified explicitly whenever quantities that depend on P_0 are reported.

Note that the definition of P_0 ignores any rear-side contribution for bifacial modules. IEC 61215 includes provisions for measuring bifacial modules using rear-side irradiance; however, these are provided for the purpose of indoor accelerated stress testing, not performance rating.

13.5.2 AC power rating

The array AC power rating, $P_{0,AC}$, is the lesser of:

– the array DC power rating P_0, and
– the sum of the inverter ratings in the system at specified operating temperature.

13.6 Yields

13.6.1 General

Yields are ratios of an energy quantity to the array power rating P_0. They indicate actual array operation relative to its rated capacity.

Yields have units of kWh·kW^{-1}, where units of kWh in the numerator describe the energy production and units of kW in the denominator describe the system power rating. The ratio of units is equivalent to hours, and the yield ratio indicates the equivalent amount of time during which the array would be required to operate at P_0 to provide the particular energy quantity measured during the reporting period.

13.6.2 PV array energy yield

The PV array energy yield Y_A is the array energy output (DC) per rated kW (DC) of installed PV array:

$$Y_A = E_A / P_0 \tag{10}$$

13.6.3 Final system yield

The final PV system yield Y_f is the net energy output of the entire PV system (AC) per rated kW (DC) of installed PV array:

$$Y_f = E_{out} / P_0 \tag{11}$$

13.6.4 Reference yield

The reference yield Y_r for a monofacial PV system can be calculated by dividing the total front-side in-plane irradiation by the module's reference plane-of-array irradiance:

$$Y_r = H_i / G_{i,ref} \tag{12}$$

where the reference plane-of-array irradiance $G_{i,ref}$ (kW·m^{-2}) is the irradiance at which P_0 is determined, usually defined under STC.

The reference yield represents the number of hours during which the solar radiation would need to be at reference irradiance levels in order to contribute the same incident solar energy as was monitored during the reporting period while the utility grid and/or local load were available.

If the reporting period is equal to one day, then Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

13.6.5 Bifacial reference yield

The reference yield Y_r^{bi} for a bifacial PV system can be calculated by taking the product of the front-side in-plane irradiation and the bifacial irradiance factor and dividing by the module's reference plane-of-array irradiance:

$$\mathrm{Y_r^{bi}} = \sum_{\mathrm{k}} \left(\mathrm{G_{i,k}} \times \tau_{\mathrm{k}} \times \mathrm{BIF_k}\right) / \mathrm{G_{i,ref}} \tag{13}$$

The reference yield represents the number of hours during which the solar radiation would need to be at reference irradiance levels in order to contribute the same incident solar energy as was monitored during the reporting period while the utility grid and/or local load were available.

If the reporting period is equal to one day, then Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

13.7 Yield losses

13.7.1 General

Yield losses are calculated by subtracting yields. The yield losses also have units of kWh· kW^{-1} (or h). They represent the amount of time the array would be required to operate at its rated power P_0 to provide for the respective losses during the reporting period.

13.7.2 Array capture loss

The array capture loss L_c represents the losses due to array operation, including losses in wiring and junction boxes prior to DC measurement, array temperature effects, soiling, etc., and is defined as:

$$L_C = Y_r - Y_A \tag{14}$$

13.7.3 Balance of systems (BOS) loss

The balance of systems (BOS) loss L_{BOS} represents the losses in the BOS components, including the inverter and all wiring and junction boxes not included in array capture loss, and is defined as:

$$L_{BOS} = Y_A - Y_f \tag{15}$$

13.8 Efficiencies

13.8.1 Array (DC) efficiency

The rated array efficiency is given by:

$$\eta_{A,0} = P_0 \,/\, (G_{i,ref} \times A_a) \tag{16}$$

where the overall array area A_a is the total module area, corresponding to the sum of the areas of the front surfaces of the PV modules as defined by their outer edges.

For a concentrator module, if the front surface is not coplanar, the front surface shall be projected onto an appropriate two-dimensional surface to define the area.

The mean actual array efficiency over the reporting period is defined by:

$$\eta_A = E_A \,/\, (H_i \times A_a) \tag{17}$$

13.8.2 System (AC) efficiency

The mean system efficiency over the reporting period is defined by:

$$\eta_f = E_{out} \,/\, (H_i \times A_a) \tag{18}$$

Formula (18) can also be rewritten as:

$$\eta_f = \eta_{A,0} \times PR \tag{19}$$

where

$\eta_{A,0}$ is the rated array efficiency defined in 13.8.1, and

PR is the performance ratio defined in 14.3.1.

13.8.3 BOS efficiency

The mean BOS efficiency over the reporting period is defined by:

$$\eta_{BOS} = E_{out} / E_A \tag{20}$$

14 Performance metrics

14.1 Overview

Performance metrics are listed in Table 8 and further defined in subsequent subclauses.

Table 8 – Performance metrics

Parameter	Symbol	Units
Rating-based (see 14.3)		
Performance ratio	PR	None
Annual performance ratio	PR_{annual}	None
25 °C performance ratio	$PR'_{25°C}$	None
Annual-temperature-equivalent performance ratio	$PR'_{annual\text{-}eq}$	None
Annual-temperature-equivalent performance ratio for bifacial systems	$PR'_{annual\text{-}eq,\ bi}$	None
Model-based (14.4)		
Power performance index	PPI	None
Energy performance index	EPI	None
Baseline power performance index	$BPPI$	None
Baseline energy performance index	$BEPI$	None

Performance metrics in Table 8 are either rating-based (see 14.3) or model-based (see 14.4). The most appropriate metric for a given application depends on system design, user requirements, and contractual obligations. This document does not specify requirements on the metrics used.

The rating-based performance ratio metrics are relatively simple to calculate but may omit known factors that cause system power output to deviate from expectations based on the name-plate rating alone. For example, systems with high DC-to-AC ratio operate at less than the DC nameplate rating during times of high irradiance, but this is an expected attribute of the system design. Similar effects may be observed when evaluating performance ratios for tracking and/or bifacial systems. Such effects are better treated by a performance index based on a detailed system model.

14.2 Summations

See 13.2 for an explanation of formulas given in 14.3 involving summations.

14.3 Performance ratios

14.3.1 Performance ratio

The performance ratio PR is the quotient of the system's final yield Y_f to its reference yield Y_r, and indicates the overall effect of losses on the system. (Alternatively, the performance ratio can be defined as a product of derate factors. See Annex D.) For monofacial PV systems it is defined as:

$$PR = Y_\mathrm{f} / Y_\mathrm{r} \tag{21}$$

$$= (E_\mathrm{out} / P_0) / (H_\mathrm{i} / G_\mathrm{i,ref}) \tag{22}$$

Expanding Formula (22) gives:

$$PR = \left(\sum_k \frac{P_{\mathrm{out},k} \times \tau_\mathrm{k}}{P_0} \right) \Bigg/ \left(\sum_k \frac{G_{\mathrm{i},k} \times \tau_k}{G_\mathrm{i,ref}} \right) \tag{23}$$

Both the numerator and denominator of Formula (23) have units of kWh· kW^{-1} (or h). Moving P_0 to the denominator sum expresses both numerator and denominator in units of energy, giving PR as the ratio of measured energy to expected energy (based only on measured irradiance and neglecting other factors) over the given reporting period:

$$PR = \left(\sum_k P_{\mathrm{out},k} \times \tau_k \right) \Bigg/ \left(\sum_k \frac{P_0 \times G_{\mathrm{i},k} \times \tau_k}{G_\mathrm{i,ref}} \right) \tag{24}$$

The annual performance ratio, PR_annual, is the performance ratio of Formula (24) evaluated for a reporting period of one year.

NOTE 1 The energy expectation expressed by the denominator of Formula (24) neglects the effect of array temperature, using the fixed value of array power rating, P_0. Therefore, the performance ratio usually decreases with increasing irradiation during a reporting period, even though energy production is increased, due to increasing PV module temperature which usually accompanies higher irradiation and results in lower efficiency. This gives a seasonal variation, with higher PR values in winter and lower values in summer. It may also give geographic variations between systems installed in different climates.

NOTE 2 Calculation of the performance ratio using GHI in place of in-plane (plane-of-array) irradiance G_i is an alternative in situations where GHI measurements are available but G_i measurements are not. In this case GHI is substituted for G_i in Formula (24), resulting in a GHI performance ratio. The GHI performance ratio would typically show high values which may even exceed unity. The values cannot necessarily be used to compare one system to another, but can be useful for tracking performance of a system over time and could also be applied to compare a system's measured, expected, and predicted performance using a performance model that is based only on GHI.

14.3.2 Temperature-corrected performance ratios

14.3.2.1 General

The seasonal variation of the performance ratio PR of Formula (24) can be significantly reduced by calculating a temperature-corrected performance ratio PR'.

NOTE While variations in average ambient temperature are the most significant factor causing seasonal variations in measured performance ratio, other factors, such as seasonally dependent shading, spectral effects, and metastabilities can also contribute to the seasonal variation of PR.

14.3.2.2 25 °C performance ratio

The 25 °C performance ratio, $PR'_{25\,°\mathrm{C}}$ is calculated by adjusting the power rating at each recording interval to compensate for differences between the actual PV module temperature and the STC reference temperature of 25 °C.

$PR'_{25\,°C}$ is calculated by introducing a power rating temperature adjustment factor $C_{k,25\,°C}$ into Formula (24), as follows:

$$\mathrm{PR'}_{25\,°C} = \left(\sum_k P_{\mathrm{out},k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_{k,\,25\,°C} \times P_0) \times G_{i,k} \times \tau_k}{G_{i,\mathrm{ref}}}\right) \tag{25}$$

where $C_{k,25°C}$ is given by:

$$C_{k,25\,°C} = 1 + \gamma \times (T_{\mathrm{mod},k} - 25\,°C) \tag{26}$$

Here γ is the relative maximum-power temperature coefficient (in units of $°C^{-1}$), and $T_{\mathrm{mod},k}$ is the module temperature (in °C) in time interval k.

With reference to Formula (26), γ is typically negative, e.g. for crystalline silicon. The measured module temperature may be used for $T_{\mathrm{mod},k}$ in Formula (26). However, if the monitoring objective is to compare $PR'_{25\,°C}$ to a target value associated with a performance guarantee, $T_{\mathrm{mod},k}$ should instead be estimated from the measured meteorological data with the same heat transfer model used by the simulation that set the performance guarantee value to avoid a bias error.

Note that Formulas (25) and (26) can be used to calculate performance ratio adjusted to a different reference temperature by substitution of the desired reference temperature in Formula (26) in place of 25 °C.

14.3.2.3 Annual-temperature-equivalent performance ratio

The annual-temperature-equivalent performance ratio $PR'_{\mathrm{annual\text{-}eq}}$ is constructed to approximate the annual performance ratio PR_{annual} regardless of the duration of the reporting period. It calculates the performance ratio during the reporting period with the power rating at each recording interval adjusted to compensate for differences between the actual PV module temperature and an expected annual-average PV module temperature. While this reduces seasonal variation in the metric, it does not remove the effect of annual-average temperature losses and leaves the value of the metric comparable to the value of PR_{annual}.

$PR'_{\mathrm{annual\text{-}eq}}$ is calculated by introducing a power rating temperature adjustment factor $C_{k,annual}$ into Formula (24), as follows:

$$PR'_{\mathrm{annual-eq}} = \left(\sum_k P_{\mathrm{out},k} \times \tau_k\right) \Big/ \left(\sum_k \frac{(C_{k,\mathrm{annual}} \times P_0) \times G_{i,k} \times \tau_k}{G_{i,\mathrm{ref}}}\right) \tag{27}$$

where $C_{k,\mathrm{annual}}$ is given by:

$$C_{k,\mathrm{annual}} = 1 + \gamma \times (T_{\mathrm{mod},k} - T_{\mathrm{mod,annual\text{-}avg}}) \tag{28}$$

Here γ is the relative maximum-power temperature coefficient (in units of °C^{-1}), $T_{\text{mod},k}$ is the PV module temperature in time interval k, and $T_{\text{mod,annual-avg}}$ is an annual-average module temperature.

NOTE With reference to Formula (28), γ is typically negative, e.g. for crystalline silicon.

$T_{\text{mod,annual-avg}}$ is chosen based on historical weather data for the site and an empirical relation for the predicted module temperature as a function of ambient conditions and module construction. It should be calculated by computing an irradiance-weighted average of the predicted module temperature and then verified using the historical data for the site by confirming that the annual-equivalent performance ratio $PR'_{\text{annual-eq}}$ for the historical data (using Formulas (27) and (28)) is the same as the annual performance ratio PR_{annual} for the historical data (using Formula (24)).

The measured module temperature may be used for $T_{\text{mod},k}$ in Formula (28). However, if the monitoring objective is to compare $PR'_{\text{annual-eq}}$ to a target value associated with a performance guarantee, $T_{\text{mod},k}$ should instead be estimated from the measured meteorological data with the same heat transfer model used by the simulation that set the performance guarantee value, to avoid a bias error.

14.3.3 Bifacial performance ratios

The monofacial performance ratio formulas presented above can be transformed to bifacial performance ratio formulas by introducing the bifacial irradiance factor (BIF) to correct the measured irradiance terms.

For example, the annual temperature-equivalent performance ratio for bifacial systems, $PR'_{\text{annual-eq,bi}}$ is calculated as for the monofacial equivalent in Formula (27) by multiplying the in-plane irradiance by the bifacial irradiance factor (BIF) as follows:

$$PR'_{\text{annual-eq,bi}} = \left(\sum_k P_{\text{out},k} \times \tau_k\right) \Big/ \left(\sum_k \frac{\left(C_{k,\text{annual}} \times P_0\right) \times G_{i,k} \times BIF_k \times \tau_k}{G_{i,\text{ref}}}\right) \tag{29}$$

where $C_{k,\text{annual}}$ is given by Formula (28). Just as this metric reduces seasonal variation due to temperature effects, it will also reduce seasonal variation due to changing albedo conditions (rain, snowfall, changes in vegetation, etc.).

Although only one example has been presented, note that the same correction could be applied to any other form of the performance ratio.

14.4 Performance indices

A detailed performance model may be used to predict electrical output of the PV system as a function of meteorological conditions, known attributes of the system components and materials, and the system design. The performance model attempts to capture as precisely as possible all factors that can affect electrical output.

In evaluating the system performance, particularly with respect to a performance guarantee, it is desired to compare the measured output with the predicted and expected outputs. For a given reporting period, the predicted output is the output calculated by the performance model when using historical weather data, while the expected output is the output calculated by the performance model when using measured weather data for the reporting period.

The ratio of measured output to expected output for a given reporting period defines a performance index. The performance index may be evaluated either on the basis of power, defining power performance index *PPI*, or on the basis of energy, defining energy performance index, *EPI*.

The ratio of measured output to predicted output for a given reporting period defines a baseline performance index. The baseline performance index may be evaluated either on the basis of power, defining baseline power performance index *BPPI,* or on the basis of energy, defining baseline energy performance index *BEPI*.

For evaluation of a performance guarantee, the performance model used for calculation of expected power or expected energy shall be identical to the performance model used for calculation of predicted power or predicted energy used in the performance guarantee.

Further details on the application of a performance model to evaluate the model-based performance indices are provided in IEC TS 61724-2 and IEC TS 61724-3.

15 Data filtering

15.1 Use of available data

Unless otherwise specified, the calculation of a reported parameter shall use all the available valid monitoring data during the indicated reporting period. Exceptions are given by 15.2 and 15.3.

15.2 Filtering data to specific conditions

Reported parameters may be calculated using a subset of data corresponding to a specific set of conditions, e.g. irradiance bins, temperature bins, selected portions of the day, selected sections of the power plant, etc., in order to facilitate performance analysis.

Such calculations that only use a subset of the monitoring data are to be clearly noted along with the range of conditions used for calculation.

15.3 Reduced inverter, grid, or load availability

In reports that include known periods of interrupted availability of inverters or reduced or interrupted demand availability from the utility grid or local loads, resulting in the PV system being unable to operate at maximum power, the analysis shall:

– exclude such periods, with the exclusion clearly noted; or
– include such periods without changes in analysis, but with the periods clearly noted; or
– include such periods, with the analysis performed two ways, with such periods both included (for the purpose of documenting actual results) and excluded (for the purpose of documenting a performance guarantee); or
– clearly note such periods and follow the analysis guidelines specified in an applicable contract or performance guarantee.

Annex A
(informative)

Sampling interval

A.1 General considerations

The sampling interval affects the quality of the data acquisition process in representing the true signal. In determining sampling intervals and/or filtering methods, the following factors should be considered:

- the rate of change of the parameter to be measured;
- the rate of response of the measurement transducer;
- the treatment of the sampled data (for example whether the data will be used in further calculations that involve other sampled datasets, as is the case when calculating power from sampled current and voltage measurements); and
- the ultimate use of the sampled data and the desired limit of uncertainty in representing the true signal parameter.

A.2 Time constants

In general, for rapidly changing signals, it is recommended that the sampling interval (τ_s) be less than 1/e (0,368) of the time constant of the measurement transducer, where the time-constant of a transducer is the time taken, after a step change in the measured variable, for the instrument to register 63,2 % of the step change in the measured parameter.

Alternatively, when the typical time constant of the measured parameter is longer than the time constant of the measurement transducer, the above requirement may be relaxed. In this case the sampling interval need only be less than 1/e of the measurement parameter time constant.

A.3 Aliasing error

The aliasing error is the error associated with information lost by not taking a sufficient number of sampled data points. To avoid a large aliasing error the Nyquist sampling theorem suggests that a minimum of two samples per cycle of the data bandwidth is required to reproduce the sampled data with no loss of information.

For example, the Nyquist theorem suggests that if the highest frequency in the signal to be sampled is fmax, then the minimum sampling frequency would be 2·fmax. However, this sampling frequency still does not achieve a very accurate reproduction of the original signal (average error between the reconstructed signal and the original signal is 32 % at 2·fmax) and an increase in the sampling frequency to 200·fmax is required to achieve an accuracy of 1 % in the reconstructed signal.

An alternative option is to filter the signal before sampling. This is a very effective method of reducing the maximum frequency of the signal, but filtering also results in the loss of information. This is not an issue if the ultimate use of the data is to calculate simple averages over a period of time. However if the data is to be used in a calculation involving other sampled parameters (for example the calculation of power from sampled voltage and current measurements) then analogue filtering before sampling removes fundamental elements of the time-dependent variation of the signal and can lead to the loss of accuracy in the calculated data.

A.4 Example

As an example, consider the appropriate sampling interval for measurements of irradiance. The greatest fluctuations in the signal occur under partly cloudy conditions, as the irradiance sensor is alternately shaded and unshaded. Assume a worst-case situation in which the irradiance changes significantly due to passing clouds approximately once every 30 s. In addition, assume that the primary monitoring purpose is only to determine the average irradiance over a reporting period of 1 h, rather than to recover the exact irradiance time series. In this case the time constants are of more importance than the aliasing error. Sampling the irradiance at least once every 10 s should be adequate. For this example, a Monte Carlo simulation shows that the typical sampling-related uncertainty in the average irradiance recorded over 1 h is on the order of 0,5 %. This is negligible compared to typical instrumental uncertainty.

Annex B
(informative)

Module temperature sensor selection and attachment

B.1 Objective

This annex provides guidelines for flat-plate PV module rear surface temperature measurement sensor selection and attachment in typical installed systems.

The sensor type and attachment method can have significant impacts on the measured temperature, leading to significant measurement errors. These errors are affected primarily by the contact between the sensor and the module's rear surface, the amount and type of insulation placed over the sensor, and the amount and type of adhesive used.

The recommendations stated in this annex are designed to minimize deviations from the ideal measurement condition while providing for secure and reliable long-term measurements.

B.2 Sensor and material selection

B.2.1 Optimal sensor types

Preference should be given to flat probes designed specifically for long-term surface measurements. Thin-film thermocouples of types T or E are generally acceptable. Small form-factor RTD and thermistor elements may be utilized provided air gaps are minimized when applying the tape overlay. However, bead thermocouples, unpackaged resistive elements, and devices encased in cylindrical probe heads should be avoided when possible.

B.2.2 Optimal tapes

To minimize errors and to weather-proof the temperature sensor, reinforcement of the sensor and sensor leads is recommended. This may be accomplished by applying an adhesive overlay or tape.

Adhesive overlays and tapes should be fabricated from materials resistant to the effects of temperature, humidity, and ultraviolet radiation. Avoid tapes not intended for use in securing sensors to surfaces – such as electrical tape, duct tape, aluminized cloth tape, foil tape, or packaging tape – as they may be structurally weak and because their adhesives tend to dry out over time or flow at elevated temperatures. Polyimide tapes (such as Kapton) are known to be susceptible to embrittlement when exposed to ultraviolet radiation and moisture in the presence of oxygen (air) and should be avoided for long-term installations. Polyester is probably the most appropriate overlay material since many backsheets are constructed of multi-layer polyester and this material holds up well against moisture, temperature, and ultraviolet light. Pressure-sensitive silicone adhesive is generally applied to polyester tapes and is recommended.

When using an overlay or tape, minimize air gaps as much as possible. Pockets of trapped air will temper the sensor response, thus negatively impacting the performance of the measurement system.

Temperature sensor readings may be affected by wind, causing temperature readings lower than the cell temperature. Application of thermally insulating tape over the sensor can be used to suppress the wind cooling effect. For this purpose, using foam resin tape with an aluminium cover layer over the temperature sensor glued to the surface of the PV module backsheet is introduced in IEC 60904-5.

B.2.3 Cyanoacrylate adhesives and backsheet integrity

The use of cyanoacrylate adhesive on module backsheets should be avoided, because it is suggested by material manufacturers that cyanoacrylate may react chemically with PET (polyethylene terephthalate) or PTFE (polytetrafluoroethylene) backsheets, potentially resulting in the degradation of the backsheet integrity and thereby affecting the PV module’s long-term encapsulation performance.

B.3 Sensor attachment

B.3.1 Permanent versus temporary

Directions are provided for both permanent and temporary attachment.

Permanent attachment is recommended when long-term monitoring is desired and the sensor will not be removed or relocated. For instance, when including back-of-module temperature measurements within a fielded data acquisition system.

Temporary attachment is recommended when the measurement sensor will need to be relocated or removed owing to the short-term nature of the monitoring, such as during commissioning or periodic maintenance.

B.3.2 Attachment location

Select a sensor location at the centre of a cell close to the centre of the module, avoiding boundaries between cells.

For crystalline silicon modules, select the centre of the centre-most cell within the module, or, when the module is built with even numbers of rows or columns of cells, select one of the cells closest to the centre.

For thin-film modules, place the sensor within the boundary of a cell near the centre of the module, avoiding scribe lines between adjacent cells if possible.

B.3.3 Bifacial modules

For bifacial modules, rear-side temperature sensors and wiring shall obscure < 10 % of the area of any cell, and wiring should be routed in between cells when possible.

B.3.4 Method

– Clean the module's rear surface and sensor element of oil and dust by using lint-free wipes dampened with a 70 % solution of isopropyl alcohol in distilled water. Allow all cleaned surfaces to dry completely before proceeding.
– Attach the sensor using the appropriate method:
  a) Permanent (see Figure B.1):
    - The adhesive should be confirmed to be compatible with the back surface material so as to not affect the long-term integrity of the module.
    - Mix a thermally conductive epoxy as per manufacturer instructions.
    - Apply the adhesive to the side of the sensor element intended to contact the module surface. Do not over-apply the adhesive; it should be as thin as possible yet fully coat the surface of the sensor element.
    - Place the sensor element in the selected location. Manipulate the sensor to remove air bubbles and obtain a uniform adhesive thickness.

- Apply a polyester tape overlay to maintain the sensor position while the adhesive cures and to provide long-term protection of the sensor element. Round die-cut shapes are ideal as their lack of corners reduces the potential of delamination. If round shapes are not available, significantly round the corners of the tape using scissors.
- Allow the adhesive to cure as per the manufacturer's instructions.

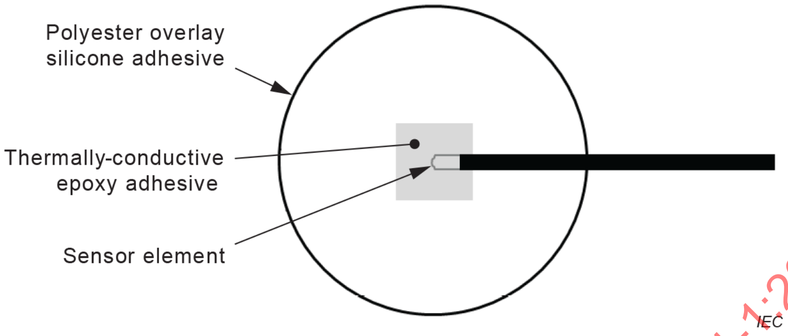


Figure B.1 – Sensor attachment, permanent

b) Temporary (see Figure B.2):

- Trim thin-film sensor encapsulation (such as tape) to within approximately 3 mm of the sensor element. Round all trimmed corners.
- Apply the sensor element to the centre of a round polyester adhesive dot or rounded polyester tape on the adhesive side. Tapes and dots fabricated with silicone adhesive are recommended. The sensor should stick to the tape.
- Place the sensor element in the selected location. Manipulate the sensor to remove air bubbles.

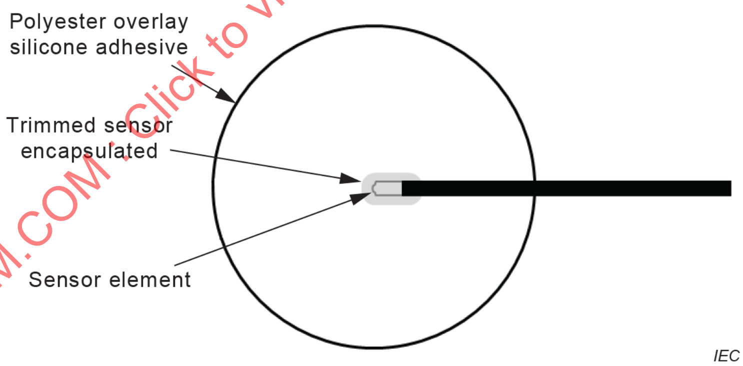


Figure B.2 – Sensor attachment, temporary

– Secure the sensor wire to the module's rear surface using polyester tape at 2 to 4 points to reduce strain on the sensor element. Generally, tape sections will not need to exceed approximately 2 cm wide by 5 cm in length. Use as little tape as possible to secure the lead wires (see Figure B.3).

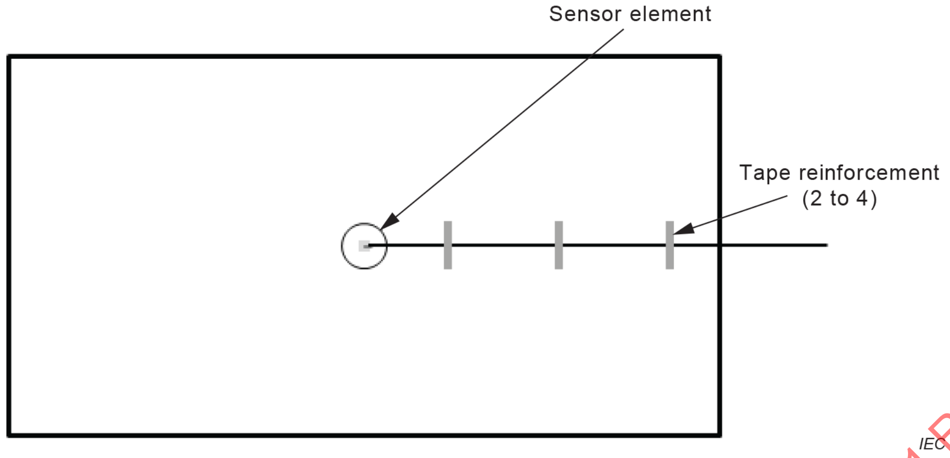


Figure B.3 – Sensor element wire strain relief

– For RTDs or thermistors, the measurement circuit may require a completion resistor. In this case select a resistor with a low temperature coefficient, e.g. ≤ 10 parts per million per °C.

Annex C
(normative)

Soiling measurement using clean and soiled PV reference device pair

C.1 Overview

This annex describes a method for measuring soiling losses by comparing two PV reference devices, one of which is allowed to soil naturally at the same rate as the modules of the PV array and the other of which is routinely cleaned and serves as a reference.

C.2 Equipment

Implementation of the method requires the following:

a) A reference PV device (either monofacial device or bifacial device), designated the “soiled” device, which is allowed to accumulate soiling at the same rate as the PV array. The soiled device may be either a PV reference cell or PV module, but should preferably be a PV module that is identical to or representative of those used in the PV array to be monitored so that it will soil at the same rate. It shall be mounted in the same plane as and at the average height of the PV array, preferably with identical mounting mechanisms.

b) A reference PV device (either monofacial device or bifacial device), designated the “clean” device, which is regularly cleaned so that it is kept free of soiling. The clean device may be either a PV reference cell or PV module, but shall have similar spectral and angular response to the soiled device. The effect of any differences in response should be included in the measurement uncertainty. The clean device shall be mounted close to the soiled device and co-planar to it within 0,5°. Cleaning may be performed either manually or by an automated system and should be done daily or at least once per week. For a bifacial device, both the front side and rear side shall be cleaned.

c) A measurement system for measuring the maximum power (method 1) and/or short-circuit current (method 2) of the soiled device. Maximum power may be measured using I-V curve tracing or max-power-point-tracking electronics.

d) A measurement system for measuring the short-circuit current of the clean device.

e) A measurement system for measuring the temperatures of both the soiled and clean devices using temperature sensors affixed to their rear surfaces.

For items c) and d), in between measurements, the measurement system shall not hold the module in an electrical state which may cause degradation or metastable drift of the device. Therefore, typical crystalline silicon modules should be held at open-circuit (or max power) in between measurements, to avoid hot spot generation, while typical thin film modules should be held at short circuit (or max power) in between measurements. Observe the module manufacturer’s directions as needed to choose the appropriate hold state.

For tracking systems, the soiled and clean devices shall be mounted in the module plane of the tracker.

C.3 Normalization

a) Choose a reference condition of irradiance and PV device temperature, e.g. STC.

b) Determine a reference value for the short-circuit current of the clean device at the designated reference condition. It is sufficient to use the manufacturer’s datasheet values. Additional measures may need to be considered for bifacial reference PV devices.

c) Using the clean device to measure irradiance, determine reference values for the max power (method 1) and/or short-circuit current (method 2) of the soiled device at the reference condition as follows:
   – Completely clean the soiled device.
   – Simultaneously measure the soiled device maximum power and/or short-circuit current and temperature as well as the clean device short-circuit current and temperature.
   – Using the clean device measured short-circuit current and temperature, with the reference data determined in step b), calculate the effective irradiance.
   – Using this calculated irradiance and the measurements for the soiled device, calculate the maximum power and/or short-circuit current of the soiled device corrected to the reference condition of irradiance and temperature.

C.4 Measurement method 1 – max power reduction due to soiling

Perform the measurement as follows:

a) Simultaneously (within 2 s) measure the short-circuit current and temperature of the clean device and the max power and temperature of the soiled device.
b) Calculate the effective irradiance from the values for the clean device measured in a), using the reference values determined in Clause C.3.
c) Calculate the expected max power of the soiled device at the irradiance determined in b) and the temperature measured in a), using the reference values determined in Clause C.3.
d) Calculate the soiling ratio *SR* by dividing the soiled device max power measured in a) by its expected max power calculated in c).

C.5 Measurement method 2 – short-circuit current reduction due to soiling

Perform the measurement as follows:

a) Simultaneously (within 2 s) measure the short-circuit current and temperature of the clean device and the short-circuit current and temperature of the soiled device.
b) Calculate the effective irradiance from the values for the clean device measured in a), using the reference values determined in Clause C.3.
c) Calculate the expected short-circuit current of the soiled device at the irradiance determined in b) and the temperature measured in a), using the reference values determined in Clause C.3.
d) Calculate the soiling ratio SR by dividing the soiled device short-circuit current measured in a) by its expected short-circuit current calculated in c).

C.6 Non-uniform soiling

Using a full-sized PV module with Method 1 (max power reduction, Clause C.4) yields more accurate results because it best represents the actual power loss due to soiling, and in particular it produces more accurate results when soiling is non-uniform across the modules, especially for typical crystalline silicon modules. Method 2 (short-circuit current reduction) may be adequate when soiling is assumed to be uniform across the modules or when the effects of soiling non-uniformity on the ratio of maximum power to short-circuit current are known to be small due to the construction or device physics of the module, e.g. for typical thin film modules. Both methods may be employed simultaneously and the most appropriate value or a weighted average may be used.

C.7 Daily average value

The soiling ratio measured by the method described above is an instantaneous value. The instantaneously measured soiling ratio tends to show a time-of-day dependence due to residual angular misalignment of the two reference devices as well as angle-dependent light scattering from soiling particles. In addition, the instantaneously measured values typically show noise due to irradiance fluctuations and other factors. Therefore, the instantaneously measured values shall be integrated to compute a daily average value.

Computation of daily average may be performed either by:

a) averaging the instantaneously calculated soiling ratios over a daily period, or

b) summing the measured max power and expected max power (see Clause C.4) or measured short-circuit current and expected short-circuit current (see Clause C.5) over a daily period and calculating the ratio of the of the sums of measured to expected values.

If averaging the instantaneously measured soiling ratios per choice a), the data should first be filtered to exclude low irradiance and outliers and/or to limit the measured values to a specific time window that minimizes the effects of angular misalignment. The number of data points passing the filter should be recorded as a quality metric and calculation of the daily average should only be performed when a sufficient number of data points are valid. The averaging should be irradiance-weighted. When angular misalignment between the clean and soiled devices has been limited to 0,5°, the averaging should include only times within ±2 h of solar noon, on a fixed tilt system, or all times when solar angle of incidence is < ~35°, on a tracking system. The time window can be extended if angular misalignment is reduced.

C.8 Renormalization

The normalization step in Clause C.3 shall be repeated at least annually.

Immediately following the normalization or following any significant rainfall, the measured soiling ratio should be close to unity. Significant deviation from unity indicates a problem with the setup. This can be used as a check of the normalization, so that the normalization may be repeated if necessary.

Annex D
(informative)

Derate factors

Derate factors quantify individual sources of loss with respect to the nameplate's DC power rating.

Derates may be defined as a series of multiplicative factors contributing to the performance ratio, PR, according to the relation:

$$PR = Y_\mathrm{f} / Y_\mathrm{r} = \prod_{k=1}^{N} DR_k \tag{D.1}$$

where the DR_k are N individual derates corresponding to different loss mechanisms, and are given by:

$$DR_k = Y_k / Y_{k\text{-}1} \tag{D.2}$$

Here Y_k is the system yield with loss mechanisms 1 through k operational, given by:

$$Y_k = Y_{k\text{-}1} - L_k \tag{D.3}$$

where L_k is the yield loss due to loss mechanism k. Y_0 corresponds to Y_r and Y_N corresponds to Y_f.

The number of derate factors may be adjusted for different purposes, depending on the system size and analysis goals.

Categorizing all losses as either array capture or BOS losses, Formula (D.1) may be written as:

$$PR = DR_\mathrm{capture} \times DR_\mathrm{BOS} \tag{D.4}$$

Here DR_capture represents the combined array capture losses, given by:

$$DR_\mathrm{capture} = Y_\mathrm{A} / Y_\mathrm{r} = (Y_\mathrm{r} - L_\mathrm{C}) / Y_\mathrm{r} \tag{D.5}$$

and DR_BOS represents the combined BOS losses, given by:

$$DR_\mathrm{BOS} = Y_\mathrm{f} / Y_\mathrm{A} = (Y_\mathrm{A} - L_\mathrm{BOS}) / Y_\mathrm{A} \tag{D.6}$$

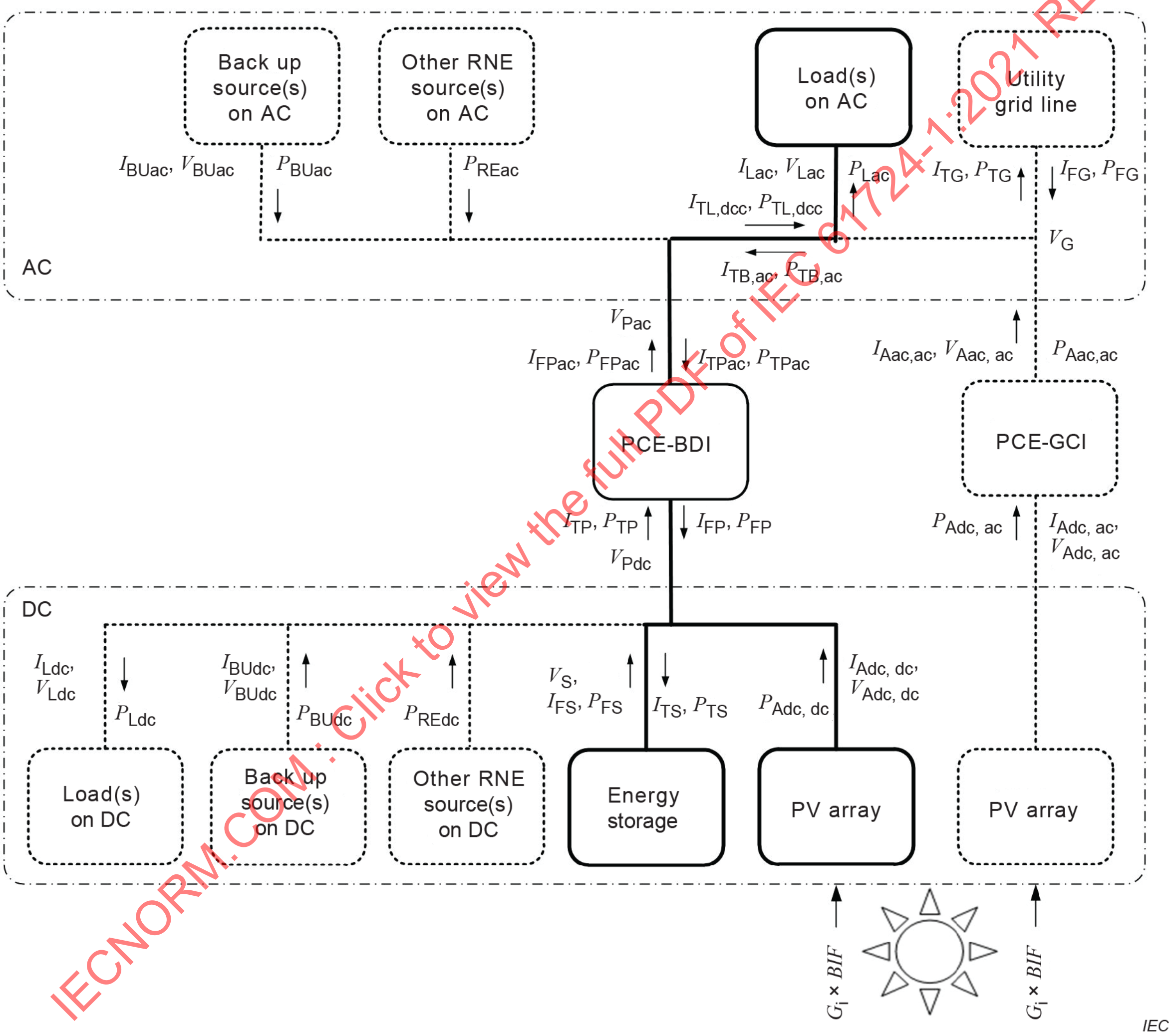
As an aid to performance diagnosis, DR_{capture} and DR_{BOS} may each be rewritten as products of derates corresponding to individual contributing loss mechanisms within the capture and BOS categories. Determination of these contributing derate factors may be done through direct measurement (for example, by measuring energies into and out of specific components of the system during the reporting period, or by measuring specific loss mechanisms such as soiling) and/or modelling (for example, by fitting a performance model to the measured data within the reporting period).

Annex E
(normative)

Systems with local loads, storage, or auxiliary sources

E.1 System types

Figure E.1 illustrates major possible elements comprising different PV system types and energy flow between the elements. Bold lines highlight a system configuration that includes local energy storage and local loads.



Key

RNE	renewable energy
PCE	power conditioning equipment
BDI	bi-directional inverter
GCI	grid-connected inverter

Figure E.1 – Energy flow between possible elements of different PV system types

For this annex, we consider the different PV system types listed in Table E.1, each including the indicated elements.

Table E.1 – Elements of different PV system types

System element	System type				
	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
PV array (DC)				√	√
PV array (AC)	√	√	√	√	√
Energy storage (DC)		√	√	√	√
PCU (GCI)	√	√	√	√	√
PCU (BDI)		√	√	√	√
Utility grid line	√	√	√		√
Load(s) (DC)		√	√	√	√
Load(s) (AC)		√	√	√	√
Back-up sources (DC)			√	√	√
Other RNE sources (DC)		√		√	√
Back-up sources (AC)			√	√	√
Other RNE sources (AC)		√		√	√

E.2 Parameters and formulas

Table E.2 lists parameters and formulas for monitoring energy flow in each system type defined in this annex.

Table E.2 – Parameters and formulas for different system types

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Meteorology						
In-plane irradiance (W·m^{-2})	G_i	√	√	√	√	√
In-plane irradiation (kWh·m^{-2})	H_i	√	√	√	√	√
In-plane rear-side irradiance (W·m^{-2})	G_i^{rear}	√	√	√	√	√
In-plane rear-side irradiation (kWh·m^{-2})	H_i^{rear}	√	√	√	√	√
PV						
Nominal PV array power (kW) = module power at STC × no. of modules in the array	P_0	√	√	√	√	√
Nominal PV array power (kW) of DC coupling system	$P_{0,dc}$				√	√
Nominal PV array power (kW) of AC coupling system	$P_{0,ac}$		√	√	√	√
PV array area (m^2)= module area × no. of modules in the array	A_a	√	√	√	√	√
PV array area (m^2) of DC coupling system	$A_{a,dc}$				√	√
PV array area (m^2) of AC coupling system	$A_{a,ac}$		√	√	√	√
PV array output voltage	V_A		√	√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
PV array output voltage of DC coupling system	$V_{\mathrm{Adc,dc}}$				√	√
PV array output voltage of AC coupling system	$V_{\mathrm{adc,ac}}$		√	√	√	√
PV array output current	I_{A}		√	√	√	√
PV array output current of DC coupling system	$I_{\mathrm{Adc,dc}}$				√	√
PV array output current of AC coupling system	$I_{\mathrm{Adc,ac}}$		√	√	√	√
PV array output power	P_{A}		√	√	√	√
PV array output power of DC coupling system	$P_{\mathrm{Adc,dc}}$		√	√	√	√
PV array output power of AC coupling system	$P_{\mathrm{Adc,ac}}$		√	√	√	√
Energy storage						
Operating voltage	V_{S}		√	√	√	√
Current to storage	I_{TS}		√	√	√	√
Current from storage	I_{FS}		√	√	√	√
Power to storage	P_{TS}		√	√	√	√
Power from storage	P_{FS}		√	√	√	√
Utility grid						
Utility grid voltage	V_{U}		√	√		√
Current to utility grid	I_{TU}		√	√		√
Current from utility grid	I_{FU}		√	√		√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Power to utility grid	P_{TU}		√	√		√
Power from utility grid	P_{FU}		√	√		√
Loads on DC						
Load voltage	V_{Ldc}		√	√	√	√
Load current	I_{Ldc}		√	√	√	√
Load power	P_{Ldc}		√	√	√	√
Loads on AC						
Load voltage	V_{Lac}		√	√	√	√
Load current	I_{Lac}		√	√	√	√
Load power	P_{Lac}		√	√	√	√
Back-up source(s) on AC			√	√	√	√
Back-up AC voltage	V_{BUac}			√	√	√
Back-up AC current	I_{BUac}			√	√	√
Back-up AC power	P_{BUac}			√	√	√
Back-up source(s) on DC						
Back-up DC voltage	V_{BUdc}			√	√	√
Back-up DC current	I_{BUdc}			√	√	√
Back-up DC power	P_{BUdc}			√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Other renewable source(s) on AC						
Other RE AC voltage	V_{REac}		√	√	√	√
Other RE AC current	I_{REac}		√	√	√	√
Other RE AC power	P_{REac}		√	√	√	√
Other renewable source(s) on DC						
Other RE DC voltage	V_{REdc}		√	√	√	√
Other RE DC current	I_{REdc}		√	√	√	√
Other RE DC power	P_{REdc}		√	√	√	√
Electrical energy						
Renewable output energy per day (kWh)	$E_{\mathrm{RE}} = E_{\mathrm{REdc}} + E_{\mathrm{REac}}$		√	√	√	√
(Net) energy to utility grid (kWh)	$E_{\mathrm{TU}} = E_{\mathrm{TU}} - E_{\mathrm{FU}}$		√	√	√	√
(Net) energy from utility grid (kWh)	$E_{\mathrm{FU}} = E_{\mathrm{FU}} - E_{\mathrm{TU}}$		√	√	√	√
Net energy to storage (kWh)	$E_{\mathrm{TS}} = (E_{\mathrm{TS}} - E_{\mathrm{FS}})$		√	√	√	√
Net energy from storage (kWh)	$E_{\mathrm{FS}} = (E_{\mathrm{FS}} - E_{\mathrm{TS}})$		√	√	√	√
Array output energy per day (kWh)	$E_{\mathrm{A}} = E_{\mathrm{Adc,dc}} + E_{\mathrm{Adc,ac}}$		√	√	√	√
Energy from back-up system (kWh)	$E_{\mathrm{BU}} = E_{\mathrm{BUdc}} + E_{\mathrm{BUac}}$		√	√	√	√
Energy to load (kWh)	$E_{\mathrm{L}} = E_{\mathrm{Ldc}} + E_{\mathrm{Lac}}$		√	√	√	√
	$E_{\mathrm{L}} = E_{\mathrm{Ldc}} + (E_{\mathrm{TL,dcc}} + E_{\mathrm{TL,ac}})$		√	√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Energy to load (kWh) from AC coupling system	$E_{TL,acc} = (E_{Aac,ac}) - E_{TB,ac}$		√	√	√	√
PV array energy yield	$Y_A = E_A / P_0$	√	√	√	√	√
PV array energy yield of DC coupling subsystem	$Y_{A,dc} = E_{Adc,dc} / P_{0,dc}$		√	√	√	√
PV array energy yield of AC coupling subsystem	$Y_{A,ac} = E_{Adc,ac} / P_{0,ac}$		√	√	√	√
Final system yield	(a) $Y_f = E_{out} / P_0$ (b) $Y_f = Y_{fac}$ (c) $Y_f = Y_{fdc} + Y_{fac}$	(a)	(b)	(b)	(c)	(c)
Final system yield of DC coupling subsystem	$Y_{f,dc} = Y_{fTB,dc} + Y_{fTL,dc}$				√	√
Final system yield of DC coupling subsystem to charge battery	$Y_{fTB,dc} = E_{ATB,dc} / P_{0,dc}$				√	√
Final system yield of DC coupling subsystem to load	$Y_{fTL,dc} = E_{ATL,dc} \times \eta_{BOS,dcc} / P_{0,dc}$				√	√
Final system yield of AC coupling subsystem	$Y_{f,ac} = Y_{fTB,ac} + Y_{fTL,ac}$		√	√	√	√
Final system yield of AC coupling subsystem to charge battery	$Y_{fTB,ac} = (E_{ATB,ac} \times \eta_{BOS,dcc}) / P_{0,ac}$		√	√	√	√
Final system yield of AC coupling subsystem to load	$Y_{fTL,ac} = E_{ATL,ac} / P_{0,ac}$		√	√	√	√
Direct PV energy contribution to E_{use} (kWh)	$E_{use,PV} = E_A \times \eta_{BOS}$ or		√	√	√	√
	$E_{use,PV} = F_A \times E_{use}$		√	√	√	√
Direct PV energy contribution to E_{use} (kWh) of DC coupling subsystem	$E_{use,PV,dc} = F_{A,dc} \times E_{use,dcc}$				√	√
Direct PV energy contribution to E_{use} (kWh) of AC coupling subsystem	$E_{use,PV,ac} = F_{A,ac} \times E_{use,ac}$		√	√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
Fraction of total system input energy contributed by PV array	$F_A = E_A / E_{in}$		√	√	√	√
Fraction of total system input energy contributed by PV array of DC coupling subsystem	$F_{A,dc} = E_{Adc,dc} / E_{in,dcc}$				√	√
Fraction of total system input energy contributed by PV array of AC coupling subsystem	$F_{A,ac} = E_{Adc,ac} / E_{in,ac}$		√	√	√	√
Total system input energy (kWh)	$E_{in} = E_A + E_{BU} + E_{FU} + E_{FS} + E_{RE}$		√	√	√	√
Total system input energy of DC coupling subsystem (kWh)	(a) $E_{in,dcc} = (E_{TB,ac}) + E_{FS} + (E_{REdc} + E_{REac})$ (b) $E_{in,dcc} = (E_{TB,ac}) + (E_{BUac} + E_{BUac}) + E_{FS} + (E_{REdc} + E_{REac})$ (c) $E_{in,dcc} = (E_{Adc,dc} + E_{TB,ac}) + (E_{BUac} + E_{BUac}) + E_{FU} + E_{FS} + (E_{REdc} + E_{REac})$		(a)	(b)	(b)	(c)
Total system input energy of AC coupling subsystem (kWh)	$E_{in,ac} = E_{Adc,ac}$		√	√	√	√
Total system output energy (kWh)	$E_{use} = E_{Ldc} + E_{Lac} + E_{TU} + E_{TS}$		√	√	√	√
Total system output energy of DC coupling subsystem(kWh)	(a) $E_{use,dcc} = E_{Ldc} + (E_{TL,dcc} + E_{TL,ac}) + E_{TS}$ (b) $E_{use,dcc} = E_{Ldc} + (E_{TL,dcc} + E_{TL,ac}) + E_{TU} + E_{TS}$		(a)	(a)	(a)	(b)
Total system output energy of AC coupling subsystem (kWh)	$E_{use,ac} = E_{TL,ac} + E_{TB,ac}$		√	√	√	√
Reference yield (h·d^{-1})	$Y_r = H_i / G_{i,ref}$		√	√	√	√
Array capture losses (h·d^{-1})	$L_c = Y_r - Y_A$		√	√	√	√
Array capture losses of DC coupling subsystem (h·d^{-1})	$L_{c,dc} = Y_r - Y_{A,dc}$				√	√
Array capture losses of AC coupling subsystem (h·d^{-1})	$L_{c,ac} = Y_r - Y_{A,ac}$		√	√	√	√

Parameter	Symbol or formula	Grid tied	Grid tied with storage	Grid tied with storage and backup	Mini-grid	Micro-grid
System losses (h·d⁻¹)	$L_s = Y_A - Y_f$		√	√	√	√
System losses of DC coupling subsystem (h·d⁻¹)	$L_{s,dc} = Y_{A,dc} - Y_{f,dc}$				√	√
System losses of AC coupling subsystem (h·d⁻¹)	$L_{s,ac} = Y_{A,ac} - Y_{f,ac}$		√	√	√	√
Performance ratio	$PR = Y_f / Y_r$	√	√	√	√	√
Performance ratio of DC coupling subsystem	$PR_{dc} = Y_{f,dc} / Y_r$		√	√	√	√
Performance ratio of AC coupling subsystem	$PR_{ac} = Y_{f,ac} / Y_r$		√	√	√	√
Mean array efficiency	$\eta_A = E_A / (H_i \times A_a)$	√	√	√	√	√
Mean array efficiency of DC coupling subsystem	$\eta_{A,dc} = E_{A,dc} / (H_{i,dc} \times A_{a,dc})$				√	√
Mean array efficiency of AC coupling subsystem	$\eta_{A,ac} = E_{A,ac} / (H_{i,ac} \times A_{a,ac})$		√	√	√	√
Overall PV plant efficiency	(a) $\eta_f = E_{out} / (H_i \times A_a)$ (b) $\eta_{tot} = E_{use,PV} / (H_i \times A_a)$	(a)	(b)	(b)	(b)	(b)
Overall PV plant efficiency of DC coupling subsystem	$\eta_{tot,dcc} = E_{use,PV,dc} / (H_{i,dc} \times A_{a,dc})$				√	√
Overall PV plant efficiency of AC coupling subsystem	$\eta_{tot,ac} = E_{use,PV,ac} / (H_{i,ac} \times A_{a,ac})$		√	√	√	√
BOS efficiency	(a) $\eta_{BOS} = E_{out} / E_A$ (b) $\eta_{BOS} = E_{use} / E_{in}$	(a)	(b)	(b)	(b)	(b)
BOS efficiency of DC coupling subsystem	$\eta_{BOS,dcc} = E_{use,dcc} / E_{in,dcc}$				√	√
BOS efficiency of AC coupling subsystem	$\eta_{BOS,ac} = E_{use,ac} / E_{in,ac}$		√	√	√	√

Bibliography

IEC TS 60904-1-2, *Photovoltaic devices – Part 1-2: Measurement of current-voltage characteristics of bifacial photovoltaic (PV) devices*

IEC 60904-3, *Photovoltaic devices – Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data*

Orange Button Taxonomy Data Definitions, SunSpec Alliance

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SOMMAIRE

COMMISSION ÉLECTROTECHNIQUE INTERNATIONALE

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PERFORMANCES DES SYSTÈMES PHOTOVOLTAÏQUES –

Partie 1: Surveillance

AVANT-PROPOS

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9) L’attention est attirée sur le fait que certains des éléments de la présente Publication de l’IEC peuvent faire l’objet de droits de brevet. L’IEC ne saurait être tenue pour responsable de ne pas avoir identifié de tels droits de brevets et de ne pas avoir signalé leur existence.

La Norme internationale IEC 61724-1 a été établie par le comité d'études 82 de l’IEC: Systèmes de conversion photovoltaïque de l'énergie solaire.

Cette deuxième édition annule et remplace la première édition parue en 2017. Cette édition constitue une révision technique.

Cette édition inclut les modifications techniques majeures suivantes par rapport à l'édition précédente:

- Présentation de la surveillance des modules PV bifaciaux.
- Mise à jour des exigences relatives aux capteurs d’éclairement énergétique.
- Mise à jour du mesurage de l’encrassement pour tenir compte des nouvelles technologies.
- Suppression des systèmes de surveillance de classe C.

- Mise à jour de différentes exigences, recommandations et notes explicatives.

Le texte de cette norme est issu des documents suivants:

FDIS	Rapport de vote
82/1904/FDIS	82/1925/RVD

Le rapport de vote indiqué dans le tableau ci-dessus donne toute information sur le vote ayant abouti à son approbation.

La langue employée pour l'élaboration de cette Norme internationale est l'anglais.

Ce document a été rédigé selon les Directives ISO/IEC, Partie 2, il a été développé selon les Directives ISO/IEC, Partie 1 et les Directives ISO/IEC, Supplément IEC, disponibles sous www.iec.ch/members_experts/refdocs. Les principaux types de documents développés par l'IEC sont décrits plus en détail sous www.iec.ch/standardsdev/publications.

Une liste de toutes les parties de la série IEC 61724, publiées sous le titre général *Performances des systèmes photovoltaïques*, peut être consultée sur le site web de l'IEC.

Le comité a décidé que le contenu de ce document ne sera pas modifié avant la date de stabilité indiquée sur le site web de l'IEC sous webstore.iec.ch dans les données relatives au document recherché. À cette date, le document sera

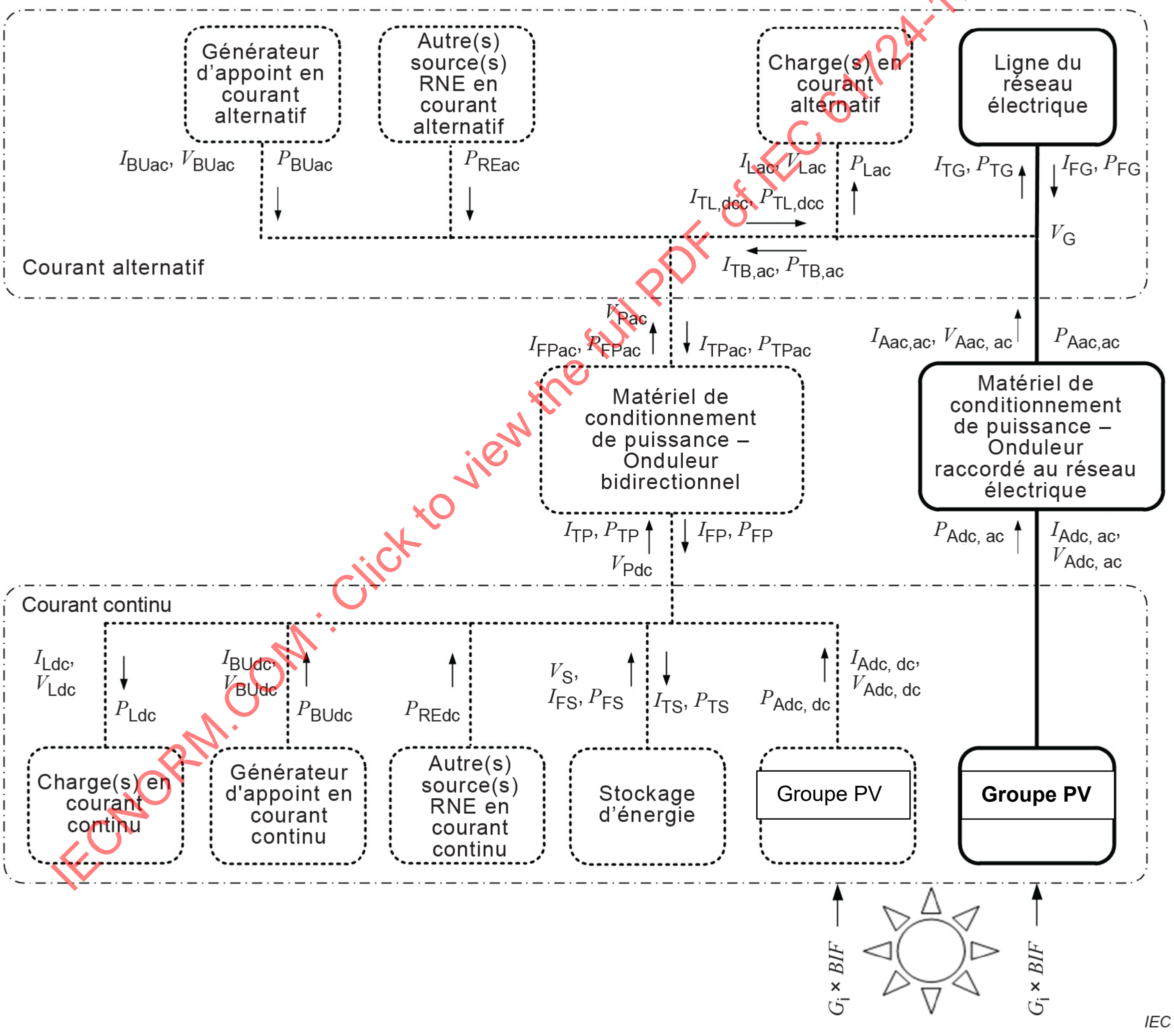
- reconduit,
- supprimé,
- remplacé par une édition révisée, ou
- amendé.

INTRODUCTION

Le présent document définit les classes de systèmes de surveillance des performances des systèmes photovoltaïques (PV) et donne des recommandations relatives au choix des systèmes de surveillance.

La Figure 1 représente des éléments majeurs de différents types de systèmes PV. Les principaux articles du présent document sont rédigés pour les systèmes raccordés au réseau électrique sans charge locale, stockage d'énergie ou source auxiliaire, comme cela est représenté par les lignes en gras à la Figure 1. L'Annexe E donne quelques informations relatives aux systèmes avec des composants complémentaires.

Les groupes photovoltaïques pris en considération dans ce document peuvent être constitués de modules plans montés sur support fixe ou sur suiveur solaire. Les systèmes à concentration sont aussi pris en considération.



Légende:

RNE: énergie renouvelable (renewable energy);

PCE: matériel de conditionnement de puissance (power conditioning equipment);

BDI: onduleur bidirectionnel (bi-directional inverter);

GCI: onduleur raccordé au réseau électrique (grid-connected inverter).

Les lignes en gras indiquent un système simple raccordé au réseau électrique sans charge locale, stockage d'énergie ou source auxiliaire.

Figure 1– Éléments possibles des systèmes PV

Les objectifs d'un système de surveillance de la performance sont variés et peuvent comprendre la comparaison des performances afin de concevoir les attentes et les garanties, ainsi que la détection et la localisation des pannes.

Pour comparer les performances afin de concevoir les attentes et les garanties, il convient de concentrer l'attention sur les données au niveau du système et sur la fidélité entre les prédictions et les méthodes d'essai.

Pour détecter et localiser les pannes, il convient qu'il y ait une plus grande résolution dans les sous-niveaux du système et que l'accent soit mis sur la répétabilité du mesurage et les mesures de corrélation.

Il convient d'adapter le système de surveillance à la taille du système PV et aux exigences des utilisateurs. En règle générale, il convient que les systèmes PV les plus grands soient équipés de davantage de points de surveillance et de capteurs de plus grande exactitude par rapport aux systèmes PV plus petits et moins coûteux.

PERFORMANCES DES SYSTÈMES PHOTOVOLTAÏQUES –

Partie 1: Surveillance

1 Domaine d'application

La présente partie de l'IEC 61724 présente une terminologie, des équipements et des méthodes relatifs à la surveillance des performances et à l'analyse des systèmes photovoltaïques (PV). Elle sert également de base à d'autres normes qui s'appuient sur les données collectées.

2 Références normatives

Les documents suivants sont cités dans le texte de sorte qu'ils constituent, pour tout ou partie de leur contenu, des exigences du présent document. Pour les références datées, seule l'édition citée s'applique. Pour les références non datées, la dernière édition du document de référence s'applique (y compris les éventuels amendements).

IEC 60050-131, *Vocabulaire électrotechnique international – Partie 131: Théorie des circuits*

IEC 60904-2, *Dispositifs photovoltaïques – Partie 2: Exigences applicables aux dispositifs photovoltaïques de référence*

IEC 60904-5, *Dispositifs photovoltaïques – Partie 5: Détermination de la température de cellule équivalente (ECT) des dispositifs photovoltaïques (PV) par la méthode de la tension en circuit ouvert*

IEC 60904-7, *Dispositifs photovoltaïques – Partie 7: Calcul de la correction de désadaptation des réponses spectrales dans les mesures de dispositifs photovoltaïques*

IEC 61215 (toutes les parties), *Modules photovoltaïques (PV) pour applications terrestres - Qualification de la conception et homologation*

IEC 61557-12*, Sécurité électrique dans les réseaux de distribution basse tension jusqu'à 1 000 V c.a. et 1 500 V c.c. – Dispositifs de contrôle, de mesure ou de surveillance de mesures de protection – Partie 12: Dispositifs de comptage et de surveillance du réseau électrique (PMD)*

IEC TS 61724-2*, Photovoltaic system performance – Part 2: Capacity evaluation method* (disponible en anglais seulement)

IEC TS 61724-3, *Photovoltaic system performance – Part 3: Energy evaluation method* (disponible en anglais seulement)

IEC TS 61836, *Solar photovoltaic energy systems – Terms, definitions and symbols* (disponible en anglais seulement)

IEC 62053-22, *Équipement de comptage de l'électricité – Exigences particulières – Partie 22: Compteurs statiques d'énergie active en courant alternatif (classes 0,1 S, 0,2 S et 0,5 S)*

IEC 62670-3, *Concentrateurs photovoltaïques (CPV) – Essai de performances – Partie 3: Mesurages de performances et rapport de puissance*

IEC 62817:2014, *Systèmes photovoltaïques – Qualification de conception des suiveurs solaires*

Guide ISO/IEC 98-1, *Incertitude de mesure – Partie 1: Introduction à l'expression de l'incertitude de mesure*

Guide ISO/IEC 98-3, *Incertitude de mesure – Partie 3: Guide pour l'expression de l'incertitude de mesure (GUM:1995)*

ISO 9060:2018, *Solar energy – Specification and classification of instruments for measuring hemispherical solar and direct solar radiation* (disponible en anglais seulement)

ISO 9488, *Énergie solaire – Vocabulaire*

3 Termes et définitions

Pour les besoins du présent document, les termes et définitions de l'IEC 60050-131, l'IEC TS 61836, l'ISO 9488, ainsi que les suivants s'appliquent.

L'ISO et l'IEC tiennent à jour des bases de données terminologiques destinées à être utilisées en normalisation, consultables aux adresses suivantes:

- IEC Electropedia: disponible à l'adresse http://www.electropedia.org/
- ISO Online browsing platform: disponible à l'adresse http://www.iso.org/obp

3.1
échantillon
données acquises à partir d'un capteur ou d'un dispositif de mesure

3.2
intervalle d'échantillonnage
intervalle entre deux échantillons

3.3
enregistrement
données enregistrées et stockées

3.4
intervalle d'enregistrement
τ
intervalle entre deux enregistrements

3.5
rapport
valeur totale calculée d'après une série d'enregistrements

3.6
période de suivi
intervalle entre deux établissements de rapport

3.7
face avant
côté d'une surface généralement orienté vers le ciel

3.8
face arrière
côté d'une surface généralement orienté vers le sol

3.9
dispositif PV monoface
dispositif PV dans lequel seule la face avant est utilisée pour la production d'énergie

3.10
dispositif PV bifacial
dispositif PV dans lequel la face avant et la face arrière sont utilisées pour la production d'énergie

3.11
coefficient de bifacialité
φ
rapport entre la caractéristique I-V de la face arrière et de la face avant d'un dispositif bifacial, en règle générale dans les conditions normales d'essai, sauf spécification contraire

Note 1 à l'article: Les coefficients de bifacialité incluent le coefficient de bifacialité sous courant de court-circuit φ_{Isc}, le coefficient de bifacialité sous tension en circuit ouvert φ_{Voc} et le coefficient de bifacialité sous puissance maximale φ_{Pmax}.

Note 2 à l'article: L'IEC TS 60604-1-2 définit les coefficients de bifacialité.

3.12
éclairement énergétique
G
flux de rayonnement incident sur une unité de surface

Note 1 à l'article: Exprimée en W·m^{-2}.

3.13
éclairement énergétique dans le plan
$\mathrm{G_i}$ ou POA
somme des éclairements énergétiques directs, diffus et réfléchis, incidents sur la face avant d'une surface parallèle au plan des modules du groupe PV, également appelé éclairement énergétique dans le plan du groupe photovoltaïque (POA)

Note 1 à l'article: Exprimée en W·m^{-2}.

Note 2 à l'article: L'abréviation "POA" est dérivée du terme anglais développé correspondant "plane-of-array".

3.14
albédo horizontal
ρ_H
proportion de lumière incidente réfléchie par le sol, mesurée dans un plan horizontal

Note 1 à l'article: Il s'agit d'une propriété du sol et d'une grandeur sans unité sur une échelle de 0 à 1.

3.15
coefficient d'éclairement énergétique arrière dans le plan
ρ_i
rapport de l'éclairement énergétique incident sur la face arrière des modules dans le groupe PV à l'éclairement énergétique incident sur la face avant

Note 1 à l'article: Il s'agit d'une grandeur sans unité, mais elle peut dépasser la valeur de 1 puisque, en plus de la lumière réfléchie, les composantes diffuses et réfléchies de la ressource solaire peuvent être mesurées à l'arrière du plan du groupe.

3.16
coefficient d'éclairement énergétique arrière dans le plan adapté spectralement
ρ_i^{SP}
rapport d'éclairement énergétique arrière dans le plan défini en 3.15 lorsque les deux grandeurs d'éclairement énergétique sont mesurées à l'aide d'un dispositif de référence dont le spectre est adapté ou avec l'application de corrections spectrales selon l'IEC 60904-7

3.17
dispositif de référence dont le spectre est adapté
dispositif de référence, par exemple une cellule ou un module PV, dont les caractéristiques de réponse spectrale sont suffisamment proches de celles des modules PV du groupe PV pour que les erreurs de désadaptation spectrale soient petites dans la plage type des spectres incidents

3.18
éclairement énergétique arrière dans le plan
$\mathrm{G_i^{rear}}$ ou $\mathrm{POA^{rear}}$
somme des éclairements énergétiques directs, diffus et réfléchis, incidents sur la face arrière d'une surface parallèle au plan des modules du groupe PV, également appelé éclairement énergétique dans le plan du groupe photovoltaïque de la face arrière

Note 1 à l'article: Exprimée en W·m^{-2}.

Note 2 à l'article: (Si elle est mesurée au moyen du coefficient d'éclairement énergétique arrière dans le plan): $G_i^{rear} = \rho_i \times G_i$ ou $G_{i,SP}^{rear} = \rho_i^{SP} \times G_i$.

3.19
dispositif de référence bifacial
dispositif PV bifacial (une cellule ou un module, par exemple) ayant sensiblement les mêmes propriétés relatives à la réponse à l'éclairement énergétique de la face avant et de la face arrière que les modules bifaciaux à surveiller

3.20
facteur d'éclairement énergétique bifacial
BIF
facteur sans unité qui peut être multiplié directement par l'éclairement énergétique dans le plan de la face avant ($\mathrm{G_i}$) pour calculer l'éclairement énergétique "effectif" qui atteint en même temps la face avant et la face arrière d'un dispositif bifacial

Note 1 à l'article: $BIF = (1 + \varphi_{Pmax} \times \rho_i)$ ou $BIF^{sp} = (1 + \varphi_{Pmax} \times \rho_i^{SP})$. Voir 3.11, 3.15, 3.16.

Note 2 à l'article: L'éclairement énergétique dans le plan de la face arrière du groupe photovoltaïque peut être mesuré en même temps que l'éclairement énergétique dans le plan de la face avant du groupe photovoltaïque en utilisant un dispositif de référence bifacial. Dans ce cas, $BIF = G_i^{BiFi\ Ref\ Device} \div G_i$. Pour des raisons de cohérence, il convient de mesurer l'éclairement énergétique dans le plan de la face avant du groupe photovoltaïque à l'aide du même type de dispositif que le dispositif de référence bifacial ou d'un type similaire.

Note 3 à l'article: L'éclairement énergétique "effectif" peut comprendre l'effet des inhomogénéités de l'éclairement énergétique arrière.

Note 4 à l'article: L'abréviation "BIF" est dérivée du terme anglais développé correspondant "bifacial irradiance factor".

3.21
éclairement énergétique horizontal global
GHI
éclairement énergétique direct et diffus incident sur la face avant d'une surface horizontale

Note 1 à l'article: Exprimée en W·m^{-2}.

Note 2 à l'article: $GHI = DNI \cdot \cos Z + DHI$ où Z est l'angle zénithal du soleil.

Note 3 à l'article: L'abréviation "GHI" est dérivée du terme anglais développé correspondant "global horizontal irradiance".

3.22
circumsolaire
entourant immédiatement le disque solaire

3.23
éclairement énergétique normal direct
DNI
éclairement énergétique rayonné par le disque solaire et la région circumsolaire du ciel dans un angle solide sous-tendu de 5° incident sur une surface plane perpendiculaire aux rayons du soleil

Note 1 à l'article: Exprimée en $W \cdot m^{-2}$.

Note 2 à l'article: $GHI = DNI \cdot \cos Z + DHI$ où Z est l'angle zénithal du soleil.

Note 3 à l'article: L'abréviation "DNI" est dérivée du terme anglais développé correspondant "direct normal irradiance".

3.24
contribution circumsolaire
contribution d'une partie spécifique de l'éclairement énergétique normal circumsolaire à l'éclairement énergétique normal direct. La contribution circumsolaire fait référence à une région angulaire spécifique en forme d'anneau décrite par une distance angulaire intérieure et extérieure par rapport au centre du soleil (voir ISO 9488)

Note 1 à l'article: Si l'angle intérieur décrivant cette région angulaire est le demi-angle du disque solaire, la contribution circumsolaire est également appelée coefficient circumsolaire.

Note 2 à l'article: En fonction de l'instrument de mesure de l'éclairement énergétique circumsolaire ou de la technologie solaire utilisée, différentes plages de longueurs d'onde sont incluses. Afin de décrire correctement l'éclairement énergétique circumsolaire, la plage de longueurs d'onde ou la réponse spectrale de l'instrument ou de la technologie solaire utilisée doivent être spécifiées.

3.25
coefficient circumsolaire
fraction d'éclairement énergétique normal direct (*DNI*) mesuré émanant de la région circumsolaire du ciel, c'est-à-dire, dans l'ouverture angulaire du capteur de *DNI* mais hors du disque solaire

3.26
forme solaire (sunshape)
profil de la luminance énergétique moyenne azimutale en fonction de la distance angulaire par rapport au centre du soleil, normalisé à 1 au centre du soleil, et en tenant compte de la plage de longueurs d'onde du rayonnement à ondes courtes (voir ISO 9488)

3.27
éclairement énergétique horizontal diffus
G_d ou *DHI*
éclairement énergétique global sur la face avant d'une surface horizontale excluant la partie émanant du disque solaire et de la région circumsolaire du ciel dans un angle solide sous-tendu de 5°

Note 1 à l'article: Exprimée en $W \cdot m^{-2}$.

Note 2 à l'article: $GHI = DNI \cdot \cos Z + DHI$ où Z est l'angle zénithal du soleil.

Note 3 à l'article: L'abréviation "DHI" est dérivée du terme anglais développé correspondant "diffuse horizontal irradiance".

3.28
éclairement énergétique direct dans le plan
$G_{i,b}$
éclairement énergétique incident sur la face avant d'une surface parallèle au plan des modules du groupe PV, émanant du disque solaire et de la région circumsolaire du ciel dans un angle solide sous-tendu de 5°

Note 1 à l'article: L'éclairement énergétique direct dans le plan $G_{i,b} = \cos(\theta) \times DNI$, où θ est l'angle entre le soleil et la perpendiculaire au plan. Lorsque le plan du groupe photovoltaïque est perpendiculaire au soleil, $G_{i,b} = DNI$.

Note 2 à l'article: Exprimée en $W \cdot m^{-2}$.

3.29
irradiation
H
intégration de l'éclairement énergétique sur un intervalle de temps donné

Note 1 à l'article: Exprimée en $kW \cdot h \cdot m^{-2}$.

3.30
conditions normales d'essai
STC
éclairement énergétique dans le plan 1 000 W m^{-2}, incidence normale, température de jonction de cellule PV 25 °C et éclairement énergétique spectral de référence défini dans l'IEC 60904-3

Note 1 à l'article: L'abréviation "STC" est dérivée du terme anglais développé correspondant "standard test conditions".

3.31
coefficient d'encrassement
coefficient de salissure
SR
rapport de la puissance réelle de sortie du groupe PV dans des conditions données d'encrassement à la puissance prévue dans le cas où le groupe PV est propre et exempt de tout encrassement

Note 1 à l'article: L'abréviation "SR" est dérivée du terme anglais développé correspondant "soiling ratio".

3.32
niveau d'encrassement
SL
perte de puissance fractionnaire due à l'encrassement, obtenu par $1 - SR$

Note 1 à l'article: L'abréviation "SL" est dérivée du terme anglais développé correspondant "soiling level".

3.33
taux d'encrassement
taux de changement du coefficient d'encrassement, exprimé en règle générale en pourcentage quotidien

3.34
puissance active
P
en régime périodique, moyenne, sur une période, du produit instantané de courant et de tension

Note 1 à l'article: En régime sinusoïdal, la puissance active est la partie réelle de la puissance complexe.

Note 2 à l'article: Exprimée en W.

3.35
puissance apparente
S
produit des valeurs efficaces de la tension électrique aux bornes d'un bipôle, élémentaire ou non, et du courant électrique dans le bipôle

Note 1 à l'article: En régime sinusoïdal, la puissance apparente est le module de la puissance complexe.

Note 2 à l'article: Exprimée en VA.

3.36
facteur de puissance
λ
en régime périodique, rapport de la valeur absolue de la puissance active P à la puissance apparente S:

$$\lambda = \frac{|P|}{S}$$

4 Classification des systèmes de surveillance

Le présent document définit deux classifications des systèmes de surveillance, la Classe A et la Classe B.

La Classe A est dédiée aux grands systèmes PV, tels que les centrales à l'échelle d'un réseau public de distribution ou les grandes installations commerciales.

La Classe B est dédiée aux systèmes plus petits comme ceux installés sur les toits ou les installations commerciales de petite ou moyenne taille.

Les utilisateurs du document peuvent spécifier la classification la plus adaptée à leur application, indépendamment de la taille du système PV.

La classification des systèmes de surveillance doit être indiquée dans toutes les déclarations de conformité au présent document.

Tout au long du présent document, certaines exigences sont désignées comme s'appliquant à une classification particulière. Lorsqu'aucune désignation n'est indiquée, les exigences s'appliquent aux deux classifications.

5 Généralités

5.1 Fidélité et incertitude de mesure

La fidélité de mesure fait référence à la répétabilité et à la résolution, dont le sens est défini dans l'IEC Electropedia.

L'incertitude de mesure fait référence à l'exactitude. Son sens est par ailleurs défini dans l'IEC Electropedia.

Les incertitudes de mesure peuvent être calculées comme cela est indiqué dans le Guide ISO/IEC 98-1 et le Guide ISO/IEC 98-3.

5.2 Étalonnage

Le réétalonnage des capteurs et de l'électronique de traitement du signal doit être effectué selon les recommandations du fabricant ou à des intervalles plus fréquents lorsque cela est spécifié dans la norme.

Il est recommandé d'effectuer régulièrement des contre-vérifications de chaque capteur par rapport aux capteurs de même type ou aux dispositifs de référence afin d'identifier les capteurs non étalonnés.

5.3 Éléments répétés

Selon la taille du système et les exigences des utilisateurs, le système de surveillance peut comprendre une redondance des capteurs et/ou la répétition d'éléments de détection pour différents composants ou différentes sous-sections du système PV global. En conséquence, les paramètres mesurés et calculés définis dans le présent document peuvent avoir plusieurs instances, chaque instance correspondant à une sous-section ou à un sous-composant du système PV.

5.4 Consommation d'énergie

La puissance parasite tirée par tout système exigé pour le fonctionnement de la centrale PV ne doit pas être considérée comme une charge fournie par la centrale.

5.5 Documentation

Les particularités de tous les composants du système de surveillance doivent être documentées. Toute inspection et toute maintenance du système, y compris le nettoyage, doivent être documentées.

5.6 Inspection

Le système de surveillance doit faire l'objet d'une inspection au moins une fois par an, et de préférence à des intervalles plus fréquents. Il convient que l'inspection recherche les dommages, les détériorations ou les déconnexions des capteurs et des enveloppes électriques, l'encrassement ou le déplacement des capteurs optiques, les connexions de câblage lâches, le détachement des capteurs de température, l'effritement des fixations et les autres problèmes potentiels.

6 Temporisation et rapport de l'acquisition des données

6.1 Échantillons, enregistrements et rapports

La Figure 2 représente les relations entre échantillons, enregistrements et rapports.

Un échantillon consiste en des données acquises à partir d'un capteur ou d'un dispositif de mesure. L'intervalle d'échantillonnage est le temps écoulé entre deux échantillons. Il n'est pas nécessaire de stocker les échantillons de manière permanente.

Un enregistrement consiste en des données introduites dans un stockage de données, sur la base des échantillons acquis. L'intervalle d'enregistrement, noté τ dans le présent document, est le temps écoulé entre les enregistrements. Il convient que l'intervalle d'enregistrement soit un nombre entier multiple de l'intervalle d'échantillonnage, et il convient que 1 h contienne un nombre entier d'intervalles d'enregistrement.

La valeur du paramètre enregistré pour chaque enregistrement est la moyenne, le maximum, le minimum, la somme ou toute autre fonction des échantillons acquis pendant l'intervalle d'enregistrement, selon le cas pour la grandeur mesurée. L'enregistrement peut également inclure des données supplémentaires telles que des statistiques complémentaires relatives aux échantillons, le nombre de points de données manquants, les codes d'erreur, les transitoires et/ou d'autres données présentant un intérêt particulier. (Pour les enregistrements de données relatives au vent, voir 9.3).

Un rapport est une valeur agrégée couvrant plusieurs intervalles d'enregistrement. La période de suivi est l'intervalle entre deux établissements de rapport. En règle générale, la période de suivi choisie se compte en jours, en semaines, en mois ou en années.

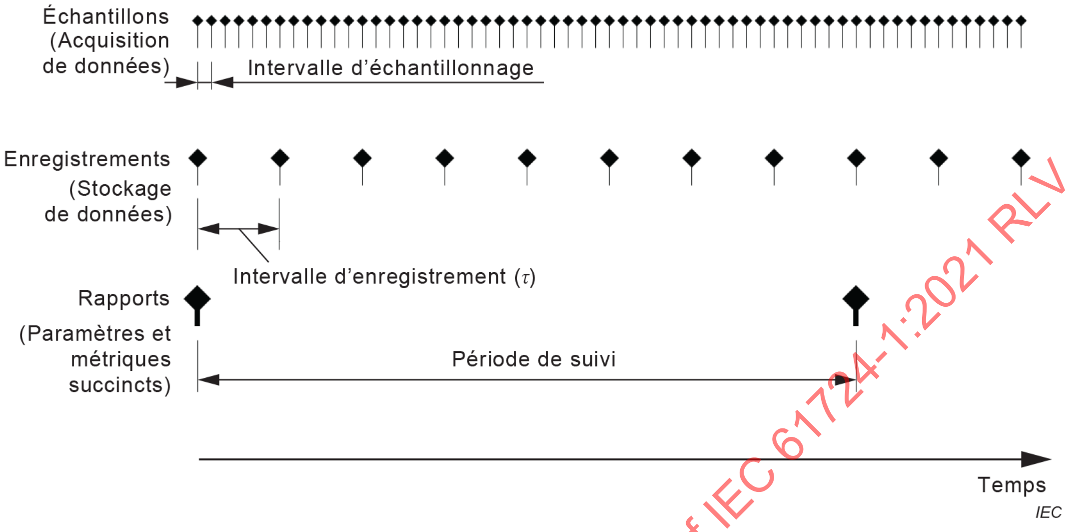


Figure 2 – Échantillons, enregistrements et rapports

Le Tableau 1 répertorie les valeurs maximales correspondant aux intervalles d'échantillonnage et aux intervalles d'enregistrement.

L'Annexe A donne de plus amples informations relatives à l'intervalle d'échantillonnage. L'intervalle d'échantillonnage maximal pour la classe A est plus long que les constantes types de temps du signal et de l'instrument pour l'éclairement énergétique, le vent et la puissance électrique. Cependant, la valeur de l'intervalle est choisie pour des raisons pratiques en prenant en considération les systèmes courants d'acquisition de données.

Les recommandations indiquées relatives à l'échantillonnage et à l'intervalle d'enregistrement s'appliquent aux mesurages au sol sur site. Pour les mesurages d'éclairement énergétique fondés sur les satellites, des intervalles plus longs, pouvant aller jusqu'à 1 h, peuvent être utilisés. Un instrument pour mesurages au sol exige des prélèvements fréquents d'échantillons pour la génération d'une moyenne temporelle valide au cours d'un intervalle d'enregistrement, par exemple dans des conditions partiellement nuageuses, alors que l'estimation par satellite utilise la moyenne spatiale de nombreux pixels dans une seule image en remplacement de la moyenne temporelle.

Tableau 1 – Exigences relatives aux intervalles d'échantillonnage et d'enregistrement

	Classe A **Haute exactitude**	**Classe B** **Exactitude moyenne**
Intervalle maximal d'échantillonnage Concernant l'éclairement énergétique, la température, le vent et la puissance électrique	5 s	1 min
Intervalle maximal d'enregistrement	5 min (1 min – recommandée)	15 min

6.2 Horodatages

Chaque enregistrement et chaque rapport doivent inclure un horodatage.

Les données relatives à l'horodatage doivent comprendre la date et l'heure correspondant au début ou à la fin de l'intervalle d'enregistrement ou de la période de suivi. Le choix de l'intervalle doit être spécifié.

Il convient que l'heure se réfère à l'heure normale locale (pas à l'heure d'été) ou au temps universel, afin d'éviter les changements d'heures hiver/été. Le choix de l'heure doit être spécifié.

Un nouveau jour doit débuter à minuit, exprimé comme suit: 00:00:00.

Lorsque plusieurs unités d'acquisition des données sont impliquées et que chacune applique des horodatages indépendamment des autres, il convient de synchroniser les horloges des unités, de préférence par un mécanisme automatisé, par exemple un système de positionnement mondial (GPS - *global positioning system*) ou un protocole de synchronisation réseau (NTP - *network time protocol*).

6.3 Noms de paramètres

Pour assurer la cohérence de l'extraction des données sur plusieurs plateformes, il est recommandé d'utiliser des noms de paramètres normalisés. Les noms normalisés des paramètres qui figurent dans le présent document sont répertoriés dans le document de définitions des données de taxonomie *Orange Button Taxonomy Data Definitions*.

7 Mesurages exigés

Le Tableau 2 présente les paramètres mesurés définis dans le présent document ainsi qu'un résumé des exigences de mesure.

L'objet de chaque paramètre de surveillance est présenté dans le Tableau 2 afin de guider l'utilisateur. De plus amples informations ainsi que des exigences supplémentaires sont fournies dans les paragraphes référencés.

Une coche (√) dans le Tableau 2 indique un paramètre dont le mesurage est exigé sur site, qualifié par des notes spécifiques, le cas échéant.

Le symbole "R" dans le Tableau 2 indique un paramètre qui peut être déterminé d'après les données météorologiques à distance ou les données satellites, en lieu et place d'un mesurage sur site.

Le Tableau 2 présente le nombre minimal de capteurs sur site lorsque cela est exigé. Dans de nombreux cas, cela est représenté par un facteur multiplié par un des multiplicateurs du Tableau 3. Lorsqu'aucun nombre n'est indiqué, seul un capteur est exigé, bien que des capteurs redondants soient généralement conseillés.

Lorsque plusieurs capteurs sont exigés, ils doivent être répartis sur la centrale PV à des emplacements représentatifs ou placés au niveau des points de surveillance indiqués dans le tableau lorsque cela est spécifié. Si la centrale comprend plusieurs sections qui relèvent de différents types de technologies ou de géographies locales sensiblement différentes ou d'autres caractéristiques de fonctionnement, alors au moins un capteur doit être placé dans chacune de ces sections et des capteurs supplémentaires doivent être ajoutés, si besoin, pour satisfaire à cette exigence.

Les cellules vides du Tableau 2 indiquent des paramètres facultatifs qui peuvent être choisis pour satisfaire à des exigences spécifiques à un système ou à des spécifications de projets.

Tableau 2 – Paramètres mesurés et exigences

Paramètre	Symbole	Unités	Objet de la surveillance	Système de Classe A		Système de Classe B	
				Exigé?	Nombre minimal de capteurs	Exigé?	Nombre minimal de capteurs
Éclairement énergétique (voir Article 8)							
Éclairement énergétique dans le plan du groupe photovoltaïque (POA)	G_i	W·m^{-2}	Ressource solaire	√	1 ×Tableau 3	√	
Éclairement énergétique horizontal global	GHI	W·m^{-2}	Ressource solaire, connexion aux données historiques et satellites	√	1 × Tableau 3	√ ou R	
Albédo horizontal	ρ_H	Sans unité	Ressource solaire, face arrière	√ pour le bifacial, Option 1 selon 8.3.3	1 × Tableau 3		
Éclairement énergétique arrière dans le plan du groupe photovoltaïque (POA) ou éclairement énergétique dans le plan du groupe photovoltaïque adapté spectralement	G_i^{rear}	W·m^{-2}		√ pour le bifacial, Option 2 selon 8.3.3	3 × Tableau 3		
	$G_{i,sp}^{rear}$	W·m^{-2}					
Éclairement énergétique diffus	G_d	W·m^{-2}	Ressource solaire	√ pour le bifacial, Option 1 selon 8.3.3 (facultatif) √ pour CPV avec une concentration < 20×	1 × Tableau 3		
Éclairement énergétique normal direct	DNI	W·m^{-2}		√ pour CPV	1 × Tableau 3		
Contribution circumsolaire, coefficient circumsolaire, forme solaire (sunshape)							

Paramètre	Symbole	Unités	Objet de la surveillance	Système de Classe A		Système de Classe B	
				Exigé?	Nombre minimal de capteurs	Exigé?	Nombre minimal de capteurs
Facteurs environnementaux (voir Article 9)							
Température des modules PV	T_{mod}	°C	Détermination des pertes liées à la température	√	3 × Tableau 3	√	
Température de l'air ambiant	T_{amb}	°C	Estimation des températures PV, connexion aux modèles de prévision	√	1 × Tableau 3	√ ou R	
Vitesse du vent		$m \cdot s^{-1}$		√	1 × Tableau 3	√ ou R	
Direction du vent		degrés		√	1 × Tableau 3		
Coefficient d'encrassement	SR		Détermination des pertes liées à l'encrassement	√ si des pertes annuelles types liées à l'encrassement sans nettoyage > 2 % sont attendues	1 × Tableau 3		
Précipitations		cm	Estimation des pertes liées à l'encrassement	√	1 × Tableau 3	√ ou R	
Neige		cm	Estimation des pertes liées à la neige	√ si des pertes annuelles types liées à la neige sans nettoyage > 2 % sont attendues et si le mesurage de l'encrassement ne mesure pas la perte liée à la neige	1 × Tableau 3		
Humidité		%	Estimation des variations spectrales				

Paramètre	Symbole	Unités	Objet de la surveillance	Système de Classe A		Système de Classe B	
				Exigé?	Nombre minimal de capteurs	Exigé?	Nombre minimal de capteurs
Suiveur solaire (voir Article 10)							
Angle d'inclinaison du système monoaxial de suivi de trajectoire du soleil	ϕ_T	degrés	Détection de défauts dans le système monoaxial de suivi de trajectoire du soleil	√ pour système monoaxial de suivi de trajectoire du soleil	1 × Tableau 3		
Erreur de système biaxial de suivi de trajectoire du soleil à l'angle primaire	$\Delta\phi_1$	degrés	Détection de défauts dans le système biaxial de suivi de trajectoire du soleil	√ pour système biaxial de suivi de trajectoire du soleil	1 × Tableau 3		
Erreur de système biaxial de suivi de trajectoire du soleil à l'angle secondaire	$\Delta\phi_2$	degrés					
Puissance électrique (voir Article 11)							
Tension (continue) du groupe	V_A	V	Énergie de sortie, diagnostics et localisation de défauts	√	Aux bornes de chaque onduleur – le cas échéant (voir 11.1)		
Courant (continu) du groupe	I_A	A		√			
Puissance du groupe (en courant continu)	P_A	kW		√			
Tension (alternative) de sortie	V_{out}	V		√	Aux bornes de chaque onduleur et au niveau du système	√	Aux bornes de chaque onduleur et au niveau du système
Courant (alternatif) de sortie	I_{out}	A		√		√	
Puissance de sortie (en courant alternatif)	P_{out}	kW		√		√	
Énergie en sortie	E_{out}	kWh		√		√	
Facteur de puissance de sortie	λ		Conformité à la demande de réseau électrique	√		√	
Demande de charge réduite			Détermination de la conformité à la demande de réseau électrique ou de charge ainsi que de l'impact sur les performances du système PV	√	Au niveau du système		
Demande de facteur de puissance de sortie du système	λ_{req}			√	Au niveau du système		

Tableau 3 – Multiplicateur référencé dans le Tableau 2

Taille du système (courant alternatif) MW	Multiplicateur
< 40	2
≥ 40 à < 100	3
≥ 100 à < 300	4
≥ 300 à < 500	5
≥ 500 à < 700	6
≥ 700	7, plus 1 pour chaque palier de 200 MW supplémentaire

8 Éclairement énergétique

8.1 Types de capteurs

Les approches pour le mesurage de l'éclairement énergétique sur site au sol comprennent les possibilités suivantes:

- Mesurer l'éclairement énergétique solaire hémisphérique à bande large, indépendant de la distribution spectrale ou angulaire. Les instruments destinés à ce mesurage sont classés comme pyranomètres, quel que soit le type de technologie.
- Mesurer l'éclairement énergétique adapté correspondant à la part utilisable par le PV de la distribution incidente spectrale et angulaire. Des dispositifs PV de référence (cellules et modules de référence) sont utilisés à cette fin.
- Mesurer l'éclairement énergétique spectrale, à partir duquel l'éclairement énergétique adapté spectralement peut être déterminé. Des spectroradiomètres ou des instruments multispectres peuvent être utilisés à cette fin.

Ces différentes approches peuvent être interverties à l'aide de modèles appropriés, avec une légère incertitude. Lorsque des transpositions et corrections fondées sur des modèles sont utilisées, elles doivent être documentées.

L'éclairement énergétique peut également être déterminé au moyen de mesurages à distance en utilisant une instrumentation par satellite en complément, ou en remplacement (lorsque le Tableau 2 le permet) pour les mesurages sur site au sol. Voir 8.3.12.

Le capteur choisi et son type doivent être documentés.

8.2 Exigences générales

8.2.1 Aperçu

Le présent paragraphe 8.2 fournit les exigences générales applicables à la plupart des mesurages de l'éclairement énergétique sur site. Les paragraphes suivants portant sur les types spécifiques de mesurages de l'éclairement énergétique peuvent comprendre des exigences différentes et/ou supplémentaires.

8.2.2 Exigences relatives aux capteurs

Les capteurs doivent satisfaire aux exigences du Tableau 4 en fonction du type de capteur.

Tableau 4 – Exigences relatives aux capteurs d’éclairement énergétique

Type de capteur	Système de Classe A	Système de Classe B
Pyranomètre	Face avant (POA et GHI): Classe A selon l’ISO 9060:2018 Spectralement plat Incertitude d’étalonnage ≤ 2 % à 1 000 W m^{-2} Plage jusqu’à 1 500 W m^{-2} Résolution ≤ 1 W m^{-2} Face arrière Classe C ou plus selon l’ISO 9060:2018 Incertitude d’étalonnage ≤ 3 % à 1 000 W m^{-2} Plage jusqu’à 1 500 W m^{-2} Résolution ≤ 1 W m^{-2}	Classe C ou plus selon l’ISO 9060:2018 Incertitude d’étalonnage ≤ 3 % à 1 000 W m^{-2} Plage jusqu’à 1 500 W m^{-2} Résolution ≤ 1 W m^{-2}
Dispositif PV de référence	Dispositif de référence de travail selon l’IEC 60904-2 Incertitude d’étalonnage ≤ 2 % à 1 000 W m^{-2} Plage jusqu’à 1 500 W m^{-2} Résolution ≤ 1 W m^{-2}	Dispositif de référence de travail selon l’IEC 60904-2 Incertitude d’étalonnage ≤ 3 % à 1 000 W m^{-2} Plage jusqu’à 1 500 W m^{-2} Résolution ≤ 1 W m^{-2}

Les pyranomètres comprennent une vaste gamme de technologies instrumentales, dont, entre autres, des pyranomètres à thermopile et des instruments construits autour d'une ou plusieurs photodiodes. Dans le contexte du mesurage de l’éclairement énergétique solaire de la face avant du Tableau 4, "spectralement plat" signifie que le mesurage de l’éclairement énergétique à large bande du pyranomètre est affecté de manière négligeable par la distribution spectrale de la lumière solaire incidente.

8.2.3 Emplacements des capteurs

8.2.3.1 Face avant

L’emplacement des capteurs de mesure de l’éclairement énergétique sur la face avant, y compris le GHI et les capteurs de plan du groupe PV, doit être choisi de façon à être représentatif, et qu’il évite, si cela est possible, les conditions d’ombrage du lever au coucher du soleil. Il convient que l’ombrage ne survienne que pendant une demi-heure au lever ou au coucher du soleil. Tout ombrage doit être documenté.

Dans le cas des mesurages de l’éclairement énergétique du plan du groupe photovoltaïque, pour des systèmes à inclinaison fixe ou de suivi, les capteurs doivent être maintenus à la même inclinaison et aux mêmes azimuts que les modules. Ceci peut être obtenu en plaçant les capteurs directement sur le support de modules ou sur des tiges séparées ou des bras d’extension équipés d'un suiveur, si cela est applicable.

NOTE De manière facultative, des capteurs d’éclairement énergétique de la face avant supplémentaires peuvent être installés dans des emplacements ombragés de manière temporaire par des rangées de modules adjacents, par exemple pendant le repli d’un système de suivi, afin de surveiller cet effet d’ombrage, mais ces capteurs ne satisfont pas aux exigences du Tableau 2 et du Tableau 3 et les mesures des performances utilisent toujours des capteurs sans ombre, sauf avis explicite contraire.

8.2.3.2 Face arrière

L’emplacement des capteurs du coefficient d’éclairement énergétique arrière et/ou d’éclairement énergétique arrière dans le plan doit être choisi de telle manière que leur champ de vision soit représentatif des conditions sur la face arrière dans la majorité du groupe, tout en réduisant le plus possible l'ombrage sur les modules. Si la surface au sol attendue est variable sur l'étendue du site, utiliser une quantité appropriée de capteurs ainsi qu'une méthodologie d'échantillonnage pour capter les variations. Il convient que les capteurs soient également placés pour capter l'éclairement énergétique arrière sans impact de l'environnement local autre que l'ombrage représentatif causé par les portions du groupe PV proches.

Il convient de placer les capteurs selon le même angle d'inclinaison que les modules, directement sur les supports de modules en utilisant des structures de soutien des poutres ou des rails, et positionnés loin des bouts de ligne, des piliers de montage et d'autres sources locales de phénomènes d'ombrage ou d'illumination accrue, tels que les réflexions des supports de modules.

La non-uniformité de l'éclairement énergétique qui atteint l'arrière de la surface du module de bord à bord constitue une préoccupation relative aux capteurs d'éclairement énergétique arrière dans le plan et les capteurs du coefficient d'éclairement énergétique arrière dans le plan. Il est recommandé de disposer plusieurs capteurs sur l'arrière de la structure de support afin de suivre et de mesurer le profil d'illumination non uniforme tout au long de la journée. Ceci permet à la fois de quantifier la non-uniformité de l'éclairement énergétique arrière et de calculer une moyenne effective de l'éclairement énergétique arrière pour les introduire dans les équations de performance choisies.

NOTE L'éclairement énergétique mesuré peut varier en fonction de la position du capteur, particulièrement dans le cas de mesurages par le capteur du plan du groupe photovoltaïque à l'arrière. Par exemple, si le capteur est placé sous une rangée de modules, il peut présenter une valeur différente de celle obtenue lorsqu'il est placé au-dessus de la rangée de modules, étant donné qu'une contribution à l'éclairement énergétique dans un plan incliné provient du sol ou des éléments à proximité.

8.2.3.3 Albédo horizontal

L'emplacement des capteurs d'albédo horizontal doit être choisi de façon à être représentatif de l'albédo sur le site. Il convient de monter les capteurs à une hauteur minimale de 1,0 m afin qu'un groupe de vision de l'éclairement énergétique suffisant soit reflété à partir du sol. Il convient que de la végétation ou que toute autre structure située à proximité, y compris les modules et la structure de soutien des modules, ne projette pas d'ombre, dans les limites d'un angle de prise de vue de ± 80 degrés. Il convient de réduire le plus possible l'ombrage apporté par le dispositif de mesure de l'albédo et par sa structure de soutien. Si la surface au sol attendue est variable sur l'étendue du site, utiliser une quantité appropriée de capteurs ainsi qu'une méthodologie d'échantillonnage pour capter les variations.

8.2.4 Réétalonnage

Le réétalonnage des capteurs doit être réalisé de sorte que le temps d'indisponibilité et l'arrêt du capteur sont réduits le plus possible, afin d'empêcher l'interruption de la surveillance. Les méthodes effectives peuvent comprendre:

- Procéder à un échange entre les capteurs installés et des unités neuves ou réétalonnées
- Lorsque cela est possible, réaliser le réétalonnage des capteurs sur site
- Fournir des capteurs redondants et alterner les programmes de réétalonnage en laboratoire

Pour les systèmes de Classe A, les capteurs doivent être réétalonnés tous les deux ans, ou plus fréquemment selon les recommandations du fabricant.

Pour les systèmes de Classe B, réétalonner les capteurs selon les recommandations du fabricant.

8.2.5 Atténuation de l'encrassement

Pour les systèmes de Classe A, les effets de l'accumulation de l'encrassement sur les capteurs d'éclairement énergétique doivent être atténués. Pour les capteurs et installations types, un nettoyage hebdomadaire est exigé. Un nettoyage moins fréquent peut avoir lieu lorsque les conditions locales le permettent ou lorsque la technologie employée atténue ou corrige l'encrassement des capteurs d'une manière équivalant à un nettoyage hebdomadaire, ou lorsqu'elle détecte l'encrassement de sorte que le nettoyage puisse être programmé au besoin.

8.2.6 Atténuation de la rosée et du gel

Pour les systèmes de Classe A, les effets de l'accumulation de la rosée et du gel sur les capteurs d'éclairement énergétique doivent être atténués pour les emplacements où il est attendu que la rosée ou le gel soit présent plus de 2 % des heures GHI annuelles.

L'examen des données météorologiques annuelles types pour le site peut permettre de déterminer si un site de centrale exige une atténuation. L'attention est portée sur la température ambiante et le point de rosée. Pour les besoins de cette évaluation, il est considéré que la rosée ou le gel sont attendus lorsque la température ambiante se situe à 1,5 °C du point de rosée.

Plusieurs moyens d'atténuation dont le chauffage ou la ventilation externe, peuvent être efficaces. Les capteurs d'éclairement énergétique doivent conserver leur exactitude et leur classification pendant l'application de l'atténuation de la rosée et du gel. Le chauffage ne doit pas perturber l'exactitude et la classification du capteur. Pour les pyranomètres, les moyens efficaces d'assurer l'exactitude des performances pendant le chauffage du capteur peuvent comprendre, entre autres, la ventilation interne et la ventilation externe.

8.2.7 Inspection et maintenance

Une inspection de routine des capteurs doit être réalisée pour vérifier l'encrassement, les erreurs d'alignement et d'autres conditions de défaut. Pour les systèmes de Classe A, les capteurs de la face avant doivent faire l'objet d'une inspection hebdomadaire.

Les capteurs doivent être entretenus selon les exigences du fabricant. Les exigences de maintenance peuvent comprendre, par exemple, l'inspection et/ou le remplacement des dessiccants, selon le cas.

8.2.8 Alignement des capteurs

Les capteurs d'éclairement énergétique pour l'éclairement énergétique horizontal global (*GHI*) doivent être mis à niveau à 0,5° près.

Les capteurs d'éclairement énergétique pour l'éclairement énergétique dans le plan du groupe photovoltaïque (*POA*) doivent être alignés sur leur plan de destination à 0,5° d'inclinaison et 1° d'azimut (Classe A) ou 1° d'inclinaison et 2° d'azimut (Classe B), avec les dispositions suivantes:

- Lorsque les capteurs sont placés directement sur le support de module, l'exigence d'alignement est satisfaite s'il peut être démontré que les capteurs sont alignés sur le support dans les limites des tolérances déclarées.
- Lorsque les capteurs sont placés sur une structure de montage différente et indépendante des modules, une attention particulière doit être portée à ce que l'alignement soit atteint et vérifié dans les limites des tolérances déclarées. Si l'alignement ne peut pas être atteint, l'erreur d'alignement doit être mesurée et documentée.

NOTE L'inclinaison du capteur peut être mesurée avec un inclinomètre. L'alignement azimutal des capteurs dans le plan du groupe photovoltaïque peut être vérifié en examinant puis en modélisant une série de données d'éclairement énergétique au cours du temps par conditions de ciel serein.

8.3 Mesurages

8.3.1 Éclairement énergétique horizontal global

L'éclairement énergétique horizontal global (GHI) se mesure avec un capteur d'éclairement énergétique positionné à l'horizontale et orienté vers le haut, ou est déterminée en associant l'éclairement énergétique normal direct et l'éclairement énergétique horizontal diffus au moyen de l'équation de 3.21.

8.3.2 Éclairement énergétique dans le plan

Pour les systèmes plans, l'éclairement énergétique dans le plan est mesuré avec un capteur d'éclairement énergétique à ouverture parallèle au plan du groupe photovoltaïque (POA), monté sur la structure de soutien du module ou sur une autre structure alignée de manière parallèle aux modules.

Dans le cas de systèmes suivis, le capteur d'éclairement énergétique doit être aligné de manière permanente sur le plan du groupe photovoltaïque réel, y compris le repli, le cas échéant.

Pour les systèmes à concentration, voir 8.3.9.

S'il est prévu que des suiveurs solaires quelconques fonctionnent de façon non normalisée par rapport au reste du groupe, il convient d'exclure ces suiveurs solaires du choix d'emplacements des capteurs pour les besoins du Tableau 2 et du Tableau 3. Ils peuvent toutefois, de manière facultative, servir d'emplacements pour des capteurs supplémentaires et complémentaires.

NOTE 1 Le mesurage de l'éclairement énergétique sur une surface faisant l'objet d'un suivi peut être faussé si le suiveur qui soutient le capteur n'effectue pas le suivi correctement. Une approche permettant de vérifier si le suivi est correct consiste à utiliser l'éclairement énergétique normal direct et l'éclairement énergétique horizontal diffus, DNI et G_d respectivement, ainsi qu'un modèle de transposition afin de calculer l'éclairement énergétique dans le plan prévu et de le comparer avec la valeur mesurée.

NOTE 2 L'éclairement énergétique POA peut également être estimé à partir de GHI à l'aide d'un modèle de décomposition et de transposition.

8.3.3 Éclairement énergétique arrière dans le plan

Il est difficile de déterminer avec exactitude la ressource solaire de la face arrière des modules PV bifaciaux. L'éclairement énergétique arrière sur un groupe PV, ainsi que le contenu spectral de l'éclairement énergétique, sont très variables dans l'espace et dans le temps en fonction des motifs d'ombrage, des détails de la structure de montage, des propriétés de la surface au sol et des variations saisonnières.

Le Tableau 2 présente deux options pour déterminer l'éclairement énergétique arrière dans les modules PV bifaciaux.

- Option 1: Mesurer l'albédo horizontal et, éventuellement, l'éclairement énergétique diffus, et utiliser un modèle optique tel que le modèle de facteur de forme ou le modèle de tracé des rayons, afin d'estimer l'éclairement énergétique arrière.
- Option 2: Mesurer directement l'éclairement énergétique arrière dans le plan ou, éventuellement, l'éclairement énergétique arrière dans le plan adapté spectralement.

Le mesurage direct de l'éclairement énergétique arrière dans le plan est réalisé à l'aide d'un capteur d'éclairement énergétique dont l'ouverture est orientée parallèlement au plan du groupe photovoltaïque (POA), monté sur la face arrière de la structure de soutien du module. Il peut être aussi réalisé à l'aide d'un dispositif de référence bifacial (voir 3.19).