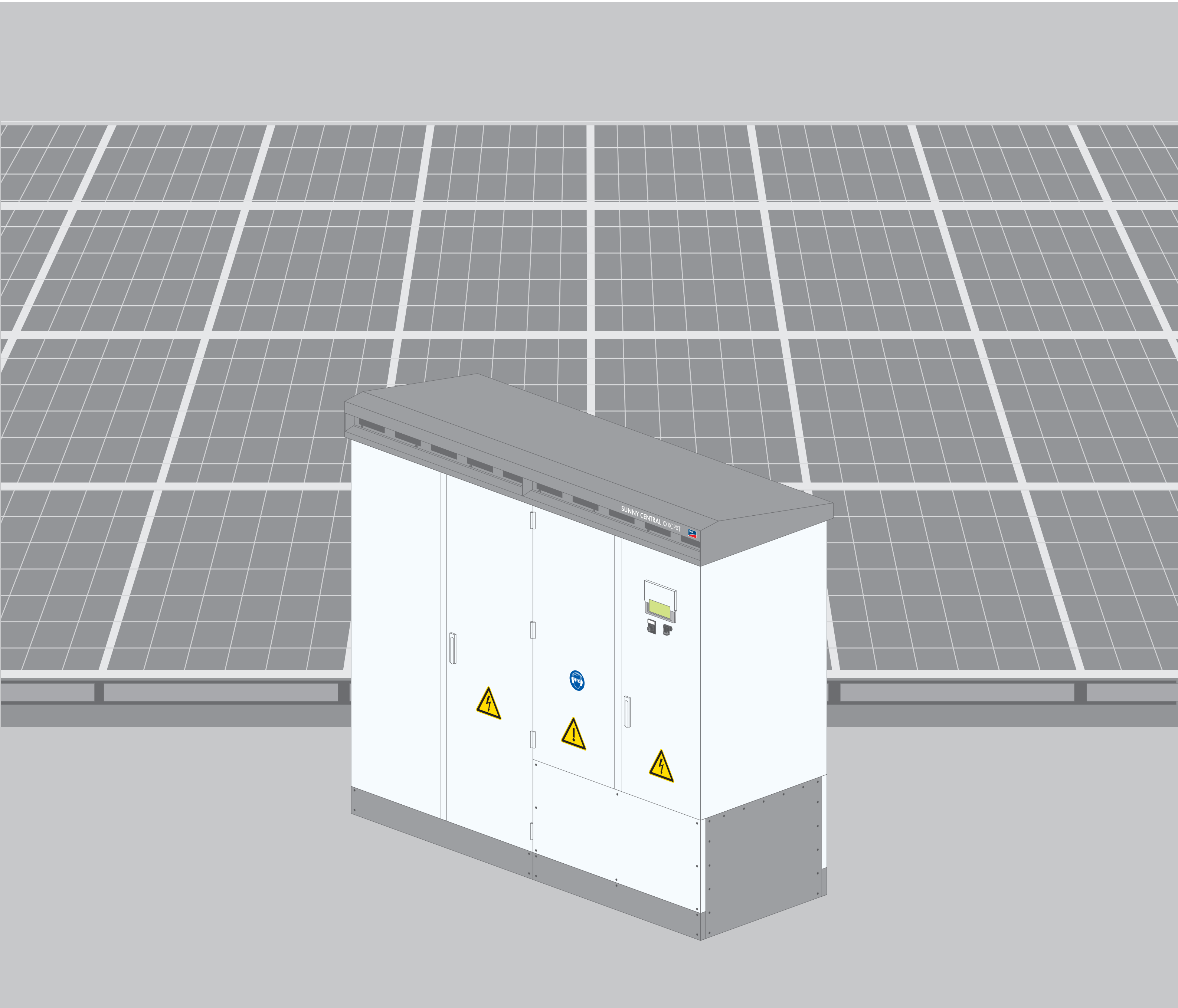
Central Inverter

Planning of a PV Generator

Planning Guidelines



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ENGLISH

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1 Information on this Document

These guidelines address various issues which must be taken into account in the planning and implementation of a centralised PV plant. Solution approaches are sketched and technical background information is given in the areas of PV connection and inverter configuration which assists project planner in the design of large centralised PV plants. The technical information in this document is subject to continuous further development and is therefore subject to change. The content is monitored continuously and updated when necessary. However, discrepancies may still arise. We assume no liability for completeness of the information.

SMA Utility Grade

In the Power Plant Solutions business area, SMA Solar Technology AG, with its integrated approach to the implementation of utility-scale PV plants, is your ideal partner. SMA Utility Grade combines leading inverter technology with a wide range of flexible system technology options and comprehensive services to successfully implement megawatt projects.

All partners benefit from SMA's extensive experience and know-how, not only in technological development, but also and especially in planning, implementation and service.

Sunny Central

For central plant concepts, SMA has developed the Sunny Central inverters for large projects. They are ideally suited for use in PV power plants with a homogenous structure thanks to their special properties. The outdoor-capable devices of the CP XT range are especially economical. With a maximum efficiency of over 98.6 percent, the Sunny Central 900CP XT is the most efficent device in its class. And with over 7,000 devices already installed* , the inverters provide an excellent combination of power and reliability. The weatherproof enclosure and the consequent reduction in weight of the overall system enable it to be set up outdoors. A costly concrete enclosure is not necessary. As numerous stress tests have shown, and deployment in many PV power plants worldwide testifies, the inverters can withstand extreme weather conditions.

* Last updated: January, 2013

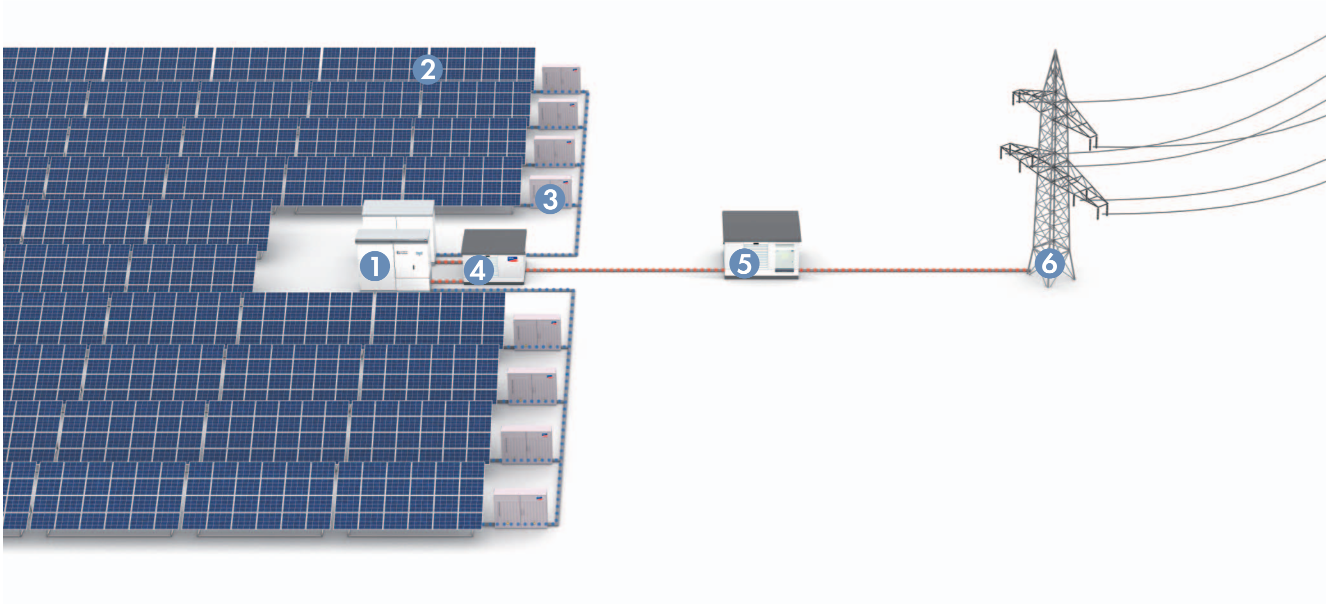


Figure 1: Typical PV plant with SMA system technology

Position	Designation
1	Inverter
2	PV modules
3	Sunny String-Monitor
4	Transformer Compact Station
5	Substation
6	Public grid

Sunny String-Monitor

Monitoring in detail: by precisely comparing individual string currents, the Sunny String-Monitor enables power deviations in the PV array to be detected accurately and evaluated directly in the inverter. The device – which can be supplied for wall mounting or as a base unit – can measure string currents and also features string fuse protection and an overvoltage protection device. The robust technology is suitable for almost any location and, with over 40,000 devices sold* , has proven itself worldwide under the most varied conditions.

* Last updated: January, 2013

2 Technical Basics

This section provides an overview of the electrical characteristics of the PV modules and components in a PV plant. Furthermore, it explains how the power distribution of the energy yield affects the design of the PV plant and what influence the standard test conditions, irradiation, temperature and grounding exert on the selection of the PV modules.

2.1 Electrical Characteristics

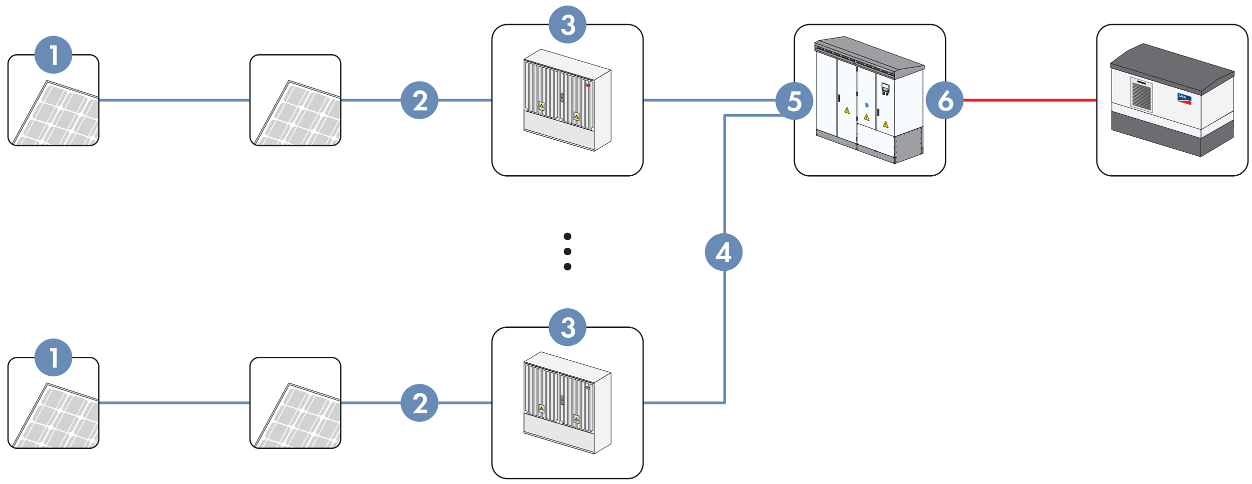


Figure 2: Overview of a PV plant

Position	Characteristics	Unit	Description
1	I_{MPP}	A	Current at maximum power
	I_{SC}	A	Short-circuit current
	P_{maxMOD}	WP	Maximum power
	$V_{DCmaxMODSYS}$	V	Maximum system voltage SKII
	V_{mpp}	V	Voltage at maximum power
	V_{oc}	V	Open-circuit voltage
	$T_{DCVocMOD}$	%/K	Temperature coefficient of open-circuit voltage
	$T_{DCIscMOD}$	%/K	Temperature coefficient of short-circuit current
	$V_{DCmaxMOD}$	V	Maximum open-circuit voltage
	$V_{DCminMOD}$	V	Minimum open-circuit voltage
2	$I_{DCmppSTR}$	A	String current
	$n_{maxMODSTR}$	–	Maximum number of PV modules per string
	$n_{minMODSTR}$	–	Minimum number of PV modules per string
	n_{MODSTR}	–	Number of PV modules per string
	$V_{DCmaxSTR}$	V	Maximum string voltage
	$V_{DCminSTR}$	V	Minimum string voltage
3	n_M	–	Number of strings per measuring input
	$I_{DCfuseSTR}$	A	Fuse size
	I_{DCSSM}	A	Output current Sunny String-Monitor
	I_{maxSSM}	A	Maximum output current Sunny String-Monitor
	$n_{STRfuse}$	–	Number of strings per fuse

Position	Characteristics	Unit	Description
4	n_{minSTR}	–	Minimum number of strings
	n_{maxSTR}	–	Maximum number of strings
	n_{STR}	–	Number of strings
5	P_{DC}	W	DC input power of the inverter
	P_{DCGEN}	W	PV array power
	$V_{DCmaxINV}$	V	Maximum input voltage of inverter
	$V_{DCmppminINV}$	V	Minimum MPP voltage of the inverter
6	P_{AC}	W	AC active power
	S_{AC}	VA	Apparent AC power
	cos φ	–	Power factor
	Q	Var	AC reactive power

2.2 Power Distribution of Energy Yield

To estimate the PV generator power, the power distribution of the energy yield is normally used. This shows what share of the total energy is provided by a PV array with a specific MPP irradiation (see figure, page 8). This distribution is based on the solar irradiation statistics on site. By taking the observed irradiation strength over the duration of its occurrence, you can determine the energy distribution of the irradiation strength. This distribution is part of meteorological data and is available for many locations worldwide (see NASA*). Ideally, the power distribution of the energy yield and the operating behaviour of the inverter will be very similar but the full and part-load operation of the inverter must be taken into account.

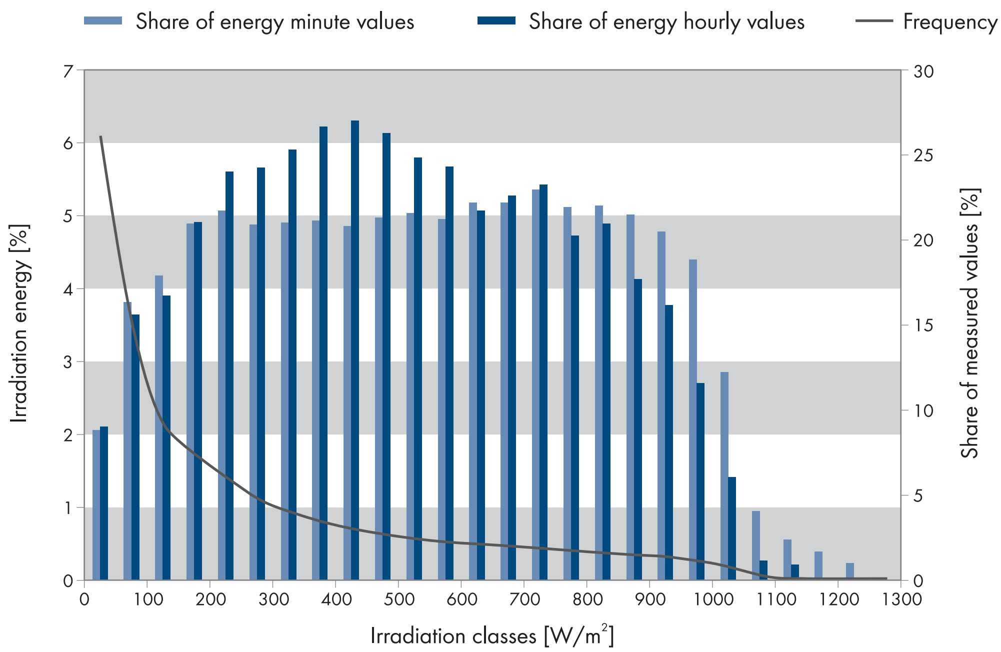


Figure 3: Energy and frequency distribution of solar irradiation (example: Potsdam, Germany).

It is important, when considering the solar irradiation, that the inverter can make use of the frequently occurring irradiation classes with optimum efficiency.

* http://eosweb.larc.nasa.gov/cgi-bin/sse/sse.cgi?+s02#s02

2.3 PV Modules

2.3.1 Characteristics

2.3.1.1 Standard Test Conditions

The standard test conditions (STC) are reference figures for PV modules and they define standard test conditions for the irradiation, the temperature and the air mass* .

Reference figure	Reference value
Irradiation	1,000 W/m²
Temperature	25 °C
Air mass	1.5

The values determined in this way enable a comparison of the PV modules but the effective operating behaviour cannot be derived directly from this. Crystalline modules, for example, with irradiation of 1,000 W/m², usually have a significantly higher cell temperature than 25 °C at which power decreases. Also, the behaviour of different cell types in diffuse light is not taken into account with this value.

2.3.1.2 Technical Data

The electrical characteristics of PV modules are dependent on temperature. Below, the typical technical data of a PV module is shown. This data is important in subsequent calculation of the PV array to adjust the inverter precisely for voltage, current and power of the PV modules. You can find the technical data on the datasheet of the PV module.

Characteristic	Unit	Description
I_{mpp}	A	Current at maximum power
I_{SC}	A	Short-circuit current
P_{maxMOD}	WP	Maximum power
$V_{DCmaxMODSYS}$	V	Maximum system voltage SKII
V_{mpp}	V	Voltage at maximum power
V_{oc}	V	Open-circuit voltage
T_{min} / T_{max}	%/K	Temperature coefficient of open-circuit voltage
T_{min} / T_{max}	%/K	Temperature coefficient of short-circuit current
$V_{DCmaxMOD}$	V	Maximum open-circuit voltage
$V_{DCminMOD}$	V	Minimum open-circuit voltage

* The air mass describes a relative measurement for the length of a path that sunlight travels through the earth's atmosphere to the ground. If the sunlight falls vertically, the air mass equals 1.0. The radiant power is at its maximum in this case. The radiant power decreases as the angle of irradiation decreases.

2.3.2 Irradiation

PV modules very rarely work at rated operation. The rated operation occurs only under standard test conditions.
PV modules work in part-load operation much more frequently than in rated operation. In part-load operation, the irradiation level and the temperature change frequently during the course of a day. The irradiation change has the greatest influence on the module current (see figure, page 10). In contrast to the MPP voltage: it remains almost constant in the event of irradiation changes, but changes significantly with the temperature.

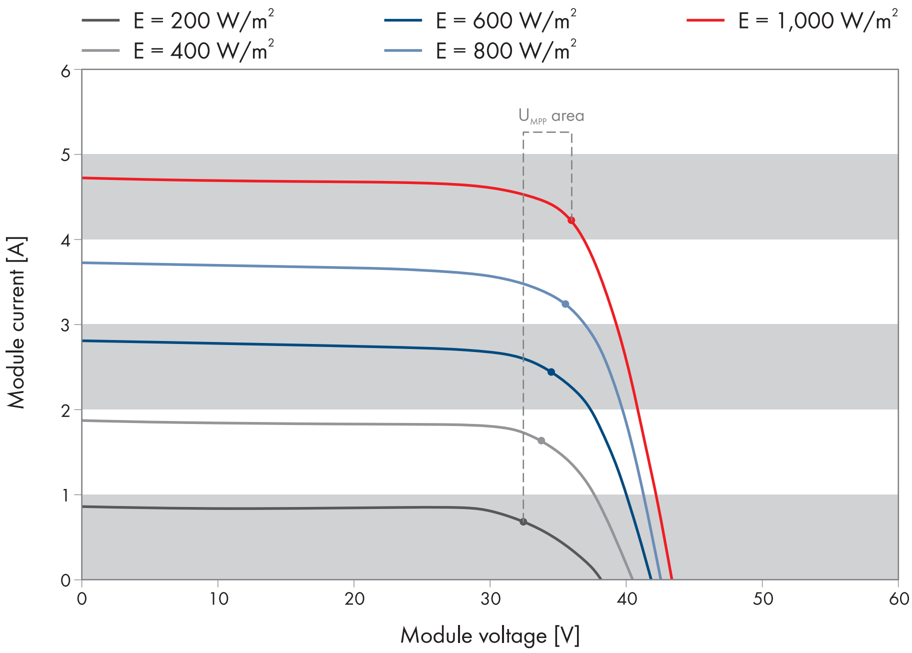


Figure 4: PV module voltage and current at varying irradiation and constant temperature (example)

2.3.3 Temperature

In the event of temperature changes, the relationships are the opposite of those of irradiation changes: if the temperature drops, the module voltage increases and the module current remains almost constant (see figure, page 11). In particular, the voltage increase at low temperatures must be considered in PV plant planning.

Since power levels decrease at high temperatures, it is important to ensure optimum heat dissipation. How the PV module is mounted is crucial here. Mounting the PV module free-standing, for example, ensures optimum yield. In contrast, facade integration of the PV modules without ventilation from the rear results in a rising module temperature which can result in yield losses.

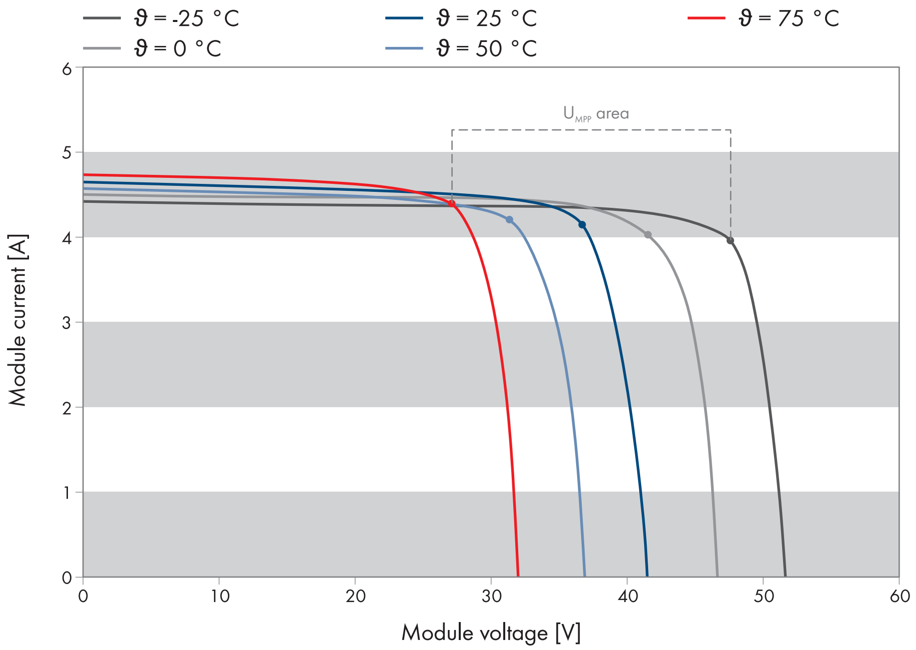


Figure 5: PV module voltage and PV module current at varying temperature and constant irradiation (example)

2.3.4 Maximum Power Point

The maximum power point (MPP) is the operating point of a PV module at which the greatest power can be obtained, that is, the point at which the product of current and voltage results in maximum power. The MPP is not constant but depends principally on the temperature and, therefore, on the PV module voltage. The irradiation, and as a result the PV module current, has a limited influence.

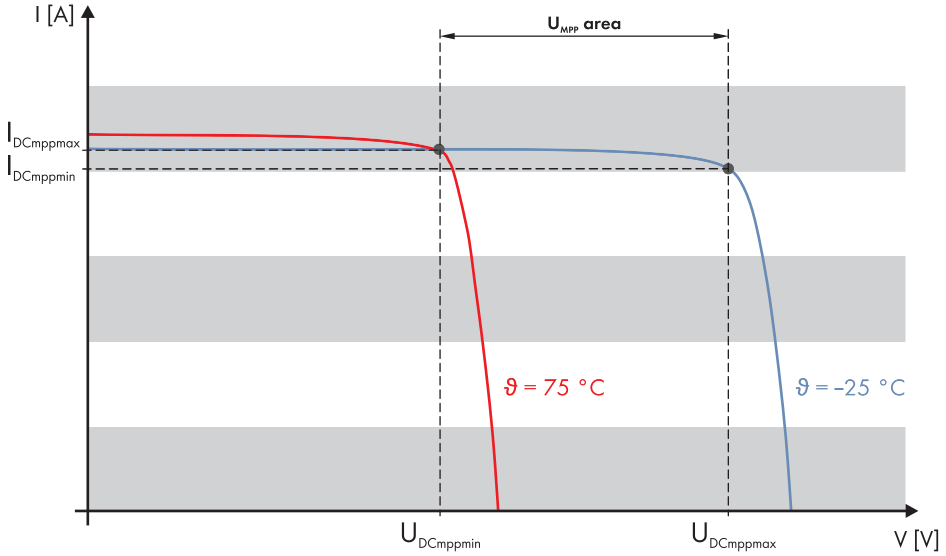


Figure 6: MPP voltage at varying temperature and constant irradiation (example)

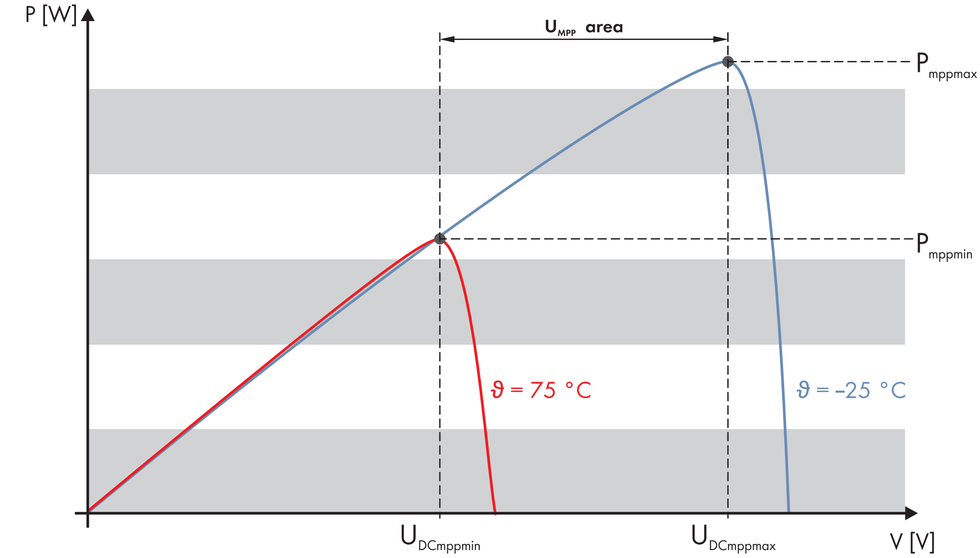


Figure 7: MPP power at varying temperature and constant irradiation (example)

2.3.5 Grounding

2.3.5.1 Negative Grounding - TCO Corrosion

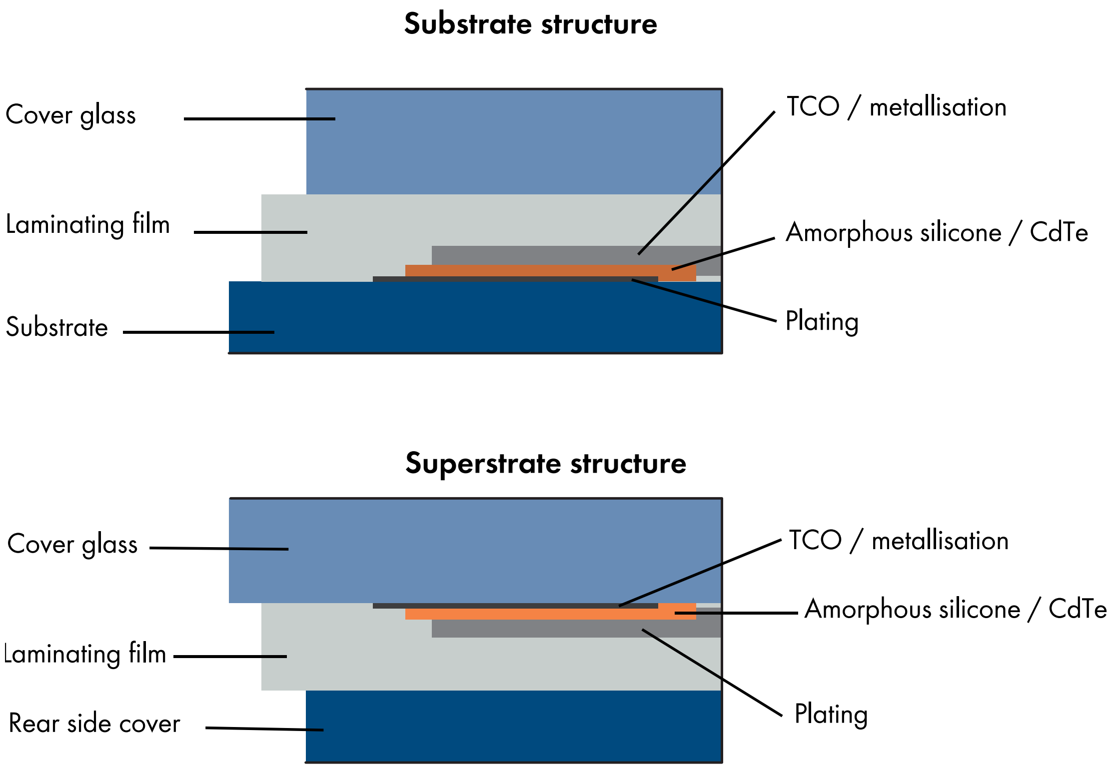


Figure 8: TCO corrosion

In the first PV arrays to be built with thin-film PV modules, corrosion of the TCO layer of some modules was observed after a relative short operating period. The corrosion of the electrically conducting layer is irreversible and leads to significant power losses. The Florida Solar Energy Center (FSEC) has been studying the causes of the corrosion since 2000. Their investigations have shown that modules with cells made of a-Si (amorphous silicone) and CdTe (cadmium telluride), which are manufactured with superstrate technology, are particularly affected. The TCO corrosion occurs when sodium ions react with moisture. The sodium is contained in the cover glass layer of the PV module. Especially at the edge of the PV module, the TCO corrosion causes cracks which affect the entire cell structure and can cause permanent damage to the PV module.

How Can TCO Corrosion Be Prevented?

- The negative grounding of the PV array gives rise to an electric field in which the positively charged sodium ions move towards the negative pole. As a result, the sodium ions become detached from the TCO layer.
- As an alternative, the module edges can be sealed. This prevents the penetration of moisture which is necessary for the corrosion process.

2.3.5.2 Positive or Negative Grounding: Potential-Induced Degradation

Potential-Induced Degradation (PID), also known as voltage-induced degradation, is a phenomenon which affects some PV modules with crystalline Si cells and leads to gradual deterioration of performance, reaching up to 30 percent and more after a few years.

PID only occurs in module types with cells made of crystalline silicone. If the modules have a negative potential to ground in operation, there is an equally high negative voltage between the cells of the PV module and the aluminium frame, which is grounded for safety reasons. The effect is stronger, the closer the module is to the negative pole of the PV array, as the potential there (and thus the voltage between cells and the aluminium frame) can reach more than half the amount of the array voltage. As a result, electrons from the materials used in the PV module can separate, follow this electric field and finally flow out via the grounded aluminium frame. The result is an increasing charge (polarisation) of the module, which adversely changes its characteristic curve and thus its power unless countermeasures are taken.

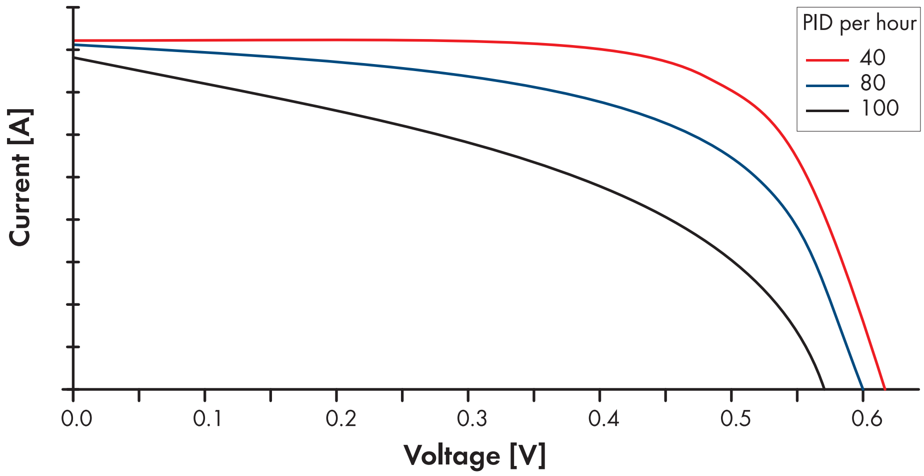


Figure 9: The characteristic curve of a PV module in the original state and during the degradation process. Typical here is a decreasing slope with a virtually unchanged open-circuit voltage and short-circuit current, while the maximum power (MPP) decreases by 30% or more.*

The electric charge of the PV module is so critical because of the way solar cells work. The photovoltaic effect is based on the fact that two different semiconductor materials are used and they establish an electric field by exchanging charges. It is this field that causes the electrons freed by light energy to leave their location and flow past the contacts as electric current. Additional load carriers can considerably interfere with this effect, causing a significant loss of power. However, it has been found that this polarisation can generally be reversed. Accordingly, it is not an irreversible effect such as corrosion and normal aging-related deterioration.

How Can the Potential-Induced Degradation Be Prevented?

- Grounding of a PV array connection means that the potential-induced degradation is avoided. To find out which pole must be grounded, see the technical data of the PV module.

* J. Berghold et.al, Potential Induced Degradation of solar cells and panels, proceedings of the 25th EU PVSEC, 2010

2.3.5.3 Positive Grounding - Polarisation

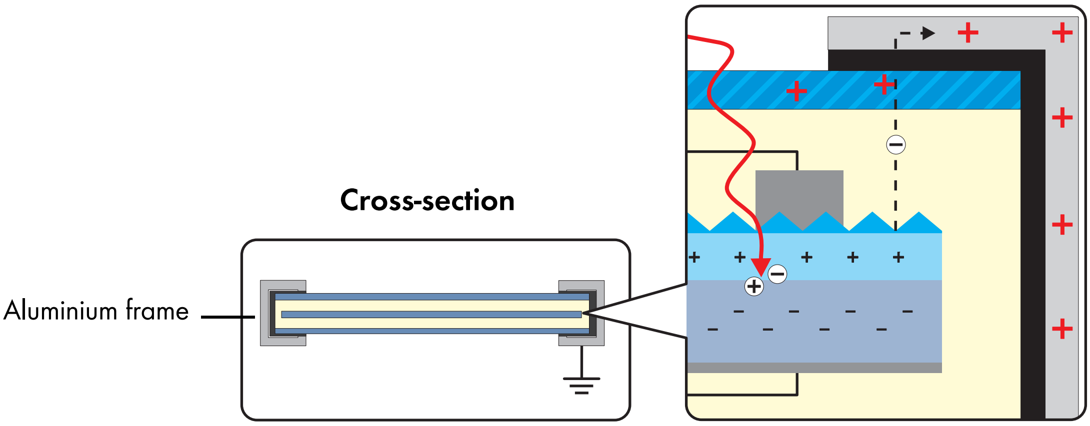


Figure 10: Polarisation

In addition to the photons of the light waves, an electric field separating the negative charge carriers from the positive ones and preventing their immediate recombination is required for the photovoltaic effect. If the DC+ and the DC- terminals of the PV cell are on one side – as in the case of back contact cells – the structure of this electric field is more complex than that of a standard cell. Operation with voltages higher than 20 V can result in static charge at the cell surface. This increases the recombination rate of the load carriers which significantly reduces the efficiency of the PV modules. This polarisation effect is reversible. As soon as the negative charges in the EVA foil have been removed, the efficiency "recovers".

How Can the Polarisation Be Prevented?

- If the positive PV array connection is grounded, the polarisation effect is avoided.
- If the PV array is or was not grounded, the original state and efficiency of the cells can be restored by temporarily applying a high negative voltage to the damaged modules. The exact regeneration procedure should be agreed upon with the module manufacturer. However, regeneration of the PV modules does not prevent the polarisation from recurring. The only solution here is positive grounding.

2.4 Inverter

2.4.1 Efficiency

2.4.1.1 η_{INV}

The maximum efficiency (η_{INV}) is a measure for the efficiency of an inverter. It is given by the relationship between the input power (P_{in}) and the output power (P_{out}). The input power is in turn dependent on the current irradiation conditions (E_{PV}). The irradiation conditions change constantly during the course of the day so that it is not always possible to determine the optimum operating point. More meaningful indicators of the efficiency of the inverter are weighted efficiencies such as the European weighted efficiency or the Californian weighted efficiency which take account of the different irradiation conditions (see figure, page 17.)

2.4.1.2 η_{Euro}

The European efficiency (η_{Euro}) is a weighted efficiency. It takes account of the fact that the irradiation conditions change frequently. The weighting is based on the conditions in Central Europe. Using the European weighted efficiency, you can carry out precise calculations for PV plants with annual irradiation totals of approximately 1,000 kWh/m^2. It is assumed that, for example, with 100% stress of the PV array, an operating time of 20% over the year is achieved.

Formula:

$\eta_{Euro} = 0.03\eta_{5\%} \times 0.06\eta_{10\%} \times 0.13\eta_{20\%} \times 0.1\eta_{30\%} \times 0.48\eta_{50\%} \times 0.2\eta_{100\%}$

2.4.1.3 η_{CEC}

The Californian efficiency (η_{CEC}) is, like the European figure, a weighted efficiency. It can be used to carry out precise calculations for PV plants for which high relative power levels (P_{in}/P_{out}) are expected. It is assumed that, for example, with 75% stress of the inverter, an operating time of 53% over the year is achieved. In contrast to the European weighted efficiency which permits any amount of decimal places, the η_{CEC} is rounded up or down in 0.5 increments. In addition, with the η_{CEC}, the DC voltage levels for the measurement of efficiency are predefined.

Formula:

$\eta_{CEC} = 0.04\eta_{10\%} \times 0.05\eta_{20\%} \times 0.12\eta_{30\%} \times 0.21\eta_{50\%} \times 0.53\eta_{75\%} \times 0.05\eta_{100\%}$

2.4.1.4 Efficiencies Compared

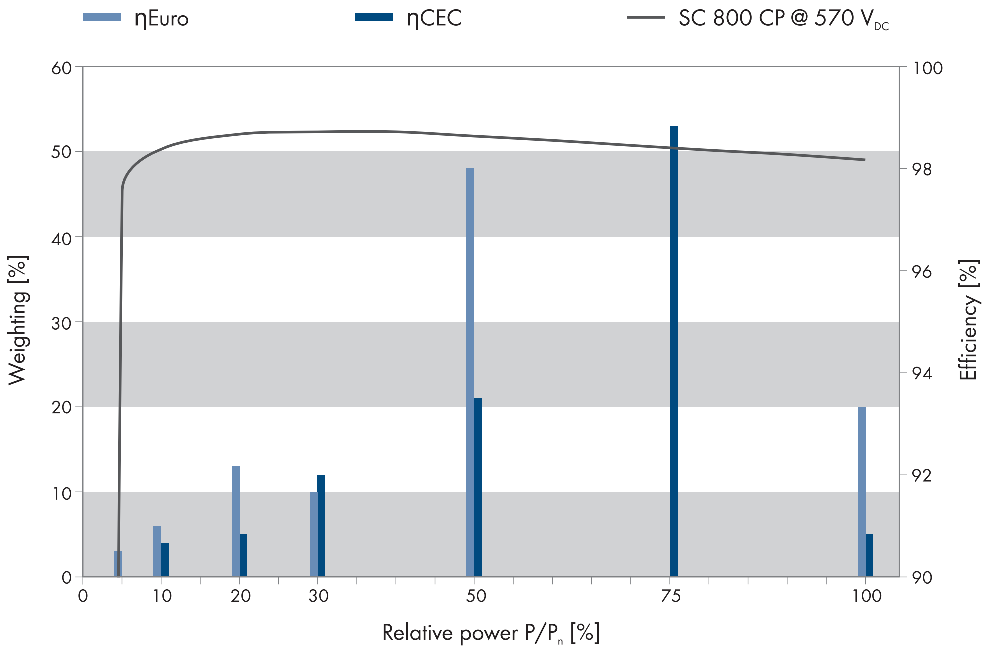


Figure 11: Comparison of maximum, European and Californian efficiency using the example of the SC800CP XT

2.4.2 Apparent, Reactive, Active Power and the Power Factor cos φ

In the alternating current grid, voltage and current have constantly changing values. They follow a sinusoidal shape with a frequency of 50 Hz in Germany. If only ohmic loads are connected, voltage and current remain in phase, this means they reach their maximum and minimum values simultaneously.

The product of voltage and current is power. Pure active power is only present if there is no phase shift. However, in reality, this is a very rare occurrence. In almost all loads, there are capacitances as well as inductances present and these cause the phase shifts. Capacitances and inductances directly cause reactive power in our grid. In the case of inductances, the current lags behind the voltage: a phase shift occurs between voltage and current. As a result, voltage and current achieve their maximum and minimum values at different times. In the case of a phase shift of 90 degrees (+ or −), the amount of the active power is zero - this means pure reactive power.

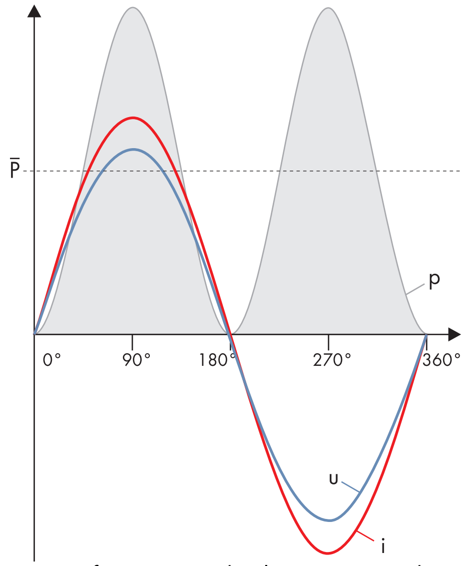


Figure 12: If current i and voltage v are in phase, a fluctuating but always positive power is the result - pure active power.

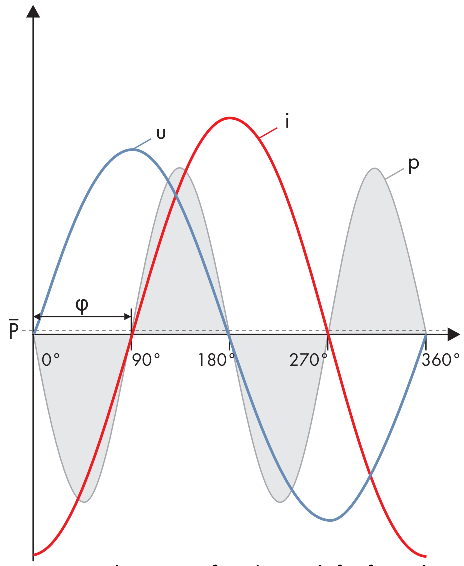


Figure 13: In the case of a phase shift of 90 degrees between i and v, the average value of the power is zero - pure reactive power.

Through geometric addition, active and reactive power result in apparent power: active and reactive power make up the sides of a right-angled triangle, the hypotenuse of this triangle is the apparent power. 400 kW active power and 300 kvar reactive power make up 500 kVA apparent power. The angle between active and apparent power is the power factor cos φ.

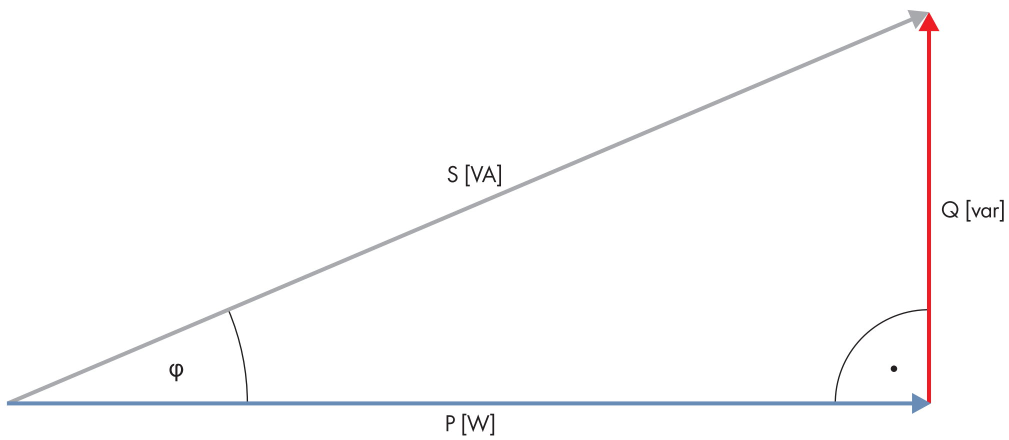


Figure 14: Active power (P) and reactive power (Q) form the sides of a right-angled triangle. The angle between active and apparent power (S) is the power factor cos φ.

The Power Factor cos φ

PV plants which feed in at medium-voltage level must provide reactive power in many markets. All Sunny Central inverters of the CP XT series are designed for feeding in reactive power. Besides the requirements of the German Association of Energy and Water Industries (BDEW), many countries have their own requirements. For a better overview, we will look at the requirements of the BDEW in more detail as these have in the past influenced other requirements worldwide.

The supply of reactive power can be either quasistatic or dynamic. In the case of quasistatic reactive power control, either a fixed reactive power set point is given or the reactive power is determined using characteristic curves. In the case of a reactive power set point, the circumstances are simple: the utility defines a fixed target value for the reactive power. This is set once during commissioning. The adjustable range of the power factor can be between 0.9 leading and 0.9 lagging. However, the reactive power can also be determined depending on the nominal active power (P_N): the set range extends from – 0.48 P_N to 0.48 P_N.

In the event of fluctuating grid conditions, a dynamic reactive power control is appropriate. This enables network operators to react flexibly to fluctuations in the grid. Typically, the utility distribute the external reactive power setpoint values by ripple control signal and these are then processed further and adapted dynamically to the setpoint values of the utility.

All procedures have one feature in common: their influence must be taken into account in plant planning, otherwise yield losses can occur. The network operator can also call for the setting of cos $\varphi \neq 1$ at a later point in time. For this reason, the PV array should be planned with the greatest possible setpoint value in order to avoid subsequent reactive power loss. The power factor, cos φ, can be between 0.95 lagging and 0.95 leading.

3 Design of the PV Plant

In this section, you will find out which calculation must be carried out when designing the PV plant. We recommend the following procedure:

- Calculate the power dimensions of the PV plant
  - Determine the AC active power and the DC input power of the inverter
  - Define the nominal power ratio
- Calculate the voltage dimensions
  - Calculate the voltage dimensions at PV module level
  - Calculate the voltage dimensions at string level
- Calculate the dimensions of the required system technology
  - Select and calculate of the required Sunny String-Monitors

3.1 Calculating the Power Dimensions

3.1.1 Determining AC Active Power

The AC active power shows how much power, at optimum weather conditions, is fed into the grid. This depends on various factors but especially on the power factor cos φ, the apparent power of the inverter, the AC voltage at the grid-connection point, and the associated requirements of the utility.*

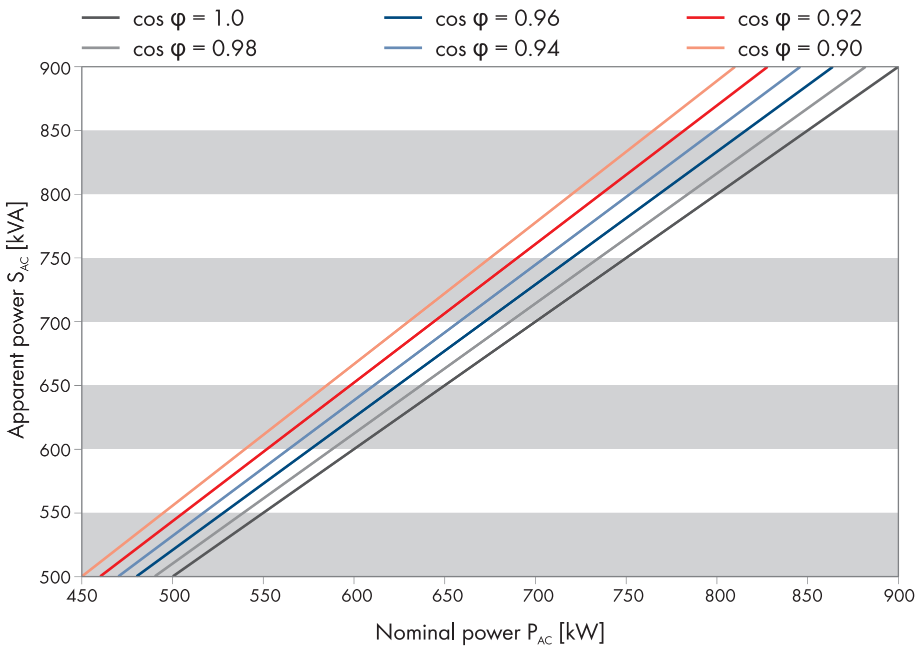


Figure 15: AC active power depending on the power factor cos φ

Formula:

$$P_{AC} = S_{AC} \times \cos\varphi\Big|_{0,9}^{1,0}$$

P_{AC}	AC active power
S_{AC}	Apparent power
cos φ	Power factor

* e.g. BDEW directive: Reactive power provision through power generation plants in the medium-voltage grid – Voltage limits and reduction of the feed-in active power. Further information: SMA White Paper PPTPM-008 Sunny Central SCxxxCP XT / SCxxxHE-20

3.1.2 Determining the DC Input Power of the Inverter

The DC input power of the inverter specifies the DC power that must reach the inverter input so that the desired AC power can be fed into the grid. The calculation should take into account that the inverter efficiency is influenced by the PV array voltage.

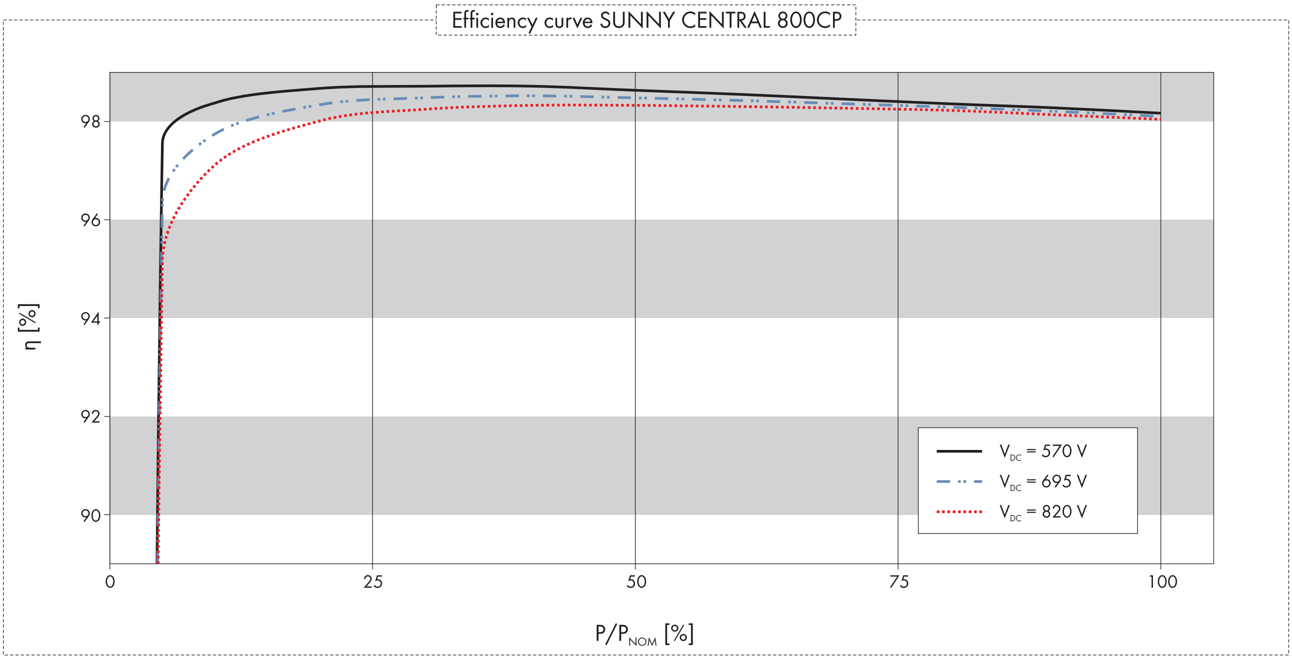


Figure 16: Efficiency of the Sunny Central 800CP XT at different PV array voltages

Formula:

$$P_{DC} = \frac{P_{AC}}{\eta}$$

P_{AC}	AC active power
P_{DC}	DC power of the inverter
η	Inverter efficiency

3.1.3 Nominal Power Ratio

The PV array and the inverter must be coordinated with each other especially fucusing to their power data. One measure for this is the nominal power ratio (NPR). It describes the ratio of DC power of the inverter (P_{DC}) to PV array power (P_{DCGEN}). The decision as to whether an inverter should be oversized ($P_{DC} > P_{DCGEN}$) or undersized ($P_{DC} < P_{DCGEN}$) can be derived from the distribution of the annual solar irradiation (see Section 2.2).

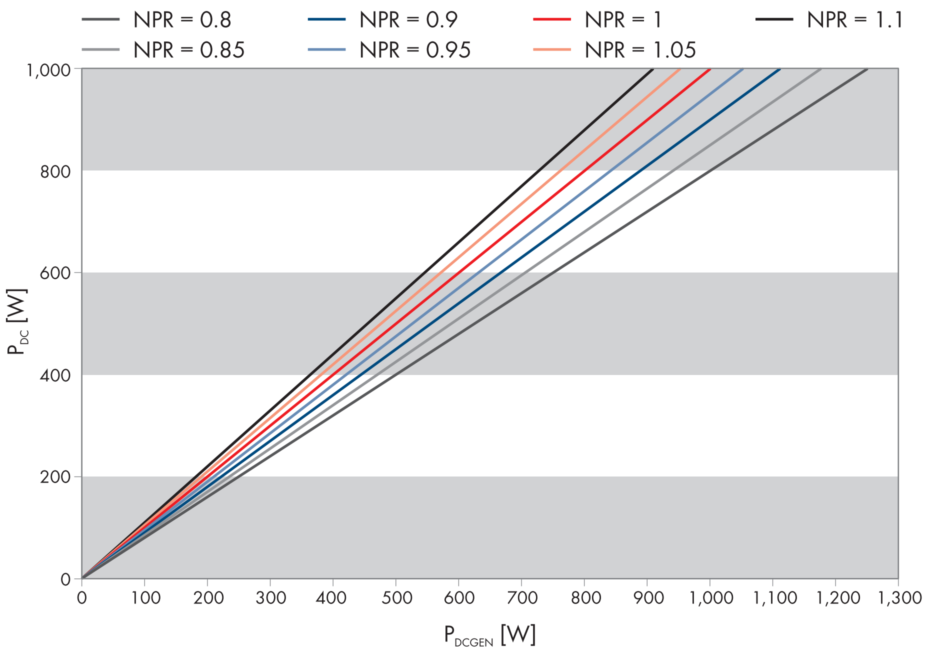


Figure 17: PV array power dependent on the nominal power ratio

Formula:

$$NPR = \frac{P_{DC}}{P_{DCGEN}}$$

NPR	Nominal Power Ratio
P_{DC}	DC power of the inverter
P_{DCGEN}	PV array power

Example: calculation of nominal power ratio

Assumptions:

P_{DCGEN} = 1,000 kW

P_{DC} = 900 kW

$$NPR = \frac{P_{DC}}{P_{DCGEN}} = \frac{900kW}{1000kW} = 0.9 \approx 90\%$$

3.2 Voltage Dimensions

3.2.1 PV Module

3.2.1.1 Determining the Maximum Open-Circuit Voltage

The open-circuit voltage is highest at low temperatures. The maximum open-circuit voltage can be calculated using the open-circuit voltage and the temperature coefficient. You must take account of the lowest temperature that can be expected at the mounting location.

Formula:

$$V_{DCmaxMOD} = V_{DCocMOD(-10°C)} = V_{ocM} x \left(1 + \frac{T_{min} x \Delta T}{100\%}\right)$$

$V_{DCmaxMOD}$	Maximum PV module voltage
V_{oc}	Open-circuit voltage of PV module
T_{min}	Temperature coefficient at minimum expected temperature
ΔT	Temperature variance between STC and minimum expected temperature

3.2.1.2 Determining the Minimum MPP Voltage

The open-circuit voltage is lowest at high temperatures. The minimum PV module voltage can be calculated using the open-circuit voltage and the temperature coefficient. You must take account of the highest temperature that can be expected at the mounting location. When the minimum MPP voltage is being determined, you should observe the degradation of the PV modules. Observe the manufacturer's information on the degradation of the PV modules.

Formula:

$$V_{DCminMOD} = V_{DCmppMOD(70°C)} = V_{mpp} x \left(1 + \frac{T_{max} x \Delta T}{100\%}\right)$$

$V_{DCminMOD}$	Minimum PV module voltage
V_{mpp}	Voltage of PV module at maximum power
T_{max}	Temperature coefficient at maximum expected temperature
ΔT	Temperature variance between STC and maximum expected temperature

3.2.1.3 Determining the Maximum PV Module Current

The PV module current is highest at high temperatures. The maximum PV module current can be calculated using the short-circuit current and the temperature coefficient. You must take account of the highest temperature that can be expected at the installation site. Due to the series connection of PV modules within a string, the PV module current is the same as the string current.

Formula:

$$I_{DCmaxSTR} = I_{DCscMOD(70°C)} = I_{sc} x \left(1 + \frac{T_{max} x \Delta T}{100\%}\right)$$

$I_{DCmaxSTR}$	Maximum string current
I_{SC}	Short-circuit current of the PV module
T_{max}	Temperature coefficient at maximum expected temperature
ΔT	Temperature variance between STC and maximum expected temperature

3.2.2 String

3.2.2.1 Determining the Maximum Number of PV Modules per String

A string may consist of only that number of PV modules which ensures that the string voltage is always below the maximum input voltage of the inverter. If the string voltage exceeds the input voltage of the inverter, yield losses can occur due to delayed starting or to damage to the inverter by overvoltage. Likewise, the maximum string voltage must not exceed the maximum permitted system voltage of the PV modules.

Formula:

$$n_{maxMODSTR} \leq \frac{V_{DCmaxWR}}{V_{DCmaxMOD}}$$

$n_{maxMODSTR}$	Maximum number of PV modules per string
$V_{DCmaxINV}$	Maximum input voltage of inverter
$V_{DCmaxMOD}$	Maximum PV module voltage

3.2.2.2 Determining the Minimum Number of PV Modules per String

A string should consist of that number of PV modules which ensures that the string voltage is always above the minimum MPP voltage of the inverter. If the string voltage falls below the minimum MPP voltage of the inverter, yield losses can occur through suboptimal MPP tracking, or MPP tracking is not possible at all.

Formula:

$$n_{minMODSTR} \geq \frac{V_{DCmppminWR}}{V_{DCminMOD}}$$

$n_{minMODSTR}$	Minimum number of PV modules per string
$V_{DCmppminINV}$	Minimum MPP voltage of the inverter
$V_{DCminMOD}$	Minimum PV module voltage

3.2.2.3 Determining the Number of PV Modules per String

The optimum number of PV modules must not be less than the minimum number of PV modules per string and must not exceed the maximum number. As a rule of thumb: the more PV modules per string, the more viable the planning of the PV array.

Formula:

$$n_{minMODSTR} \leq n_{MODSTR} \leq n_{maxMODSTR}$$

$n_{minMODSTR}$	Minimum number of PV modules per string
n_{MODSTR}	Number of PV modules per string
$n_{maxMODSTR}$	Maximum PV module voltage

3.2.2.4 Determining the String Number

With a defined total power of the PV array and a predefined number of PV modules per string, it is possible to calculate the minimum number of strings required to achieve the total power. The minimum number of strings can be calculated from the ratio of the total PV array power and the power of all the PV modules of a string.

Formula:

$$n_{minSTR} = \frac{P_{DCGEN}}{P_{maxMOD} \times n_{MODSTR}}$$

n_{minSTR}	Minimum number of strings
P_{DCGEN}	PV array power
n_{MODSTR}	Number of PV modules per string
P_{maxMOD}	Maximum power of the PV module

3.3 Calculating System Technology Dimensions

3.3.1 Selecting the Sunny String-Monitors

When selecting a Sunny String-Monitor, take the following aspects into account:

- Maximum number of connected strings per measurement channel on Sunny String-Monitor. This value depends on the set tolerance (see Section 3.3.3).
- Maximum string current (see Section 3.3.4).
- Selection of the system variants depending on the ambient temperature and maximum string current (see Section 3.3.5).
- The maximum number of Sunny String-Monitors per inverter must not exceed nine.

3.3.2 Calculating the Number of Sunny String-Monitors Required

Sunny String-Monitor	Calculation
Sunny String-Monitors 8-21 • Regarding the decimal places: With $n_{SSM8} \neq 0$, an additional Sunny String-Monitor 8-21 is required.	$n_{SSM8} = \frac{n_{STR}}{n_{STRM} x 8}$ n_{SSM8} Number of Sunny String-Monitors 8-21 required n_{STR} Number of strings n_{STRM} Number of strings per measurement channel
Sunny String-Monitors 16-21 • Regarding the decimal places: With $n_{SSM16} < 0.5$, an additional Sunny String-Monitor 8-21 is required. • Regarding the decimal places: With $n_{SSM16} > 0.5$ an additional Sunny String-Monitor 16-21 is required.	$n_{SSM16} = \frac{n_{STR}}{n_{STRM} x 16}$ n_{SSM16} Number of Sunny String-Monitors 16-21 required n_{STR} Number of strings n_{STRM} Number of strings per measurement channel
Sunny String-Monitors 24-21 • Regarding the decimal places: With $n_{SSM24} <0.33$, an additional Sunny String-Monitor 8-21 is required. • Regarding the decimal places: With $0.33 < n_{SSM24} < 0.66$, an additional Sunny String-Monitor 16-21 is required. • Regarding the decimal places: With $0.66 < n_{SSM24} < 1$, an additional Sunny String-Monitor 24-21 is required.	$n_{SSM24} = \frac{n_{STR}}{n_{STRM} x 24}$ n_{SSM24} Number of Sunny String-Monitors 24-21 required n_{STR} Number of strings n_{STRM} Number of strings per measurement channel

For the selection of the Sunny String-Monitors, the following procedure is recommended:

1. Select the relevant fuse configuration table according to the respective ambient temperature (see page 28 and page 27).
2. In the first column, select the maximum string current (for the calculation, see Section 3.2.1.3).
3. In the second column, select the number of strings per Sunny String-Monitor according to the system design.
4. In the third column, select the number of required string fuses. Here, consider whether double assignment of the fuse in respect of current-carrying capacity of the PV modules is possible or not.
5. In the fourth column, select the number of required measurement channels.

Regarding the distribution of strings to individual Sunny String-Monitors, in certain plant designs it may be advisable to combine various Sunny String-Monitor system options.

Fuse Configuration with a Screening Factor of 0.60 and Ambient Temperature of Max. +40°C

- Maximum current per fuse: 0.60 x $I_{nomfuse}$
- Maximum current per measurement channel: 25 A
- Output current in the Sunny String-Monitor: 280 A

For fuse sizing, take the reverse-current resistance of the PV modules into account.

Max. string current [A]	Max. number of string inputs	Number of string fuses	No. of measurement channels	Nominal current of the fuse [A]	Max. assembly current [A]	Output current [A]	Device
$I_{DCmppSTR}$	–	n_{fuse}	n_M	$I_{DCfuseSTR}$	–	I_{maxSSM}	–
4.167	48	48	8	8	200	200	SSM8-21
5.833	48	16	16	30	140	280	SSM16-21
5.833	48	48	16	10	140	280	SSM16-21
5.833	48	24	24	20	94	280	SSM24-21
5.833	48	48	24	10	94	280	SSM24-21
6.000	24	8	8	30	144	144	SSM8-21
6.250	32	16	8	25	200	200	SSM8-21
6.250	32	32	8	12	200	200	SSM8-21
8.330	24	24	8	15	200	200	SSM8-21
8.750	32	16	16	30	140	280	SSM16-21
8.750	32	32	16	15	140	280	SSM16-21
9.000	16	8	8	30	144	144	SSM8-21
11.670	24	24	24	20	94	280	SSM24-21
12.500	16	16	8	25	200	200	SSM8-21
17.500	16	16	16	30	140	280	SSM16-21
18.000	8	8	8	30	144	144	SSM8-21

Fuse Sizing with a Screening Factor of 0.55 and Ambient Temperature of Max. +50 °C

- Maximum current per fuse: 0.55 x $I_{nomfuse}$
- Maximum current per measurement channel: 25 A
- Output current in the Sunny String-Monitor: 280 A

For fuse sizing, take the reverse-current resistance of the PV modules into account.

Max. string current [A]	Max. number of string inputs	Number of string fuses	No. of measurement channels	Nominal current of the fuse [A]	Max. assembly current [A]	Output current [A]	Device
$I_{DCmppSTR}$	–	n_{fuse}	n_M	$I_{DCfuseSTR}$	–	I_{maxSSM}	–
4.167	48	48	8	8	200	200	SSM8-21
5.500	24	8	8	30	132	132	SSM8-21
5.500	48	16	16	30	132	264	SSM16-21
5.830	48	48	16	12	140	280	SSM16-21
5.835	48	24	24	25	94	280	SSM24-21
5.835	48	48	24	12	94	280	SSM24-21
6.250	32	16	8	25	200	200	SSM8-21
6.250	32	32	8	15	200	200	SSM8-21
8.250	16	8	8	30	132	132	SSM8-21
8.250	32	16	16	30	132	264	SSM16-21
8.330	24	24	8	20	200	200	SSM8-21
8.750	32	32	16	20	140	280	SSM16-21
11.670	24	24	24	25	94	280	SSM24-21
12.500	16	16	8	25	200	200	SSM8-21
16.500	8	8	8	30	132	132	SSM8-21
16.500	16	16	16	30	132	264	SSM16-21

Example: Selection of a Sunny String-Monitor based on maximum string current

The following initial situation is given in a project:

- Inverter: Sunny Central 760CP
- 160 strings
- 32 strings per Sunny String-Monitor
- Maximum continuous string current $I_{DCmppSTR}$: 8.1 A
- Maximum ambient temperature: 39 °C
- The reverse-current resistance of the PV modules requires fusing of 15 A maximum.

Procedure:

1. Refer to the table for ambient temperatures of max. +40 °C on page 27.
2. If the maximum string current is 8.1 A, the Sunny String-Monitor must be designed for this value or higher. This means that all the options from 8.250 A to 16.500 A listed in the table are suitable.
3. In accordance with the plant design, select connection of 32 strings to one Sunny String-Monitor.
4. The reverse-current resistance of the PV modules requires that max. 15 A fuses are used. For this reason, it is important that every single string is protected with a fuse.
5. The table shows that a Sunny String-Monitor with 16 measurement channels is required.

Result: Sunny String-Monitor SSM16-21 with 32 string inputs and 32 string fuses.

Five Sunny String-Monitors are required for this project.

Max. String current [A]	Max. number of string inputs	Number of string fuses	Number of measurement channels
4.167	48	48	8
5.500	24	8	8
5.500	48	16	16
5.830	48	48	16
5.835	48	24	24
5.835	48	48	24
6.250	32	16	8
6.250	32	32	8
8.250	16	8	8
8.250	32	16	16
8.330	24	24	8
8.750	32	32	16
11.670	24	24	24
12.500	16	16	8
16.500	8	8	8
16.500	16	16	16

3.3.3 Maximum Number of Connected Strings

You can connect several strings in parallel in the Sunny String-Monitor. The maximum number of strings connected in parallel per measurement channel depends on the adjustable tolerance in the inverter. The tolerance indicates how far the string current is allowed to deviate from the mean value. If the string current is outside the tolerance limits, the data logger in the inverter detects the deviation and stores it. The tolerance can be set between 10% and 100%.

If you connect more strings in parallel than the calculated maximum, it will not be possible to detect a string failure.

The maximum number of strings that can be connected in parallel to a measurement channel can be determined as follows:

Formula:

$$n_{STRM} = \frac{0.9}{\text{Tolerance}}$$

n_{STRM}	Number of strings per measurement channel
0.9	Defined inverter-internal value
Tolerance	Deviation of string current in relation to the string current mean value

3.3.4 Maximum String Current

The following current values must not be exceeded:

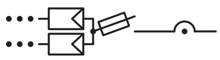
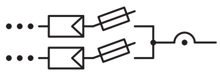
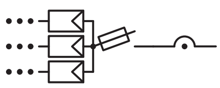
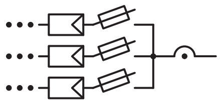
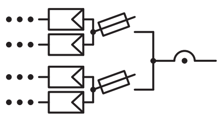
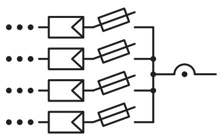
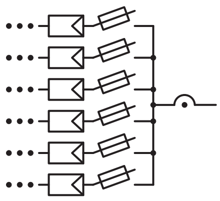
- Maximum fuse current of the fuse in the Sunny String-Monitor dependent on the nominal current and on the ambient temperature (see the fuse configuration table on page 28 and page 27)
- Maximum current per measurement channel: 25 A
- Maximum current of the DC switch-disconnector according to the technical data of the Sunny String-Monitor
- Maximum total current according to the technical data of the Sunny String-Monitor

3.3.5 Selecting the System Options

The various Sunny String-Monitors differ according to the number of measurement channels for string current monitoring:

- The Sunny String-Monitor 8-21 has eight measurement channels.
- The Sunny String-Monitor 16-21 has 16 measurement channels.
- The Sunny String-Monitor 24-21 has 24 measurement channels.

Up to six strings can be connected to a measurement channel and individual string failures can be safely recognised. Different numbers of string inputs and string fuses can be assigned to the measurement channels. This enables optimum design of the PV plant and the PV array can be protected from reverse currents.

Circuitry options	**Sunny String-Monitor 8 string inputs / fuses**	**Sunny String-Monitor 16 string inputs / fuses**	**Sunny String-Monitor 24 string inputs / fuses**
	8/8	16/16	24/24
	16/8	32/16	48/24
	16/16	32/32	48/24
	24/8	48/16	–
	24/24	48/48	–
	32/16	–	–
	32/32	–	–
	48/48	–	–

4 Example Design of a PV Array

PV Module	Technical Data
Manufacturer	Canadian Solar
Module type	CS6P-240P (EU)
Maximum power ($P_{DCmaxMOD}$)	240 Wp
Open-circuit voltage (V_{oc})	37 V
Voltage at maximum power (V_{mpp})	29.9 V
Short-circuit current (I_{SC})	8.6 A
Current at maximum power ($I_{DCmmpMOD}$)	8 A
Maximum system voltage SKII ($V_{DCmaxMODSYS}$)	1,000 V
Temperature coefficient of short-circuit current ($T_{DCIscMOD}$)	0.065%/K
Temperature coefficient of open-circuit voltage ($T_{DCVocMOD}$)	−0.34%/K

Site Conditions	Definition
Location	Cologne/Bonn
Grid connection voltage	20 kV
Minimum ambient temperature	−15°C
Maximum ambient temperature	40°C
Minimum cell temperature of the PV module*	−12°C
Maximum cell temperature of the PV module*	70°C

* Calculated from the maximum or minimum ambient temperature

Assumptions PV Array	Technical Data
Nominal power ratio	0.82
PV peak power	approx. 1 MWp

Selection Inverter Sunny Central 800CP XT	Technical Data / Assumptions
Efficiency	98%
Power factor cos φ	1

Calculating the Power Dimensions	Calculations
AC active power	$P_{ACWR} = (S_{ACnennWR} x \cos\varphi\|_{0.9}^{1.0}) = (800kW x 1) = 800kW$
DC input power of the inverter	$P_{DCWR} = \frac{P_{ACWR}}{\eta} = \frac{800kW}{0.98} = 816kW$
PV array power	$P_{DCGEN} = \frac{P_{DCWR}}{N} = \frac{816kW}{0.82} = 995kW$

Voltage Dimensions	Calculations
Maximum open-circuit voltage	$V_{DCmaxMOD} = V_{oc} x \left(1 + \frac{T_{DCUocMOD} x \Delta T}{100\%}\right) =$ $37V x \left(1 + \frac{-0.34(\%/K) x - 37K}{100\%}\right) = 41.65V$
Minimum open-circuit voltage	$V_{DCminMOD} = V_{mpp} x \left(1 + \frac{T_{DCUocMOD} x \Delta T}{100\%}\right) =$ $31V x \left(1 + \frac{-0.34(\%/K) x - 45K}{100\%}\right) = 24.8V$
Maximum PV module current	$I_{DCmaxSTR} = I_{sc} x \left(1 + \frac{T_{DCIocMOD} x \Delta T}{100\%}\right) =$ $8.6A x \left(1 + \frac{-0.065(\%/K) - 45K}{100\%}\right) = 8.85A$
Maximum number of PV modules per string	$n_{maxMODSTR} \leq \frac{V_{DCmaxWR}}{V_{DCmaxMOD}} \leq \frac{1000V}{41.65V} \leq 24.0 \approx 24$
Minimum number of PV modules per string	$n_{minMODSTR} \geq \frac{V_{DCmppminWR}}{V_{DCminMOD}} \geq \frac{535V}{24.8V} \geq 21.6 \approx 22$
Number of PV modules per string	$n_{minSTR} \leq n_{STR} \leq n_{maxSTR}$ $22 \leq 24 \leq 24$
Maximum string voltage	$V_{DCmaxSTR} = n_{MODSTR} x V_{DCmaxMOD} = 24x(41.65V = 999.6V)$
Minimum string voltage	$V_{DCminSTR} = n_{MODSTR} x V_{DCminMOD} = 24x(24.8V = 595V)$
Minimum number of strings	$n_{minSTR} = \frac{P_{DCGEN}}{P_{maxMOD} x n_{MODSTR}} x n_{MODSTR} = \frac{995kW}{240W x 24} = 172.7 < 173$
Maximum number of strings	$n_{maxSTR} = \frac{I_{DCmaxWR}}{I_{DCmaxSTR}} = \frac{1400A}{8A} = 175$
Number of strings per inverter	$n_{minSTR} \leq n_{STR} \leq n_{maxSTR}$ $173 \leq 173 \leq 175$

Calculating System Technology Dimensions	**Calculations**
Definition: Number of strings per measuring input of Sunny String-Monitor	$n_{STRM}=1$
Definition: Number of strings per fuse	$n_{STRfuse} = 1$
Definition: Number of strings per Sunny String-Monitor	$n_{STRSSM} = 32$
Definition: Number of measuring inputs	$n_{STRM} = \frac{n_{STRSSM}}{n_{STRfuse}} = \frac{32}{2} = 16$ Sunny String Monitor 16-21 (SSM16)
Number of Sunny String-Monitors	$n_{SSM16} = \frac{n_{STR}}{n_{STRSSM}} = \frac{173}{32} = 5.4$ Pre-decimal place = 5: Use of 5 x SSM16 Post-decimal place < 0.5: Use of 1 x SSM8
Fuse sizes of the Sunny String-Monitors	$I_{DCfuseSTR} = \frac{n_{STRfuse} x I_{DCmppSTR}}{f_{red}} = \frac{1x8A}{0.6} = 13.3A \approx 15A$
Output current of the Sunny String-Monitors	$I_{DCSSM} = I_{DCmppSTR} x n_{STRSSM} = 8Ax32 = 256A$ $I_{maxSSM} > I_{DCSSM}$ 280A > 256A

5 Appendix

5.1 Formula Symbols

Formula symbol	Explanation	Unit
$\cos \varphi$	Power factor	–
E_{PV}	Irradiation	W/m^2
$I_{DCmaxSTR}$	Maximum string current	I
$I_{DCmaxINV}$	Maximum inverter current	I
I_{mpp}	Current at maximum power of PV module	I
I_{SC}	Short-circuit current of the PV module	I
NPR	Nominal power ratio	–
n_M	Number of measurement channels	–
n_{STRM}	Number of strings per measurement channel	–
$n_{maxMODSTR}$	Maximum number of PV modules per string	–
$n_{minMODSTR}$	Minimum number of PV modules per string	–
n_{maxSTR}	Maximum number of strings	–
n_{minSTR}	Minimum number of strings	–
n_{MODSTR}	Number of PV modules per string	–
n_{STR}	Number of strings	–
$n_{STRfuse}$	Number of strings per fuse	–
P_{AC}	AC active power	W
P_{maxMOD}	Maximum power of the PV module	W
P_{DC}	DC power of the inverter	W
P_{DCGEN}	PV array power	W
P_{in}	Power input	W
P_{out}	Power output	W
Q	AC reactive power	Var
S_{AC}	Apparent power	VA
$V_{DCmaxMOD}$	Maximum PV module voltage	V
$V_{DCmaxMODSYS}$	Maximum system voltage SKII of PV module	V
$V_{DCmaxSTR}$	Maximum string voltage	V
$V_{DCmaxINV}$	Maximum input voltage of inverter	V
$V_{DCminMOD}$	Minimum PV module voltage	V
$V_{DCminSTR}$	Minimum string voltage	V
$V_{DCmppminINV}$	Minimum MPP voltage of the inverter	V
V_{mpp}	Voltage of PV module at maximum power	V
V_{oc}	Open-circuit voltage of PV module	V
$T_{DCIscMOD}$	Temperature coefficient of short-circuit current of PV module	%/K
$T_{DCVocMOD}$	Temperature coefficient of open-circuit voltage of PV module	%/K
T_{min}	Temperature coefficient at minimum expected temperature	K
T_{max}	Temperature coefficient at maximum expected temperature	K
η_{CEC}	Californian efficiency	–

Formula symbol	Explanation	Unit
η_{Euro}	European weighted efficiency	–
η_{INV}	Maximum efficiency	–
ΔT	Temperature difference	K

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