# UL 61724-1

## STANDARD FOR

Photovoltaic System Performance –
Part 1: Monitoring

UL Standard for Photovoltaic System Performance – Part 1: Monitoring, UL 61724-1

First Edition, Dated January 29, 2019

***Summary of Topics***

***This is the First Edition of ANSI/UL 61724-1, an adoption of IEC 61724-1, Photovoltaic System Performance – Part 1: Monitoring (First Edition, issued by the IEC March 2017). Please note that the National Difference document incorporates all of the U.S. national differences for UL 61724-1.***

The new requirements are substantially in accordance with Proposal(s) on this subject dated July 27, 2018 and December 7, 2018 .

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# UL 61724-1

## Standard for Photovoltaic System Performance – Part 1: Monitoring



**First Edition**

**January 29, 2019**

This ANSI/UL Standard consists of the First Edition.

The most recent designation of ANSI/UL 61724-1 as an American National Standard (ANSI) occurred on January 29, 2019. ANSI approval for a standard does not include the Cover Page, Transmittal Pages, Title Page, or Preface. The National Difference Page and IEC Foreword are also excluded from the ANSI approval of IEC-based standards.

Comments or proposals for revisions on any part of the Standard may be submitted to UL at any time. Proposals should be submitted via a Proposal Request in UL's On-Line Collaborative Standards Development System (CSDS) at https://csds.ul.com.

No Text on This Page

## CONTENTS

**Annex A (informative) Sampling interval**



**Annex B (informative) Module backsheet temperature sensor selection and attachment**



**Annex C (informative) Derate factors**

**Annex D (normative) Systems with local loads, storage, or auxiliary sources**



**Bibliography**

# PREFACE

This UL Standard is based on IEC Publication 61724-1: First edition Photovoltaic System Performance – Part 1: Monitoring. IEC publication 61724-1 is copyrighted by the IEC.



Note – Although the intended primary application of this Standard is stated in its Scope, it is important to note that it remains the responsibility of the users of the Standard to judge its suitability for their particular purpose.

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## NATIONAL DIFFERENCES

National Differences from the text of International Electrotechnical Commission (IEC) Publication 61724-1 are indicated by notations (differences) and are presented in bold text.

There are five types of National Differences as noted below. The difference type is noted on the first line of the National Difference in the standard. The standard may not include all types of these National Differences.

***D1* –** These are National Differences which are based on ***basic safety principles and requirements***, elimination of which would compromise safety for consumers and users of products.

***D2* –** These are National Differences from IEC requirements based on existing ***safety practices***. These requirements reflect national safety practices, where empirical substantiation (for the IEC or national requirement) is not available or the text has not been included in the IEC standard.

***DC* –** These are National Differences based on the ***component standards*** and will not be deleted until a particular component standard is harmonized with the IEC component standard.

***DE* –** These are National Differences based on ***editorial comments or corrections***.

***DR* –** These are National Differences based on the ***national regulatory requirements***.

Each national difference contains a description of what the national difference entails. Typically one of the following words is used to explain how the text of the national difference is to be applied to the base IEC text:

**Addition / Add** - An addition entails adding a complete new numbered clause, subclause, table, figure, or annex. Addition is not meant to include adding select words to the base IEC text.

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**Modification / Modify** - A modification is an altering of the existing base IEC text such as the addition, replacement or deletion of certain words or the replacement of an entire clause, subclause, table, figure, or annex of the base IEC text.

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# FOREWORD

## INTERNATIONAL ELECTROTECHNICAL COMMISSION

## PHOTOVOLTAIC SYSTEM PERFORMANCE – Part 1: Monitoring

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 first edition cancels and replaces the first edition of IEC 61724, published in 1998. This edition constitutes a technical revision.

This edition (in conjunction with IEC TS 61724-2:2016 and IEC TS 61724-3:2016) includes the following significant technical changes with respect to IEC 61724:

a) IEC 61724 is now written with multiple parts. This document is IEC 61724-1, addressing PV system monitoring. IEC TS 61724-2 and IEC TS 61724-3 address performance analysis based on the monitoring data.

b) Three classes of monitoring systems are defined corresponding to different levels of accuracy and different intended applications.

c) Required measurements for each class of monitoring system are stated, along with the required number and accuracy of sensors.

d) Options for satellite-based irradiance measurement are provided.

e) Soiling measurement is introduced.

f) New performance metrics are introduced, including temperature compensated performance ratios and others.

g) Numerous recommendations and explanatory notes are included.

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

| FDIS | Report on voting |
|---|---|
| 82/1215/FDIS | 82/1248/RVD |

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

This publication has been drafted in accordance with the ISO/IEC Directives, Part 2.

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 "http://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.

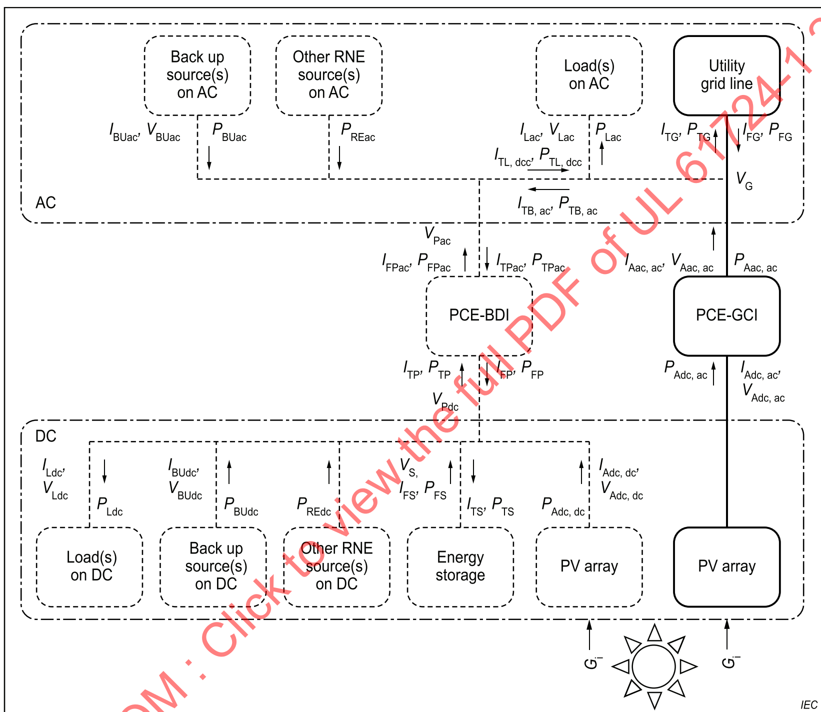
A bilingual version of this publication may be issued at a later date.

# INTRODUCTION

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

For simplicity, 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 D includes details for systems with additional components.

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**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**

***Figure 1DV DR Modification in accordance with the following:***

**Wherever the term " bidirectional inverter " is used, replace with the term " multimode inverter".**

The purposes of a performance monitoring system are diverse and can 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.

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 and localizing faults, there may 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 equipment, methods, and terminology 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. In addition, it 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 – 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 60904-10, *Photovoltaic devices – Part 10: Methods of linearity measurement*

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

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

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 (a.c.) – Particular requirements – Part 22: Static meters for active energy (classes 0,2 S and 0,5 S)*

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, *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*

**2DV DC *Addition of the following standards that are also available for use:***

**ANSI C12.1, *Electric Meters – Code for Electricity Metering***

**ANSI C12.20, *Electricity Meters 0.1, 0.2 and 0.5 Accuracy Classes***



## 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**
$\tau$
time between records

3.5
**report**
aggregate value based on series of records

3.6
**reporting period**
time between reports

3.7
**irradiance**
*G*
incident flux of radiant power per unit area

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

3.8
**in-plane irradiance**
$G_i$ or *POA*
the sum of direct, diffuse, and ground-reflected irradiance incident upon 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 $W \cdot m^{-2}$.

3.9
**global horizontal irradiance**
*GHI*
direct plus diffuse irradiance incident on a horizontal surface

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

3.10
**circumsolar**
immediately surrounding the solar disk

3.11
**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 to entry: Expressed in units of $W \cdot m^{-2}$.

3.12
**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

3.13
**diffuse horizontal irradiance**
$G_d$ or *DHI*
global horizontal irradiance 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 to entry: Expressed in units of W·m$^{-2}$.

3.14
**in-plane direct beam irradiance**
*$G_{i,b}$*
in-plane irradiance 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($\theta$)×$DNI$, where $\theta$ 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$^{-2}$.

3.16
**irradiation**
*$H$*
irradiance integrated over a specified time interval

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

3.17
**standard test conditions**
STC
reference values of in-plane irradiance (1000 W·m$^{-2}$), PV cell junction temperature (25 °C), and the reference spectral irradiance defined in IEC 60904-3

3.18
**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

3.19
**soiling level**
*$SL$*
fractional power loss due to soiling, given by 1 – $SR$

3.20
**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.

3.21
**apparent power**
*S*
product of the r.m.s. voltage between the terminals of a two-terminal element or two-terminal circuit and the r.m.s. 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.

3.22
**power factor**
$\lambda$
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.

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



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

| Typical applications | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>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 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 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 by the manufacturer or at more frequent intervals where specified.

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 systems required for operation of the PV plant shall be considered a power loss of the plant, not 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.

### 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.

## 6 Data acquisition timing and reporting

### 6.1 Sampling, recording, and reporting

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

A record is defined as data entered into a data log for data storage, based on acquired samples, and the recording interval, denoted by $\tau$ 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 7.3.3.)

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

Figure 2 illustrates the relations between samples, records, and reports. Table 2 lists maximum values for sampling intervals and recording intervals. Further considerations relating to the sampling interval are addressed in Annex A.

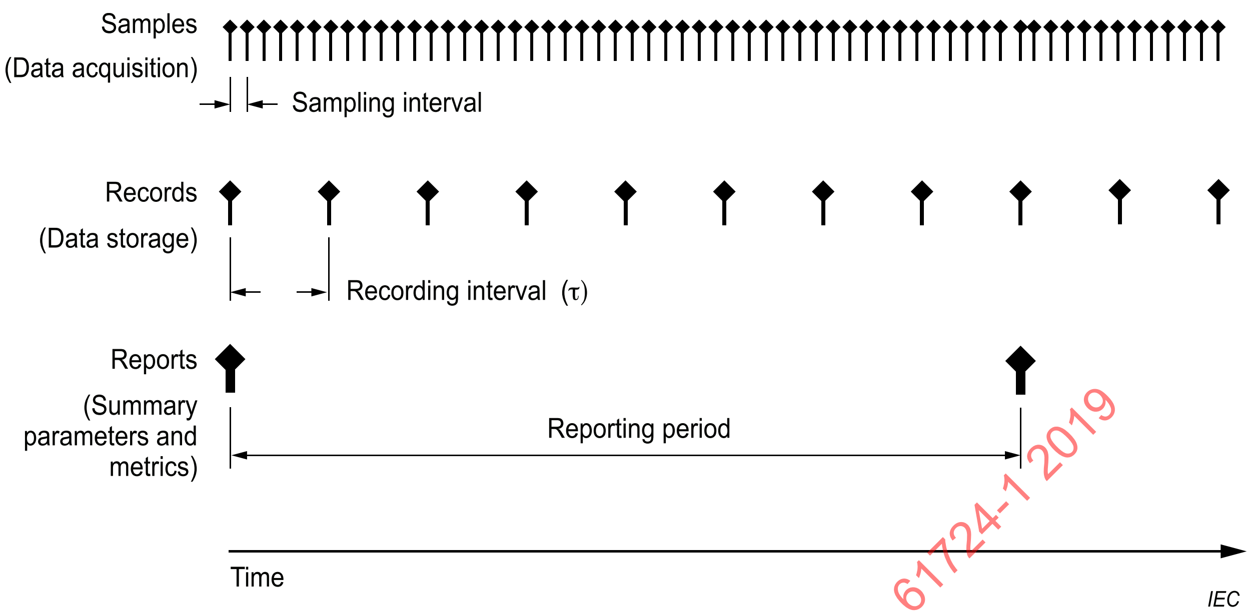


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**Figure 2**
**Sampling, recording, and reporting**

**Table 2**
**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.)

## 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.

When multiple data acquisition units are involved that each independently apply timestamps, the clocks of the units shall 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.*

## 7 Measured parameters

### 7.1 General requirements

Table 3 lists measured parameters defined by this document and a summary of measurement requirements. The purpose of each monitoring parameter is listed in Table 3 in order to guide the user. More details and additional requirements are provided in the subsequent referenced subclauses.

A check mark (√) in Table 3 indicates a required parameter to be measured on site, qualified by specific notes where included.

Table 3 lists the minimum number of on-site sensors, in many cases by reference to Table 4. 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, or placed at monitoring points indicated in the table. If the plant includes multiple sections that have different PV technology types or substantially different local geography, then at least one sensor shall be placed in each section.

The symbol "E" in Table 3 indicates a parameter that may be estimated based on local or regional meteorological data or satellite data, rather than measured on site.

Empty cells in Table 3 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 3**
**Measured parameters and requirements for each monitoring system class**

| Parameter | Sym-bol | Units | Monitoring purpose | Required? Class A High Accuracy | Class B Medium Accuracy | Class C Basic Accuracy | Number of sensors |
|---|---|---|---|---|---|---|---|
| **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 |

**Table 3 Continued on Next Page**

## Table 3 Continued

| Parameter | Sym-bol | Units | Monitoring purpose | Required? | | | Number of sensors |
|---|---|---|---|---|---|---|---|
| | | | | Class A High Accuracy | Class B Medium Accuracy | Class C Basic Accuracy | |
| 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× concentra-tion | √ or E for CPV with < 20× concentra-tion | | 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 | | de-grees | | √ | | | 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 | | | | |
| Humidity | | | Estimation of spectral variations | | | | |
| **Tracker system (see 7.4)** | | | | | | | |
| Error in dual-axis tracker primary angle | $\Delta\varphi_1$ | de-grees | Tracker system fault detection, dual-axis | √ for CPV with >20× concentra-tion | | | Table 4 column 1 |
| Error in dual-axis tracker secondary angle | $\Delta\varphi_2$ | de-grees | | √ for CPV with >20× concentra-tion | | | Table 4 column 1 |
| Single-axis tracker tilt angle | $\varphi_T$ | de-grees | 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) | $V_A$ | V | Energy output, diagnostics and fault localization | √ | | | At each inverter (optionally at |

Table 3 Continued on Next Page

**Table 3 Continued**

| Parameter | Sym-bol | Units | Monitoring purpose | Required? Class A High Accuracy | Required? Class B Medium Accuracy | Required? Class C Basic Accuracy | Number of sensors |
|---|---|---|---|---|---|---|---|
| Array current (DC) | $I_A$ | A | | √ | | | each combiner box or each string) |
| Array power (DC) | $P_A$ | kW | | √ | | | |
| Output voltage (AC) | $V_{out}$ | V | Energy output | √ | √ | | 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 | $\lambda$ | | 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 | $\lambda_{req}$ | | | If applicable | If applicable | | At system level |

**Table 4**
**Relation between system size (AC) and number of sensors for specific sensors referenced in Table 3**

| System size (AC) | Number of sensors: Column 1 | Number of sensors: 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 |



## 7.2 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 $0\ W{\cdot}m^{-2}$ to $1500\ W{\cdot}m^{-2}$ and a resolution of $\leq 1\ W{\cdot}m^{-2}$.

NOTE Over-irradiance in the range 1000 W·m$^{-2}$ to 1500 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<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
|---|---|---|---|
| Thermopile pyranometer | Secondary standard per ISO 9060<br>or<br>High quality per WMO Guide No. 8<br>(Uncertainty ≤ 3 % for hourly totals) | First class per ISO 9060<br>or<br>Good quality per WMO Guide No. 8<br>(Uncertainty ≤ 8 % for hourly totals) | Any |
| PV reference device | Uncertainty ≤ 3 %<br>from 100 W·m$^{-2}$ to 1500 W·m$^{-2}$ | Uncertainty ≤ 8 %<br>from 100 W·m$^{-2}$ to 1500 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<br>High accuracy | Class B<br>Medium accuracy | Class C<br>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<br>High accuracy | Class B<br>Medium accuracy | Class C<br>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, $-1\ \mathrm{W \cdot m^{-2}}$ to $-3\ \mathrm{W \cdot m^{-2}}$, 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 $G_d$ (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.

##### 7.2.1.8.3 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 $G_{i,b}$:

(1)

$$G_i = G_{i,b}$$

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 $f_d$:

(2)

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

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 $I_{sc}$ versus $G_{i,b}/G_i$ data.

(3)

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

where

$\alpha_{Isc}$ 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 (see Clause 3) and 0° angle of incidence.

The term $f_d$ then becomes:

(4)

$$f_d = \frac{b}{m + b}$$

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 versus 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.

#### 7.2.1.8.4 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.

#### 7.2.1.8.5 Circumsolar ratio 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. 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. Therefore, measuring the circumsolar ratio may be useful for performance characterization purposes; however, *CSR* measurement devices have not yet been standardized.

### 7.2.2 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 1000 $W \cdot m^{-2}$, but 20 % at 100 $W \cdot m^{-2}$ – i.e, a constant ~20 $W \cdot m^{-2}$ throughout the 100 $W \cdot m^{-2}$ to 1000 $W \cdot m^{-2}$ 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 1000 $W \cdot m^{-2}$, and 10 % at 100 $W \cdot m^{-2}$ – i.e, a constant ~10 $W \cdot m^{-2}$ throughout the 100 $W \cdot m^{-2}$ to 1000 $W \cdot m^{-2}$ 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 1000 $W \cdot m^{-2}$ 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 (1000 $W \cdot m^{-2}$) 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.



## 7.3 Environmental factors

### 7.3.1 PV module temperature

The PV module temperature, $T_{mod}$, is measured with a temperature sensor affixed to the back of one or more 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<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
|---|---|---|---|
| Recalibration | Once every 2 years | Per manufacturer's recommendations | Not applicable |

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 so that the material is not attacked or degraded 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 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 owing to 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.

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.



### 7.3.2 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<br>High accuracy | Class B<br>Medium accuracy | Class C<br>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.

### 7.3.3 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 s) and the data record should contain not only averaged but also maximum values. (See 6.1.)

Wind measurement equipment shall 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.



**Table 10**
**Wind sensor maintenance requirements**

| Item | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
|---|---|---|---|
| Recalibration | Per manufacturer's recommendations | Per manufacturer's recommendations | Per manufacturer's recommendations |

### 7.3.4 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 nonuniform 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.

### 7.3.5 Rainfall

Rainfall measurements may be used to estimate the cleanliness of modules. However, if soiling ratio is measured, the module cleanliness is directly known.

### 7.3.6 Snow

Snowfall measurements may be used to estimate losses due to shading from snow. However, these losses will also be included in measurements of soiling ratio. 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.

### 7.3.7 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 this data.

## 7.4 Tracker system

### 7.4.1 Single-axis trackers

The real-time tracker tilt angle $\varphi_T$ shall be measured on representative trackers. 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.

### 7.4.2 Dual-axis trackers for >20x systems

#### 7.4.2.1 Monitoring

For high-concentration (> 20×) systems, the real-time tracker pointing errors ($\Delta\varphi_1$ and $\Delta\varphi_2$) shall be 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 7.5). Reporting of tracker pointing error data shall be per 7.4.6 of IEC 62817:2014.

#### 7.4.2.2 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 $m \cdot s^{-1}$ to 3,5 $m \cdot s^{-1}$, 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 the test report and shall serve as indication that alignment tolerance is sufficient.

### 7.5 Electrical 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 1000 $W \cdot m^{-2}$) 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.



**Table 11**
**Inverter-level electrical measurement requirements**

| Parameter | Measurement Uncertainty | | |
|---|---|---|---|
| | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
| Input voltage (DC) | ±2,0 % | n/a | n/a |
| Input current (DC) | ±2,0 % | n/a | n/a |

**Table 11 Continued on Next Page**

**Table 11 Continued**

| Parameter | Measurement Uncertainty | | |
|---|---|---|---|
| | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
| 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 |

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.

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

**Table 12**
**Plant-level AC electrical output measurement requirements**

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

**Table 12DV D2** ***Addition of the following note to the end of Table 12:***

**Note: In the US, electricity service providers may require measurements that conform to the requirements of ANSI C12.1 and ANSI C12.20.**

## 7.6 External system requirements

The monitoring system should 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.

# 8 Data processing and quality check

## 8.1 Daylight hours

Processed data for irradiance and PV-generated power should be restricted to the daylight hours of each day (sunrise to sunset, irradiance ≥ 20 W/m$^2$) to avoid extraneous night-time data values that introduce errors in analyses, unless such errors have been demonstrated to be negligible.

**8.1DV DE** ***Addition of the following note:***

**NOTE: Owners may wish to gather data at night to verify system losses and as a system diagnostic measure.**

## 8.2 Quality check

### 8.2.1 Removing invalid readings

The measured data shall 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 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.

### 8.2.2 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 61724-2 and IEC 61724-3.

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

## 9 Calculated parameters

### 9.1 Overview

Table 13 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 13**
**Calculated parameters**

| Parameter | Symbol | Unit |
|---|---|---|
| **Irradiation (9.3)** | | |
| In-plane irradiation | $H_i$ | $kWh \cdot m^{-2}$ |
| **Electrical energy (9.4)** | | |
| PV array output energy (DC) | $E_A$ | kWh |
| Energy output from PV system (AC) | $E_{out}$ | kWh |
| **Array power rating (9.5)** | | |
| Array power rating (DC) | $P_0$ | kW |
| Array power rating (AC) | $P_{0,AC}$ | kW |
| **Yields and yield losses (9.6 and 9.7)** | | |
| 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 (9.8)** | | |
| Array efficiency | $\eta_A$ | None |
| System efficiency | $\eta_f$ | None |
| BOS efficiency | $\eta_{BOS}$ | None |

### 9.2 Summations

In the formulas given below involving summation, $\tau_k$ 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 $\tau_k$ the power should be expressed in kW and the recording interval in hours in order to obtain energy in units of kWh.

### 9.3 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:

(5)

$$H = \sum_k G_k \times \tau_k$$

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

(6)

$$H_i = \sum_k G_{i,k} \times \tau_k$$

## 9.4 Electrical energy

### 9.4.1 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.

### 9.4.2 DC output energy

The PV array DC output energy is given by:

(7)

$$E_A = \sum_k P_{A,k} \times \tau_k$$

### 9.4.3 AC output energy

The AC energy output is given by:

(8)

$$E_{out} = \sum_k P_{out,k} \times \tau_k$$

## 9.5 Array power rating

### 9.5.1 DC power rating

The array DC power rating, $P_0$, is the total DC power output of all installed PV modules at the power rating reference condition, assumed to be standard test conditions (STC) or concentrator standard test conditions (CSTC) unless stated otherwise. $P_0$ 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.

### 9.5.2 AC power rating

The array AC power rating, $P_{0,AC}$, is the lesser of the array DC power rating $P_0$ or the sum of the inverter ratings in the system at a specified operating temperature.

## 9.6 Yields

### 9.6.1 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.

### 9.6.2 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:

$$Y_A = E_A / P_0 \tag{9}$$

### 9.6.3 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:

$$Y_f = E_{out} / P_0 \tag{10}$$

### 9.6.4 Reference yield

The reference yield $Y_r$ can be calculated by dividing the total in-plane irradiation by the module's reference plane of array irradiance:

$$Y_r = H_i / G_{i,ref} \tag{11}$$

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

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.

## 9.7 Yield losses

### 9.7.1 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.

### 9.7.2 Array capture loss

The array capture loss $L_c$ represents the losses due to array operation, including array temperature effects, soiling, etc., and is defined as:

(12)

$$L_C = Y_r - Y_A$$

### 9.7.3 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, and is defined as:

(13)

$$L_{BOS} = Y_A - Y_f$$

## 9.8 Efficiencies

### 9.8.1 Array (DC) efficiency

The rated array efficiency is given by:

(14)

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

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:

(15)

$$\eta_A = E_A / (H_i \times A_a)$$

### 9.8.2 System (AC) efficiency

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

(16)

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

Formula (16) can also be rewritten as:

(17)

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

where $\eta_{A,0}$ is the rated array efficiency defined in 9.8.1 and $PR$ is the performance ratio defined in 10.3.1.

### 9.8.3 BOS efficiency

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

(18)

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

## 10 Performance metrics

### 10.1 Overview

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.

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. 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.

**Table 14**
**Performance metrics**

| Parameter | Symbol | Units |
|---|---|---|
| **Rating-based (10.3)** | | |
| Performance ratio | $PR$ | None |
| Annual performance ratio | $PR_{annual}$ | None |
| Annual-temperature-equivalent performance ratio | $PR'_{annual\text{-}eq}$ | None |
| STC-temperature performance ratio | $PR'_{STC}$ | None |
| **Model-based (10.4)** | | |
| Power performance index | $PPI$ | None |
| Energy performance index | $EPI$ | None |
| Baseline power performance index | $BPPI$ | None |
| Baseline energy performance index | $BEPI$ | None |

## 10.2 Summations

See 9.2 for an explanation of equations given in 10.3 involving summations.

## 10.3 Performance ratios

### 10.3.1 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. It is defined as:

(19)

$$PR = Y_f / Y_r$$

(20)

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

Expanding Formula (20) gives:

(21)

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

Both the numerator and denominator of Formula (21) 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:

(22)

$$PR = \left( \sum_{k} P_{\mathrm{out},k} \times \tau_{\mathrm{k}} \right) \Bigg/ \left( \sum_{k} \frac{P_0 \times G_{\mathrm{i},k} \times \tau_{\mathrm{k}}}{G_{\mathrm{i,ref}}} \right)$$

The annual performance ratio, $PR_{annual}$, is the performance ratio of Formula (22) evaluated for a reporting period of one year.

NOTE 1 The energy expectation expressed by the denominator of Formula (22) 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 (22), 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*.

### 10.3.2 Temperature-corrected performance ratios

#### 10.3.2.1 General

The seasonal variation of the performance ratio *PR* of Formula (22) 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*.

#### 10.3.2.2 STC performance ratio

The STC performance ratio, $PR'_{STC}$ 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).

$PR'_{STC}$ is calculated by introducing a power rating temperature adjustment factor $C_k$ into Formula (22), as follows:

$$PR'_{STC} = \left( \sum_k P_{out,k} \times \tau_k \right) \Big/ \left( \sum_k \frac{(C_k \times P_0) \times G_{i,k} \times \tau_k}{G_{i,ref}} \right) \quad (23)$$

where $C_k$ is given by:

$$C_k = 1 + \gamma \times (T_{mod,k} - 25\ °C) \tag{24}$$

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 (24), γ is typically negative, e.g. for crystalline silicon. The measured module temperature may be used for $T_{mod,k}$ in Formula (24). However, if the monitoring objective is to compare $PR'_{STC}$ 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 (23) and (24) can be used to calculate performance ratio adjusted to a different reference temperature by substitution of the desired reference temperature in Formula (24) in place of 25 °C.

#### 10.3.2.3 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 $C_k$ into Formula (22), as follows:

$$PR'_{annual\text{-}eq} = \left( \sum_k P_{out,k} \times \tau_k \right) \Bigg/ \left( \sum_k \frac{(C_k \times P_0) \times G_{i,k} \times \tau_k}{G_{i,ref}} \right) \tag{25}$$

where $C_k$ is given by:

$$C_k = 1 + \gamma \times (T_{mod,k} - T_{mod,avg}) \tag{26}$$

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

NOTE With reference to Formula (26), γ is typically negative, e.g. for crystalline silicon.

$T_{mod,avg}$ 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 $PR'_{annual\text{-}eq}$ for the historical data (using Formulas (25) and (26)) is the same as the annual performance ratio $PR_{annual}$ for the historical data (using Formula (22)).

The measured module temperature may be used for $T_{mod,k}$ in Formula (26). However, if the monitoring objective is to compare $PR'_{annual\text{-}eq}$ 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.

## 10.4 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.

## 11 Data filtering

### 11.1 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 11.2 and 11.3.

### 11.2 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.

### 11.3 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:

a) exclude such periods, with the exclusion clearly noted; or

b) include such periods without changes in analysis, but with the periods clearly noted; or

c) 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

d) 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 ($\tau_s$) 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 one hour 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.

#### 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.