GUIDELINE

Assessing Fire Risks in Photovoltaic Systems and Developing Safety Concepts for Risk Minimization

Project Sponsor

Dr.-Ing. Klaus Prume, Project Sponsor Jülich
Dipl.-Ing. Jochen Viehweg, Project Sponsor Jülich

Affiliated Partners

TÜV Rheinland Energie und Umwelt GmbH
Fraunhofer-Institut für Solare Energiesysteme (ISE)

Project Partners

Berner Fachhochschule Technik und Informatik
Berufsfeuerwehr München
Currenta GmbH & Co. OHG
Deutsche Gesellschaft für Sonnenenergie e.V. Berlin
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Declaration

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Coordination:

Office of Energy Efficiency & Renewable Energy
Golden Field Office
Synthia Archuleta

15013 Denver West Parkway
Golden, CO 80401

Telephone: 240-562-1590

www.energy.gov
www.energy.gov/eere/office-energy-efficiency-renewable-energy
synthia.archuleta@ee.doe.gov

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Legal information

TÜV Rheinland Energie und Umwelt GmbH
Am Grauen Stein
51105 Cologne, Germany
Telephone: +49 221/806-5222
E-mail: solarenergie@de.tuv.com
Fax: +49 221/806-1350

Authors

TÜV Rheinland Energie und Umwelt GmbH:

Annett Sepanski, Florian Reil, Willi Vaaßen, Dr. Eckart Janknecht, Uwe Hupach, Dr. Nicolas Bogdanski, Bettina van Heeckeren

Fraunhofer-Institut für Solare Energiesysteme (ISE):

Dr. Heribert Schmidt, Georg Bopp, Hermann Laukamp, Robin Grab, Severin Philipp

Branddirektion München

Horst Thiem, Josef Huber

DGS – Deutsche Gesellschaft für Sonnenenergie e.V.

Ralf Haselhuhn

Berner Fachhochschule BFH

Prof. em. Dr. Heinrich Häberlin

Energiebau Solarstromsysteme GmbH

Andreas Krutzke, Benedikt Neu, Armin Richter

Currenta GmbH & Co. OHG

Dr. Björn Bansemer, Michael Halfmann

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Willi Vaaßen, TÜV Rheinland and Heribert Schmidt, Fraunhofer ISE

and on behalf of the Project Team

Contents

Introduction

The Act on the Sale of Electricity to the Grid (StrEG) and the Renewable Energy Sources Act (EEG) led to a boom in the installation of photovoltaic (PV) systems in Germany particularly in the years 2005 through 2012. The installed power output of solar power plants grew by more than 60% annually in the years 2007 to 2010. The great demand for PV modules and inverters brought about a rapid increase in the number of manufacturers of photovoltaic components worldwide. Installation companies were able to meet the demand for installing PV systems only through the massive support from auxiliary personnel. By the year's end, bottlenecks in installing and connecting the systems arose because of the EEG deadline regulation. As a result, the quality of the system installation unfortunately often fell by the wayside.

In 2006, individual cases of electric arcs and their extension to roof constructions could already be observed. In 2008 and 2009, reports on PV component fires increased in frequency.

In June 2009, larger fire damage originating from what was then the world's most powerful PV roof system in Bürstadt (Hesse) caught great public attention and became a “hot topic” in the order of business.

Long-term studies of PV systems found burn and overheating marks on various PV system components. The flaws discovered in inspections of the systems, such as damaged or discolored modules, weathered cables, local fusion in junction boxes and improper installations, as well as fire incidents of various degrees of severity, have led to a drastically increased awareness of the safety aspect of PV systems, especially roof-mounted systems and building-integrated PVs (BIPVs). In addition to economic and environmental considerations, this aspect plays a fundamental role in the acceptance and further spread of photovoltaics.

PV systems are almost always energized, even in overcast weather. The trend towards increasingly larger systems has led to the realization of DC voltages of 1,000 V and soon 1,500 V. Contact protection and especially protection against electric arcs are accordingly becoming more important.

Another aspect is the safety of emergency personnel and firefighters in particular. Here there has prevailed widespread uncertainty, which in part led to drastically exaggerated or even false reports in some media and consequently to public qualms about the safety of roof-mounted PV systems.

Here are just a few representative headlines from 2010 and 2011:

Firefighters let houses with solar roofs burn down

For fear of powerful electric shock, firefighters often cannot extinguish fires at homes with solar installations on their roofs.

Photovoltaics

Constantly live: solar roofs are fire hazards

By Klaus D. Voss

Photovoltaic systems cannot be switched off Once a fire starts, the fire department has hardly a chance.

Burning solar roofs

A nightmare for the fire department

SOLAR ENERGY

Fire on the roof

Solar modules can be surprisingly dangerous

For the risk analysis and derivation of recommendations for action for emergency personnel, various series of experiments were performed with the participation of the fire departments and the German Federal Agency for Technical Relief (THW) for assessing the electrical hazards from PV facilities and fire-related emissions from PV modules (including thin-film modules).

Reviews and systematic causal analyses of known incidents of damage on the one hand and fundamental, scientifically substantiated studies of PV modules on the other hand made possible a realistic assessment of electric arc hazards as part of this research project. Support in this regard was provided by the feedback from PV experts, fire departments and operators of PV facilities in an initiated online survey on fire and overheating damage to PV systems. A significant share of the derived findings was provided by a generally recognized procedure for risk assessment (FMEA), employed by an expert committee for system analysis covering all components of a PV system including installation and system operation.

On the basis of the identified risk potential, studies on the component and system levels regarding the possibilities of risk reduction yielded concrete recommendations for action for the component manufacturers as well as for planners and installers of photovoltaic systems. In addition, significant results concerning risk minimization were taken up by the PV standardization committees.

In the course of the project, the three public, well attended workshops in Cologne and Freiburg afforded ample opportunities for technical discussions in addition to the presentation of the work results. In addition to the project's homepage at http://www.pv-brandsicherheit.de, numerous publications on the subject of preventive fire protection in cooperation with the industrial associations DGS and BSW and with the Munich Fire Department made the obtained findings available to the general public and in particular to emergency services.

Particular issues were or are being pursued in separate, advanced research projects such as fire tests on BIPV modules, switches and disconnectors for photovoltaic systems, inspection of electric arc detectors and risk assessments for PV systems with storage solutions (accumulators).

1 Status of PV system designs and requirements

1.1 PV system design

A photovoltaic (PV) system converts solar energy directly into electrical energy by means of several solar modules (a string) electrically connected in series. In the case of a grid-connected PV system, inverters aid in converting the direct current produced in the solar modules to alternating current, which may then be fed into the grid via transformers.

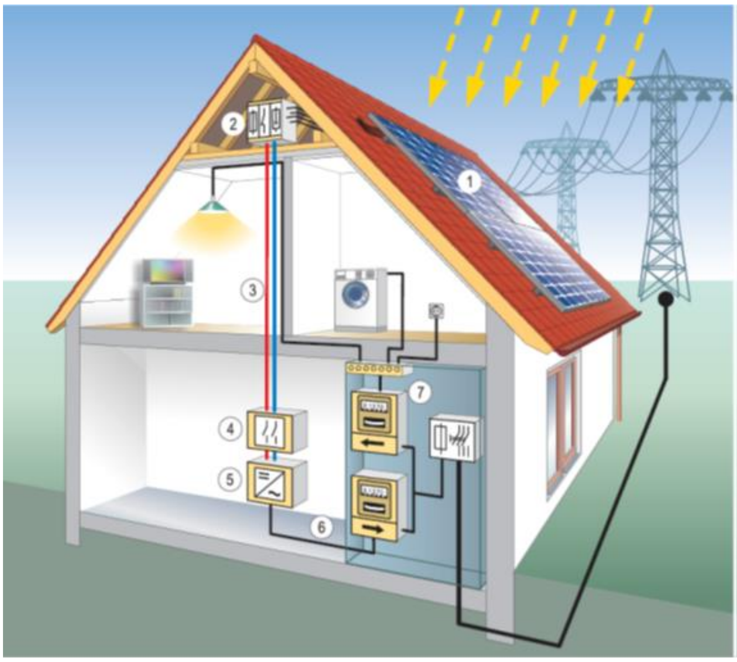

Figure 1-1: Grid-connected PV system with direct feed

The diagram shows the schematic layout of a grid-connected photovoltaic system, consisting basically of the following main components:

(1) PV generator (several PV modules connected in series and in parallel with mounting frame)
(2) Generator junction box (with protective technology)
(3) Direct current wiring
(4) DC main switch
(5) Inverter
(6) Alternating current wiring
(7) Meter cabinet with sub-circuit distribution, consumption and feed meters and house connection

Single-family homes often employ only module strings, so that the strings can be directly connected to the inverter and the aforementioned generator junction box omitted.

In cases of larger systems, generator junction boxes (GJBs) are used for the parallel connection of the strings. Very large systems and systems with many separate inverters employ DC coupling boxes interconnecting multiple GJB outgoing lines.

The generator junction box contains connecting terminals and disconnection points as well as possibly string fuses and string diodes. Often the generator junction boxes contain integrated surge arresters for diverting overvoltage to the ground. The potential equalization or grounding conductors therefore lead into the generator junction boxes.

The selection of DC switches should make sure that they have the appropriate switching capacity for direct current (at least DC 22B switching capacity).

Lines are differentiated into module lines, string lines, direct current main line and alternating current connecting line. The electrical connecting lines between the individual modules of a solar energy generator and to the generator junction box are referred to as module lines or string lines. These lines are used outdoors. To ensure ground-leakage-proof and short-circuit-proof routing, double-insulated single-core cables are used. Solar energy lines as per EN 50 618 or VDE-AR-E 2283-4 (designation: PV1-F) have become standard in outdoor use. The standard version of the double-insulated rubber hose line of type H07 RN-F often used outdoors is approved only for operating temperatures of up to 60°C and is not UV-resistant. This line should therefore not be used as a solar line. Aging of these lines or use of other unsuitable lines can result in insulation flaws and electric arcs.

1.2 Categorization of different PV systems

Generally PV systems can be divided into *open-space systems* and *building systems*. Building systems can in turn be classified as *roof-parallel elevated systems* on pitched roofs, *elevated systems* on flat roofs or (seldom) on pitched roofs, *roof-integrated systems*, *PV curtain walls* and *facade-integrated systems*. The roof-parallel systems often comprise the largest interconnected module fields and under certain circumstances may hinder firefighting more. Generally the integrity of the fire compartments must be maintained. Construction over fire compartments is not permitted.

Table 1-1: Categories of PV systems

 Open-space facility, Source: Krug Immobilien GmbH	 Pitched roof: roof-parallel system, source: www.photovoltaik.org	 BIPV: roof-integrated PV system, source: Photovoltaik Buero
 Flat roof: elevated PV system, source: Solaranlagen-Portal	 BIPV: facade-integrated system, source: Solarfabrik GmbH	 Oldenburg PV wall curtain, source: Colt Int. GmbH

In line with the electrical circuitry concept, we can distinguish between PV systems with central inverters and those with decentralized inverters. Systems with central inverters rarely occur with small voltages (up to 120 V), but typically with higher DC voltages (up to 1,000 V, in the future also 1,500 V). Large systems occasionally employ master-slave devices or even inverters with assigned medium-voltage transformers.

Decentralized systems are implemented with multiple string or subgenerator inverters, with module inverters or with module-oriented direct current converters (power optimization).

1.3 Status of the requirements on components, systems and installation

Studies on the causes of fire incidents involving PV systems have shown that to a rough approximation 1/3 of the damage cases are due to component defects, 1/3 to deficient planning and 1/3 to faulty installation (see section 3.3.2, Statistical damage analyses)

This section lists the current standards and requirements from the German Renewable Energies Act (EEG) for the most important PV system components. One reason – among many others –for installation errors is that the manufacturer’s documentation often contains insufficient or even no information on possible danger sources. An overview will show what types of information are typically provided by manufacturers and which types would also be desirable to have. In addition, we list guidelines and special connection conditions from the energy industry.

1.3.1 Standards, regulations and guidelines

Regarding photovoltaic systems we must distinguish between standards that are applicable generally and therefore to PV systems in particular and standards specially devised for PV systems. The most important series of standards for low-voltage systems in general is the DIN VDE 0100, based on the European Low-Voltage Directive. Most standards pertaining to PV systems are compiled in the DIN VDE 0126 series.

Besides these standards, we also have the more detailed application guidelines of the VDE, the guidelines of the BDEW, in particular the medium-voltage guidelines, and the accident prevention regulations of the workers' compensation boards (Berufsgenossenschaften).

The Deutsches Institut für Bautechnik (DIBt) has published a set of instructions for assembling and installing PV systems and defined construction regulations in the building regulation list with relevance to PV modules and their application (download link in Appendix II, p. 253).

For the building rules and building standards the Deutsches Institut für Bautechnik (DIBt) regularly publishes the building regulation list and interprets the European Construction Products Regulation (EU-CPR) for Germany. This also yields requirements for PV systems and their components. The requirements (mechanical strength, structural stability, fire protection, etc.) are given in the bulletin ‘Hinweise für die Herstellung, Planung und Ausführung von Solaranlagen’ (Information on the Manufacture, Planning and Implementation of Solar Energy Systems), published in November 2012. The industry association BSW and the professional association DGS are also working on the development of professional rules and on standardization in the field of solar energy. Examples are professional rules for the planning, installation and maintenance of PV systems in accordance with fire protection (download link in Appendix II, p. 253).

The lists given here present an overview only of the most important standards and series of standards in reference to photovoltaics and make no claim to completeness.

1.3.1.1 Requirements on PV system configuration

General requirements on low-voltage systems up to 1,500 V DC system voltage, which also include PV systems, are formulated in the international series of standards DIN IEC 60364 *Low-Voltage Electrical Installations*, listed in the VDE as DIN VDE 0100. The series contains, among other things, safety regulations, terminological definitions and instructions on selecting, designing and assembling operating equipment, and defines the required resistance of the system to external factors. DIN VDE 0100-712, *Requirements for Special Installations or Locations – Photovoltaic (PV) Power Supply Systems*, refers in particular to PV systems. It explains the basic design of the systems, in particular its connection to necessary switchgear, and requires protective measures against fault currents, overcurrents and surges and contact with live components as well as against environmental factors, but only superficially treats these subjects. They are discussed in further depth in the respective generally applicable standards on these subjects, namely DIN EN 62305-3 on *Protection against Lightning and Overvoltage*, DIN EN 61140 on *Protection against Electric Shock* and DIN EN 61439-1 on *Low-Voltage Switchgear and Controlgear Assemblies*.

In addition, on some subjects there also exist standards on generating systems in general and on PV systems in particular. DIN EN 61173 on *Overvoltage Protection for Photovoltaic (PV) Power Generating Systems* explains measures for avoiding surge damage, in particular potential equalization, grounding and shielding. Supplement 5 to DIN EN 62305-3 contains similar information on lightning protection. The necessary switchgear and grid interface of a PV system are described in VDE AR 4105 and DIN EN 61727.

Limits for grid perturbations are also defined. Guideline VdS 3145 formulated by the VDE and GDV contains a compilation of specifications on PV system safety. They include safety recommendations for planning and operating the systems, both on the system level and for individual components. Particular focus lies on the avoidance and limitation of fires as well as on the resistance of the system to environmental factors, also in view of state building regulations.

Some special cases of PV applications are also treated by standards and guidelines: DIN EN 61194 states the parameters of the different components of a *PV stand-alone system* and states the requirements on its documentation.

DIN EN 62124 (VDE 0126-20) contains requirements on the design qualification of storage systems operated in conjunction with PV systems. Charge controllers for such PV accumulators are treated in DIN EN 62509.

To ensure the safety of emergency services in the event of a fire, application guideline VDE-AR-E 2100-712 specifies measures for preventing contact with live components. Especially highlighted are the installation requirements on the DC lines and the labeling of the cable routing in a schematic accessible to firefighters. The following table summarizes the currently available standards on the configuration of photovoltaic systems.

Table 1-2: Important standards and series of standards pertaining to the configuration of PV systems

System configuration	
Designation	**Content**
DIN EN 61277 *Terrestrial photovoltaic (PV) power generating systems – General and guide*	General information on PV systems
DIN IEC 60364 DIN VDE 0100 *Erection of low-voltage installations*	Design, connection and components of low-voltage systems, protective measures
DIN VDE 0100-712 *Requirements for special installations or locations – Solar photovoltaic (PV) power supply systems*	PV-specific part of DIN VDE 0100. Covers design of PV systems and necessary protective measures
DIN EN 61140 *Protection against electric shock*	Contains measures for preventing injuries from electric shock
DIN EN 61439 *Low-voltage switchgear and controlgear assemblies*	Regulates the combination of switchgear units in a building unit
DIN VDE 0126-1-1 *Automatic disconnection device between a generator and the public low-voltage grid*	States requirements and disconnection parameters for an automatic switch at the grid interface (obsolete, superseded by VDE AR-N 4105)
DIN EN 61727 *Photovoltaic (PV) systems – Characteristics of the utility interface*	Defines requirements on the grid interface of a PV system and lays down limits for grid perturbations
DIN EN 62305-3 Bbl 5 VDE 0185-305-3 Bbl 5 *Lightning and overvoltage protection for photovoltaic power supply systems*	Contains information on lightning and overvoltage protection for PV systems (no standardized specifications)
DIN EN 61173 *Overvoltage protection for photovoltaic (PV) power generating systems*	States measures against overvoltage damage to PV systems
DIN EN 62124 VDE 0126-20 *Balance-of-system components for photovoltaic systems – Design qualification for natural environment*	Contains criteria for the design suitability of balance-of-system components, mainly accumulators
DIN EN 61194 *Characteristic parameters of stand-alone photovoltaic (PV) systems*	States parameters of various components of a stand-alone PV system

System configuration	
Designation	**Content**
VDE-AR-E 2100-712 *Measures for the DC range of a PV installation for the maintenance of safety in the case of firefighting or technical assistance*	States measures for avoiding contact with live components in case of fire
VDE-AR-N 4105 *Generators connected to the low-voltage distribution network – Technical requirements for the connection to and parallel operation with low-voltage distribution networks*	States requirements on the technical connection conditions of the distribution grid operators

1.3.2 Requirements on PV modules

PV modules generally undergo design testing prior to use or marketing. The requirements on design suitability are laid down in DIN EN IEC 61215 for crystalline and DIN EN IEC 61646 for thin-film modules, and contain comprehensive aging and stress tests. Besides resistance to temperature fluctuations, UV radiation, moisture, wind and other mechanical influences, electrical characteristics of the modules are also examined.

Safety aspects are tested irrespective of the cell technology as per DIN EN 61730-1 and DIN EN 61730-2. Part 1 describes the design and material requirements. Part 2 describes the tests on modules pre-aged as per DIN EN IEC 61215 or DIN EN IEC 61646. These additional stress tests include mechanical stress, fire tests and intensified insulation resistance measurements. Design certification as per DIN EN 61730 forms the basis of CE marking of PV modules for the European market. Modules meeting class A requirements as per DIN EN 61730-1:2004 apply as protection class II operating equipment as per DIN EN 61140.

The quality seal as per RAL GZ 966 is issued if the RAL quality and test requirements for solar energy systems are met. This set of quality marks and quality criteria defines the target requirements for the manufacture of high-quality components as well as for the proper conception and professional execution, servicing and operation of solar energy (photovoltaic and solar heat) systems. The RAL-Gütegemeinschaft für Solarenergieanlagen e.V. is one of 130 independent quality associations specifying and monitoring the RAL quality and test requirements of their respective industrial and service sectors (*RAL since 1980: Deutsches Institut für Gütesicherung und Kennzeichnung e. V.*)

DIN EN 50380 regulates the data sheets issued by the manufacturers for each module series as well as the mandatory data on the model plates. DIN EN IEC 60904-1 also defines the standard test conditions (STC) for determining electrical parameters of modules. DIN EN 50548 formulates requirements on module junction boxes. The international version of this standard, IEC 62790, will supersede this European standard in the future. Methods for testing the conformity with these requirements are also laid down. Requirements on PV plug connections are described in IEC 62852 (or DIN EN 50521). For PV lines there exists a draft standard, prEN 50618, based on the applicable TÜV Rheinland internal test specification 2PfG 1169.

For the special application of building-integrated photovoltaics, modules must comply with the special demands of DIN 18008 (formerly (e.g. Technical Guidelines for Linearly Supported Glazing (TRLV)). DIN VDE 0126-21 defines different types of modules for building-integrated use, states application-specific demands and refers to other requirements, such as design certification as per DIN EN IEC 61215 or DIN EN IEC 61646 and DIN EN 61730-1/-2.

Besides the particular requirements on building-integrated modules, there exist other standards for particular areas of application and for particular designs, plus further standards are under development. Some examples are modules for maritime or near-coastal applications, modules in noxious gas environments, modules operating under concentrated sunlight and modules with integrated electronics (such as AC modules).

Table 1-3: Important standards for photovoltaic modules

Modules	
Designation	**Content**
DIN EN IEC 61215 *"Crystalline silicon terrestrial photovoltaic (PV) modules – Design qualification and type approval"*	Type approval for crystalline modules according to aging characteristics
DIN EN IEC 61646 *"Terrestrial thin-film photovoltaic (PV) modules – Design qualification and type approval"*	Type approval for thin-film modules according to aging characteristics
DIN EN 61730 *"Photovoltaic (PV) modules – Safety qualification –* *Part 1: Requirements for construction* *Part 2: Requirements for testing"*	Safety qualification of PV modules
DIN EN 50548 (IEC 62790) DIN VDE 0126-5 *"Junction boxes for photovoltaic modules"*	Requirements and test procedures for junction boxes for use on PV modules
DIN EN 50521 (IEC 62852) *"Connectors for photovoltaic systems"*	Requirements and test procedures for junction boxes for use on PV connectors
DIN VDE 0126-21 *"Photovoltaics in construction"*	Requirements on building-integrated PV modules
DIN EN 50380 *"Datasheet and nameplate information for photovoltaic modules"*	Provides information that must be contained in PV module datasheets and nameplates
DIN EN 60904-1 VDE 0126-4-1 *"Measurement of photovoltaic current-voltage characteristics"*	Defines test procedures and standard test conditions (STC) for creating module characteristic curves

Modules	
Designation	**Content**
DIN EN 13501-1 *“Fire classification of construction products and building elements”*	Fire classifications according to fire behavior, for the classification of modules
DIN 4102-1 *“Fire behaviour of building materials and building components”*	Fire classifications according to flammability, for the classification of modules

1.3.2.1 Requirements on PV inverters

Safety standards for PV inverters are laid down in DIN IEC 62109. Covered are risks from mechanical and electrical stress as well as from fire. Also treated is the correct design of the inverter. The electrical AC requirements are determined by the technical connection conditions of the distribution grid operator, the VDE-AR-N 4105 and the DIN EN 61000 series on *“Electromagnetic Compatibility (EMC)”*. The latter concerns the compatibility of grid parameters with connected systems and defines limits for grid perturbations and fluctuations.

DIN EN 50524 governs the content of datasheets and labels for inverters, in particular voltage and current parameters at input and output, as well as efficiency, which is specified as a weighted European efficiency level. Its measurement is laid down by DIN EN 50530, which also stipulates the test conditions and measurement circuits.

In the event of collapse of the grid voltage, the inverter must automatically disconnect from the grid. Tests as per DIN EN 62116 must be performed to check the suitability of measures that are to fulfill this requirement. However, no conditions are therein formulated requiring the inverter to be disconnected from the grid, since such conditions depend on local factors, in particular the requirements of the distribution grid operators (technical connection conditions, German abbreviation: TAB).

Table 1-4: Important standards and series of standards for PV inverters

Inverter	
Designation	**Content**
DIN IEC 62109 VDE 0126-14 *Safety of power converters for use in photovoltaic power systems*	Defines mechanical and electrical safety requirements on PV inverters
EN 61000 *Electromagnetic compatibility (EMC)*	Electromagnetic compatibility of grid and connected systems and equipment
DIN EN 50530 VDE 0126-12 *Overall efficiency of grid-connected photovoltaic inverters*	Defines test procedures for determining the efficiency of PV inverters
DIN EN 50524 VDE 0126-13 *Datasheet and nameplate information for photovoltaic inverters*	Provides information that must be contained in PV inverter datasheets and nameplates
DIN EN 62116 VDE 0126-2 *Utility-interconnected photovoltaic inverters – Test procedure of islanding prevention measures*	Defines procedures for testing the suitability of measures for disconnecting PV inverters with abnormal grid voltages

1.3.2.2 Requirements on mounting systems

At present no special standardizations exist for mounting systems for photovoltaic systems. To be applied are instead the general standards for steel and aluminum structures from the European codes, namely EN 1990, EN 1993 and EN 1999. They govern the planning, measurements and design of support structures.

DIN EN 1090-1 governs the proof of conformity with European standards and regulations, which is a prerequisite for use of the CE mark, for steel and aluminum structures.

Designing for local environmental influences is performed as per DIN 1055. Besides wind and snow loads, temperature effects and effects of earthquakes are also considered here.

Table 1-5: Important standards and series of standards for PV mounting systems

Mounting systems	
Designation	**Content**
DIN 1055 *Actions on structures*	Specifies load assumptions for different environmental influences, in particular wind and snow loads
DIN EN 1993 *Design of steel structures*	Contains information and regulations on the design of steel structures
DIN EN 1999 *Design of aluminium structures*	Contains information and regulations on the design of aluminum structures
DIN EN 1090 *Execution of steel structures and aluminium structures*	Governs the proof of conformity (CE mark) for steel and aluminum structures

1.3.2.3 Requirements on DC components and solar energy storage systems

The DC components include DC cable, connector and DC circuit breaker. Cable layouts and circuit breakers are treated in DIN VDE 0100-712 (see 2.3.2.1 “Requirements on PV System Configuration”). PV plug connections are governed by a separate standard, DIN VDE 0126-3. Besides requirements on mechanical and electrical strength, it also contains requirements on shape for protection against polarity reversal, relockability and labeling. In addition, test procedures for complying with these specifications and aging tests are presented.

PV-specific specifications on wiring are given in the application guideline VDE-AR-E 2100-712. It stipulates routing the lines in at least fire-inhibiting material, if occurring within the building. General requirements on cable routing appear in the VDE series VDE 0604.

The original standard for solar energy storage systems is DIN EN 62093. It formulates criteria for the design qualification of all components of a storage system, including charge controllers and batteries, as well as test procedures. The focus lies on stress from environmental influences, i.e. mechanical and thermal stress as well as moisture.

Only lead and nickel-cadmium batteries are considered, however. It is supplemented by DIN EN 62509 and DIN EN 61427-1.

DIN EN 62509 presents requirements on the power parameters and charge management of PV battery charge controllers, to allow maximum possible battery lifetimes. The standard pertains only to lead batteries. DIN EN 61427-1 defines operating conditions for solar energy accumulators and contains requirements on mechanical stressability, safety and documentation. Test procedures for capacity, charge retention, efficiency and service life are also laid down. While the standard covers all common cell technologies, including Li ion cells, it refers only to off-grid applications.

A standard for grind-counted storage systems is in preparation under the designation DIN EN 61427-2 (as of July 2015).

Table 1-6: Important standards for DC components or storage systems

DC components and solar energy storage systems	
Designation	**Content**
DIN EN 50521 DIN VDE 0126-3 *Connectors for photovoltaic systems – Safety requirements and tests*	Contains requirements on the mechanical and electrical strength of PV connections and defines test procedures for approval
DIN EN 62093 VDE 0126-20 *Balance-of-system components for photovoltaic systems – Design qualification for natural environment*	Contains requirements on the design qualification of solar batteries and their charge controllers; geared to lead batteries
DIN EN 61427-1 VDE 0510-40 *Secondary cells and batteries for renewable energy storage – General requirements and methods of test*	Requirements on solar energy batteries in off-grid applications irrespective of the cell technology
DIN EN 62509 VDE 0126-15 *Battery charge controllers for photovoltaic systems*	Contains electrical requirements on PV battery charge controllers, geared to lead batteries

1.3.3 Manufacturers’ installation instructions

The manufacturers of the system components publish the requirements on the installation and initial start-up of their products in the form of installation instructions (Table 1-7). Besides technical product information and assembly instructions, they also include references to relevant standards and provisions as well as warranty and guarantee terms.

Major differences found between the manufacturers in the scope and descriptive detail of the installation instructions show that the latter alone often do not suffice for the technically correct installation of a PV system.

1.3.3.1 PV modules

Considered were selected manufacturers from Germany, China, Japan and the United States who cover all market segments and common cell technologies. The module series to which the instructions refer date to the years 2008 to 2012. Since the manufacturers were chosen arbitrarily, this listing makes no claim to completeness. A complete list of module manufacturers, from which these manufacturers were selected, was published in the journal PHOTON Profi [source: Market overview of solar modules in: PHOTON Profi, 2/2010 issue].

Table 1-7: Typical contents of installation instructions for PV modules

	Manufacturer 1	Manufacturer 2	Manufacturer 3	Manufacturer 4	Manufacturer 5	Manufacturer 6	Manufacturer 7	Manufacturer 8	Manufacturer 9
Installation									
Instructions on handling	X	X	X	X	X	X	X	X	X
Installation by suitable specialist	X	X	X	X	X		X	X	X
Work safety regulations	X	X		X	X	X	X		
Antifall guard for installer	X			X	X	X			
Inspection for mechanical integrity prior to installation	X				X				X
Mechanical requirements									
Instructions on installation location and orientation	X	X	X	X	X	X	X	X	X
Static strength	X	X	X	X	X	X	X	X	X
Ventilation of the module rear side	X	X	X	X	X	X	X	X	
Protection against moisture	X	X			X	X	X	X	X

Restriction on modifications	**X**	**X**			**X**	**X**		**X**	**X**
Avoidance of flammable materials	**X**	**X**		**X**		**X**		**X**	**X**
UV protection for cables and junction box	**X**	**X**	**X**			**X**	**X**	**X**	
Mounting on fire-resistant supporting surface	**X**	**X**		**X**		**X**			**X**
Lightning protection	**X**				**X**	**X**	**X**		
Corrosion protection	**X**	**X**			**X**				
Strain relief of connecting cable	**X**						**X**		
Instructions on overhead glazing		**X**					**X**		
Electrical requirements									
Instructions on circuitry	**X**			**X**	**X**	**X**	**X**	**X**	**X**
Potential equalization	**X**	**X**	**X**	**X**		**X**	**X**	**X**	**X**
Designing for 1.25 UOC and ISC	**X**	**X**		**X**		**X**	**X**	**X**	**X**
Disconnection before work	**X**			**X**					**X**
Notes on further regulations									
References to standards	**X**	**X**		**X**	**X**	**X**	**X**	**X**	**X**
References to guidelines	**X**	**X**	**X**		**X**	**X**	**X**	**X**	**X**
Reference to technical connection conditions (TAB)	**X**								

All installation instructions for modules formulate mechanical and electrical requirements on the system and specify procedures for their installation. Besides instructions on work safety, they also include instructions on handling the modules to prevent damage during installation, such as glass or cell breakage and delamination.

The mechanical criteria demanded by a majority of the manufacturers mainly include an installation location free from mechanical stress at any temperature, the use of a suitable mounting system and attention to the maximum snow load. In addition, some manufacturers also prohibit modifications to the module frame, the module surface or the junction box.

Other instructions refer to topics relevant to fire protection, such as the presence of flammable materials in the vicinity of the modules, fire and surge protection and the proper handling and installation of the wiring.

Most installation instructions also give a detailed treatment of the electrical requirements on PV systems, in particular the assembly of strings in compliance with limits on voltages and short-circuit currents. Some manufacturers also recommend certain cable cross sections for DC and ground cables.

Besides the manufacturers' requirements, all installation instructions also refer to standards or other provisions and guidelines (VDE, VDEW, TAB), in particular DIN 1055 on load assumptions and IEC test standard 61730.

Altogether noteworthy is that German module manufacturers provide more comprehensive installation instructions than their international competitors, especially when it comes to safety and protective measures. Manufacturer 1, a well-known German company, covers every recorded subject in its instructions.

Besides the installation instructions, module manufacturers also publish compilations of technical information in the form of datasheets. While standardized as per DIN EN 50380, they show small discrepancies in scope among the manufacturers.

<u>Conclusion</u>

As with the datasheet standard, standardization of installation instructions must be demanded.

1.3.3.2 Inverters

Installation instructions from European, US and Chinese inverter manufacturers were evaluated.

Table 1-8 shows an excerpt of the market overview representative of the current market from the journal *PHOTON* (source: Market overview of inverters, PDF version, [1])

Table 1-8: Typical contents of installation instructions for inverters

	Manufacturer A	Manufacturer B	Manufacturer C	Manufacturer D	Manufacturer E	Manufacturer F	Manufacturer G	Manufacturer H	Manufacturer J	Manufacturer K
Installation										
Instructions on handling				X	X		X	X	X	
Installation by suitable specialist	X	X	X	X	X	X	X			X
Work safety regulations	X					X				X
Inspection for mechanical integrity prior to installation		X	X			X				X
Mechanical requirements										
Restriction on modifications	X	X	X	X	X	X	X			X

	Manufacturer A	Manufacturer B	Manufacturer C	Manufacturer D	Manufacturer E	Manufacturer F	Manufacturer G	Manufacturer H	Manufacturer J	Manufacturer K
Instructions on installation location	X	X	X	X	X	X	X	X	X	X
- Safety distances	X	X	X	X		X	X	X	X	X
- Mounting on flame-retardant material	X	X	X	X		X	X	X		
- Protection against UV radiation	X	X	X	X	X	X	X	X		X
- Air feed	X	X	X	X	X	X	X		X	X
- Ambient temperature	X	X	X	X	X	X	X	X		X
- Protection against wet		X	X	X		X	X	X		
Instructions on DC connection	X	X		X				X		X
Instructions on AC connection	X				X		X		X	
AC cable routing	X	X	X	X	X	X	X	X	X	
Strain relief					X				X	
Electrical requirements										
Limits on input voltage and power	X	X	X	X	X	X	X	X	X	X
Residual-current circuit breakers	X	X	X	X	X		X	X	X	
AC interconnection	X	X		X	X			X	X	
Grounding at inverter	X	X	X	X		X	X	X	X	X
Grounding of generator terminal	X	X	X	X	X	X	X		X	
Notes on further regulations										
References to standards	X	X	X	X	X	X				
References to guidelines	X		X		X				X	
Reference to technical connection conditions (TAB)		X	X					X		

The installation instructions for inverters are considerably more comprehensive than for other components. Besides instructions on installation, they also cover operation and maintenance topics as well as contain information on the peripherals of the inverter, such as the residual-current circuit breaker and AC cables.

Nearly all manufacturers require installation on a flame-retardant or non-flammable surface, specify safety distances and recommend measures for sufficient heat dissipation at the inverter. Usually they also treat the potential equalization at the generator or grounding at the inverter itself. References to more detailed standards and guidelines are contained in all installation instructions to varying degrees.

Work safety issues are given relatively little attention. While individual protective measures such as disconnection before working on the inverter and the consideration of the discharge times of the capacitors precede the particular operational steps, references to work safety guidelines, protective equipment and to the use of the corresponding tools are usually lacking. Strain relief and fastening the connecting cables are also seldom addressed. The various manufacturers treat the subject of connection in very different ways. While some instructions provide extensive information or at least some notes on connection, others fully neglect the subject.

1.3.3.3 DC cables and connectors

Some large manufacturers of solar cell connection systems provide special instructions for the user, while others limit themselves to brief guides. Mostly Installation instructions and product information are found (

Table 1-9). Installation instructions for modules also contain in part information on the connecting lines and connectors.

Table 1-9: Typical contents of installation instructions for DC components

	Manufacturer a	Manufacturer b	Manufacturer c	Manufacturer d
Installation				
Installation by suitable specialist	**X**	**X**		
Work safety regulations	**X**			
Use of suitable tool	**X**	**X**	**X**	**X**
Inspection for mechanical integrity prior to installation				**X**
Mechanical requirements				
Restriction on modifications	**X**	**X**		**X**
Inspection of the plug connection		**X**		**X**
Compatibility	**X**	**X**		
Protection against dirt	**X**	**X**	**X**	
Protection against moisture	**X**	**X**		
UV protection		**X**		
Strain relief	**X**			

	Manufacturer a	Manufacturer b	Manufacturer c	Manufacturer d
Fastening	**X**			
Notes on crimping	**X**	**X**	**X**	
Bending radii	**X**	**X**		
Notes on further regulations				
References to standards		**X**	**X**	
Reference to work safety guidelines	**X**			
References to general provisions		**X**		

Generally the manufacturers allow only trained personnel to handle their system components. The products may be neither modified nor combined with other makes. In particular, established manufacturers reject combinations with connectors from other manufacturers.

No connections may be established with dirty or wet connectors. In the cable routing, cables and plugs must not lie in water or be exposed to sunlight over long periods of time, junction boxes and plug connections must not be stressed and bending radii must be maintained.

Especially extensive are the instructions for establishing crimp connections. Major manufacturers provide detailed and illustrated instructions in this regard, covering, among other things, the use of suitable crimping tools from the respective manufacturers.

The scope of the instructions varies more for cables and connectors than for other system components. Documentation from various manufacturers also contains in part contradictory information on the compatibility of different systems. In particular, many smaller companies claim compatibility of their systems with wide-spread connector systems, while manufacturers of the latter categorically advise against combinations with other systems.

1.3.3.4 Mounting systems

The assembly instructions for mounting systems are comparatively extensive, but geared more to the assembly than to the design and static strength of the system (

Table 1-10). Accordingly, they contain only few specifications on the condition of the completed installation. Generally all manufacturers demand a static inspection of the construction by appropriately trained personnel. Local snow and wind loads in particular are to be observed. Some instructions contain recommendations for avoiding damage from lightning and overvoltage by means of adapted cable routing and grounding of the subframe.

All manufacturers provide more or less detailed information on work safety during the installation and most refer to legal work safety regulations and guidelines of the professional associations. They also specify suitable tools, either generally or also in specific cases. Only one manufacturer recommends checking the condition of materials before the start of assembly.

Table 1-10: Typical contents of installation instructions for mounting systems

	Manufacturer I	Manufacturer II	Manufacturer III	Manufacturer IV	Manufacturer V	Manufacturer VI	Manufacturer VII	Manufacturer VIII	Manufacturer IX
Assembly									
Installation by suitable specialist	X	X	X	X	X				X
Work safety	X	X	X	X	X	X	X		X
Antifall guard for installer			X	X	X	X	X		X
Use of suitable tool	X			X		X	X		
Check of screwed connections	X	X	X	X	X				
Requirements for installation conditions (weather condition - no moisture)		X							
Inspection for mechanical integrity prior to installation	X								
Mechanical requirements									
Static inspection	X	X	X	X	X	X	X	X	X
Snow loads	X	X			X	X	X	X	X
Wind loads	X	X	X		X	X	X	X	
Lightning and surge protection		X	X	X	X	X		X	
Water drainage	X		X					X	
Notes on further regulations									
References to standards	X	X	X	X	X	X		X	
Reference to work safety guidelines	X	X	X	X		X	X		
References to general provisions	X	X	X	X	X				

The assembly instructions for mounting systems differ only slightly in scope; only one manufacturer provides additional information on requirements for module orientation and cable routing. Nearly all instructions refer to standards on the layout of the mounting technology. Often mentioned are DIN 1055 on “Actions on structures,” DIN 4113 on aluminum constructions, DIN 18800 on measuring steel structures and DIN 4102 on fire characteristics of construction materials. In addition, some assembly instructions also mention national construction regulations (regional building codes).

1.3.4 Installation requirements of the distribution grid operators

The installation requirements of the distribution grid operators (VNB) for connecting PV systems to low-voltage and medium-voltage grids are formulated in the Technical Connection Conditions (TAB), which as per § 19 of the German Energy Industry Act must be made publicly accessible. The TABs refer to the connection of domestic and industrial consumers, in addition to generation systems operated in parallel with the grid. They define limits on grid perturbations pertaining to system safety and stability, prescribe protective and monitoring equipment and regulate the properties of the fed-in electrical power.

While the distribution grid operators of the major energy utilities (such as On-edis, Westnetz) issue their own TABs, the smaller distribution grid operators employ the guidelines created by the Federal Association of the German Energy and Water Industries, which contain no regulations on generating systems, but refer to the VDE application guideline on “Generators Connected to the Low-Voltage Distribution Network,” VDE-AR-N 4105:2011-08, or to the “Technical Guideline on Power Generating Systems at the Medium-Voltage Power Grid”. Besides the technical connection parameters, the TABs also regulate organizational procedures for registration, commissioning and maintenance of the connection.

1.3.4.1 Grid connection

The system is connected to the distribution network via the grid connection or node. For systems > 30 kW this will generally be the previous connecting point of the property. A meter connection column as per VDE-AR-N 4102 is then to be set up as a switching and disconnecting point, to which the TABs require unrestricted access for the distribution grid operators, unless an automatic disconnection device was installed. Like the rest of the system, the connection may be set up only by qualified specialist companies.

In addition, the distribution of the power input over the phases of the grid connection is regulated. The asymmetry between the external conductors with feed-in to the low-voltage grid must not exceed 4.6 kVA; from 5 kWp a system generally requires a three-phase connection. Up to 30 kWp the three-phase connection can also be established by using multiple single-phase connections to the phases of distributed inverters, if the maximum permissible asymmetry is not exceeded.

1.3.4.2 Measurement technology

The electricity meters documenting the consumed or produced energy must be designed according to the level of the connection power. The TABs stipulate load profile meters from 100,000 kWh of consumed energy per year or 100 kW of fed-in power. The TABs also organize the provision, installation, operation and readout of the measuring equipment. The meter cabinet with connection and mounting equipment is provided by the customer. Depending on the distribution grid operator, a remote readout accompanies operation of the load profile meters, either by radio signal or by telephone line. With regular operating currents > 60 A the electricity meter has the form of a measuring transformer. In the event that the customer opts for comparative measurements, the TABs arrange for shared use of the transformer.

1.3.4.3 Switch and remote control technology

For galvanic isolation as per DIN VDE 0105 part 100, a switch device with load switch capacity is specified at the AC end. For systems ≤ 30 kWp this can be an automatic disconnection device with two parallel grid monitoring units, each coupled in series with a load disconnect switch or power switch. The switch device is triggered if the voltage or frequency limits defined in the TABs are exceeded or the connection to the local power transformer is broken and must be designed for the maximum short-circuit current. Following a power outage in the distribution network, the system may switch back on at the earliest after 3 minutes (low voltage) or 15 minutes (medium voltage).

Besides the automatic disconnection the TABs require for PV systems the installation of a ripple control receiver for limiting the maximum feed-in power. The signal is transmitted via the phone connection, by radio or through audio frequencies in the grid, depending on the network operator. Power generation is reduced in the increments 60%, 30% and 0% of the maximum feed-in power and is converted by relay. Systems ≤ 30 kWp require no ripple control receiver, if the feed-in is permanently throttled to 70% rated generator power.

1.3.4.4 Reactive power compensation

The TABs obligate the operator of a power generator to provide a certain share as reactive power. Its power factor cos φ is specified by the distribution grid operator, is graduated according to system size, operating point and rate period of the feed-in and lies in the range of 0.9 (underexcited) to 1. Consumed or fed-in reactive power exceeding the tolerances is charged to the system operator according to the conditions stated in the TABs. Capacitors installed for the reactive power compensation must always cut in and shut off together with the generator, in order to avoid capacitive reactive power.

1.3.4.5 Grid perturbations

Generally other grid components and connections must not be perturbed by operation of the generator. In specifying limits for disturbance variables, some TABs refer to DIN EN 61000-2-2, while others define their own limits. Conformity with the grid operator’s requirements comes with the manufacturer’s declaration or the operator’s own calculations.

The individual disturbance variables defined for the limits are:

Voltage pulses from cutting in or shutdown of the generators or major consumers, flickering at the grid connection point, harmonic currents and voltage asymmetries between the external conductors. In addition, some TABs also contain limits for impairment of intra-grid audio frequencies for ripple control receivers.

For avoiding grid perturbations, the system is disconnected from the grid if the maximum registered feed-in is exceeded.

1.4 Maintenance status and quality assurance

1.4.1 Manufacturer’s warranty and guarantee conditions

Most components of a PV system come with a manufacturer's guarantee in addition to the legally required product warranty. The manufacturer’s guarantee is tied to the particular manufacturer’s guarantee conditions, which demand measures for maintenance and servicing in addition to proper installation. The specifications of the guarantee conditions are generally implemented, since failure to do so would void the manufacturer's guarantee.

Besides the manufacturer’s guarantees, there is also the installer’s warranty, which depending on the type of contract holds for two (purchase agreement), four (construction contract) or five (contract for services) years. In addition, many installers also provide further services for promoting sales.

The terms “warranty” and “guarantee” are used in various ways in this regard, and sometimes incorrectly. For example, a manufacturer will use the term “Leistungsgewährleistung” (performance warranty) in the German translation of the guarantee conditions for the manufacturer’s products.

The following discusses in more detail the guarantee conditions for the individual components. We exclude DC components, since they are covered only by the two-year legal warranty. Our lists of manufacturers make no claim to completeness, but represent a comprehensive cross section of the market.

1.4.1.1 PV modules

The manufacturer’s obligations over the module service life break down into three different warranty and guarantee claims.

The legal warranty applies for 24 months from delivery of the module and comprises functionality and appearance.

In addition, all module manufacturers provide a product warranty or guarantee that is valid for 5 to 10 years. It covers production as well as material defects and for some manufacturers also includes aging beyond usual extent.

The performance guarantee goes into effect in case of reduced power by the module. This guarantee stipulates linear or graduated degression rates for the product service time below which a replacement must be provided.

Common are periods of 10 years for a performance guarantee over 90% of the module power and over 20 years for 80% of the power. Manufacturers are increasingly providing performance guarantees of up to 30 years, with a linearly expected annual loss in power of 0.5 to 0.7%. [2]

Regarding performance guarantees, it must be kept in mind that power tolerances (module datasheet) are always used in solar module calculations. Added are measurement tolerances making verification of the claim for the performance guarantee difficult. In case of a specified module power tolerance of ±3% and a measurement tolerance of ±3% as well, a power reduction greater than 10% can be verified only if the measurement value is less than the rated power by more than 16%. Table 1-11 contains an overview of warranty and guarantee conditions from different manufacturers.

All three forms of warranty provide compensation by exchanging or repairing the module in question, or financially in the form of reimbursement of the residual value or payment for revenue lost because of the reduced performance. Some manufacturers also assume the costs incurred from replacement and transport of the modules.

Table 1-11: Criteria in module manufacturers' warranty and guarantee conditions

	Manufacturer 1	Manufacturer 2	Manufacturer 3	Manufacturer 4	Manufacturer 5	Manufacturer 6	Manufacturer 7	Manufacturer 8
Types of warranty and periods [years]								
Legal warranty	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
Product guarantee/warranty	**10**	**12**	**5**	**5**	**10**	**10**	**10**	**10**
Performance warranty	**25**	**25**	**25**	**20**	**30**	**25**	**25**	**25**
Warrantee								
End customer	**X**	**X**			**X**		**X**	
First purchaser		**X**	**X**	**X**	**X**	**X**		**X**
Damage								
Material and workmanship flaws	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Reduced performance	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Visual flaws		**X**				**X**		
Services								
Exchange of product	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Repair	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Acceptance of replacement costs	**X**	**X**	**X**	**(X)**		**X**		
Reimbursement of residual value	**X**			**X**	**X**	**X**		**X**
Compensation for loss of revenue from reduced performance	**X**							**X**
Conditions								
Installation as per installation instructions	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Proper assembly	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Normal use	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Regular maintenance	**X**		**X**		**X**	**X**		
Use in original system	**X**			**X**	**X**		**X**	**X**

	Manufacturer 1	Manufacturer 2	Manufacturer 3	Manufacturer 4	Manufacturer 5	Manufacturer 6	Manufacturer 7	Manufacturer 8
Exclusion of liability for:								
Stand-alone systems	X	X	X	X	X	X	X	X
Force majeure	X	X	X	X	X	X	X	X
Vandalism	X	X	X	X	X	X	X	X
Combination with other module types	X	X	X	X	X	X	X	X
Overvoltage, grid perturbations		X				X	X	X

A precondition for warranty claims is proper use of the module as intended, in particular compliance with the installation instructions (see 2.3.1 Manufacturers' Installation Instructions). Ascertained infringements of the installation instructions or generally recognized codes of practice void all warranty claims against the manufacturer and revert to the constructor of the system if the latter is still liable.

About half of the module manufacturers require appropriate maintenance of the system for continuation of liability. Hardly any of the manufacturers state this requirement in terms of maintenance intervals or scope of the measures, however. Merely one set of installation instructions recommends an annual visual inspection of the wiring and mounting system.

1.4.1.2 Inverters

Unlike modules, inverters do not come with any separate performance guarantee. Reduced performance is instead covered by the manufacturer's guarantee, which applies alongside the two-year legal warranty and runs for two to seven years.

In addition, some of the manufacturers offer an incremental extension of the product guarantee for up to 25 years, at an extra charge. In a warranty case, the defective device is generally repaired or replaced by the manufacturer. Financial compensation is not provided for.

Table 1-12: Criteria in warranty and guarantee conditions for inverters

	Manufacturer A	Manufacturer B	Manufacturer C	Manufacturer D	Manufacturer E	Manufacturer F	Manufacturer G	Manufacturer H	Manufacturer J
Forms/max. period [years]									
Warranty	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
Factory product guarantee	**5**	**7**	**2**	**5.5**	**5**	**5**	**12**	**2.5***	**5**
Product guarantee subject to extra charge	**20**	**25**	**20**	**-**	**-**	**20**	**-**	**-**	**-**
Warrantee									
End customer	**X**	**X**	**X**		**X**	**X**	**X**	**X**	
First purchaser				**X**					**X**
Damage									
Material and workmanship flaws	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Reduced performance	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Visual flaws			**X**	**X**					
Services									
Exchange of product	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Repair	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	
Acceptance of replacement costs	**(X)**	**X**	**X**	**X**	**(X)**		**(X)**	**(X)**	**X**
Reimbursement of residual value							**X**		
Compensation for loss of revenue from reduced performance				**X**					
Conditions									
Installation as per installation instructions	**X**			**X**	**X**	**X**	**X**	**X**	**X**
Proper assembly	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Normal use	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Regular maintenance	**X**			**X***	**X**	**X**	**X**		
Exclusion of liability for:									
Force majeure	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Overvoltage, grid perturbations	**X**	**X**	**X**	**X**	**X**	**X**		**X**	**X**
Infringements of common regulations		**X**	**X**	**X**	**X**	**X**	**X**		**X**

*****Only for some product series

Asserting a claim under the guarantee presupposes that the inverter has been properly mounted and operated. Not all manufacturers refer to the installation instructions, however, but instead refer to common regulations, mainly those from the VDE. No liability exists for damage caused by force majeure or overvoltages. Exempted from the guarantee are usually also wear parts like filters and varistors.

Manufacturers differ greatly in the requirements on maintenance. While some of them state no express conditions at all, others require merely “proper operation” of the inverter. Still others even mention specific measures, such as cleaning the air filters or a visual inspection of the connection terminals, and specify maintenance intervals.

1.4.1.3 Mounting systems

For mounting systems, a ten-year factory product warranty in addition to the legal warranty is common. Only the larger manufacturers publish comprehensive warranty conditions, however. Usually details on the guarantee are published in the datasheets of the particular system or in a brief guarantee certificate. The factory guarantee covers defects related to material flaws and production errors and or a product exchange or factory repair in case of damage. Assumption of transport costs is not common.

Table 1-13: Criteria in warranty and guarantee conditions for mounting systems

	Manufacturer I	Manufacturer II	Manufacturer III	Manufacturer IV	Manufacturer V
Forms/max. period [years]					
Warranty	**2**	**2**	**2**	**2**	**2**
Factory product guarantee	**10**	**10**	**10**	**15**	**10**
Warrantee					
End customer	**X**		**X**		**X**
First purchaser		**X**		**X**	
Damage					
Material and workmanship flaws	**X**	**X**	**X**	**X**	**X**
Visual flaws					
Services					
Exchange of product	**X**	**X**	**X**	**X**	**X**
Repair		**X**			**X**
Acceptance of replacement costs		**X**			**X**
Reimbursement of residual value	**X**				**X**

	Manufacturer I	Manufacturer II	Manufacturer III	Manufacturer IV	Manufacturer V
Compensation for loss of revenue from reduced performance					
Conditions					
Installation as per installation instructions	X	X	X	X	X
Proper assembly	X	X	X	X	X
Normal use	X	X	X	X	X
Regular maintenance	X	X			
Use in original system					X
Exclusion of liability for:					
Force majeure	X	X	X	X	X
Infringements of common regulations	X		X	X	X

Warranty claims can be accepted only if assembly was performed in compliance with the installation instructions by a qualified handicraft business. In addition, the static design must comply with the conditions in the particular application. Some guarantee conditions refer here to DIN 1055 (see 2.3.2 Standards, Regulations and Guidelines). Disassembly of the mounting system or parts thereof for use in a different system is not expressly precluded, if the static requirements are met. Most manufacturers require regular maintenance of the system as a precondition for continuation of the warranty. They do not specify maintenance intervals or specific measures, however.

1.4.2 Facilities for quality assurance and maintenance

Besides the manufacturers of PV components, there exists a series of other institutions and facilities for ensuring the quality of PV systems. On the one hand, there exist normative specifications by the manufacturers, dealers and installers. On the other hand, industrial and professional associations as well as independent test centers offer further voluntary certifications and documentation templates.

1.4.2.1 Quality assurance for the components

The first step in quality assurance lies in the manufacturer’s quality checks during production. The corresponding normative specifications include ISO 2859 on “Sampling procedures for inspection by attributes” and ISO 3951 on “Sampling procedures for inspection by variables”. The first refers to inspection characteristics that have the character of attributes, while the second focuses on constant product properties.

Both describe procedures for continual quality control in production and at goods issue, and state sampling sizes and scope. On the basis of these standards, intermediate dealers have developed their own processes for quality assurance.

Compliance with quality standards can be monitored on a voluntary basis by independent test centers. For example, TÜV Rheinland offers “power-controlled” certification for module manufacturers. A precondition for the issue of a certificate is a high standard of quality assurance with particular attention to compliance with performance tolerances for modules. Several prominent module manufacturers both in and outside of Germany are availing themselves of this offer.

Other institutes undertaking independent quality inspections for components are (in Germany) the Fraunhofer ISE, the VDE, PI Berlin and (internationally) Ispra, UL and JET, for example.

For the further improvement of quality assurance for PV modules and the assessment of PV modules in solar parks, a research project is being jointly conducted between 2013 and 2017 by Sunnyside upP, ISC of Constance, RWTH Aachen, the Solarfabrik and TÜV Rheinland. The project is being supported with funding from the Federal Ministry for Economic Affairs and Energy (BMWi) on the basis of a resolution of the Bundestag with reference number 0325588D.

1.4.2.2 Quality assurance for assembly and acceptance inspection

At least as important as the quality of the employed components is the correct performance of assembly by the installer. Complaints by end customers pertain as much to improperly performed work as to defective components. This is equally true of damage-causing events, including fire, as will become clear in section 3.3 Damage and fire event analysis of PV systems.

Damage from installation flaws noticed in due time are covered by the installer’s warranty. If this warranty has already expired, the end customer must pay for the damage themselves.

For detecting defects in the system even prior to acceptance and for the best possibility of reacting to subsequent damage, DIN 62446 (VDE 0126-23) contains specifications on commissioning inspections, documentation and maintenance (see section 5.5). This standard expressly does not apply to systems with integrated power storage systems, however. The documentation is produced by the constructor of the system and provided to the end customer at commissioning. It contains a wiring diagram, product data sheets of all employed components and instructions on operation and maintenance.

The wiring diagram consists of a sketch of the overall system up to the grid connection point and information on the individual components, such as manufacturer, component description, string size, rated current and voltage, position and accessibility. As instructions for further operation of the system, the owner is provided information in case of a system malfunction or emergency shutdown as well as information on the system condition and existing warranty claims. At this point the installer also has the possibility of leaving behind maintenance instructions.

Regarding the commissioning inspection, DIN EN 62446 supplements IEC 60364-6, “Low-voltage electrical installations – Part 6: Verification” (German implementation of DIN VDE 0100-600), dividing the inspection into viewing, measuring and testing. The visit comprises a visual inspection of the system according to criteria determined by the standard as well as a check of conformity of all components with common safety regulations. Testing and measurements contain every additional inspection of functional availability and safety of the system, in particular the application of measuring procedures described in the standard. DIN EN 62446 makes these general specifications for the case of a PV system and expands the test criteria of IEC 60364-6 along these lines.

As an orientation aid for the system documentation, several associations have issued standardized preprinted forms to ensure the quality of the documentation, such as the “PV passport”; see section 2.4.3.

Another tool for ensuring quality are the RAL quality and test requirements for PV systems (RAL GZ-966) compiling the common technical rules for installing and operating PV systems and serving as a template for technical terms of delivery. They contain a list of requirements on the production of components as well as on the planning, installation and maintenance of entire systems. In doing so, they capture at least the status of current standardization, while tightening the latter in a few points. The use of RAL GZ-966 in supply agreements is subject to a charge for the contractor and presupposes certification by the RAL Quality Association. To obtain this certification, the company must undergo an initial inspection and thereafter repeat inspections at intervals of at most two years, during which its capability for complying with RAL GZ-966 will be assessed.

For PV power plants qualification services are provided by various institutes, test facilities and experts. The advantage is quality assurance parallel to construction, with a quality check by an independent third party at the acceptance inspection of the system.

In addition, services that are focused on the certification of installation specialist companies (for example, by TÜV Rheinland) or on PV experts (for example, by the VDS (Association of German experts)) can ensure a high installation quality.

1.4.2.3 Maintenance

Instructions for the maintenance of low-voltage systems in general appear in DIN VDE 0105-100 “Operation of electrical installations – Part 100: General requirements”. Repeat inspections of the system must occur at appropriate intervals, so that any deterioration of safety conditions will be detected before damage to people or property occurs.

As in the commissioning inspection, different measures for viewing, testing and measuring are provided for, which are not mandatory, however, but are to be implemented so as to exclude any detriment to system safety. The repeat inspections of PV systems are regulated in DIN EN 62446, which treats the commissioning inspection as a standard for the scope of the repeat inspections. The recommendations on maintenance and cleaning contained in the system documentation must also be followed. However, specific time intervals between the repeat inspections are not specified here either. To close this gap, DIN VDE 0100-712 is currently undergoing expansion, and will possibly recommend *maintenance intervals between two and three years*.

A few guarantee conditions, in particular for inverters, also state measures for maintenance (see section 2.4.1: “Manufacturer’s Warranty and Guarantee Conditions”).

While other countries, such as Switzerland, stipulate maintenance intervals for electrical energy producing plants (including PV systems) by law, Germany merely offers recommendations from insurance companies via standards and guidelines. Exceptions are individual cases of binding agreements between investors and operators, for example.

Regular maintenance measures are the precondition for undisrupted and safe operation of the system. Faulty components or installations, environmental effects and general aging processes can lead to local overheating over the course of the operating period and in the worst case cause electric arcs.

1.4.3 Requirements by law and by institutions (VDS, GDV, BSW)

The specifications of the particular regional building code with the corresponding requirements must be heeded. This applies also and especially to roof accessibility for fire extinguishing purposes and to the structural fire protection requirements. The system is commissioned and connected to the grid as per VDE AR 4105 and the general supply conditions (AVBEltV).

Together with the Verband der Sachversicherer (VdS) (Registered Association of Property Insurers), the Gesamtverband der Deutschen Versicherungswirtschaft e.V. (GdV) (Registered Association of German Insurers) formulates guidelines for systems and products. These VdS guidelines basically comprise measures on personal, property and building protection for the purpose of damage prevention. The Technical Guideline for Photovoltaic Systems, VdS 3145, dated 07/2011, offers information from the insurers' perspective on selecting, planning, installing and operating grid-connected PV systems with the aim of avoiding or minimizing operational disruptions, fires and damage. Guideline VdS 2010 on "Risk-Oriented Lightning and Surge Protection" authoritatively specifies the risk and protection classes for lightning and surge protection. Guideline VdS 2025 provides information on planning, designing, installing and operating cable and electrical line systems.

Together with the German Electrical and Electronic Manufacturers' Association (ZVEH), the German Solar Industry Association (BSW) has developed the "PV passport *www.photovoltaik-anlagenpass.de*. It basically consists of a multi-page form and inspection log for a professional inspection and documentation and specifies the guidelines to be followed in planning and installing the PV system (see also 8 Supplement, IX Appendices, c).

2 Electric arcs: Physical background and DC issues

Electric arcs are plasma currents and perceivable as searing light that is arc-shaped from a certain length, with typical crackling noises. The temperatures of an electric arc can reach several thousand degrees.

While AC electric arcs have self-extinguishing properties owing to the voltage and zero-current crossings, DC electric arcs can generally burn with stability, which poses a considerable risk of fire.

All electric arcs are accompanied by a high-frequency, electrical noise that can be registered in the conductor as well as through detection of the electromagnetic waves. The characteristics of a DC electric arc, for example, the way it can appear in the PV generator field, differ from those of an electric arc in the AC circuit. This will be explained in detail in the following.

2.1 Definition and properties of an electric arc

An electric arc is a gas discharge occurring between two electrodes in which an electrical potential difference causes an impact ionization, which in turn allows a continual flow of current.

Above a certain temperature a conductive plasma is formed from the nitrogen in the air. This state can occur if contacts through which an electric current is flowing are pulled apart, for example. As the contact pressure of the contacts decreases, the transition resistance increases. Fusion will occur at points, followed by boiling of the contact material. The remaining metallic bridge finally explodes. An initial metallic vapor electric arc can become a stable gas discharge electric arc if the current and voltage are sufficiently high [3].

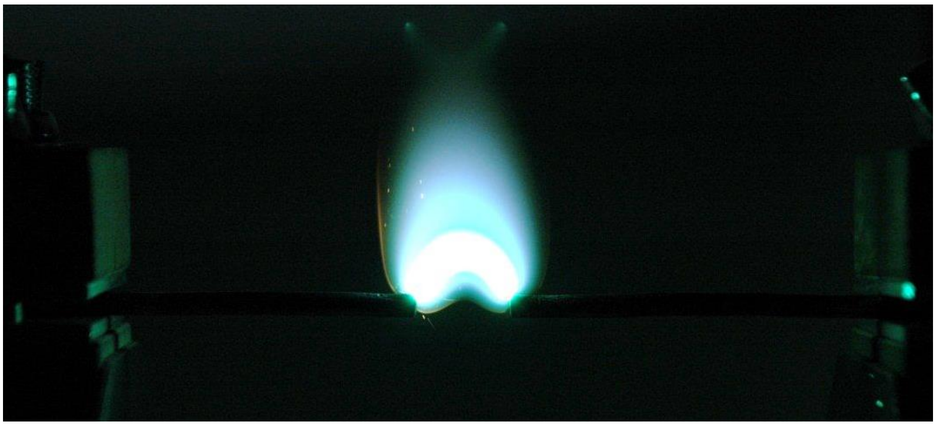

Figure 2-1: Stable DC electric arc between copper electrodes, photo: TÜV Rheinland

For a stable, freely burning electric arc to occur, sufficient voltage must be available to the electric arc. This electric arc voltage consists of the cathode drop, the anode drop and the column drop linearly dependent on the length of the electric arc. The minimum voltage for an (extremely short) electric arc thus consists of an anode drop and a cathode drop; no electric arcs are possible with a lower voltage.

Both the minimum voltage and the minimum current of an electric arc depend on the material. In the case of copper, they are 13 V and 0.4 A, respectively, according to the literature [4]. Series of measurements performed at TÜV Rheinland have confirmed these magnitudes [5]:

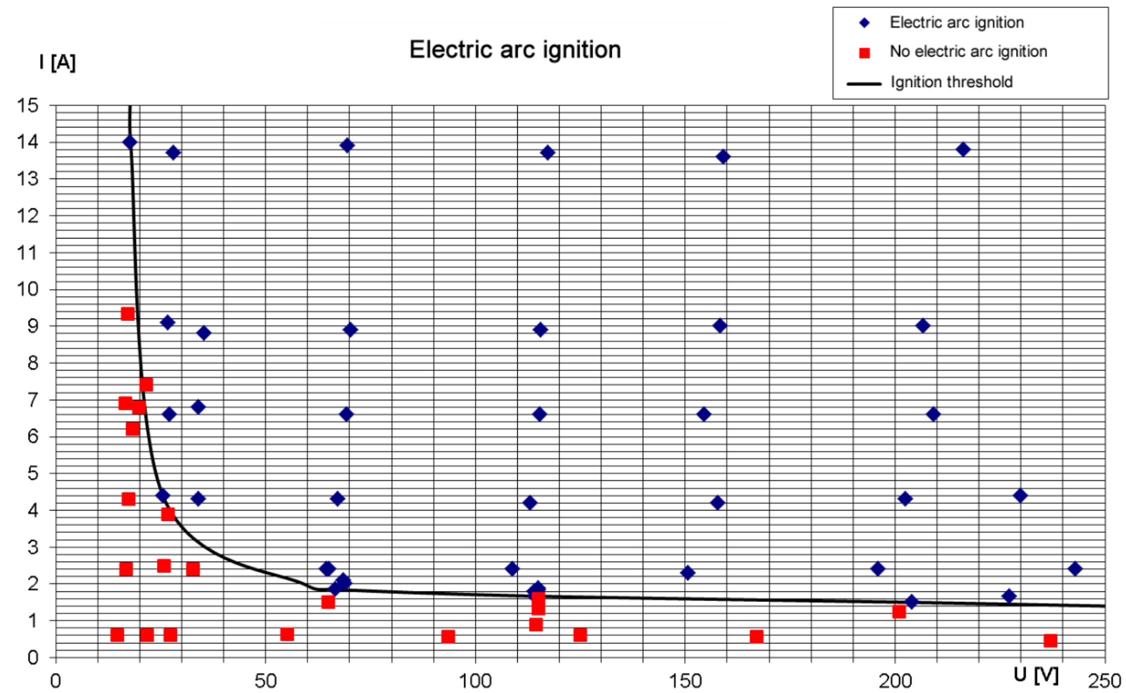

Figure 2-2: Electric arc ignition limit determined on the basis of copper electrodes, source: TÜV Rheinland

An electric arc emits very bright light in both the visible and UV light ranges and can cause eye damage. The electric arc itself is distinguished by extremely high temperatures of 10,000 K and higher [6], so that the resulting fire can easily spread to surrounding components.

A powerful voltage flashover produces a very loud noise, comparable to a thunder clap, caused by the air escaping at ultrasonic speed from the discharge channel. In addition, the explosion-like spread of the hot air creates a pressure wave. In contrast, an arc flash of just a few amperes produces only a soft crackling and no perceptible difference in pressure.

The electric arc emits electromagnetic radiation of frequencies up to the MHz range through cables as well as through the air. Unfortunately, no spectrum characteristic of all types of electric arc exists that would enable reliable identification of an electric arc in a PV system under any circumstances. Identification is possible based on certain shared properties of these spectra, however. The procedure is described in section 5.3.5 Electric arc detection.

2.2 Arc quenching

The purpose of an arc quenching device is to increase the energy beyond what is necessary for maintaining an electric arc in the stable range and thereby to rupture the arc path.

Generally this rupture is brought about by increasing the required arc voltage. The following measures are used with conventional switch elements:

- Lengthening the electric arc column
- Cooling the electric arc
- Pressure on the electric arc
- Segmentation of the electric arc

Figure 2-3 shows schematically how these measures can be implemented in an arc quenching device.

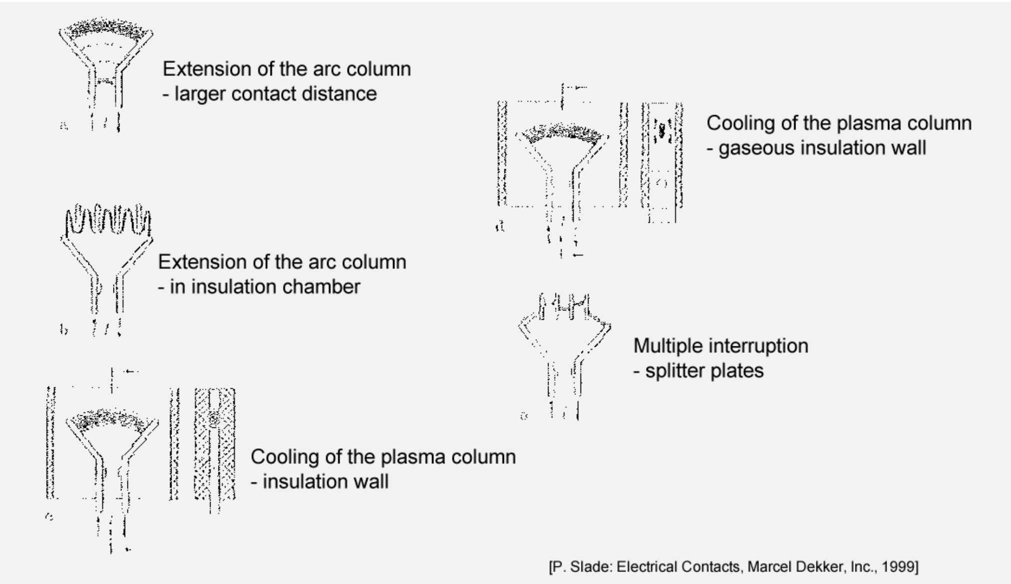

Figure 2-3: Different possibilities of electric arc quenching **[4]**

2.2.1 Arc flashes in AC and DC systems

Transmission and distribution of electrical energy occurs mainly in AC systems. Alternating current is distinguished by the periodic reversal of the current flow, which has a positive effect on the arc safety of electrical systems.

As an AC voltage or alternating current approaches its zero-point crossing in the case of an existing electric arc, the current and voltage levels required for maintaining the arc are exceeded, which quenches the arc.

A repeated voltage increase will often not cause re-ignition, since this would require a much higher voltage than that needed to maintain an electric arc.

Since the arc path is still partially ionized and heated by the pre-existing electric arc and leakage currents can occur along damaged insulation segments, a new flashover is still possible in unfavorable cases. In these cases, an intermittent electric arc occurs that is briefly extinguished twice per current period, in order to re-ignite again at sufficient voltage.

The situation is different with a DC system, as is present in PV modules, the module wiring and the string distribution of a PV system up to the inverter. Here there is no zero-point crossing. Electric arcs persist and burn with stability as long as the voltage and current suffice for maintaining them. This can certainly be the case for longer periods of time (up to some ten minutes).

Since DC electric arcs are not intermittent, but constant, their radiation has a different characteristic than that of AC arcs. For this reason DC and AC arcs cannot always be detected by the same method.

2.2.2 Electric arc characteristics with different DC sources

If an electric arc is supplied by an energy source, the U/I characteristics of the generator and the arc ignition boundary (see Figure 2-2) intersect. Figure 2-4 shows the arc ignition boundary for a fixed electrode spacing with the characteristics of a PV generator and an active linear two-terminal circuit (voltage source with an internal resistor) with identical no-load voltage and identical short-circuit current. We can clearly see that the PV generator characteristic intersects the electric arc ignition boundary. If on the other hand we compare the characteristic of the active linear two-terminal circuit with the electric arc ignition boundary, we find that no intersection occurs. The electrode spacing is too great to maintain the voltage of the arc at a given resistance.

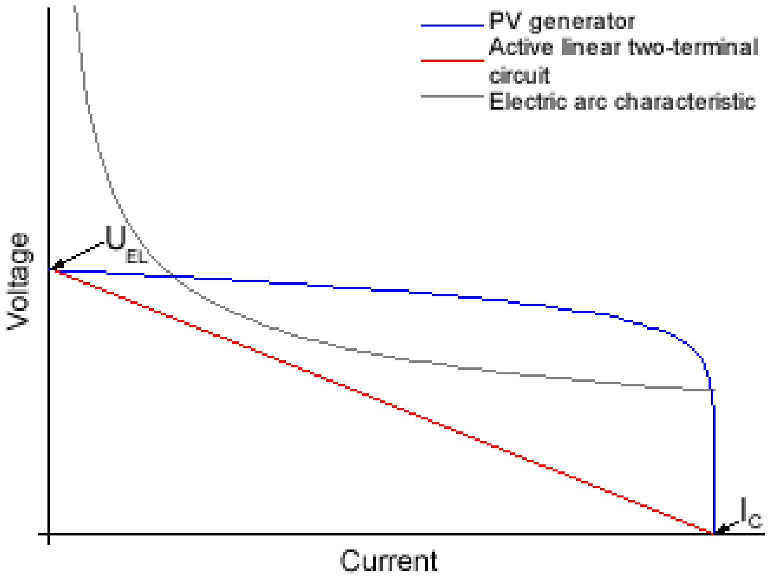

Figure 2-4: U/I characteristic of an active linear two-terminal circuit and of a PV generator and the electric arc ignition threshold with fixed contact spacing (schematic).

As a consequence, electric arcs in PV systems can already remain stable longer with smaller contact spacing than in conventional DC systems, owing to the current source-like properties of the solar generator. In addition, switchgear designed for conventional DC sources cannot necessarily shut down a PV generator with the same parameters (I_{SC}, U_{OC}).

Summary

An electric arc is a gas discharge (plasma) between two electrodes caused by impact ionization that allows a flow current depending on the material and the presence of minimum levels of current and voltage. In DC systems this current is not self-extinguishing.

Because of their particular PV generator characteristic, PV systems support electric arcs in case of a fault. The electric arc issue therefore deserves special attention in reference to fire risks.

3 Safety and quality in photovoltaics – risks and errors

Besides structural properties (such as spacing), the material properties of the participating components are crucial in the development and spread of a fire. Here different factors like fire resistance, sustained combustion or smoldering or the possible dripping of burning parts determine the spread and ultimately the effects of a fire. Since polymer materials make up a significant share of a PV module, their properties in particular greatly influence fire behavior.

The research project investigated two different scenarios of PV fire emergence.

(1) Fires in or at the building and spreading to the installed PV system.
(2) PV system as cause of fire given overheating with scorching or production of an electric arc at defective contact points in the module (or other components), corresponding to the damage analysis in section 3.3

The assessment and requirements of the material properties differ in part among these scenarios. Finally, the materials should meet all requirements as much as possible.

While section 3.1 considers the properties of a PV module regarding resistance to fire from an external source, section 3.2 analyzes the risks of arcing in a PV system and section 3.3 presents the results of a detailed damage analysis of actual events of overheating and PV fires in recent years in Germany.

The requirements and approaches to preventing fire emergence within the PV system especially due to arcing are described in sections 3.5 and 3.6.

3.1 Fire behavior of modules

Different components of a photovoltaic system are combustible because of their polymer content. Section 4.6 describes in particular the composition of PV modules as they are mostly installed in existing PV systems in Germany. The polymer content of crystalline glass thick-film modules (c-Si) is 5 – 10% [7], [8], [9], or about 600 – 1,200 g/m². This content largely pertains to the embedding material (EVA embedding film) and the backing (PET/PVF). In addition, various adhesives and sealants are used, along with insulation materials in junction boxes, connecting cables and connectors.

Given an assumed module area of 50 m² (approx. 38 standard modules, approx. 9 kW_p), up to 60 kg of polymer materials thus come from the modules alone. Other polymers occur in string cables, junction boxes and inverters.

Polymers generally produce a high combustion heat amounting to about the level from heating oil, according to a VDS publication [10], as in the case of polyethylene, for example (PE: 46 MJ/kg > heating oil: 43 MJ/kg), as illustrated in the following figure.

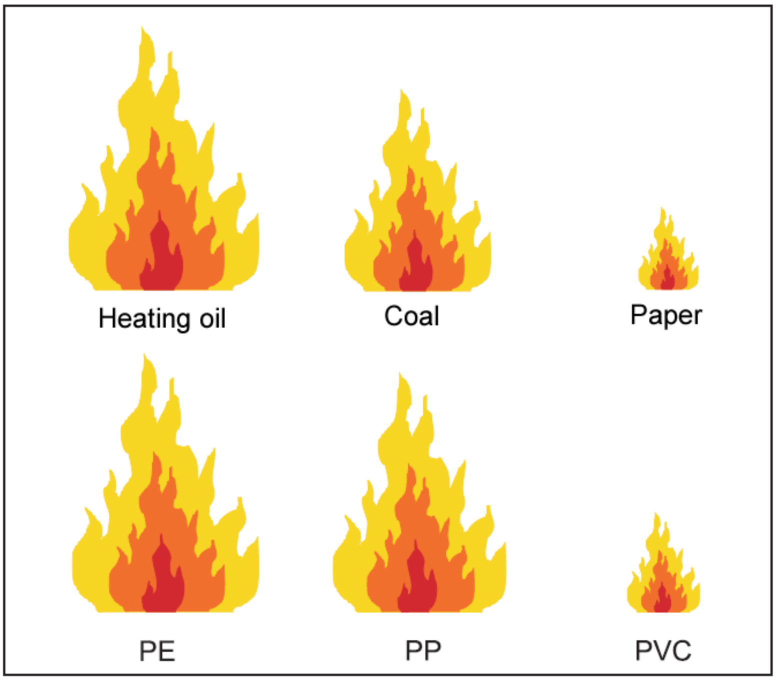

Figure 3-1: Combustion heat of different polymers compared with conventional heating substances **[10]**

In the event of a fire involving a PV system, the fire behavior of the employed polymers and their mass in the components play an important role in fire development and spread.

3.1.1 Fire tests (resistance to flying sparks and heat)

PV modules forming part of a roof (building-integrated PV modules (BIPV)), are tested as roof coverings in Germany. Generally roofs must be sufficiently resistant to fire from external sources and to heat radiation. PV modules as roof components must meet these requirements. There are different test procedures for assessing the fire behavior of roofs with respect to external and internal sources. DIN VDE 0126-21 on “Photovoltaics in Building” declares the special requirements on BIPV modules. In addition, in its bulletin from 2012 the DIBt refers to the necessity of a general building authority test certificate (abP) with inspection as per EN 13501-5 (ENV 1187-1) or DIN 4102-7 for roof-mounted PV modules.

On the other hand, PV modules of an elevated solar system are located outside the building envelope on roofs (“hard roof coverings”) and are not subject to any particular requirements of the building authority approval for fire protection in reference to resistance to flying sparks and heat, but they are regarding inflammability with min. *normal flammability* through DIN EN ISO 11925-2 and EN 13501-1, class E, as per requirements of the state building codes.

Section 1.3.2 lists all the normative requirements on PV modules. A detailed description of the fire tests of PV modules including pass criteria provided for in Germany and internationally appears in a research report of the BAM from 2014 [11]. The research investigated fire behavior including emissions from PV modules in laboratories.

Three of the most common types of modules were also studied in the fire lab. The identified fire behavior is described below, while pollutant emissions are discussed in detail in section 4.6.

3.1.2 Flammability and fire spreading

A market review by Photon from 2012 (see section 4.6.3) revealed that the market share of crystalline modules as the clearly leading technology has remained relatively constant at 80% to 90%, while the share of all thin-film technologies in total lies between 10% and 20% (with a declining tendency in recent years). The Currenta fire laboratory conducted three series of experiments with the following technologies:

- c-Si (crystalline thick-film module, glass film laminate)
- CIS (thin-film module based on cesium indium selenium semi-conductors, glass film laminate)
- CdTe (thin-film module based on cadmium telluride semi-conductors, glass-glass laminate)

(see also section 4.6.6).

An elevated solar system parallel to the roof and in a pitched position (23° incline) was emulated, with the fire spreading from the underside of the module (fire emergence scenario: influence of a roof timber fire). The experimental setup and performance of the experiment are described in detail in 4.6.6.1, the results can be found in IX Appendices in the Supplement.

The experiments were performed underneath an exhaust hood based on ISO 9705, with an exhaust flow rate of about 1 m³/s. The following variables were measured for describing the fire behavior:

- Heat release rate
- Smoke production rate
- Temperatures on front and back of the module
- Mass loss of the modules and mass of the fire residue
- Destroyed module surface

Two different burner outputs of 25 kW and 150 kW simulated different levels of fire stress.

In the 25 kW burner output experiments, only locally limited, otherwise primarily surface, damage occurred on all three module types.

Figure 3-2: Damage from stress with 25 kW burner output, left: c-Si, center: CIS (transversely placed), right: CdTe (transversely placed)

At 150 kW burner output, on the other hand, all module types were destroyed over wide areas:

Figure 3-3: Damage from stress with 150 kW burner output, left: c-Si, center: CIS (transversely placed), right: CdTe (transversely placed)

<u>Glass film modules (c-Si, CIS)</u>

The results of the lab tests can be summarized as follows: burning material already fell from test samples within about 1.5 – 4 minutes; after 2 – 4 minutes the backsheet became detached and a full-scale fire started after 6 – 8 minutes. The upper glass plate burst after 7 – 10 minutes. After about 12 minutes most of the combustible parts had already disintegrated.

<u>Glass-glass module (CdTe)</u>

This test sample already began dripping burning material after 2.5 minutes; the glass (rear side) fractured after about 4 minutes, and fire penetration occurred 30 minutes later.

As long as combustible material was still present after the end of the flame impingement, all 3 test types subjected to the 150 kW burner continued burning for 2 – 3 minutes. In the tests with merely 25 KW burner output no significant after-burning was determined.

In other words, under relatively low stress, e.g. with a smaller electric arc turned off by an arc detector, no independent spread of fire occurred on these specimens.

On the other hand, once a full-scale fire develops in a PV module, it can continue burning and thereby spread the fire to other elements. This is also the case with glass-glass modules.

If we consider the heat release rate in these tests, we see that the fire develops primarily between approximately 4 minutes and about 12 minutes after the start of flame impingement, after which time it decreases relatively fast. Below we show this in the case of the c-Si module. The other two module types showed similar developments over time; merely the values differ.

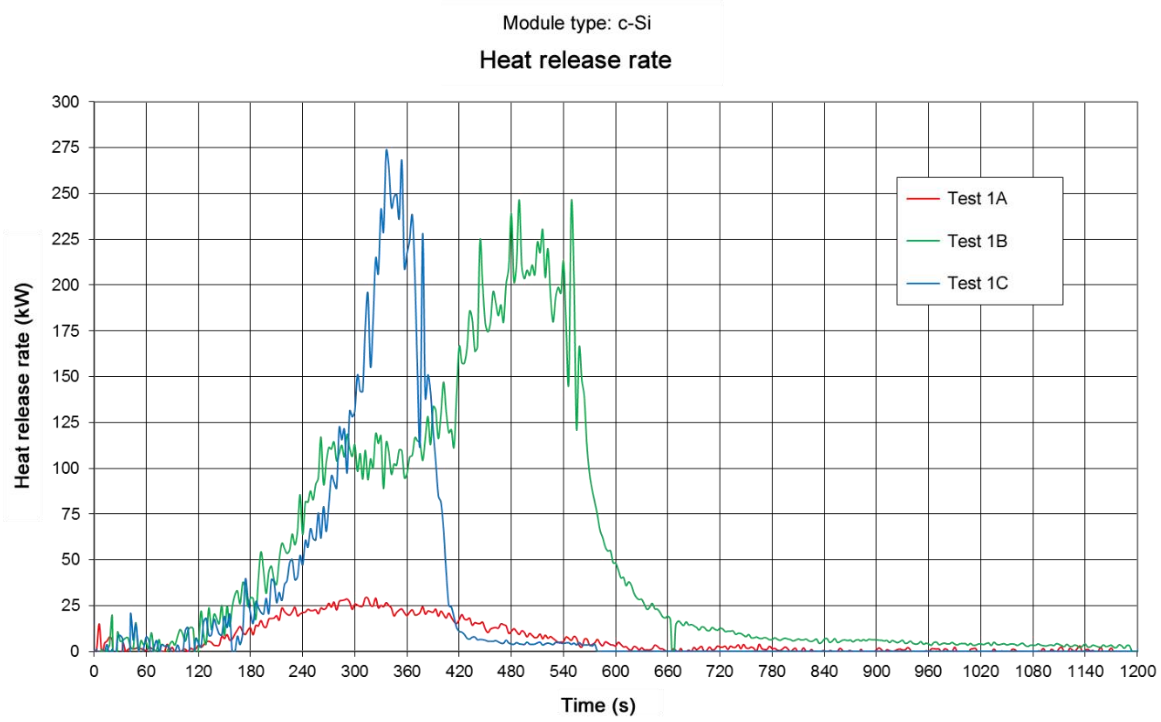

Figure 3-4: Heat release rate of the c-Si module during the tests (red – 25 kW, green –150 kW burner, (blue – the fire was extinguished after 7 minutes, so not relevant here)

The fire tests conducted by experts from the Bundesanstalt für Materialforschung und -prüfung (Federal Institute for Materials Research and Testing, BAM) in a research project [12] on the fire behavior of PV modules contained several different series of tests, including a series with stress analogous to the test series described here, with a gas flame impinging from below. The burner output was merely 30 kW with a compact flame (spot stress as opposed to wide-area application in the tests performed in this project).

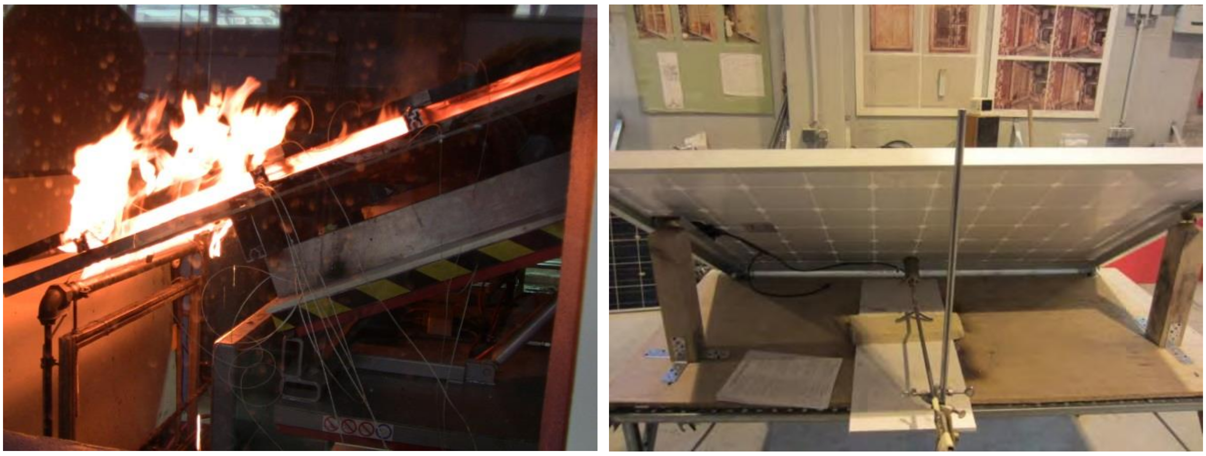

Figure 3-5: Left: TÜV/Currenta test setup with surface burner, photo: TÜV Rheinland, right: BAM with point-like gas burner centrally positioned, photo: BAM **[12]**

As results BAM found that:

- Damage from flame impingement from below was significantly greater than in the standard fire tests with flame impingement from above (burning brand tests), for both crystalline thick-film modules (glass-film) and thin-film modules (glass-glass).
- No flame penetration occurred in the crystalline modules, although the modules themselves were damaged over large surface areas.
- Thin-film modules suffered flame penetration already after 2 minutes with only low surface damage.

By comparison, significant differences were found in the results for the fire behavior of PV modules. The statements on the time of burn-through, extent of destruction, detachment of burning parts and fire propagation vary depending on the flame intensity and impinged module area.

Specific statements on fire behavior accordingly apply only to the examined test samples in the particular test constellation. No generalizations can be made!

General statements from previous fire tests on modules or module samples agree with one another.

Conclusion

PV modules are combustible irrespective of their technology and design, and can independently continue burning in the event of a full-scale fire.

Within a few minutes, burning materials (films, fused glass) can begin dripping. Depending on the flame impingement, glass plates can also burst after a few minutes.

Glass-glass modules develop less combustion heat and smoke gas because of their lower polymer content.

3.2 Assessment of the electric arc risk in PV systems

Like any electrical system, a PV system can release large amounts of heat in spots in case of a malfunction, and thereby become a fire source. Section 3.3.2 contains an analysis of how often this case actually occurs (see also [13]).

Even if fires caused by PV systems are fortunately rare, fire incidents often pose severe risks for people and property.

To develop effective strategies for avoiding fires or reducing their propagation, we must know the effects triggering and promoting fire.

The largest danger potential within a PV system comes from electric arcs. An enormous amount of heat, measuring several thousand degrees, develops that can destroy the surrounding materials and lead to a fire.

If electric current is flowing, heat is generated by the electrical resistance of the conductor. In case of a malfunction, increasing heat can also come from local elevations in resistance, as at aging contact points. This sets in motion a dangerous spiral with forced aging at increased temperatures, at the end of which scorching or, in the worst case, an electric arc can occur depending on the given materials and structural design.

Contacts and therefore potential risk points exist in large numbers in any PV system. A single module alone contains hundreds of contacts between the individual cells and strings.

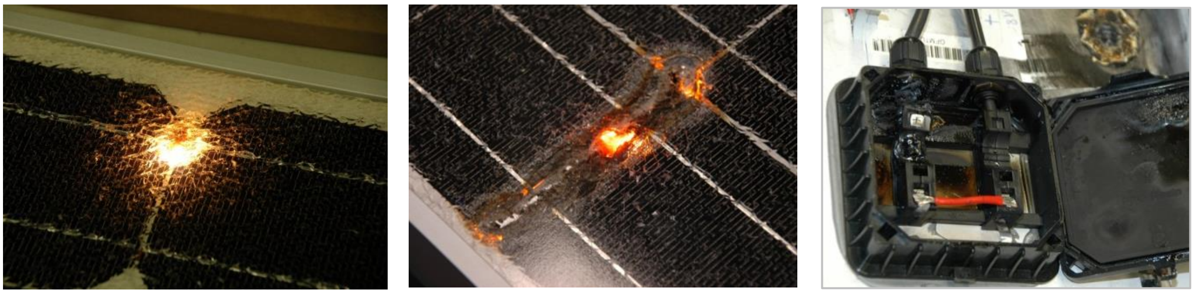

Figure 3-6: Electric arcs in PV modules, photos: TÜV Rheinland

If a terminal of the solar generator is grounded, damaged insulation can allow short-circuiting to ground by the other terminal and thereby ignite an electric arc. Since the overwhelming majority of systems in Germany do not have grounded solar generators as in the US, this danger is low here (Germany), however.

Another possible source of risk is a short circuit between the terminals of the system or simultaneous short circuits of both terminals to ground (so-called parallel electric arcing). Since in such cases the entire system voltage is available for ignition and for maintaining the electric arc, even smaller currents will suffice for a stable electric arc, as shown in figure 3-2. On the other hand, such scenarios are fortunately quite unlikely, since cables in PV systems are double-insulated. In addition, a genuine parallel electric arc requires simultaneous damage to two main cable strings immediately adjacent to one another as well as an initial contact for the electric arc ignition. A double short circuit to ground is in turn hardly possible in contemporary inverters, since their insulation monitoring will already detect the first short-circuit to ground and shut down the system.

Much more likely is the occurrence of a serial electric arc. A typical PV system contains countless serial points of connection – for example, in the module between the individual cells, at the string connectors and in the module junction box, outside the module in junction boxes or connectors and inside the inverter. If one of these connections is faulty or deteriorates in the course of the operating period, resulting in an elevated transition resistance, this area will become overheated from the current flow. The heat development can cause other contact material to diffuse or even melt down until at some time the connection fully breaks. In this case, an electric arc can form over the (initially very small) air gap. Serial electric arcs are typically lower in energy compared with parallel electric arcs, since a large part of the voltage drops via the inverter and these arcs often occur only in one of several parallel strings. This also makes them more difficult to notice, however, since the system seems to continue running normally. Figure 3-7 schematically illustrates different points of risk.

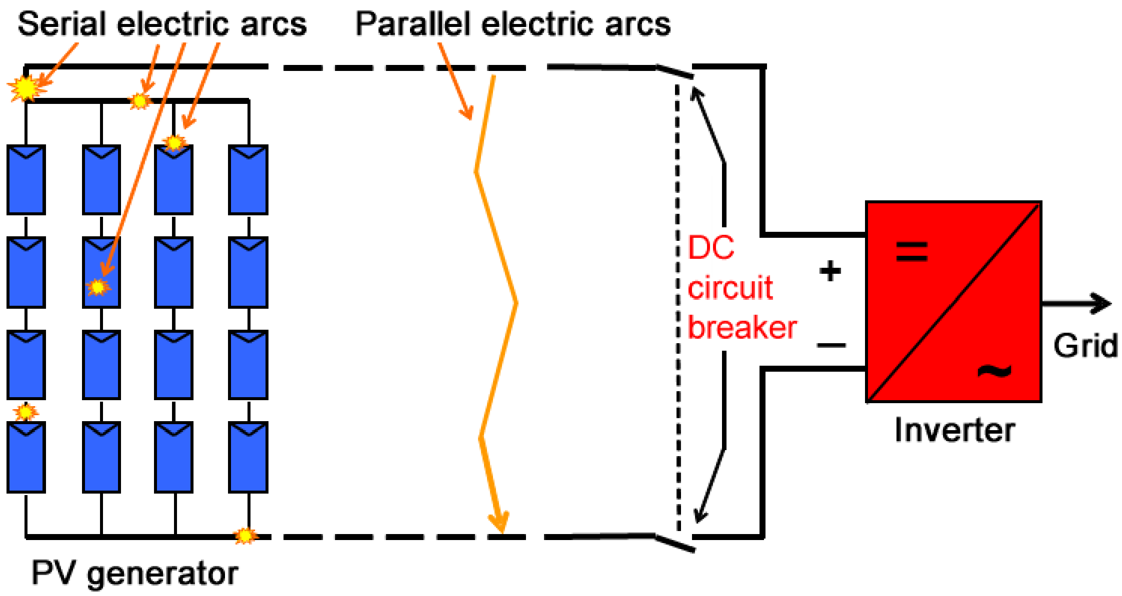

Figure 3-7: Possible propagation of serial and parallel electric arcs in a PV system [source: **[14]**]

3.3 Damage and fire event analysis of PV systems

3.3.1 Introduction

The project specifically researched cases of fire and overheating in PV systems in order to identify possible weak points and derive potential for improvement. Since the point was to find weak points, overheating and fire incidents were considered together, thus neglecting the influence of the surroundings of the damaged component on the level of damage.

The following sources of information were analyzed:

- Internet and media reports
- Operational reports from fire departments
- Assessor reports and statements
- Damage reports from Mannheimer Versicherung
- Internet-based survey

The recorded information was checked as to plausibility and if necessary followed up and evaluated. In many cases only incomplete details were available, so that only partially plausible estimates about the origin of damage were possible or the ultimate cause of fault could not be identified. If a damage appraisal was available, the conclusions from this report were adopted.

The analyses presented in the following reflect the status of January 2013. At this point in time, Germany had approximately 1.3 million PV systems with a total output of over 30 GWp. Individual fire incidents in 2013 entered into the analysis.

The following incidents of damage from overheating or fire involving PV systems in Germany were researched or reported:

- approximately 430 cases of fire or overheating in PV systems,
- about 220 cases thereof with external causes of fire
- about 210 cases with the cause of fire lying in the PV system

While far from recording all incidents, the analysis is probably the most comprehensive published compilation to date.

In 2013 and 2014, a series of further fire events was found whose causes and effects correspond to the statistics of section 3.3.2, so that a representative data stock may be assumed.

Two known fire cases 2013 and 2014 illustrate the point:

1. Fire incident in Walldorf: fire in a photovoltaic system on a warehouse roof

Foto: PR Video

Figure 3-8: Incinerated PV modules on a flat roof, substructure here with plastic trays(!)

In June 2014 PV modules in the system in question caught fire on a flat roof owing to a technical defect, resulting in property damage amounting to several thousand euros. Firefighters were able to promptly extinguish the fire, without it spreading to the building. As can be seen on the photo, the elevation was provided by plastic trays. These plastic trays are generally *normally flammable* (class E as per EN13501-.1). When selecting installation materials, especially for roof-mounted systems, attention must be given to the significant **potential for ignition and propagation of fire** if plastic is to be used.

2. Fire incident on Norderney: In August 2013, a fire started here in a workshop with adjoining vehicle depot. The fire spread rapidly, the roof structure and entire PV system collapsed, and the damage amounted to several million euros.

Figure 3-9: After a fire in a workshop with warehouse and depot (photo: Norderney Fire Department)

These examples demonstrate the scenarios basically to be distinguished among fire incidents at buildings with PV installations: on the one hand, the origin of the fire lying in the PV system itself, and on the other hand the "collateral fire" at a PV system caused by an external source (in this case, a building fire).

3.3.2 Statistical damage analyses

The approximately 210 damage incidents with causes lying inside the PV system were further analyzed. Table 3-1 breaks down these cases according to level of damage. Figure 3-10 explains these figures.

Table 3-1: Extent of damage in approx. 210 cases

Component damaged	59
PV system damaged	75
Building damaged	67
Building burned down	12

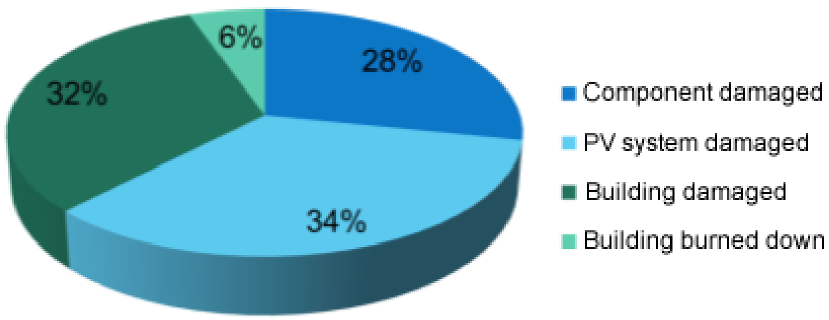

Figure 3-10: Overview of damage levels in the examined cases

These cases were further analyzed, depending on the available information. Despite uncertainties about the exact development of the damage in individual cases, the totality of the cases allows some robust conclusions to be drawn. The following aspects are of interest:

- Cause of fault
- Component causing the fire
- Age of system
- Type of system
- Severity of damage, impact on surroundings

The following presents these results in the form of analytical graphs.

A general observation reveals that the destructive force of an electric arc greatly increases if a serial arc develops into a parallel arc, as in the case of the electric arc from a string reaching a bundle of string lines. The Lorentz force gives the parallel electric arc the tendency to move away from the PV modules and thereby shift the fire hazard in the direction of the inverter.

3.3.2.1 Influence of the system type on damage frequency

The following graph shows how often the different types of system suffer damage.

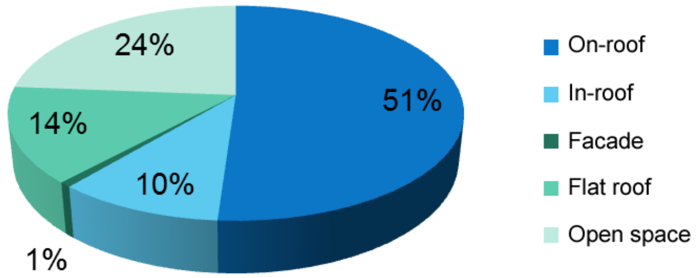

Figure 3-11: Breakdown of damage according to system type (based on 139 incidents of damage)

The ascertained distribution roughly corresponds to the market shares estimated by the German Solar Industry Association (BSW), with around 70% capacity on buildings and about 30% in open space. Less than one percent of the capacity has the form of building-integrated (in-roof) systems. Systems with building-integrated modules make up around 10% of the damage statistics, however.

Among all cases with building damage, building-integrated systems are more prominent. Figure 3-12 shows the distribution of cases where a building was damaged or destroyed and where information on the PV generator mounting type was available.

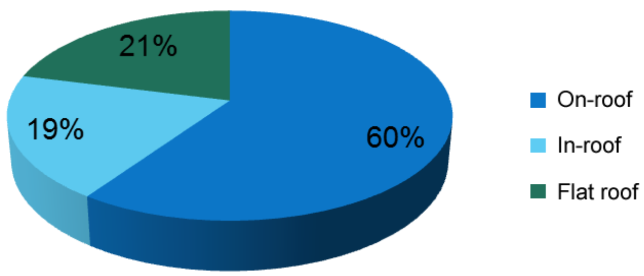

Figure 3-12: Damage distribution in cases with damage to buildings. “In-roof” also includes facade-integrated systems (based on 57 damage incidents).

Given an estimated BIPV share of 1% of the installed PV capacity, the share of PV-caused fires with damage to buildings among BIPV systems is around 20%!

This can be explained by the absence of the protective effect of the “hard roof covering” in tiled roofs. Should overheating or an electric arc occur in the PV system, the ignition source in the case of in-roof systems already lies within the building!

Conversely, particular care must be taken when planning and installing roof-integrated systems.

3.3.2.2 Cause of damage

Figure 3-13 shows the distribution of causes of damage for 103 cases, corresponding to the outside numbers. Installation errors and product flaws greatly predominate over external factors as the cause. The share of malfunctions involving aluminum lines in the particular category are already captured as installation or planning errors and for the sake of clarity appear as the shaded areas and are described by the inside numbers.

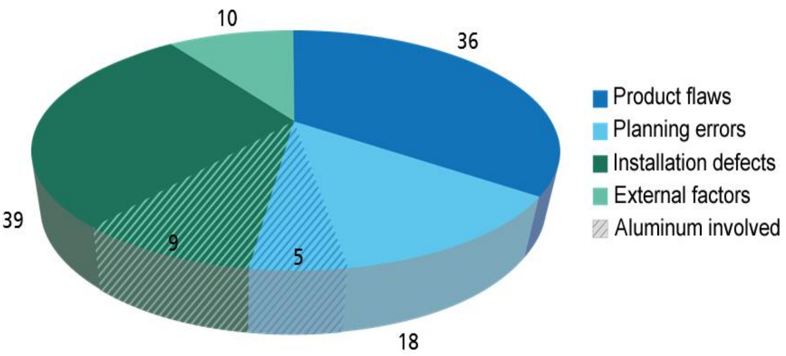

Figure 3-13: Number of causes of damage for more than 100 cases

The following explains the causes in more detail.

“Product flaws” concern especially modules and inverters. In the past, several module manufacturers were affected by serial defects. This led in part to recall and exchange campaigns. Some series of inverters also appear to be consistently defective in design or manufacturing.

“Planning errors” concern on the one hand the mechanical design with errors like:

- Modules jammed together, causing them to fracture and electric arcs to be ignited
- Shear forces acting on module junction boxes from mounting rails placed too closely together damaged the boxes and led to electric arcs
- Unprotected installation of generator junction boxes and inverters outdoors with subsequent stress from temperatures and condensation resulted in fires at these components
- Firewalls missing at the introduction of DC lines into the building, so that a fire can be directly conducted into the building

The electrical layout also has numerous defects, such as

- Unsuitable inverters outdoors
- Unsuitably placed inverters (direct insolation, corrosive gases)

- Undersized cables and lines
- Undersized DC main switch
- Wrong types of fuses at the DC end
- Heat loss from fuses neglected
- DC lines in generator junction boxes rubbing against metallic edges
- Unsuitable terminals at aluminum lines
- Subsequent PV generator expansion without checking the load capacity of the operating equipment

Planning errors can have a large influence on the possible consequences of a fire. If the inverter is suspended on a concrete wall, an electric arc at the DC connection can cause only a soot mark. If it is suspended from a beam or stands on a wooden base, the building can catch fire. The surroundings of the inverter have an equally great influence. Should burning material fall onto a stone floor, nothing will happen, but if it falls into stored hay a major fire can ensue.

Several experts describe construction situations in [15], [16] and [17], for example, where requirements on electrical installations in fire-hazardous locations [18] were grossly neglected, as shown here in the agricultural installation sector:

Figure 3-14: Non-fire-protected installation of inverters on wood, also with difficult accessibility for maintenance; photos: W. Schröder, PV expert, 2014

“Installation defects” are the most frequent causes of faults. In part these flaws may be due to the difficult installation conditions under great time pressure during the winter. Some of these flaws are so massive, however, that inadequate expertise on the part of the installers must be assumed.

Here is a list with defects that have caused fires:

- DC connector poorly plugged in
- Plug poorly (or not at all) crimped
- Screw terminal not tightened
- Inadequate insulation of lines with clamping of the conductor insulation
- Improper workmanship of the aluminum lines (wrong terminals, no torque monitoring)
- No strain relief at cables (leads to mechanical stress on the terminals)

“External factors” are primarily animal bites, individual strikes by lightning and in one case a workman who struck the covered DC cable bundle with a screw that was too long.

“Aluminum line”: These defects are already included in the above defects. We list them here separately in order to underscore their significance.

3.3.2.3 Components causing faults

Past discussions on fire hazards from PV systems have focused on the supposedly more critical DC currents. Owing to the numerous electrical connections, the many components exposed to weather and the self-stabilization of any electric arcs given the current source characteristic of the solar cells, the risk of fire emergence in the PV generator sector is estimated to be significantly higher than in the AC part.

Figure 3-15 shows that defects are also more frequent in the AC PV system part, however. This is surprising, since in the AC part the number of components is less than in the DC part by at least a factor of 10, proven operating equipment with long lead times are available, AC installations usually occur in weather-protected spaces and electricians are generally well trained for AC installations.

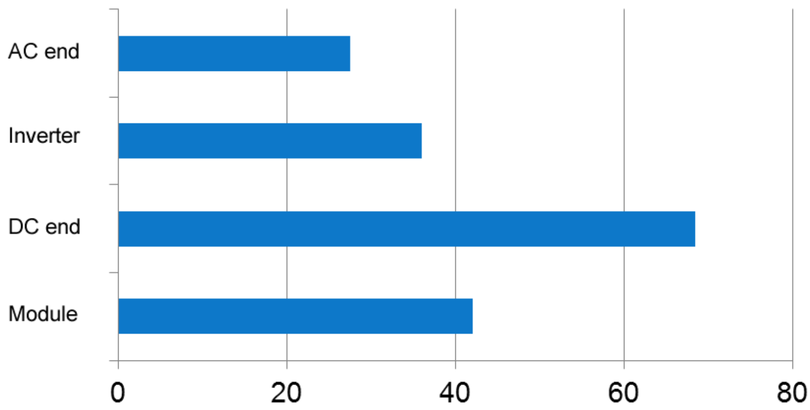

Figure 3-15: Rough distribution of the system parts where defects occurred (for altogether 17,174 defects)

If we assign the defects to the components in as detailed a way as possible, we can see how often single components were found to be affected (Figure 3-16).

Note: The components destroyed in the event of damage (fire damage) are not always the causal components of the event.

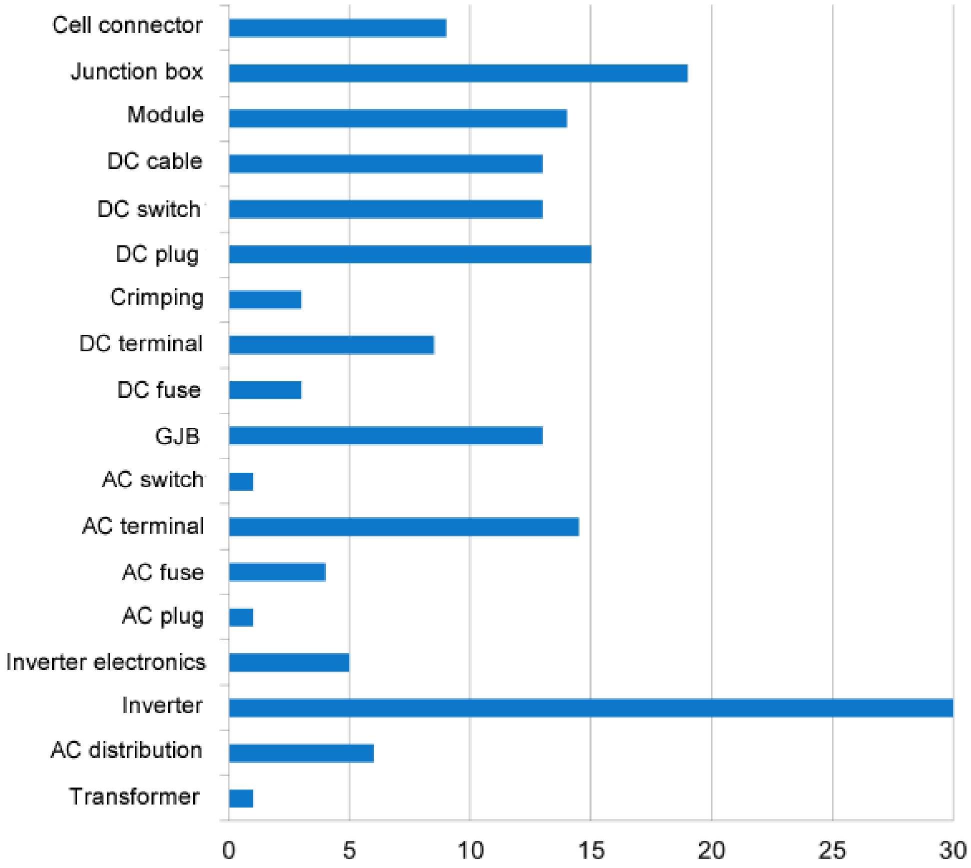

Figure 3-16: Number of defects per component (total number of defects: 174).

"Junction box" stands for module junction box, "crimping" for crimp contacts of DC plugs, "GJB" for generator junction box, "IN" for inverter, and "Transformer" for the grid transformer of the feed-in station.

Specified are the defect sites that could be determined with the possible cause in each individual case. That is, if module damage was reported, it falls under "module" and if damage to the module junction box was reported, it falls under "junction box". The total number of defects in (e.g.) modules is obtained by adding together the numbers of defects under "Modules," "Junction boxes" and "Cell connectors".

Most defects occur in modules and inverters. This result is not very surprising: the module is a prominent component quantitatively speaking, and the inverter the most complex component, of a PV system.

At the DC end, most system components have about the same frequency of defects. If we count together "DC plugs" and "Crimping," "DC plugs" with the number 18 are the second most frequently defective components, following the modules.

In the AC sector, the "AC terminal" is the most common location of defects, following the inverter. Here installation errors become especially evident.

Defect locations in the generator junction box, at the inverter and in the AC distribution often cannot be identified more precisely. It is supposed, however, that in many cases poor connection points were the cause.

Reports in the online survey and statements from experts indicate that in particular screw terminals have a greater risk of causing overheating compared with other connecting technologies.

3.3.2.4 *Age of the systems*

Figure 3-17 shows the distribution of system age at the onset of damage. We find a significant accumulation of damage during the first year of operation.

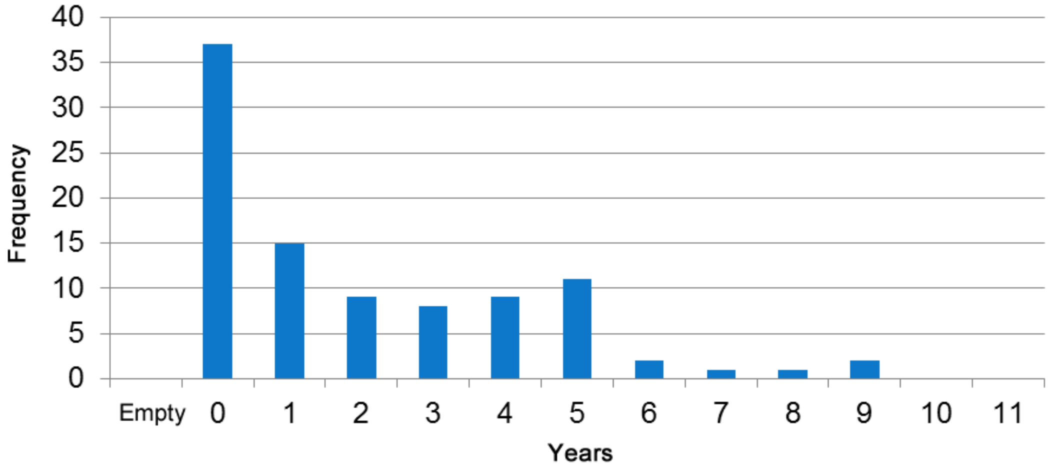

Figure 3-17: System age at time of damage (99 cases)

Some of the damage already occurred during construction. In the authors' view, the high number of early occurrences of damage reflects on the one hand production defects especially with inverters and on the other hand the numerous installation flaws that led to fires even after a few weeks at full load.

The high number of installation flaws may in part be due to the poor working conditions. In 2011, for example, around 40% of the newly installed capacity was installed in December [19], under enormous time pressure and adverse working conditions. The cause is known to be related to the cut-off date at that time for a massive compensation reduction according to the Renewable Energy Sources Act.

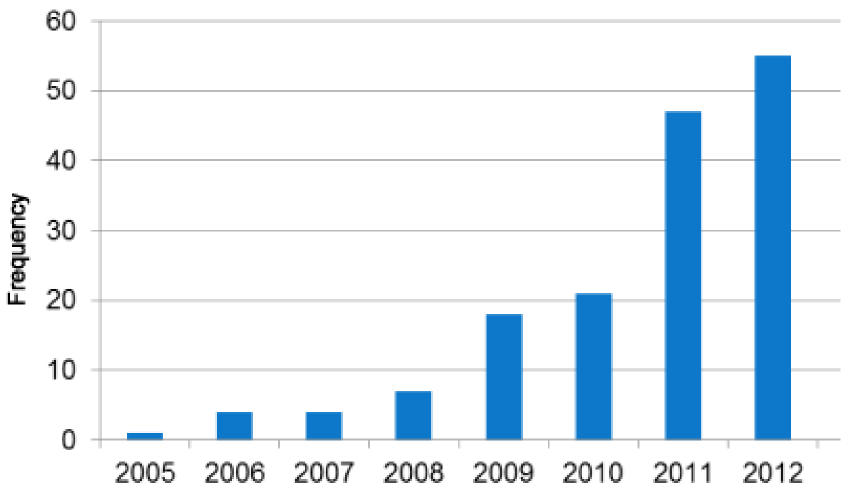

Figure 3-18: Damage incidents according to year of occurrence. The damage frequency also increases with the addition rate (data for altogether 157 cases).

Figure 3-18 shows the number of damage incidents found per year. We see a sharp increase in the years 2011 – 2012, reflecting, with something of a delay, the numerous expansions of the 2010 – 2012 of around 7 GWp each.

From the capacity of around 25 GWp installed by the end of 2011 and the 65 damage cases in 2012 we can roughly estimate a frequency of potentially fire-inducing cases of 0.3% per MWp and year – most likely a conservative estimate, insofar as it includes the installation flaws during the construction boom of December 2011. The number of installation flaws should be significantly less in “normal” years.

3.3.2.5 Time of the malfunction

The following two graphs will aid an understanding of the mechanisms that can lead to a fire. They show the dependence of malfunction frequency on the month and time of day.

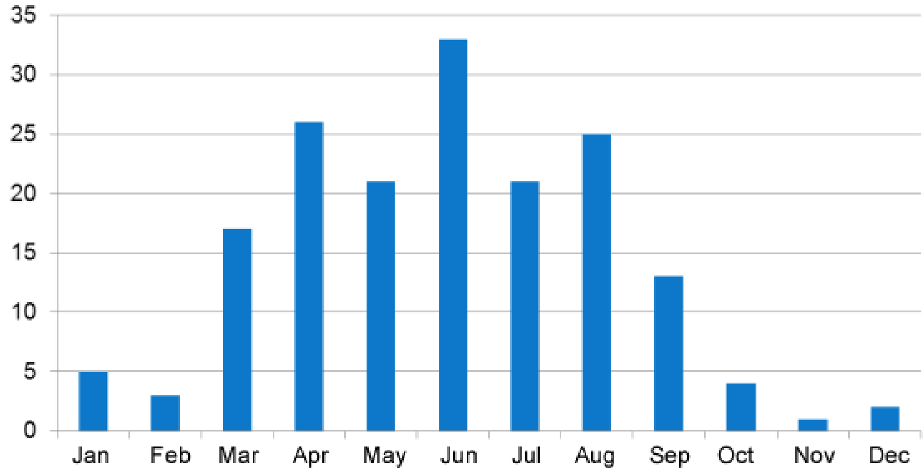

Figure 3-19: Number of damage cases per month (total: 171).

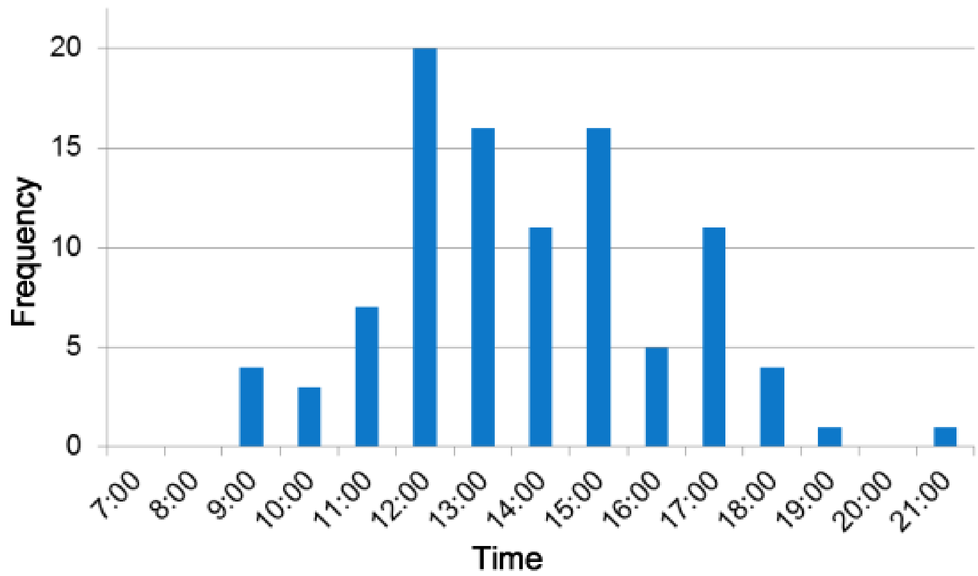

Figure 3-20: Number of damage incidents as a function of the time of day (here 99 – for many cases no time could be specified)

Both graphs show a strong dependence of malfunction frequency on the available solar energy. The malfunction frequency increases with the irradiation power.

This indicates that most malfunctions are current-related, i.e. due to the failure of connections or contacts and to overloading of the operating equipment. Insulation flaws accordingly play only a minor role.

3.3.2.6 Conclusions from the damage analysis

Modules and inverters are relatively conspicuous components, as expected. Defects were surprisingly often found in the following components/aspects:

- DC plugs
- in the AC distribution with all components and especially with the terminal connections
- improper workmanship of aluminum lines

Summary

The main causes of fires are “installation flaws” and inverter product defects.

All connections provided by the customer are potentially critical.

The defects causing fires are by far connection flaws in the main current path, or “serial defects”. Short circuits and insulation flaws are comparatively less frequent.

3.3.3 Damage patterns of particular malfunctions

To illustrate the above observations, we present in the following some damage cases in more detail.

3.3.3.1 DC plug connectors

DC plug connectors emerge as frequently affected components in the malfunction statistics of figure 6. Identified causes of faults in this component are:

- Poor crimping – e.g. with combination pliers,
- Poor insertion – i.e. connectors not fully inserted,
- Improper assembly of the plug – a contact piece slips back unnoticeably when inserted
- Cross-pairing (combination of plug and socket from different manufacturers)

Plug incorrectly inserted

A roof-integrated PV system caught fire in the middle of the afternoon. The fire encompassed and destroyed the entire roof structure. In the debris the fire expert found remnants of various connectors (Figure 3-21). The right plug pin was fully preserved, the left one was vaporized by an electric arc.

Figure 3-21: The remains of two connectors from the debris of a house [9] (photo: Institut für Schadenverhütung und Schadenforschung (IFS))

The appraiser came to the conclusion that "the cause of damage was the damaged plug connection, or its improper assembly." [16]

In terms of risk, an installation or product flaw and an "in-roof" PV system came together with a proximate, high fire load.

Cross-pairing of connectors

Some manufacturers of connectors advertise their products by claiming their "compatibility" with the products from other manufacturers.

Tests at TÜV Rheinland [20] and at Multi-Contact [21] show that these claims are untenable. Even if good contact connection exists at the time of installation, we may not assume that pairs of contacts from different manufacturers will attain a service life of 25 years. Accelerated aging tests of such "cross-pairs" showed greatly elevated contact resistance in some cases. This cross-pairing leads to overheating of the plug connection and in the long term can lead to contact interruption with ignition of an electric arc.

Multi-Contact consequently rejects any warranty claim in the event of cross-pairing.

3.3.3.2 DC switches

DC main switches were found to be the source of malfunction in 13 cases. The damage cases do not unequivocally show whether the issue was general product weaknesses or overloading of the components due to poor planning and disregard of the permissible temperature range or rated current of the switches. Both complexes of causes are indicated.

The IFS published the following report on a fire in a 1 MWp system on an industrial roof (Figure 3-22):

"…An IFS appraiser found in the investigation that overheating had occurred at the DC main switch in the precollector housing. Switches of identical design were present in each of the nearly 130 precollectors. An inspection revealed that several switches had already suffered damage from scorching …" [22].

Figure 3-22: Fire at a generator junction box. The center of the photo shows a box of the same design. It has no protective roof. (Source: Bühl Volunteer Fire Department)

The appraiser found the following note in a catalog from Santon (with no year of publication):

"Operate the switches, which are seldom used, several times (10x) at least once a year in order to clean the contacts" [23].

The appraiser then found the cause of fire to lie in the failure to perform maintenance of the switches. A study of the other generator junction boxes found other switches with heat marks. Altogether about 10% of the boxes were affected. Incidentally, the note on maintenance appeared in fine print on the final page of the catalog.

At least two other manufacturers of such switches also had problems with flat connectors at similar switches and changed the type of contact connection. These flat plugs probably also caused overheating.

The switches from the above fire incident were installed in generator junction boxes mounted without protection on the roof (Figure 3-23). Elevated temperatures accordingly developed in the distribution boxes – estimated to be above 60°C. This accelerated the contact degradation.

The corresponding product standard for switches, DIN IEC 60947-3, presupposes a maximum ambient temperature of briefly 40°C [24]. The switches were therefore probably operated outside their permissible temperature range.

Elevated ambient temperatures

The above example showed that elevated ambient temperatures increase the susceptibility of operating equipment. The following example further supports this hypothesis. It also indicates the difficulties in exactly determining the cause of fire damage. Last but not least, the example also clarifies the system planner's responsibility to take into account the expected operating conditions of all parts of the system. In particular, the planner must allow for stress from high summerly temperatures.

In the following case, the summerly heat stress on the operating equipment was evidently underestimated. A fire broke out in the engineering room of a PV system aged about six years, containing several subsystems of the same type (Figure 3-23)

Figure 3-23: Engineering room of a PV system following a fire

The appraiser engaged by the plant insurer identified an overloaded DC main switch as the cause of fire.

The switch with 16 A rated current sufficed for a generator rated current (I_MPP) of 14.0 A, without a reserve for *overcurrents caused by excessive irradiation and elevated ambient temperatures*.

Like the other 14 switches of the system, the switch was subjected to significantly increased heat stress.

- The inverters were mounted more closely together than as specified in the assembly instructions.
- The DC main switches were mounted tightly between the inverters.
- The roof above the operation room was only poorly insulated. During mid-summer air temperatures of over 40°C regularly prevail here.
- The PV inverters added up to 5 kW of dissipated heat.

The maximum permissible operating temperature of the switch was 40°C! We must therefore assume that the switch's permissible temperature range was regularly significantly exceeded.

Six of the switches survived the fire practically unscathed. Two of these switches showed preliminary damage in the form of incipient carbonization at the flat connectors (Figure 3-24).

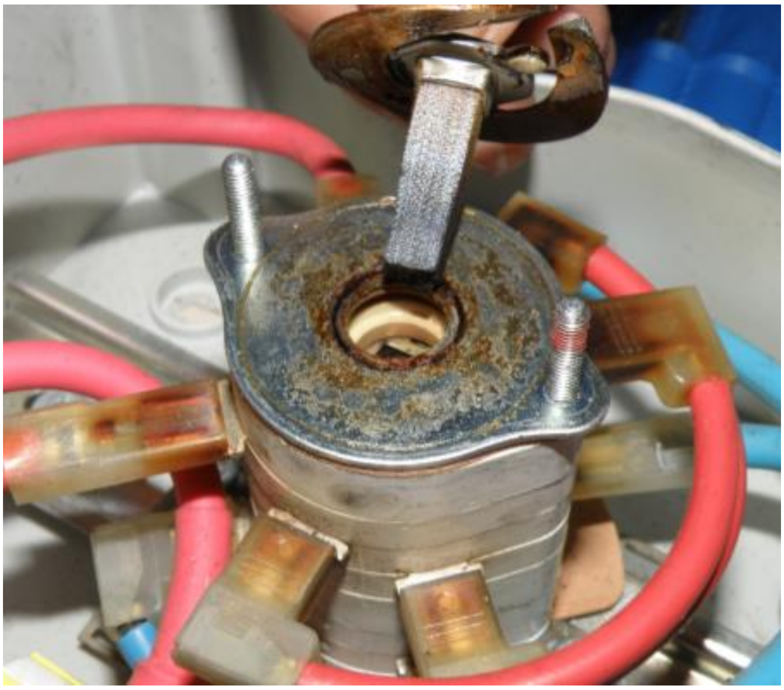

Figure 3-24: Significant marks of overheating at connections and inside a "surviving" switch

Disassembly of the above switch also revealed considerable overheating marks inside the switch. Insulation material, isolating disks and the axle were charred. The heat evidently came from the switch contacts and not as originally conjectured from the weakened flat connectors. The switch axle had shrunken in diameter from the heat stress and fractured in the middle. Most likely it fractured right at the moment when the switch was needed – when the fire department wanted to disconnect the system while extinguishing the fire.

Noteworthy is that inverters and switches were mounted on a brick wall, so that the fire did not spread further.

Test of switch contact resistance

It is well known that sufficiently long "non-operation" of the DC switches due to oxidation of the contact surfaces and friction corrosion from temperature-related changes in length (so-called "fretting") result in increasingly higher contact resistance. As the resistance increases, so does of course the dissipation loss, increasing the contact temperature and thereby accelerating oxidation. Self-excitation occurs. Ultimately, a temperature may occur that is high enough to scorch the switch or set it on fire.

The increase in contact resistance can be undone through regular switch operation. For this reason, one of the numerous switch manufacturers requires that its switches be operated ten times once a year.

To test the effect of the maintenance recommendation, surviving switches from the damaged PV system described above were removed and their contact resistance measured in the lab. The switches had most likely not been operated for about six years. Figure 3-25 shows the results of the test.

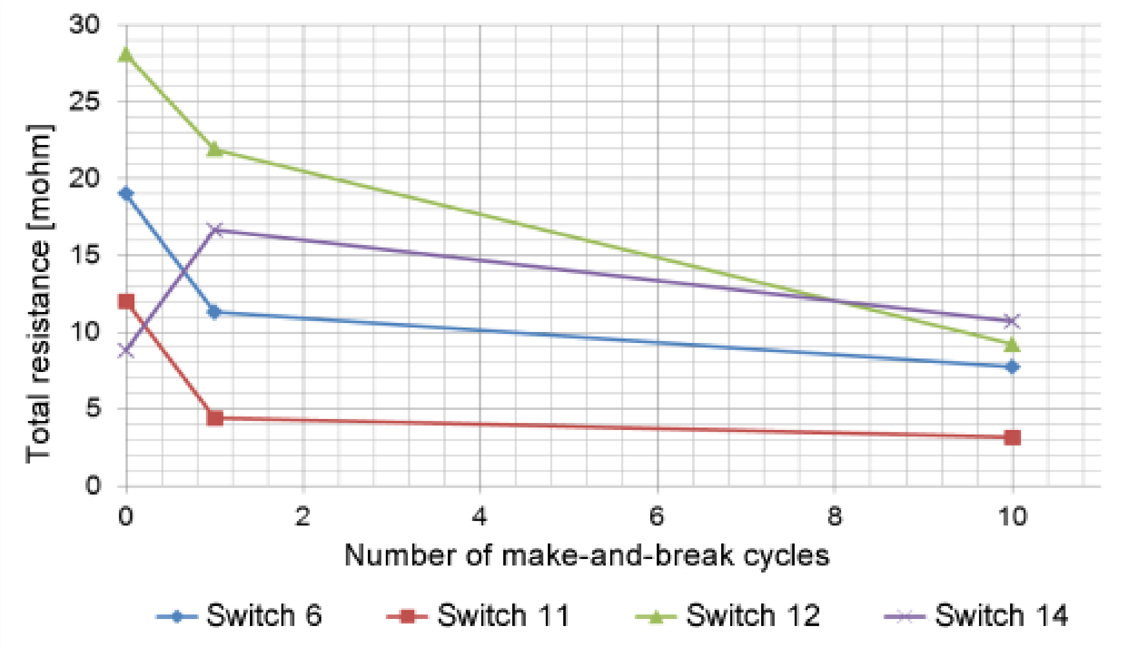

Figure 3-25: Total resistance of four switches as a function of the number of make-and-break cycles. Switches 6, 11 and 12 are of the same type; switch 114 is a different type.

The contact resistance decreases at three out of four switches – on the average about 1/3 of the initial value. The ohmic losses also decrease accordingly. At the worst-case switch, this loss is initially about 17 W under rated current load and drops to about 6 W.

Switches with contact rockers show the same behavior (Figure 3-26) as a field test found.

Figure 3-26: Tested DC main switch with contact rocker

Eight switches in an approximately 10-year-old PV system were also tested as to contact resistance. These switches also showed a significant decrease in contact resistance after multiple operations (de-energized state). The resistance dropped on average to nearly a third of the initial value.

These switches must also undergo routine maintenance.

Summary of the switch studies

- Switches react to continually elevated ambient temperatures with accelerated contact degradation.
- Planning should oversize the switches. Like the DC lines, the switches should have a load capacity of at least 125% of the rated current of the system. Switches subject to elevated ambient temperatures must be designed as per the manufacturer's derating specifications.
- All switches should be inspected once a year in order to discover any signs of overheating.
- All switches should undergo maintenance once a year and then be operated ten times (de-energized).

Section 6 contains these important findings.

3.3.3.3 Improper handling of modules

One system operator observed that an installer had misused the connections of a module as a “transport aid” during assembly. This evidently overloaded the strain relief and somewhat pulled apart the contacts of the module junction box. During the following summer, the power output of the corresponding subgenerator dropped. Figure 3-27 shows why: one of the contacts shows signs of an electric arc:

Figure 3-27: Damaged plug contacts in a module junction box

While searching for the cause of diminished performance, the installer found two modules each with a destroyed contact in the module junction box. Because of internal electric arcs the string current was fully interrupted. Fortunately these electric arcs remained confined to the interior of the box.

The photo shows that the left connector slipped slightly downwards relative to the right one. This probably happened because of the aforementioned mechanical “misuse” of the module connecting lines.

3.3.3.4 Loose clamp connection

Because of their cost advantage, aluminum conductors are finding increasing use in PV systems. Since aluminum melts at lower temperatures compared with copper, increased contact resistance will lead faster to disconnection of the conductor and possibly to an electric arc.

Here is an example of where the appraiser found a defective clamp connection that in combination with an aluminum conductor caused a fire. An AC distribution unit had burned out.

Figure 3-28: Burned-out AC connection of a PV system (photo: Uli Motzer, Württembergische Versicherung)

Figure 3-29: The end of an aluminum line (photo: Uli Motzer, Württembergische Versicherung)

The cause of fire was found to lie in a loose contact point. Figure 3-29 shows the conductor end of another cable of the system. The line had also not been correctly connected, as the signs of fusion at the conductor show.

The matter of hot contacts was also observed at the fuses; see Figure 3-30. Screwed contacts were involved in this case. A high transition resistance occurred at the screw contact.

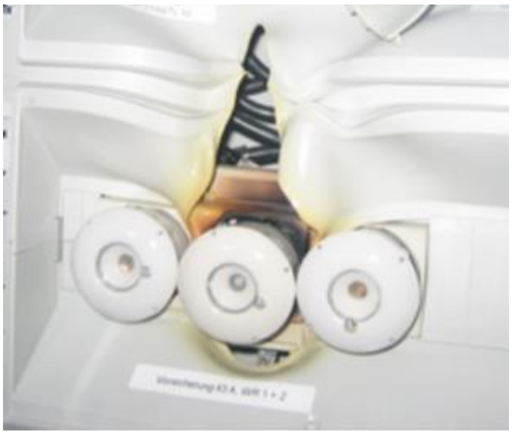

Figure 3-30: Heated fuse link (photo: H. Godard, Energossa)

3.3.3.5 Fire propagation through cable bundle

The insulation of common lines is combustible and can fuel a fire. Cable bundles often contribute to the spread of a fire. Here an insulation fire and electric arcs between the positive and negative lines in the bundle combined together. The great heat from the electric arc can cause even flame-retardant materials to catch fire.

The propagation can be thermally driven, if namely a fire can spread upwards, or a weaker, electromagnetic propagation of an electric arc at a distance from the current source may occur, as Figure 3-31 shows:

Figure 3-31: Charred lines at an inverter (source: Weyerbusch Fire Department)

Given the damage pattern, this fire probably originated in the vicinity of the DC connections of the inverter. It spread upwards as a cable fire with (parallel) electric arcs in the cable bundle and thus to the roof structure.

A spatial separation of the two polarities at the inverter would have probably interrupted the electric arc at an early stage.

3.3.3.6 Disregard of the requirements on "fire-hazardous operating facilities"

The experience of the Württembergische Versicherung is that PV systems on agricultural buildings – like the buildings themselves – are subject to an increased risk of fire [18]. The probable reason is, among other things, that combustible substances are often stored or dust accumulates in buildings of this kind, with the requirements on the installation of electrical systems in "fire-hazardous operating facilities" [18] being often disregarded

The free brochure of the Association of Property Insurers (VdS) [25] presents these requirements in easily understandable form.

Disregard of these specifications reduces the risk of fire propagation and therefore overall damage.

According to this document, the most important requirement is that PV system operating equipment be installed outside the fire-hazardous area. In the hazardous areas only electrical operating equipment may be used that is “required for the immediate operation in these areas.”

In many cases inverters are mounted on wood. This practice is grossly negligent and generally prohibited by the manufacturer’s product documentation!

Two examples illustrate this:

In the first case, inverters and lines were mounted on OSB boards; see Figure 3-32. A fire damaged components in the engineering room of a PV installation. The OSB board used in the installation then also caught fire. Evidently little flammable material was otherwise present, and the fire department arrived quickly, so that the fire could be contained.

Figure 3-32: Installation of inverters on OSB board. Left: site of the fire, photo: Volunteer Fire Department of the Community of Perl, 2011. Right: here things look OK, but the fire protection is inadequate, photo: W. Schröder, PV expert, 2014

In 2009, the Ellwangen Fire Department reported a fire incident that ended mildly, “Smoldering Fire on Agricultural Property”. The fire was noticed relatively soon, so no greater damage occurred.

Figure 3-33 shows that a smoldering fire was caused by a cable, probably damaged by an animal bite, belonging to a photovoltaic system in the unused hay storage floor of a barn.

Figure 3-33: Mild fire case (photo: Ellwangen Fire Department)

The course of the fire turned out to be a stroke of luck, since the straw did not catch fire.

In a similar installation situation, wood and straw caught fire, and when the fire department arrived the building was fully engulfed in flames. Total damage occurred [26].

3.3.4 Large-scale fires

Two damage cases are still under investigation at present (2013), in each of which a PV system on an industrial roof supposedly caused a fully developed fire at a building. In one of these cases, the appraiser found evidence that an incorrectly designed fire department switch (!) caused the fire because it couldn't extinguish the switch electric arc.

In both cases the fire quickly spread to the interior of the building. Experiences with similar systems allow us to conjecture that the lines of the PV systems were led through simple roof penetrations into the building and no firewall was used. The cable bundle thus probably provided the electric arc with a direct path into the building.

In another major fire the sanded bitumen roof sheeting caught fire. This normally qualifies as "hard roofing," i.e. as protection against radiant heat and flying sparks. In combination with an installed PV system, this protective effect does not suffice, as a fire caused by a PV system in Goch (April 1, 2012) impressively showed. It quickly engulfed the large roof surface of a warehouse and led to a dripping, burning flow of bitumen (Figure 3-34).

Such roofs should be provided with preventive fire protection measures as described in section 6.1 in order to minimize the risk that a major fire develops from a poor contact.

Figure 3-34: Electric arc event in a roof-mounted elevated PV system. Left: Bitumen roof sheeting burns with heavy smoke development and produces burning droplets. Right: Fortunately the building could be saved, photos: Goch Volunteer Fire Department

3.3.5 Conclusions and recommendations

The number of reported fires per year has greatly increased in recent years (Figure 3-18). This trend is correlated with the sharp increase in number of installed PV systems in recent years.

Appraisers have repeatedly found that a great number of PV systems violated elementary installation requirements.

Summary of fire case analyses

It is foreseeable that in coming years a significant increase in fires caused by PV systems is to be expected. Increased aging of the materials will lead to an increase in insulation faults, contact problems and transition resistance. Under unfavorable conditions these flaws can trigger a fire.

Recommendations on risk reduction

We see remedies to the previously identified faults as lying on three different levels:

- **Installer training** – Professional and quality-conscious installations can avoid most installation flaws.
- **Inspections** (testing) – Solid acceptance inspections help detect initial flaws and repeat inspections help detect hidden installation errors and developing product flaws due to aging or defects related to extraordinary stress (bad weather).
- **Technological development**
  - Avoidance of screwed connections in load current circuits
  - Electric arc detectors can generally turn off an electric arc

Section 0 summarizes detailed recommendations.

3.4 Damage analyses of a solar system supplier

3.4.1 Damage determined at the incoming goods inspection

To ensure its customers constantly high product quality, especially in the case of PV modules, the solar system supplier “Energiebau Solarstromsysteme GmbH” conducts a comprehensive incoming goods inspection. Random samples are taken from incoming deliveries as per DIN ISO 2859 and examined for any production flaws or transport damage according to a comprehensive list of criteria.

First is the visual inspection that checks compliance with the manufacturing tolerances. Recorded are, among other things, the dimensions and workmanship of the frame, the relative positions of the individual cells, the quality of the glazing and lamination as well as the connections between cell pressure, busbars and main busbars. Also inspected are junction boxes and lines, connectors and module labels and markings.

Besides the visual inspection, an electroluminescence (EL) test is conducted. For this purpose the module as a whole is photographed. The resulting images enable easy detection of cell fractures and defective connections at contacts.

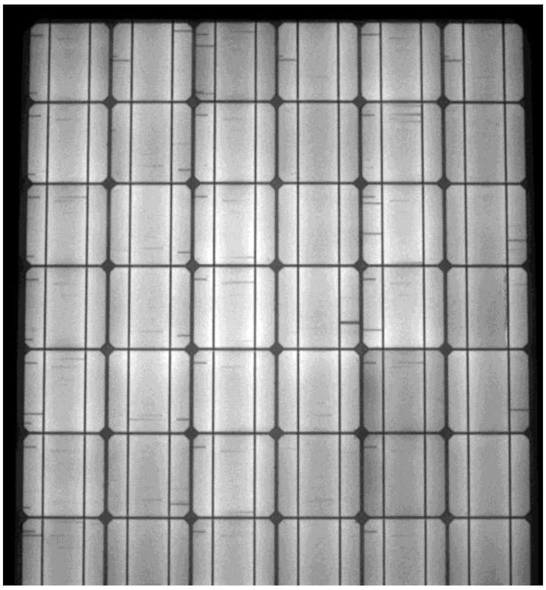

Figure 3-35: EL image of an intact module

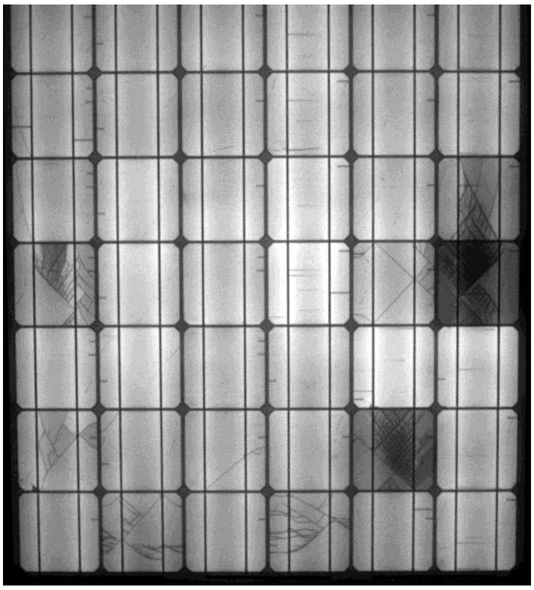

Figure 3-36: EL image of a module with microcracks and cell fractures

Between March 2011 and March 2013, Energiebau inspected nearly 24,000 modules, 20.2% of which showed flaws. *This percentage is not representative of all modules supplied by manufacturers, however.*

The processes at incoming goods are structured in such a way that batches suspected of poorer quality are inspected more intensively than usual. If spot checks of a delivery reveal defects a larger number of modules is examinated.

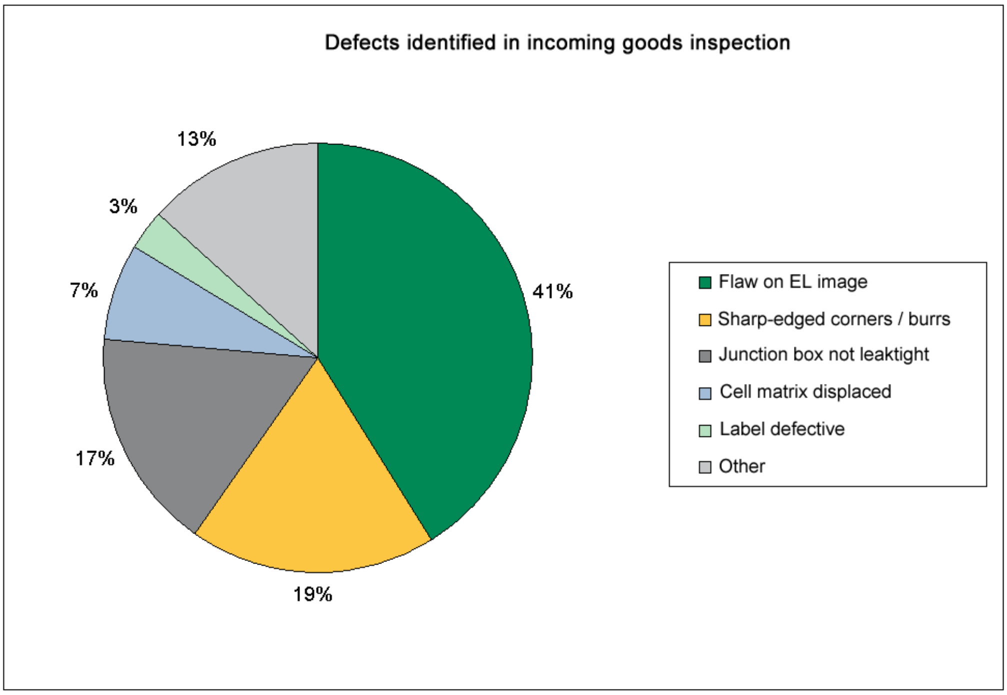

Figure 3-37: Damage frequently found in incoming goods inspections (over 50 units/year)

The most commonly found defects appear as flaws on the EL image. These are predominantly cell fractures, but can also be defective connections at contacts or cell pressures.

Second most common are poorly manufactured frames with burrs or sharp-edged corners, caused by imprecisely manufactured or joined frame parts.

Other defects are imprecisely fabricated lids for junction boxes whose poor seating leads to leakage, shifts in the cells and incorrectly printed or stuck-on nameplates.

Around 13% of damage cases are attributable to other less common defects, among them defective cell pressure, optical damage and delamination (see also Table 3-2).

Table 3-2: Percentages of most common damage patterns relative to total number of damage cases

Defect	Relative frequency in %
Flaw on EL image	41%
Sharp-edged corners / burrs	19%
Junction box not leaktight	17%
Cell matrix displaced	7.2%
Label defective	3.0%
Defective cell pressure	1.7%
Color deviation	1.5%
Scratches	1.4%
Cell connectors moved to side	1.1%
Foreign matter in module	1.1%
Glass flaws	0.8%
Dents in backsheet	0.8%
Deviation from right angle	0.8%
Delamination	0.8%
Deformations / dents	0.6%
Silicone residue	0.6%

3.4.2 Damage in complaints

Despite comprehensive quality controls, time and again defective modules are delivered to customers or damaged during transport. These defects are then recorded as complaints, resulting in a wholly different distribution of the damage patterns for various reasons.

On the one hand, certain defects can already be detected prior to delivery in the incoming goods inspection and complaints can be submitted to the manufacturer. In addition, certain defects become evident only after longer operating periods and can therefore be noticed only at the customer’s end. This includes (e.g.) reduced performance from potential-induced degradation (PID).

Finally, damage such as scratches, dents and cell or glass fractures may occur only during transport to the customer or through improper handling on the construction site.

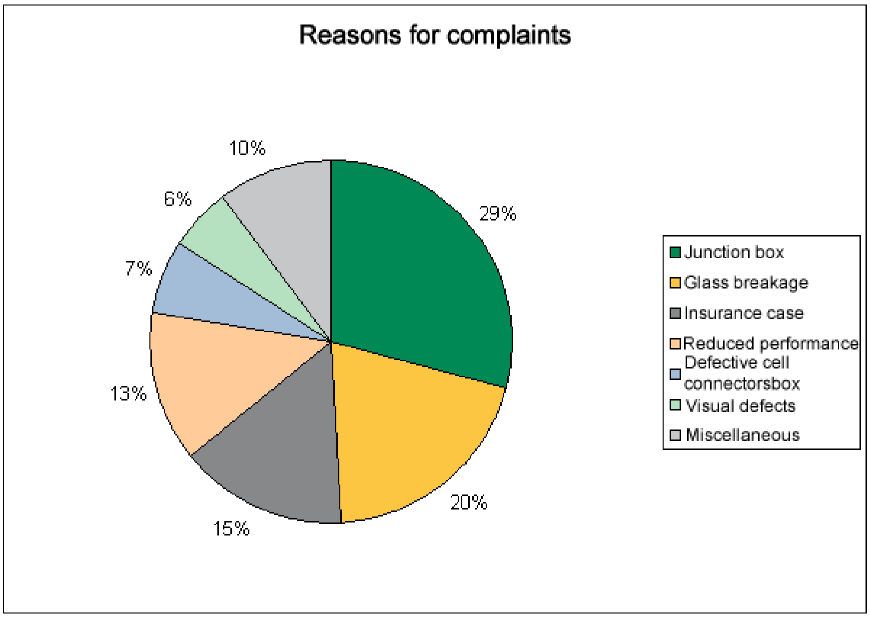

Figure 3-38: Frequencies of defects among modules subject to complaints

The most frequent complaint across all manufacturers concerned defective junction boxes.

Besides housings and housing lids falling off because of poor workmanship, this item also includes defective soldered joints and defective bypass diodes. Owing to the frequency of this flaw, we may assume a particular risk of electric arcing to be posed by defective junction boxes.

Other frequent defects are general insurance cases and glass breakage usually occurring during transport or assembly, but also sometimes caused by overheated cells.

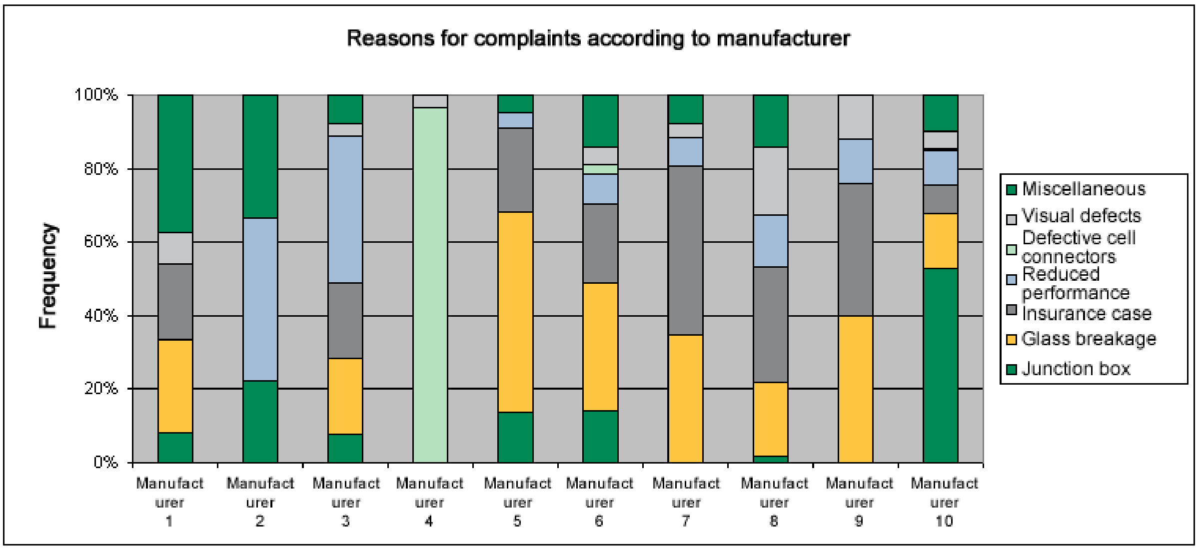

Figure 3-39: Frequency of damage patterns among different manufacturers

Figure 3-39 clearly shows for manufacturer 10 most complaints pertain to a defect in the junction box. The graph also shows that manufacturer 4 has a problem with poor contact connections between the cells.

Altogether we find that for end customers transport-related damage is considerably more of an issue. This indicates that modules are improperly handled at the construction site despite the information provided in the assembly instructions.

In contrast, reduced performance and defective cell connectors are more seldom to be found in completed systems than in the incoming goods inspection. This shows that EL imaging is an effective means for detecting such defects and for filtering out the affected modules.

3.5 Potential electric arc risks in PV systems

3.5.1 Module

3.5.1.1 Cell connectors

Soldered connections are basic weak points regarding the occurrence of an electric arc within a PV module.

Especially many solder joints occur in the connections between the individual solar cells. The busbars of the cells here are interconnected via soldered cell connectors. How many busbars and therefore cell connectors the installed solar cells possess consequently plays a role. Larger cells often contain three busbars to create redundancies and a uniform distribution of the cell currents in the event of failure of individual contact transitions or local temperature elevations – the failure or disconnection of just one busbar will then not suffice to ignite an electric arc [5].

A brief search surveyed the numbers of cell connectors among 50 crystalline PV modules currently on the market. Most of the modules contained two busbars (Figure 3-40).

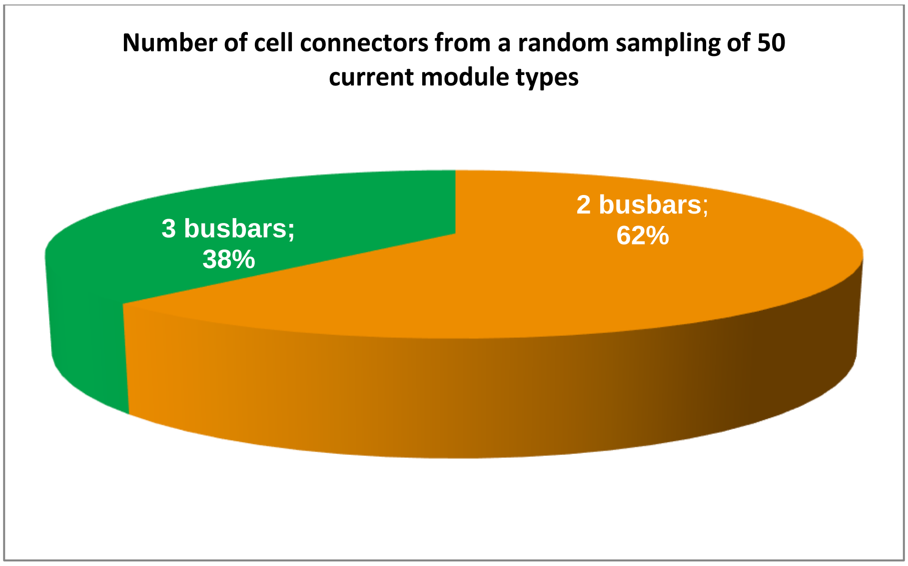

Figure 3-40: Number of cell connectors used in different types of modules

A more detailed analysis of the Cologne solar system supplier “Energiebau” found that only two busbars are used with 5” cells. In the case of 6” cells, both two and three busbars are common.

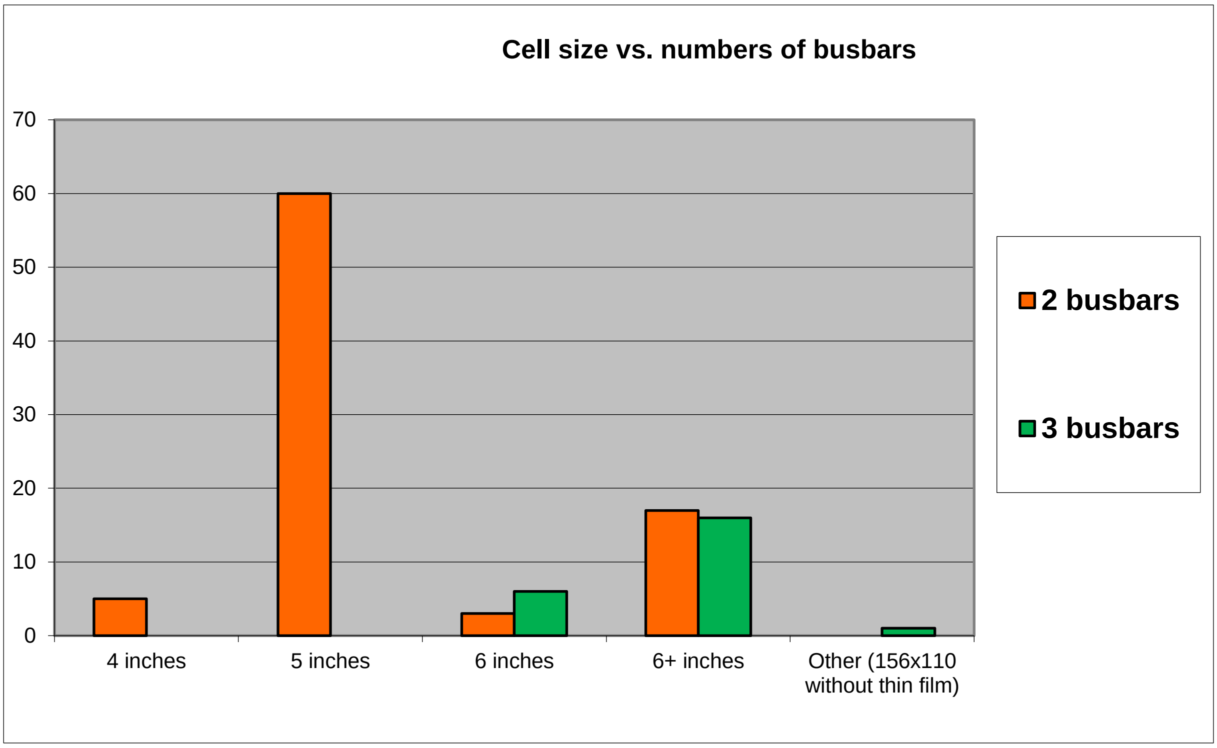

Figure 3-41: Frequency of numbers of busbars as a function of cell size

The overview is based on data on representative modules on the market. Each additional cell connector increases the redundancy. Should defective soldered contacts occur, the current can flow through other busbars.

In the case of three busbars, the occurrence of an electric arc at the cell contacts is therefore less probable. On the other hand, the cell area is slightly reduced that can be actively used for generating electricity.

An electric arc at a cell connector can then occur if only one of the cell connectors still provides a conductive connection and if at this point the metallic contact is also lost.

The latter is to be expected if the contact is already poor and the resulting heat leads to further fusion of the contact material. In addition, the bypass diode belonging to the affected cell string must be interrupted, since the voltage of a single cell string will not suffice for igniting an electric arc. [27] [28]

To emulate this chain of faults, TÜV Rheinland conducted experiments with prepared modules. In one module, both cell connectors between two individual cells were disconnected and the bypass diodes removed from the junction box. Electric arcs were then ignited that generated temperatures far above the melting temperature (600°C) of (e.g.) thermally pre-stressed glass (Figure 3-42). The front glass and the photoactive silicon layers melted and formed burning droplets [29].

Figure 3-42: Effects of an induced electric arc through partition of the cell connectors, photos: TÜV Rheinland

The electric arc will continue burning until sufficient voltage for maintaining it is no longer available. This situation can be attained by turning off the voltage or by increasing the distance between the electric arc contacts. If this distance is so large that the available voltage no longer suffices, the electric arc will extinguish itself. This time can be very long, however (several minutes).

The electric arc burns not only at the direct contacts of the cell, but it can also continue burning between the cells. The electric arc will then move back and forth between the cells. Owing to the large amount of available material, the contacts will burn down only slightly. In the lab experiments the electric arc was always extinguished by turning off the voltage. The electric arc burning the longest was turned off after 16 minutes. During this time the electric arc moved several times from one cell side to the other.

Until the electric arc was extinguished, it emitted a great deal of heat, greatly damaging the surrounding module materials. The latter also burned, but after a period of time extinguished themselves after the electric arc was turned off. Until then, the flames were intensively blazing from the underside of the module, however. In cases of very long-burning electric arcs the temperatures increase until the glass melts (1,000°C to 1,500°C) and liquid silicon drips down from the module.

Causes of electric arcs in the real world can be previous hot spots that can usually occur at soldered cell connectors but also at the soldering between cell connectors and at busbars inside the modules.

3.5.1.2 Module junction box

Recent studies have found that the connection between contact terminals and connecting lines in the module junction box require particular attention. The design here provides sufficient contact material to keep an electric arc continually stable. In addition, the junction box, generally made of plastic, provides combustible material in the close vicinity. The possible spread of the electric arc to the surroundings must be taken into account and the risk classified as high.

Figure 3-43: Junction box after electric arc between connecting line and connection terminal **[5]**

The red line between the two terminals in Figure 3-43 serves to bypass the module already defective from earlier tests. The electric arc occurred with the cable on the left.

The effects of a fire in a module junction box can thus be considerable. Whether a fire can occur in the first place depends on several factors:

(1) Stability of the connections (and the strain relief)
(2) Corrosion protection (leaktightness)
(3) Heat dissipation in the junction box (bypass diodes)
(4) Fire-relevant material properties
(5) Lightning and surge protection

For estimating the actual risk of fire, at this point we now give an overview of the typical designs and materials available on the market.

Re 1. Stability of the connections

Current developments at junction box manufacturers are based on the premise of automation capacity and process reliability (e.g. Spelsberg, Phoenix Contact, Conergy) for ensuring a constantly high level of quality in production (reducing risk of dirt, long-term stability of adhesive leaktightness).

Generally there are 3 types of line connections (Figure 3-44):

- Soldered connections
- Clamp connections
- Screw connections

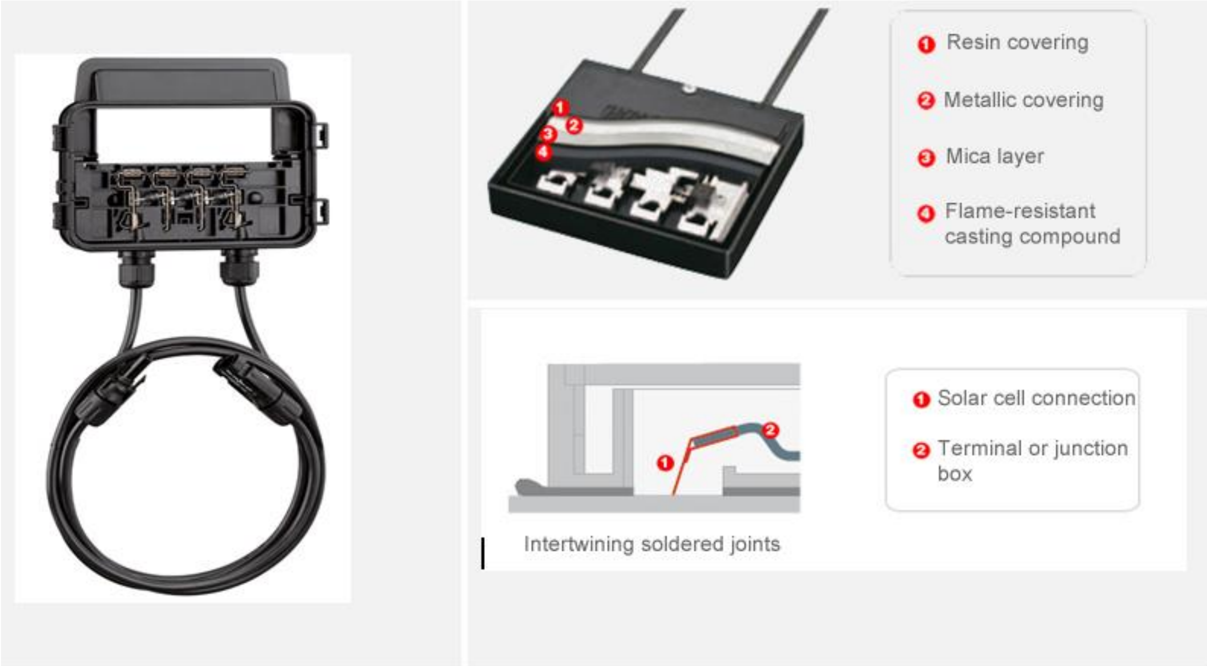

Photo: Günther Spelsberg, terminals

Photo: Mitsubishi Electric Corporation, soldered contacts

Figure 3-44: Contact variants

Clamp connections are not very susceptible to faults. Use of unsprung screw connections is not recommended nowadays, since they provide reliable contact only given optimal assembly, and this contact can progressively deteriorate while the clamp connection automatically adjusts itself.

But even soldered connections can fail if assembly is not performed properly. This risk tends to be greatest with manual soldering processes. At present all three joining technologies are available on the market (Figure 3-44), with clamp connections of a variety of kinds and quality being primarily used.

In addition, solid and reliable strain relief plays a great role, since tensile forces can occur in both the short term (e.g. during transport and installation) and long term (e.g. from the weight of the cables). It must be ensured that these forces cannot affect the quality of the connection.

Re 2. Corrosion protection

Junction boxes are indicated as belonging to the high protection class IP65.

Uncast junction boxes can have disadvantages compared with cast junction boxes as the result of temperature changes and moisture effects. The risk of moisture penetrating the box and corroding the contact point is therefore greater. In addition, in the event of an electric arc, a greater oxygen feed occurs, which helps maintain the electric arc and therefore promotes fire emergence.

A casting compound affords several advantages: leaktightness, electrical insulation and fire inhibition [30]. However, a disadvantage is the low ease of maintenance. Defective bypass diodes cannot be replaced if necessary. It must be kept in mind that some clamp connections should not be cast, because casting would greatly hinder readjustment and overheating or even an electric arc could result.

Re 3. Heat dissipation in the junction box

Junction boxes are also subject to elevated temperatures in normal operation. In the case of a fault, the temperature in the box can climb to over 200°C; in case of an electric arc, temperatures of several

1,000°C are attained. Besides the corresponding material selection, quick dissipation of the created heat is therefore very important.

Figure 3-45 shows various solutions, such as a spacer for the module (Huber & Suhner, HA3 and RH3 product families), metallic plates with cooling fins (aluminum, FPE Fischer, Solon), sheathing with heat-conductive silicon and heat-conductive connections to the aluminum frame (Spelsberg). The preconditions for protection class 2 must be maintained, however.

Photo: Huber & Suhner, junction box with spacer

Photo: FPE Fischer, aluminum junction box with cooling fins

Figure 3-45: Heat dissipation

Re 4. Fire-relevant material properties

Current junction boxes are nearly all made exclusively of plastic. These materials must meet the following requirements:

- Temperature resistance
- Non-inflammability and absence of halogen
- Strength
- Weather resistance
- Cold shock resistance.

A series of technical plastics, such as Ultramid®-A3XZG5 (PA) from BASF and RYNITE® PET plastics (PES) from DuPont are available for this purpose. They are thermoplastically and minerally reinforced by glass fiber content, for example.

Since 2007, aluminum junction boxes have also been on the market, from FPE Fischer (currently FPEAL008 Intersolar 2011, for example ([31]). These junction boxes also contain a plastic box inside for accommodating the electrical connections. According to the manufacturer, the aluminum version of the outer skin guarantees extremely long durability outdoors and is non-critical with overheating – that is, long-lived, safe, low in maintenance and stable in performance.

The aluminum box is used by (e.g.) Solar Energy, SOLAR MODUL ISE 175M/B and Sunworxs GmbH, SUNWORX SW 240P.

Tin-plated copper wire is used as a conductor material in solar cables (DC lines). Regulations require that the cables withstand an operating temperature of 120°C. The temperature in case of a longer persisting short circuit lies even at around 250°C. This temperature must be withstood by the plastic materials.

Re 5. Lightning and surge protection

A PV system generally does not increase the likelihood of a lightning strike. There is no general requirement on installing lightning protection for PV systems. If a building already has a lightning protection system, a retrofitted PV system must be integrated in the existing concept. On public buildings a lightning protection system must be installed for PV systems.

Section 1.3.1.1 lists the applicable standards and guidelines to be followed regarding lightning and surge protection.

The effects of a direct or indirect lightning strike must be considered separately.

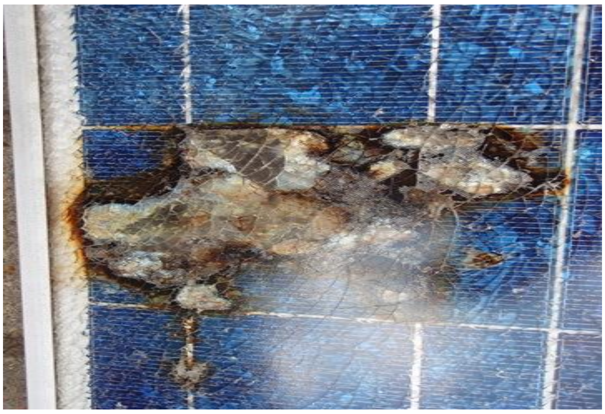

Figure 3-46: Direct lightning damage to a 10-year-old system (source: Photovoltaik-Büro Ternus&Diehl GBR)

In the rare event of a direct lightning strike at the solar generator, considerable damage to the modules must be expected (see Figure 3-46). Fire emergence from the heat effects of the lightning current cannot be ruled out. The bypass diode is most likely broken down and if lightning current capable surge arresters are installed, the inverter is probably defective.

Much more common are indirect or near-strikes, where a partial lightning current flows through a nearby part of a lightning protection system or through the electrical installation, or an overvoltage is induced there.

In these cases, graduated surge protection at the PV generator or at a grid feed point can greatly reduce the risk of damage to the bypass diodes and the inverter (internal lightning protection). Schottky bypass diodes remain greatly threatened, however; see following section.

Especially in the case of frameless modules with lightning protection systems at small distances (less than about 1 – 2 m) from the modules, partial lightning currents can also already induce voltages in the wire loops inside the modules so high as to cause damage to the corresponding bypass diodes.

Framed modules are somewhat less sensitive, but here too very small distances of less than 40 – 80 cm can be critical [32].

Surge protection is also receiving much attention given the recently observed trend in multiple electronic protective devices within the module junction box (intelligent junction box).

Conclusions

The risks at the junction box must be considered high as to the effects of electric arcs and the development of fires compared with other components. That’s why a good joining technology is especially important in order to prevent overheating and electric arcs as much as possible.

In addition, favorable corrosion, heat dissipation, material and overvoltage properties are important factors in designing a low-fire-risk module junction box.

3.5.1.3 Bypass diode

To protect solar cells against impermissibly high block voltages due to inactive (e.g. shaded) cells, bypass diodes are commonly used. They are usually integrated in the junction box and ensure that the current generated by the other modules is conducted through the diodes and past the shaded solar cells.

Where previously P/N diodes were mainly used, Schottky diodes that develop less heat loss are now being used. The breakdown voltage in the blocking direction is considerably less with these diodes, however, so that they can be damaged from singular overvoltage events (e.g. surge voltage from proximate lightning strikes).

Schottky diodes also have the property of significant cutoff currents at high temperatures, possibly resulting in thermal instability (thermal runaway).

Three possible fault cases can occur:

The diodes are permanently conductive (imperfect short circuit), partially conductive (significantly higher leakage current/heating) or interrupted, which underscores the original protective character.

Bypass diodes present the problem that they greatly heat up from the power output they attain if they carry high currents over longer periods of time. This heating can ultimately lead to overheating and in the worst case trigger a fire.

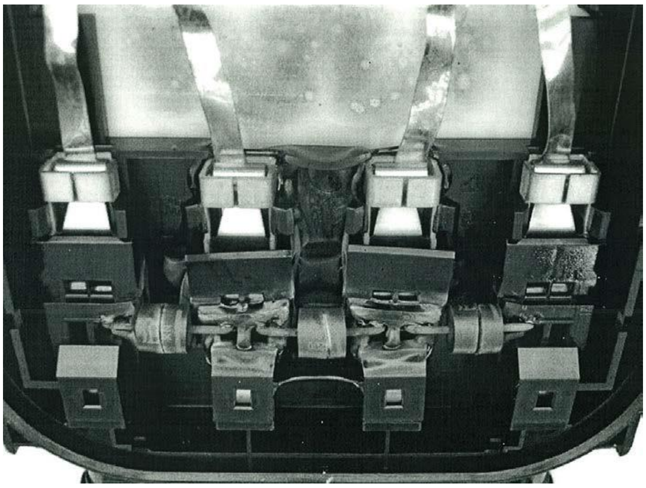

Figure 3-47: Module junction boxes with defective bypass diodes as the result of coupled lightning currents

A module junction box must permanently withstand the heat emitted by the current-carrying bypass diodes. Apart from this, heat development always poses the risk that in the long term contact connections will corrode or even melt.

Should a contact at a bypass diode slowly deteriorate, a continued load on the diode will increase the release heat produced in the contact. In the final stage, this will lead to very intense overheating with scorching or an electric arc.

In case of defective contacts or destruction of the diode (from overheating, for example), the diode is "open," i.e. it no longer performs its protective function. In this case, shading or contact flaws can create hot spots in the module that will damage the module and in unfavorable circumstances cause a fire.

Following surges (e.g. lightning strike) a bypass diode will typically fail because of an (imperfect) short circuit or increased reverse current (partially conductive). This will result in a yield loss, while the protective function need not necessarily be affected. On the other hand, a persistently high current flow through the diode can accelerate aging and thereby increase the electric arc risk at the contact points.

The risk from bypass diodes evidently often lies in the long-term stress. Regular and persistent shading increases heat development of the diodes with correspondingly accelerated aging mechanisms. While Schottky diodes reduce heat development, they are more sensitive to surge events.

Innovative, diodeless protective circuits (so-called "active bypass diodes" or "smart bypass diodes") can significantly mitigate this problem. These products replace the diode by a MOSFET that when actuated has a contact resistance of only a few milliohms, so that the voltage drop via the MOSFET at a current of (e.g.) 10 A is only a few 10 millivolts compared with around 400 … 600 mV with conventional diodes. This also reduces the heat development by a factor of 5… 10, so that the aforementioned problems no longer occur. In addition, active bypass diodes come with integrated surge protection and are therefore many times more resistant to induced overvoltages.

The energy for actuating the MOSFET is obtained through a special control circuit from the only slight voltage drop at the MOSFET, so that the component has only two connections and – without an additional power supply – can be used like a conventional bypass diode.

Active bypass diodes are offered by MICROSEMI (LX2400) [31], for example, with an innovative ultra-thin version (LX2410) being suitable even for lamination into the module. Other manufacturers include STmicroelectronics (e.g. SPV1001) and Texas Instruments (e.g. SM 74611).

3.5.2 Plug connections and wiring

3.5.2.1 Connectors

A photovoltaic system typically contains a large number of plug connections. Each individual module as well as the inverters is usually connected via plug connectors. Owing to their large number, a considerable potential exists here for the occurrence of serial electric arcs.

Progressive professionalization in component development has led to commercially available plug connectors whose inadvertent detachment and contact corrosion can be prevented quite reliably.

The greatest risks lie in the pairing of connectors of different makes and in the crimping of connectors onto cables in the field [33]. The former should always be avoided, for even if the plugs from two different manufacturers mechanically fit together, the electrical transition resistance may significantly increase, resulting in intense heating of the component (Figure 3-48). Even knock-offs of brand-name connector models have occasionally come to light. The quality of such products is dubious, and if a fake is suspected the connector should never be used.

Figure 3-48: Result of pairing connectors from different manufacturers **[33]**

If connectors must be crimped onto cables in the field in order to enable the connection, crimping tongs designated by the manufacturer of the plug must always be used, and with the precisely defined contact pressure. Only then can a gastight, permanent connection point be guaranteed (Figure 3-49).

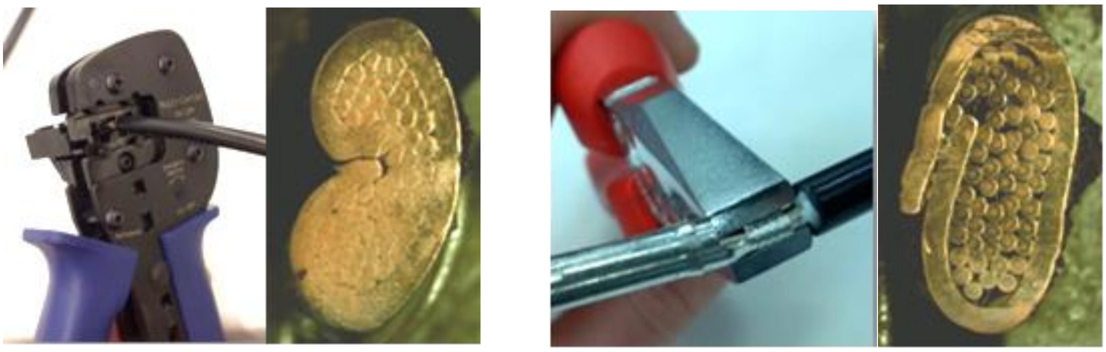

Figure 3-49: Comparison: correct and incorrect crimping in the field **[33]**

3.5.2.2 Lines and line routing

While serial electric arcs occur mainly at contact and connection points, a damaged cable can lead to a very high-energy parallel electric arc if it can form a conductive connection between the positive and negative terminals (or, in the case of a grounded solar generator, between the ungrounded terminal and an object at ground potential). This can mainly occur if the cable insulation is damaged.

Ground and short-circuit-proof line routing is a measure for avoiding parallel electric arcs. That is, both the positive and negative lines are double-insulated or their insulation is reinforced or, in the case of single insulation, routed in separate cable routing systems. An electric arc is highly improbable given *four insulation layers* between positive and negative conductors.

So that only minimal hazardous surges will be induced by a lightning strike, the size of the loop formed by the wiring should be kept as small as possible. At the same time, however, the risk of a parallel electric arc, i.e. contact between two conducts of opposite polarity, must be kept as low as possible. Both requirements are met by laying double-insulated cables next to one another or, even better, with *separate routing* of the two main lines in directly adjacent cable conduits.

The cable routing should also stress the cable insulation as little as possible. That is, the routing should not expose the cables to any direct sunlight, place them continually under water or run them over sharp edges.

The cables should be fastened so that no movement can be caused by wind, with subsequent friction damage to the insulation. Permitted bending radii should be complied with and not exceeded.

3.5.3 Fuses

In the early years of photovoltaics (1985 – 1995), string fuses were often used. It was found, however, that they often failed, causing local overheating or even switch cabinet fires.

The applicable VDE 0100, part 712, accordingly requires them only if the current-carrying capacity of a line could be exceeded. They are therefore installed only in very few PV systems.

For approximately two yearsspecial PV fuses have been available that are designed so as not to trip accidentally, given the correct dimensions, and so that they can interrupt an overcurrent even in a system with high voltages (typically up to 1,000 V_{DC}). At approximately €10 a piece they are quite expensive, however.

Detailed studies have shown that string fuses are helpful at all only with a very limited class of possible faults in a PV system. In all other cases, a string fuse is of no use, and constitutes an additional cost factor as well as several further contact points that present the corresponding electric arc risk potential.

The only scenario in which string fuses can provide protection concerns reverse currents, which can drive parallel strings into a string with partially short-circuited bypass diodes. The permissible reverse current for PV modules is usually twice the maximum short-circuit current. Only if more than 10% of the bypass diodes are short-circuited can a reverse current exceeding this threshold value flow under full insolation [34]. This fault is very improbable, however.

We therefore propose that string fuses be required only for PV systems in which PV modules are installed in a combustible environment.

Since at most (n-1) x the short-circuit current of a string can flow through a short-circuited string of a solar generator consisting of n parallel strings, protection against such faults in the solar generator with fuses is possible in practice only from 3 to 4 parallel strings [35].

During the current international revision of VDE 0100, part 712, intense discussion occurred on whether string fuses for the protection of PV modules and cables against a reverse current should be mandatory again from 3 or some other number (to be calculated) of parallel strings. Given the international claim by standard IEC 60364-9-1: “Low-voltage electrical installations – Part 9-1: installation, design and safety requirements for photovoltaic systems (PV),” we must assume that fuses are required, since in the US and Australia the European concepts of protective insulation and ground-leakage-proof and short-circuit-proof routing are not widespread and therefore parallel electric arcs are to be expected more than is the case in Europe.

Recommendation for standardization:

For Germany, we propose a national addition to the international standard requiring string fuses only for systems with the PV modules installed in a combustible environment.

3.5.4 Isolators and disconnection points

Figure 3-50 shows the schematic design of a PV system with DC switch points as often used in practice in installations at the DC end. The German installation standard for photovoltaic systems [36] specifies a load-break switch (also called a DC isolator) at the DC end of the inverter.

Since this switch must safely disconnect an inverter from the solar generator even under rated load or in the event of an inverter short circuit at the input end, the switch must have the correct dimensions. The use of a DC switch designed for the conditions of a DC power source without consideration of the properties of a PV generator (current source characteristic) can lead to a switch arc that can no longer be extinguished!

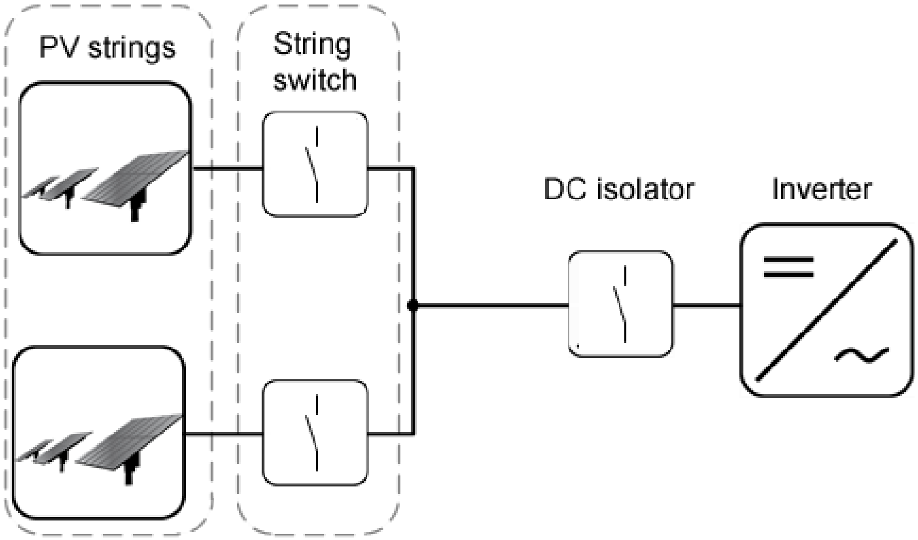

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Figure 3-50: Block diagram of a PV system with switch points

Especially larger PV systems employ switching devices to shut down individual strings. For cost reasons circuit breakers are often used here. Circuit breakers must not switch off the circuit when live. They may only be operated if the circuit was previously interrupted by a load disconnecting element [37].

Regarding the occurrence of fault arcs in circuit breakers, the switches must be designed for the operating measurement currents.

Alternatively, DC circuit breakers specially developed for the requirements in PV systems are available on the market.

Some PV systems employ DC contactors. They are designed for remote-controlled switching on and off under load as well as for conducting currents, but may not be used as short-circuit breakers or isolators [37].

Generally each piece of electrical equipment bringing a new contact connection into the system poses the risk of an electric arc. Only proper dimensioning and installation can keep this factor small.

3.5.5 Generator junction boxes

Several PV strings are compiled in the generator junction box. The string cables, the DC main cable and if necessary the potential equalization cable are connected.

The generator junction box contains connecting terminals and disconnection points as well as possibly string fuses and string diodes. Often the generator junction boxes contain integrated surge arresters for diverting overvoltages to the ground. The potential equalization or grounding conductors therefore lead into the generator junction boxes.

DC main switches or line safety switches are sometimes accommodated in the generator junction box. String monitoring elements are finding increasing use in larger systems. These elements report any string malfunction to the data monitoring system, so that troubleshooting can be initiated.

The generator junction box should comply with protection class II and have a clear separation between the positive and negative ends inside.

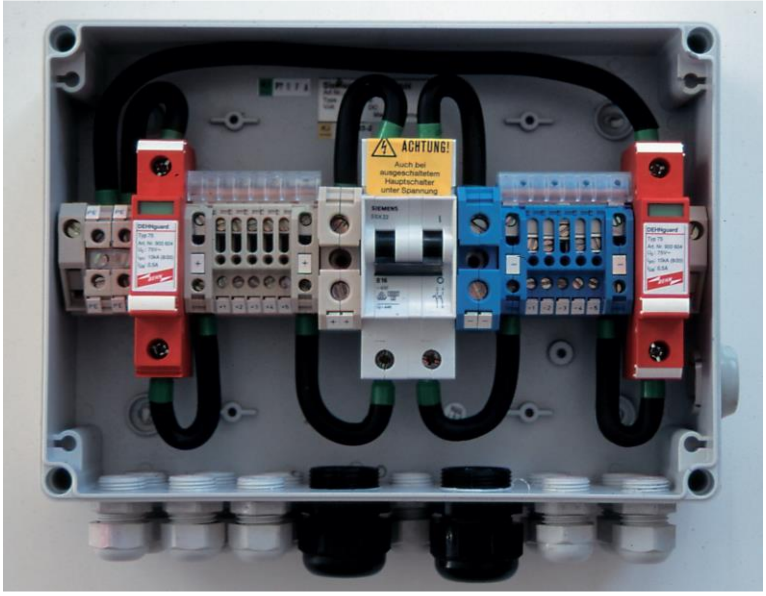


Figure 3-51: Generator junction box [source: DGS-Berlin]

Since the generator junction box is located outdoors, it should have at least protection level IP 54 and be weather and UV resistant. In addition, we recommend selecting installation site so that the junction box is protected against rain and insolation. Accessibility of the junction box should be ensured because of possible, later maintenance work.

In junction boxes with screw terminals the exact connection is important, since a faulty connection can cause the entire string to fail. Junction boxes with spring-type terminals or other suitable terminal systems require no core end sleeves and are easy to handle.

The design of the generator junction box must comply with VDE 0660-600-1 (EN 61439-1). For constructing the circuitry, terminal blocks may be used that are fastened to the top-hat rails. The positive and negative ends must be consistently separated and be both ground-leakage-proof and short-circuit-proof.

String diodes for uncoupling the individual strings were originally used in strongly shaded systems with central inverters. Their usefulness is very questionable, however. If string diodes are nevertheless used, they must have a voltage strength as per VDE 0100-712 corresponding to the doubled generator off-load voltage at STC.

The string fuses protect the cables against overload in case of a fault. They must be designed for DC operation. Unsuitable DC fuses have been used as string fuses. Since the current may fluctuate because of cloud movement, an electric arc may occur in a normal DC fuse, but not suffice to melt the insulation granulate. The result is non-tripping of the fuse and slow heating that can lead to a fire in the fuse box.

Some manufacturers have in the meantime developed suitable PV fuses. To date there exists only one draft standard, IEC 60269-6 FDIS 09/2010, which takes into account the specific use conditions of fuses in PV systems.

Some manufacturers offer suitable PV fuses with DC switch-off capability and full-range characteristic as per this draft standard with the designation gR or gPV (see Figure 3-52**)**. The selection and dimensioning of the fuses and fuse holders must absolutely comply with the following reduction factors for the fuse rated current In (= rated current):

1. for the elevated operating temperatures (e.g. for 60°C. e.g. 0.84)
2. for the accumulation, i.e. multiple fuse holders too densely arranged

3. reduction factor for plastic sheathing of fuse link
4. load cycle factor (considers aging; usually 0.9).

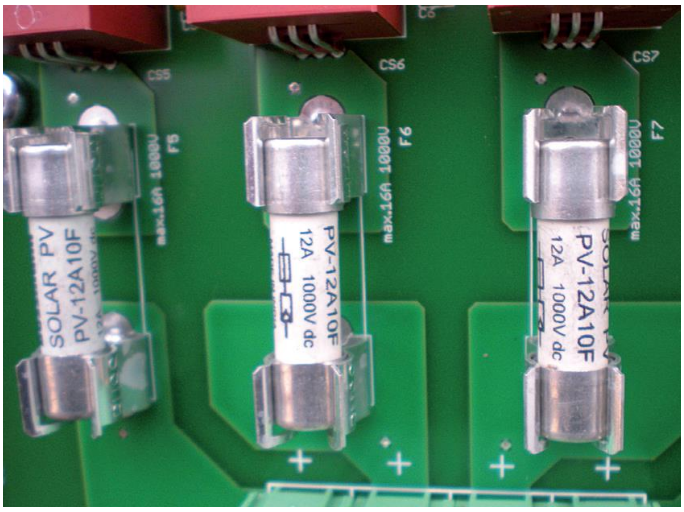


Figure 3-52: PV fuse as per standard [source: SIBA]

3.5.6 Inverters

The inverter is the most complex individual component of a photovoltaic system. All components listed in the preceding sections, like plugs, clamp connectors, switches and cables, occur inside an inverter, along with passive, electronic and power-electronic components. Depending on the equipment features of an inverter, up to several hundred single parts may be assembled together.

Individual serial defects have been encountered in the past that are attributable to inadequate dimensioning of components or even conductor tracks, in part also to production flaws of the PCBs themselves (interlay connections) or even to the poor quality of the soldered joints (cold soldered joints).

These are not solar-specific defects, however, but can occur in any piece of electronic equipment. These defects were accordingly rectified, and according to the above statement the inverters may be said to have a high level of reliability and pose a “normal” fire risk.

Figure 3-53 and Figure 3-54 show the typical single parts of a string inverter:

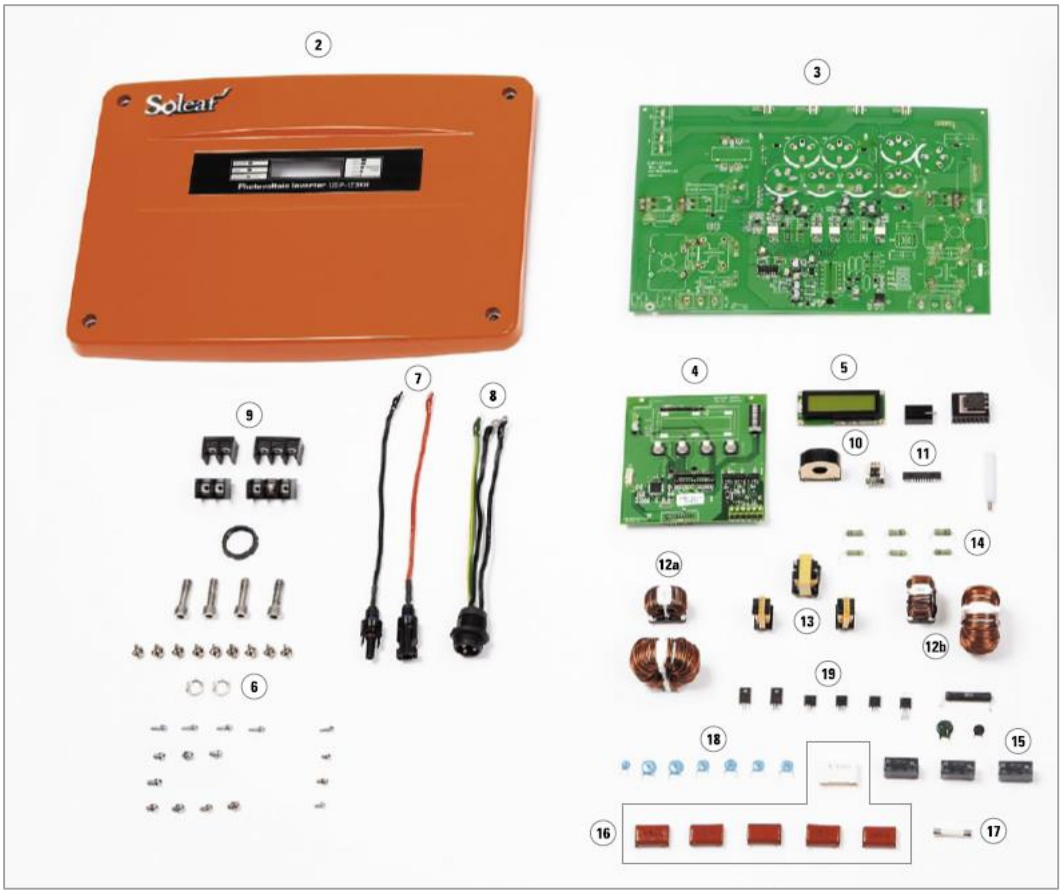


Figure 3-53: Single parts of a string inverter **[38]**

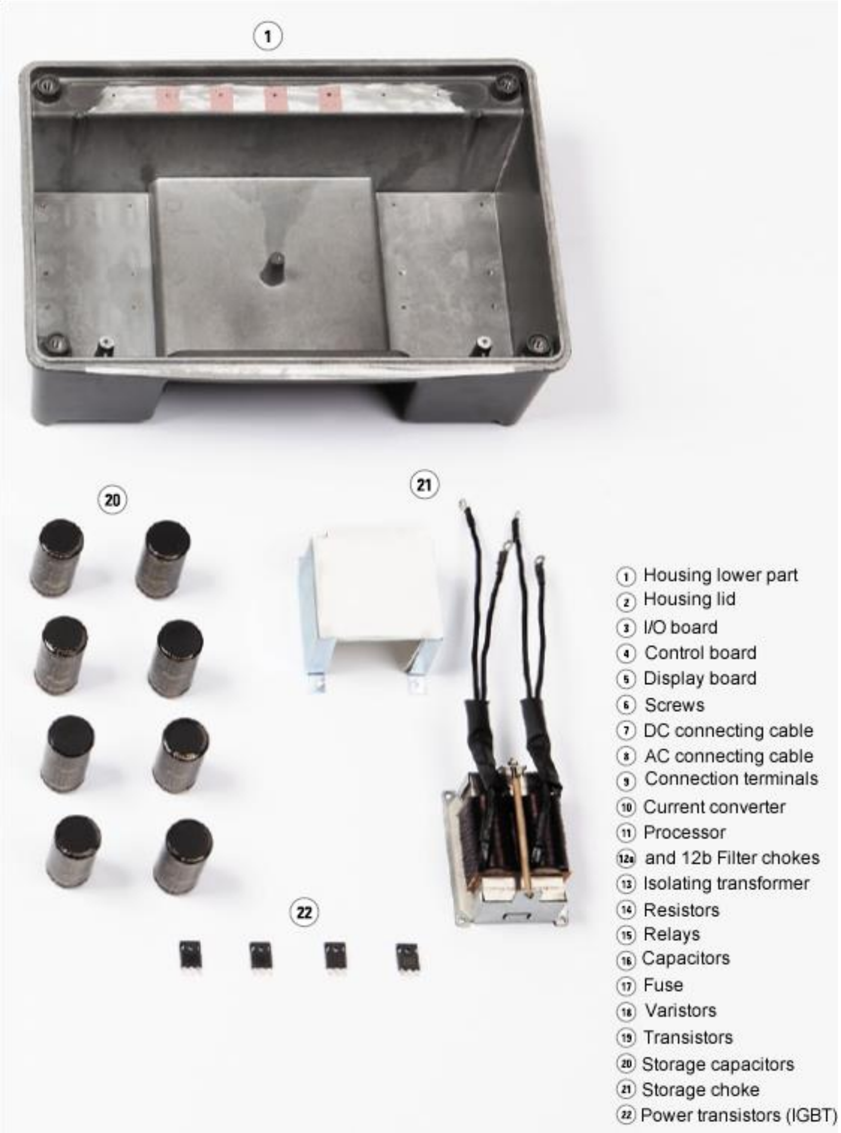


Figure 3-54: Single parts of a string inverter **[38]**

Figure 3-55: Example of a central inverter in a switch cabinet

From experience with numerous inverters we can identify certain potential sources of faults that should be given particular attention during the design phase:

PCBs

In the case of inverters with an output of up to some 10 kW, attempts are made for manufacturing reasons to accommodate all components if possible on one or a few PCBs. Merely the usually heavy and voluminous inductive components (restrictors, possibly transformers) are separately accommodated in the housing, some in their own chambers of the housing. They are connected to the main PCB via cables and clamps. In the case of inverters in the power range of 100 kW and more, the construction occurs in a switch cabinet – subassemblies like buffer capacitors, power semiconductors and inductivities are interconnected via power rails or plates with high-power capability; the actuation as well as the control and regulation technology are compiled on PCBs.

The PCB design must maintain the necessary conductor cross sections, which usually occurs anyway given the requirement of low resistance or high efficiency. Thermographs of inverters show that no problems with excess temperatures occur here.

Interlay connections (vias) with power PCBs constitute a potential weak point – here there is a solution consisting of numerous small parallel-operating vias or the general insertion of a component to such an interlayer connecting point.

The normatively stipulated distances between the conductor tracks must be maintained given the occurring voltage and expected degree of dirt on the PCB.

Connectors / clamps

Today's string inverters are usually fully connected by plug connectors. At the DC end, the same insertion systems are used as in solar modules. At the AC end commercially available or modified multipole AC or three-phase connectors are used. The current carrying capacity of these connectors must be sufficient.

Critical at this point is that usually no prefabricated connecting cables can be used here, rather the installer must manually install the plugs at the connecting cables on site. This always poses the risk of insufficient quality of crimp connections or of the strain relief, a risk that can be minimized only by conscientious work.

According to the findings of the damage analysis within the research project, fire-relevant faults often also occur along the familiar, conventional AC wiring!

In the device itself, the connections sometimes employ clamps on the PCB. Here spring-type terminals are preferable, since they ensure a continually constant contact pressure of the conductors.

In designing the PCB and mounting it on the device, it must be kept in mind that in part unpredictable and considerable forces can occur during transport and assembly, possibly leading to damage to the conductor tracks with possible consequences later on.

As shown above, it is advantageous to accommodate all components on one PCB or on as few PCBs as possible. This will minimize the number of connections between the PCBs / subassemblies, thereby increasing reliability. At the same time, costs will be saved and sources of faults during manufacture of the devices diminished. Here the market continues to have negative examples of numerous individual PCBs and a correspondingly high number of connectors.

Switches

In Germany, a load-break switch is normatively required at the DC end of an inverter. This switch is usually integrated in the device, but can also be added on externally as an extra component. The switch must be suitable for DC and be designed for the special current-voltage curve of a PV system.

Capacitors

Capacitors are used at many places in an inverter. Critical to fire protection are the X and Y capacitors, attached both at the DC end and at the AC end for suppressing EMC interference. Since they electrically occur directly behind the input terminals, they are subject to high voltage spikes and must be correspondingly sturdy – only the pertinent, permitted capacitors may be used here.

The higher-capacity electrolyte capacitors used as input buffer capacitors are not critical components according to present experience. Advantageous for the service life of the devices is the selection of a high temperature class, such as 105°C.

Surge arresters / varistors

At the input and output ends inverters usually contain lightning fine protection in the form of varistors or a combination of varistors and gas arresters. Varistors are potentially jeopardized components, since their response voltage diminishes because of small but quite frequent surges, until finally a noticeable leakage current already flows through them at the normal operating voltage. This leads to overheating and sometimes also to the varistors burning away – a fault that is often to be found in inverters.

To reduce this risk, the varistors with their response voltage must be selected with sufficient distance from the normal operating voltage. Also used are temperature-monitored varistors in which a switch element suppresses the current flow through the varistor once the latter exceeds a temperature threshold.

Since it also suppresses the actual surge protection function, this condition should be indicated. Another solution is the series connection of a varistor with a spark gap.

Housing

Among string inverters, both devices with metallic housing and ones with plastic housing are to be found on the market. Among large devices, metallic switch cabinets are generally used.

For fire protection reasons metallic housing is advantageous, since they inhibit the spread of any possible fire within the device itself. A high IP class (e.g. IP65) is also an advantage, since the very thick housing seal usually occurring in this case will inhibit the oxygen supply to the internal source of fire.

Fans

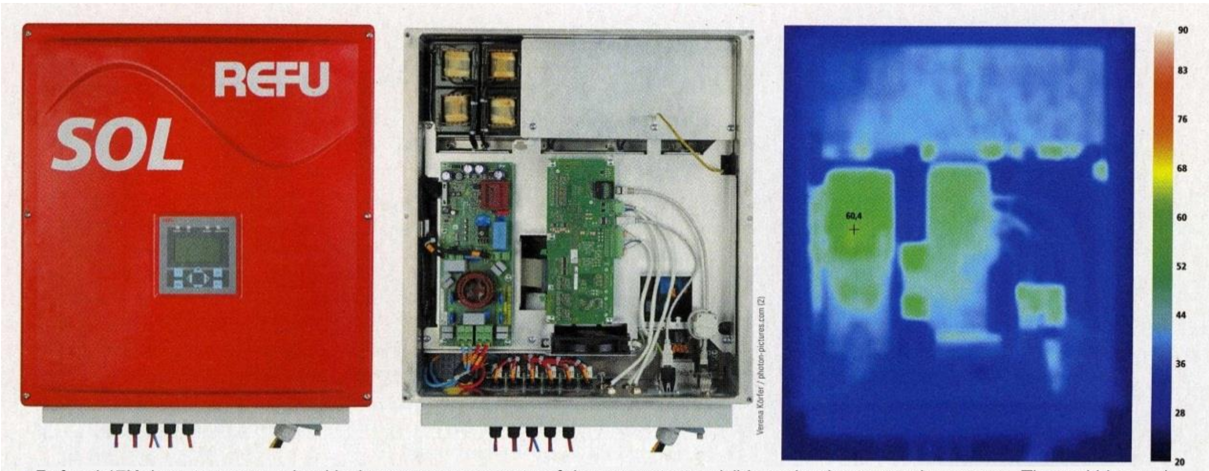
At present both inverters with active cooling by one or more fans and inverters without fans are commercially available.

The advantage of devices with fans is that the total work performed by a small cooling unit with one fan is less compared with a fanless device with a correspondingly large cooling unit. A disadvantage is that the fan is generally a wear part, but more important is the argument pertaining to dirt on the fan and in the cooling duct from forced ventilation.

Of course, even a fanless device can develop a hot spot from dirt or from being covered and present a fire hazard. Crucial to both concepts is therefore monitoring of the cooling unit temperature combined with a corresponding power limitation and if necessary signaling of the fault condition.

Some devices also have fans inside the housing in order to prevent hot spots. Here there is no danger of dirt, although the operating period of the fans must be kept in mind.

Well-designed devices optimized for high efficiency also attain temperature levels of some 10°C above the ambient temperature under continual load. As an example, we show here a device from REFUsol (Figure 3-56):



▲Refusol 17K does not approach critical temperatures at any of the components visible to the thermography camera. The multi-layered design blocks the view of the power section, however.

Figure 3-56: Design and thermography of a highly efficient PV inverter. Maximum measured temperature: 60.4°C **[38]**

3.5.7 AC installation

Unexpectedly many cases of fire damage originate at the AC end of PV systems. In many such cases, inferior quality of workmanship was identified as the cause. The following defects have been observed:

- Cables were undersized
- Screw terminals were not tightened
- Cable insulation was also clamped or cable ends were not fully inserted in the terminal, making the contact surface too small.
- Sizing rules for fuses and LS switches were disregarded insofar as the increased heat stress related to accumulation, coincidence and elevated ambient temperatures was disregarded.
- Grid stations designed for “power utility loads” and with a coincidence factor of 0.7 were used in PV systems. There the coincidence factor is at least 0.85.

All these defects can lead to an increased temperature stress of the affected operating equipment and thereby create an increased degradation risk for the contact points. In the long term, this degradation can cause overheating of the contact up to the point of fire.

There are also indications that the typical load cycles in photovoltaic systems cause particular stress on contacts. Daily changes between no-load operation and rated load and long-term operation under rated load together with the corresponding temperature cycles seems to accelerate aging among many types of contacts. This concerns at least terminal blocks, screw terminals at operating equipment, busbar connections and blade contacts of NH fuses.

This cyclical load may not be sufficiently considered in current product standards.

Given the possibilities of faults and failure, the condition of the connection points should be regularly checked.

3.6 Risk analysis

3.6.1 Methodology

Photovoltaic systems are complex electro-technical systems with numerous individual components. A total of more than 30 GW installed in Germany as of 2013 corresponds to about 150 million modules, approximately 450 million bypass diodes, approximately 10 billion solar cells (3 Wp) and approximately 50 billion soldered joints. Added are cables, distributors, string diodes, DC fuses, DC switches, inverters, AC fuses, IT interfaces, etc., as well as mechanical components like elevating supports and even tracking systems.

As in any technical system, there is a risk of damage from a malfunction in the system. For insurance companies as well as for the installers and operators of PV systems it is therefore necessary to assess this risk.

Pertinent methods are known in the insurance industry; see [39] for an overview.

An approach to identifying and if possible eliminating any sources of faults already during the development phase of a product or a system is provided by the so-called **FMEA** (Failure Mode and Effects Analysis, or also “Effects Analysis” for short) [40].

A research project applied this method to a complete grid-connected PV system (without accumulator). The procedure and results are presented in the following.

FMEA is a method formally required (DIN EN 60812, “Failure Mode and Effects Analysis”) and established in the industry, especially among manufacturers of mass products like motor vehicles, for identifying and assessing possible sources of faults and designating remedial measures already during the development phase of a product. Added is a team of about 10 experts from the widest possible variety of departments that under the management of a moderator considers in detail the components of an overall system or even just a single component.

The risk assessment is based on a combination of years of experience and factual knowledge, but also on “gut feelings”. Controversial assessments are thoroughly discussed, for ultimately the team must agree on a level of risk.

The risk is assessed according to three criteria: A, B and E. Each of these criteria is rated from 1 to 10 on an integral scale according to a specific list, with 10 corresponding to the highest risk in each case (Table 3-3).

“A” describes the probability (**A**uftrittswahrscheinlichkeit) of a fault occurring
“B” describes the significance (**B**edeutung) of a fault, i.e. its consequences.

“E” describes the probability of detection (**E**ntdeckungswahrscheinlichkeit) or, better, the “probability of non-detection,” so that the factor 10 is assigned to a fault that cannot be detected.

Table 3-3: Specific assessment list for PV system analysis

	Probability of occurrence		Probability of initiating a fire (at the component)		Probability of detection
1	Negligible Theoretically conceivable, practically impossible	1	Negligible Fire emergence is theoretically possible, practically never observed	1	Very high E.g. failure of the system, very reliable system monitoring, etc.
2		2		2	
3	Remotely conceivable Has already been observed, but considered the exception	3	Remotely conceivable Fire emergence is theoretically possible given certain conditions	3	High Fault detection exists, but can occasionally fail under certain conditions
4		4		4	
5	Low, seldom Seldom observed, occurs rather sporadically	5	Low, seldom Fire emergence is possible, but seldom occurs	5	Occasional Fault characteristics are easy to detect, e.g. visible, but are not systematically captured
6	Occasional Occurs at regular intervals	6	Occasional Fire emergence is possible, occurs occasionally	6	Low, seldom Fault can be detected by control measures or from its effects
7		7		7	
8	High Has been often observed	8	High Occurrence of the fault has already caused a fire in the past	8	Remotely conceivable Fault can be identified through precisely defined tests
9		9		9	
10	Very high It is practically certain that the fault will occur in the foreseeable future	10	Very high Occurrence of fault very often causes a fire	10	Negligible Hidden malfunction, characteristic cannot be tested

Multiplying together the three individual criteria yields the so-called risk priority number RPN, which can lie between 1 and 1,000.

Further analysis of the RPN can vary in nature – one possibility is to specify a limit value above which the risk is regarded as critical and countermeasures, such as design modifications, become necessary.

The FMEA conducted here specified an RPN of 150 as the threshold value. Rating all three criteria a “5” would therefore yield a non-critical RPN of 125.

This purely formal procedure is controversial and should always be supplemented by “common sense” and the results of the team discussion (see section 4.5.2).

3.6.2 Assessment of the risk points in PV systems

An FMEA can be conducted for a single component, such as a module junction box, or, as in this case, for a complete system; the level of detail will then vary accordingly.

Since within a PV system individual functions or technologies, such as soldered connections, were used at multiple points, the latter were compiled as much as possible and assessed.

The following groups were considered:

- Connectors (module, DC main cable, inverter at AC end)
- Terminals (field distributors, inverters at DC and AC ends)
- Soldered connections (cells/strings, junction box, inverter)
- Diodes (bypass diodes, string diodes)
- Modules (cells, glass, backsheet, connection technology)
- Fuses (DC end, AC end)
- Cables (DC end, AC end)
- Switches (DC end)
- Inverters
- Planning and installation

The moderator formulated altogether 39 questions, yielding approximately 140 assessments, including any necessary iteration, for reducing the RPN.

Table 3-4 shows an example of the assessments according to three criteria given a scorched DC plug related to incomplete insertion.

The “probability of occurrence” at 4 was regarded as relatively low. On the other hand, the “fire-inducing probability,” i.e. the probability that the plug would become scorched, was assigned a “7,” and therefore regarded as quite probable.

The “fire-inducing probability” always refers only to the considered component, since a spread of the fire to other components or to the building depends on many boundary conditions that cannot be estimated here.

A high fire-inducing probability therefore does not necessarily mean that the building will catch fire. An example could be a scorched connector between two modules above a hard roof covering (roof tiles), a situation that generally would not cause a fire.

The third criterion, namely that the fault (defective plug insertion) be already detected prior to the occurrence of scorching, was rather improbable, and thus an “8”. Altogether, multiplication yields an RPN of 224 – significantly above the selected RPN limit of 150!

Table 3-4: Example of assessment of an incompletely inserted DC plug

			Actual status			
Component involved / location	Potential faults	Potential causes	Probability of occurrence	Probability of fire emergence	Probability of fire emergence	RPN
DC plug						
DC plug connector	Plug connector scorched	Plug not fully inserted	4	7	8	*224*

According to Figure 3-57, of the 39 groups considered, 21 attained an RPN above the limit of 150; Figure 3-58 lists the other 18 below the threshold.

The group of experts regarded the (impermissible!) combination of connectors from different manufacturers as especially critical, assigning an RPN of approximately 450.

Besides faults in component manufacture, primarily installation flaws and planning errors emerge as critical.

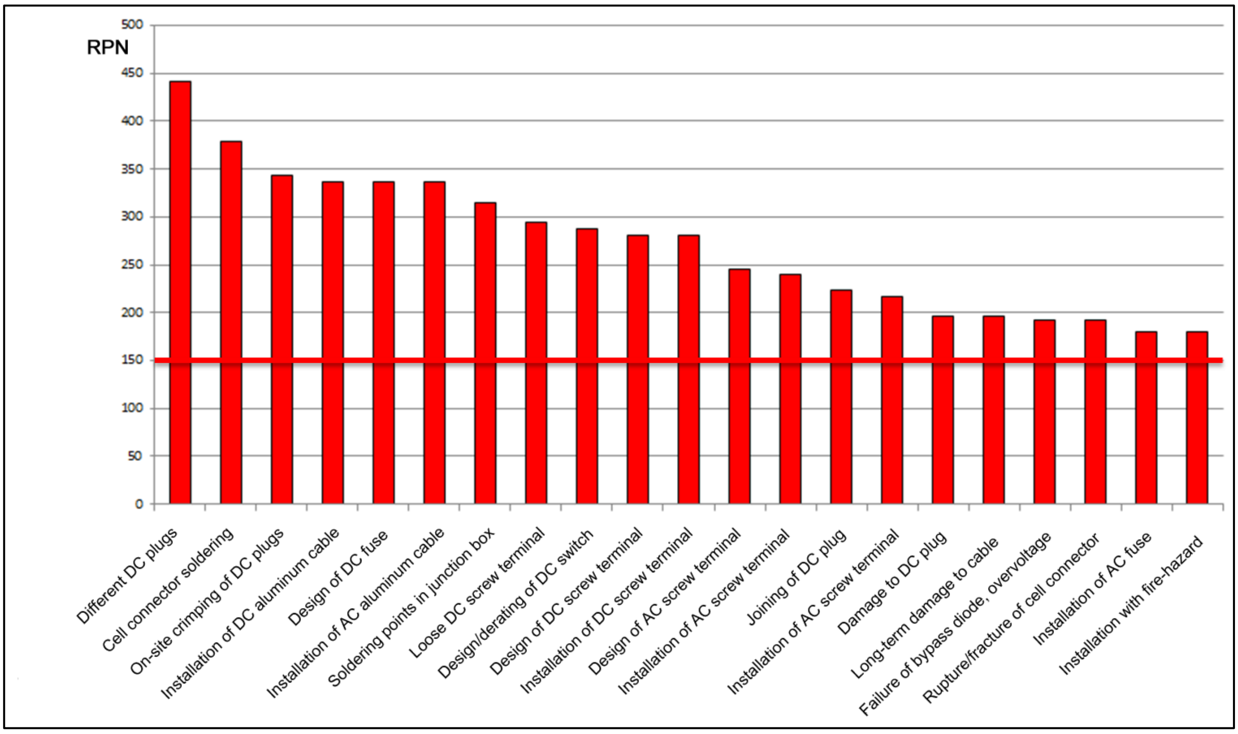


Figure 3-57: Subassemblies/functions with an RPN > 150

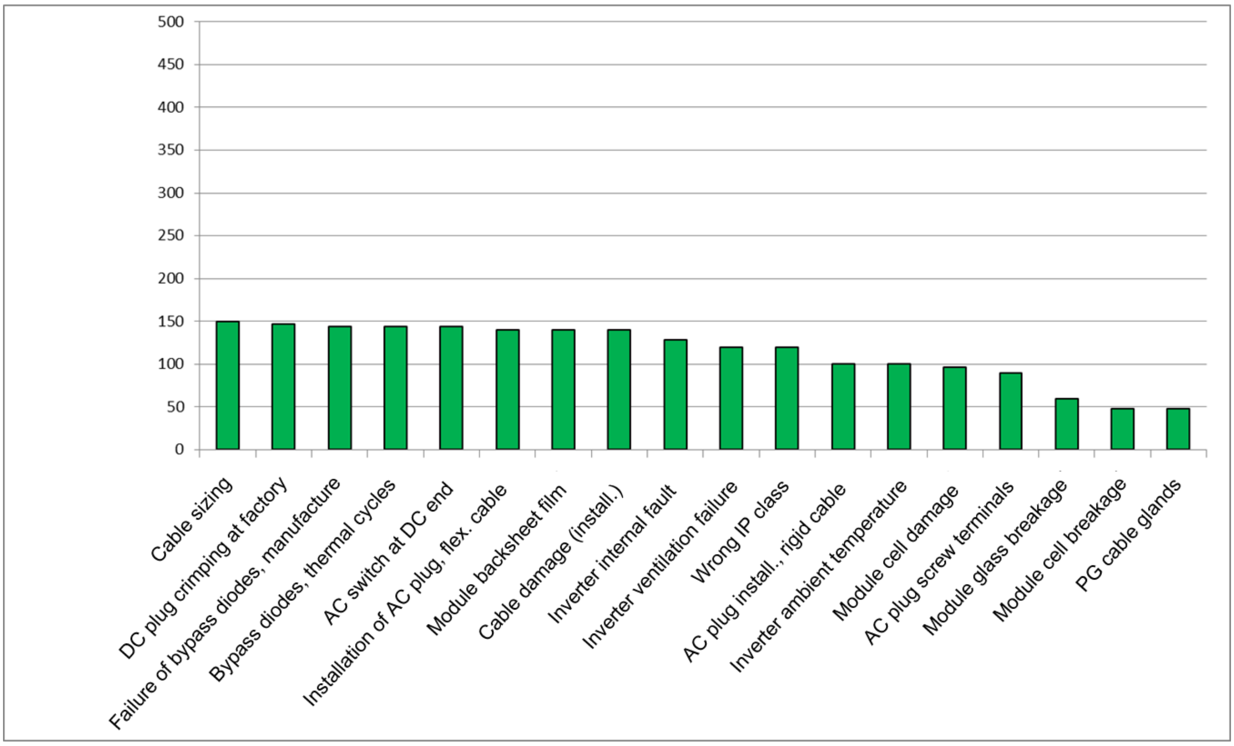


Figure 3-58: Subassemblies/functions with an RPN <= 150

The following table shows a typical assessment of various improvement measures with an incompletely inserted DC plug, alongside the comments from the FMEA team.

Table 3-5: Typical assessment of different improvement measures

Improved status					
Possible remedial measures	Probability of occurrence	Probability of fire emergence	Probability of detection	RPN	Comments:
Initial status	4	7	8	224	
Training of the installers	3	7	8	168	Time and cost pressure
Plug design: Snap tabs, touch & feel, color ring, etc.	2	7	7	98	
Acceptance inspection (DIN 0126-23)	4	7	7	196	Not sufficient!
Acceptance inspection (expanded methods, e.g. IR)	4	7	6	168	If necessary, new measuring methods
Regular repeat inspection (DIN 0126-23)	4	7	7	196	Not sufficient!
Regular repeat inspection (expanded method, e.g. IR)	4	7	5	140	If necessary, new measuring methods
Electric arc detector	4	4	7	112	If reliable!

Training or raising the awareness of the installers can improve the quality of the installation, thereby improving the criterion rating for “occurrence probability”.

The FMEA team viewed the improvement potential as insufficient given the time and cost pressure during the installation, however.

Purposive could be improvements at the plug itself (snap tabs, touch & feel, conspicuous color ring in case of wrong insertion, etc.), also regular repeat inspections with expanded methods (infrared camera) or also an electric arc detector, if the latter can also detect such problems (scorching, but no electric arcs) at an early stage and reliably.

Fortunately, according to Figure 3-59 practical proposals could be found for all groups and functions with an RPN greater than 150, by means of which the RPN could be brought below the critical limit.

The complete results of the FMEA can be viewed in the Appendix (IX Appendixes).

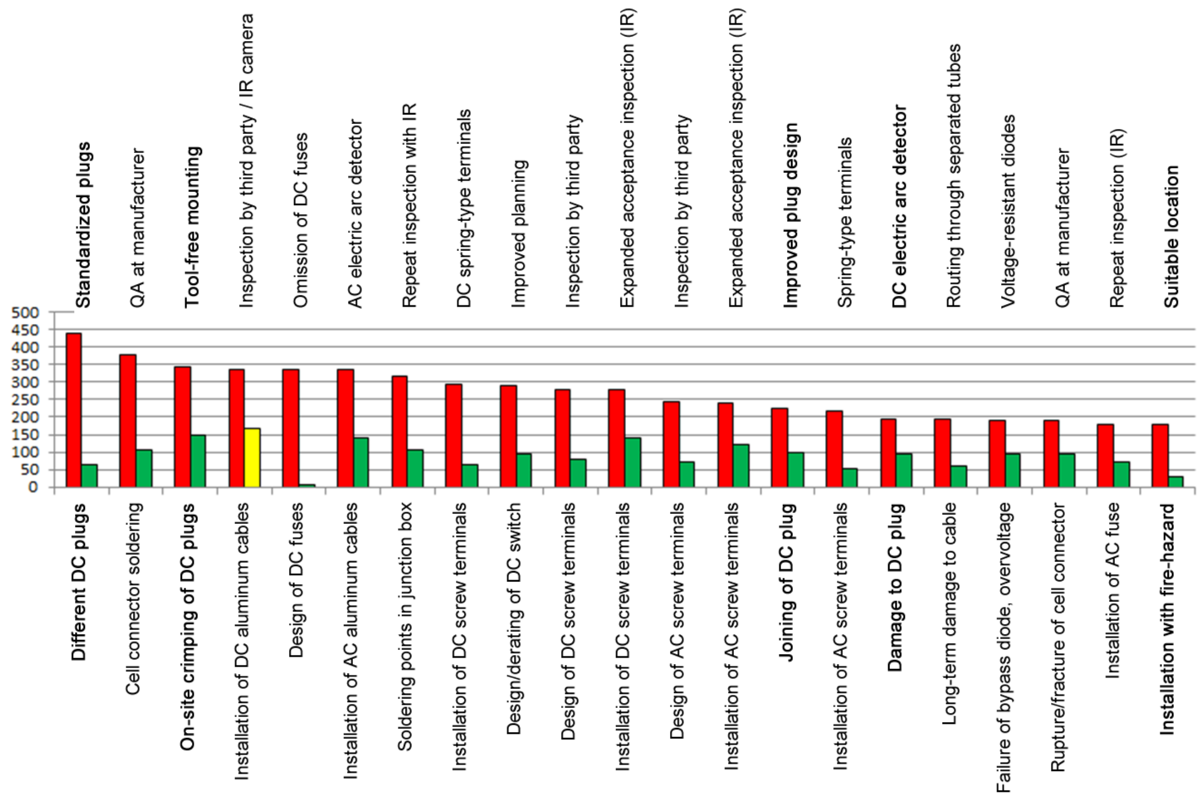


Figure 3-59: Subassemblies/functions with an RPN > 150 and proposals with lowest RPN in each case

3.6.3 Conclusions

Taking together the improvement measures shown in the above graphics and primarily mentioned in the discussions during the FMEA, we arrive at the following ranking:

(1) Compliance with the existing standards and regulations

(2) Acceptance and repeat inspections by independent third party

(3) Expanded acceptance and repeat inspections (IR camera, EL, new methods) by independent third party

(4) Training of planners and installers

(5) Quality assurance at component manufacturer

(6) Spring-type terminals instead of screw terminals

(7) Worldwide standardization of components (especially DC plug connectors)

(8) Electric arc detector and automatic shutdown (see notes from section 5.3.5)

(9) Design improvements at connectors, for example

(10) "Sleek" system design (omission of superfluous components)

(11) Structural measures (e.g. protected routing of lines)

(12) Many other, for the most part already familiar, detailed solutions)

Conclusion

As a main source of faults we unfortunately had to recognize the "human factor". The proposed improvement measures therefore lie mainly in the realm of quality assurance pertaining to the components as well as to the planning and construction of the systems.

Regular inspections by independent third parties were considered very useful, however the financial cost must stand in a reasonable relationship to the revenue from the system.

Additional safety components can further reduce the risk, but were mentioned only in second place, following professional planning and construction of the systems with high-quality components.

Altogether, the participants considered the FMEA to be very useful, for it was comparable to brainstorming – numerous fault scenarios were addressed and analyzed.

4 Endangerment of emergency services in damage incidents

4.1 Risk analysis for rescue workers

Possible hazards for emergency services attending to PV systems are assigned to nine possible categories according to the hazard scheme routinely used by German fire departments (AAAACEEEE rule):

1. **A**temgifte (respiratory poisons)
2. **A**nxiety attacks
3. **A**usbreitung (propagation)
4. **A**tomic radiation
5. **C**hemical substances
6. **E**rkrankung / Verletzung (illness / injury)
7. **E**xplosion
8. **E**lectricity
9. **E**insturz (collapse)

For analyzing the hazard to rescue workers, the scenarios must be identified that in operations at PV systems could lead to possible injuries or health impairment:

1. Respiratory poisons – yes, PV modules are combustible and contain, besides glass and aluminum (frames), also a great variety of plastics as well as, depending on the technology, toxic heavy metals. Smoke gases and soot particles can be hazardous.
2. Anxiety attacks – no, PV fires generally do not present an increased risk of explosion nor do they involve fast mechanical motions or present otherwise threatening scenarios.
3. Propagation – yes, a fire can spread due to the compact design and cables between the components.
4. Atomic radiation – no, does not apply.
5. Chemical substances – yes, primarily in the form of respiratory poisons (covered by 1.).
6. Illness/injury – yes, but the illness risk is already covered by 1.; a risk of injury exists from (e.g.) electric shock and falling because of a shocked reaction or from falling system parts; since this is covered by 8. and 9., we do not consider the point separately.
7. Explosion – in the strict sense, no, apart from PV systems with accumulators and flooded basements – these systems are investigated in a subsequent study and are not separately considered here. Explosion-like effects can occur, however, if a roof timber fire spreads to the PV system and causes the module glass panes to burst. Reports are known according to which glass fragments were found up to a radius of 20 to 30 meters. Wafer fragments detached by the heat effects of large-scale fires were thermally lifted to great heights and transported several hundred meters.
8. Electricity – yes, in particular the live DC end poses hazards in case of damage, with danger of contact and hazards during extinguishing operations.
9. Collapse – yes, the heat can impair the bearing capacity of a steel structure. In the case of a wood structure, the bearing capacity is reduced by the burning with a decrease in cross section. These effects apply analogously to bearing base frames of the PV modules.

Table 4-1: Fire department hazard matrix for operations at PV systems

Which hazards are detected?									
Hazards	Respiratory poisons	Anxiety reaction	Propagation	Atomic radiation	Chemical substances	Illness / injury	Explosion	Electricity	Collapse
Which hazards must we combat?									
People	x		x				(x)	x	x
Animals	x		x				(x)	x	x
Environment	x		x						
Property			x						
Against which hazards must we protect ourselves against?									
Team							(x)	x	x
Equipment									x

The fire department operational scenarios can generally also be classified according to firefighting and technical assistance types of operations. There are also events that fit into both categories, however. The greatest possible hazardous area, namely “Electric shock,” was subdivided into the three subareas “General scenarios,” “Firefighting” and “Technical assistance.”

Risk assessments classify the different scenarios by means of the **parameters extent of damage** and **probability of occurrence**.

These parameters are employed as per the guideline created in 2012 for preparing hazard assessments in the Fire Service of the German Social Accident Insurance (DGUV).

The **probability of occurrence (P)** breaks down into five categories:

- **0** Never (absolutely no possibility of encountering the hazard)
- **1** Exceptionally
- **2** Occasionally
- **3** Probably
- **4** Always

The possible **health consequences (C)** also break down into five categories:

- **0** No consequences
- **1** Minor, light and reversible injuries, such as minor cut wounds, scrapes, sprains
- **2** Moderately severe injuries, such as bone fractures, 2nd degree burns
- **4** Highly life-threatening injuries; severe, permanent damage to health, such as paraplegia, blindness, etc.
- **8** Extreme case (death)

The risk matrix (Table 4-2) shows the risk assessment (R) based on the probability of occurrence (P) and the expected health consequences (C). Source: Deutsche Gesetzliche Unfallversicherung (DGUV) [1]

Table 4-2: Risk matrix of the fire department

Probability (P)		Risk R = P x C				
Always	4	0	4	8	16	32
Probably	3	0	3	6	12	24
Occasionally	2	0	2	4	8	16
Exceptionally	1	0	1	2	4	8
Never	0	0	0	0	0	0
		0	1	2	4	8
		No consequences	Low	Moderate	High	Extreme case (death)
		Consequences (C)				

The risk group 0 1-2 3-6 8-32 can be directly read off the intersection of probability of occurrence (P) and consequences C in the matrix.

Table 4-3 shows the identified *risk groups* and the resulting need for action by specifying the urgency and scope of the required measures. Possible technical or organizational measures are described in section 6.

Table 4-3: Risk groups and need for action

Risk group	Risk	Measures
8 - 32	Large	Measures with increased protective effects are urgently required
3 - 6	Moderate	Measures with increased protective effects are urgently required
1 - 2	Low	Organizational and personal measures suffice
0	-	No additional measures necessary

4.2 Electrical hazard for rescue workers

Hazards from electric shock during firefighting operations at PV systems must be considered in various scenarios and appropriate measures taken to protect teams and equipment as well as any other persons, animals and the environment from electrical hazards.

Not only insolation at the PV modules can generate electrical voltage. In individual cases hazardous voltages can occur even with the use of artificial lighting, as in the illumination of the scene of a fire. Scientific studies have shown that in particular the use of halogen spotlights can generate a significant amount of energy under unfavorable conditions. This danger can be countered by maintaining a sufficient distance of the illuminants from the modules (see distance formula according to the study conducted in the research project, section 4.5.2). That’s why the individual results do not distinguish between natural and artificial lighting.

4.2.1 General scenarios

The category of “General scenarios” considers all events that are not specifically assignable to firefighting or to technical assistance.

The contact safety of PV systems is extremely important on roofs. Injuries from electric shock are very dangerous especially on roofs, since besides injuries from electric currents they can also lead to severe secondary injuries (falling from the roof).

Figure 4-1: Firefighting operation at a PV fire on a residential building (here 2008 in Bremen),
photo: www.feuerwehr.de

4.2.1.1 Exposure of live cables

The effects of a fire, but also mechanical causes, such as a storm, can damage the electrical lines of the PV systems, irrespective of the type of installation or system (e.g. roof or wall-mounted, open-space system).

Hazard: contact with live cables by rescue workers

Protective goal: avoidance of electric shock for rescue workers

Risk measure: 16

Assessment: Owing to the severity of injury (possible fatality), the assessment leads to a high risk.

4.2.1.2 Damage to PV modules (e.g. from the aerial ladder basket)

The use of different (electrically conductive) work equipment can damage PV modules and consequently lead to indirect contact with live parts.

Hazard: electric shock

Risk measure: 4

Protective goal: avoidance of voltage transfer or indirect contact

Assessment: While the rescue workers are at risk of an electric shock (if at all) only if the system is grounded, a precondition for the shock occurring is that they first build up voltage by touching two different potential points (e.g. step voltage).

4.2.1.3 Accessing the roof

The roof surface may have to be accessed during firefighting operations and technical assistance, for example, in order to remove snow from statically endangered roofs. Here it is also possible that module surfaces have to be trod upon. Pre-damaged modules or modules damaged after being trod upon can lead to contact with parts carrying voltage directly or indirectly.

Hazard: electric shock

Risk measure: 8

Protective goal: avoidance of contact with parts carrying voltage directly or indirectly.

Assessment: Modules are not designed for being trod upon. Treading on the modules can damage them and thereby endanger rescue workers. While the probability of coming into contact with voltage is classified as rather low, a considerable degree of injury is possible.

4.2.1.4 Occurrence of electric arcs

Damage due to fire or mechanical effects can cause electric arcs. The high amount of released energy with electric arc temperatures of several thousand degrees can cause burns or temporary eye damage (flash).

Hazard: burns, physiological blindness with eye damage

Risk measure: 2

Protective goal: avoidance of contact with the electric arc or looking into the electric arc

Assessment: In contrast to the usual electrical hazards not perceptible to the human senses, electric arcs are easily discernible owing to their visual and acoustic form of appearance. The probability of occurrence may therefore be assumed to be rather low.

4.2.1.5 Flooding

Flooding of components of the PV system from (e.g.) flood water, quench water or fire extinguishing foam can lead to contact between live parts and water. Carryover of voltage to the immediate surroundings of the affected system parts is then possible.

Hazard: electric shock

Risk measure: 24

Protective goal: avoidance of indirect contact from water contact

Assessment: Especially in extended or angled buildings or with poor visibility from smoke gases it will not be clear whether live system parts are affected by the flooding. The risk of electrical current flowing through the body from the flooded areas must be heeded.

4.2.2 Firefighting

4.2.2.1 Water pressurization

Water (or other extinguishing agents) striking damaged system parts can lead to voltage transfer irrespective of the type of installation (roof or wall mounted, open-space system).

Hazard: Electric shock

Risk measure: 4

Protective goal: Avoidance of voltage transfer

Assessment: Owing to the low conductivity of the water stream (see section 4.5.1), voltage transfer occurs only with the coincidence of several unfavorable parameters (unsuitable extinguishing agent, puddle formation, extinguishing distance not maintained). For this reason, the probability of occurrence is rather low. On the other hand, the resulting injuries can be considerable.

4.2.2.2 Opening the roof cladding

In individual cases, fire extinguishing operations may necessitate opening the roof for tactical reasons. Contact with live parts from damaged PV systems may then occur.

Hazard: electric shock

Risk measure: 16

Protective goal: avoidance of direct or indirect contact

Assessment: Opening the roof cladding first leads to the exposure of live parts. The probability of occurrence is moderate. The injuries can be considerable owing to the voltage of the still intact PV modules.

4.2.2.3 Fire at an open-space PV system

Fires at open-space PV systems can cause hazardous damage to inverter or transformer stations and (rather seldom) to feed-in stations. At these “medium voltage stations” voltages of up to 20 kV can generally occur.

Hazard: electric shock (high voltage)

Risk measure: 8

Protective goal: avoidance of direct or indirect contact

Assessment: The system parts at the high-voltage end are generally labeled and secured against unauthorized entry. The probability of occurrence can therefore be set very low; because of the high voltages in the systems, extensive injuries must be expected, however.

4.2.3 Technical assistance

Technical assistance operations in connection with photovoltaic systems can involve different scenarios:

- Building and system damage from storms
- Flood water effects
- Accidents (explosions), traffic accidents with removal of objects, vehicles and debris.

We do not separately consider the rescue of people here, since the possible hazards are those encountered by firefighting operations and are described in this section.

4.2.3.1 Building damage or system damage with still functional or partially functional PV systems

The collapse of buildings or parts of buildings as well as other types of mechanical damage to systems or their parts can lead to voltage transfers or exposed live parts at the scene of a fire. Such damage can also be caused by unusually strong winds or stress going beyond general traffic loads (e.g. snow, ice).

Hazard: electric shock

Risk measure: **16**

Protective goal: avoidance of direct or indirect contact with live parts

Assessment: Exposed live parts can considerably injure rescue workers through the high voltages. A higher probability of occurrence must also be expected because of the complexity of the destroyed surroundings.

4.2.3.2 Removal of objects, vehicles and debris

Traffic accidents or other incidents pose the risk that objects of varying size and conductivity damage system parts and present an electrical hazard.

Hazard: electric shock

Risk measure: **12**

Protective goal: avoidance of direct or indirect contact with live parts when removing objects

Assessment: The accident mechanism in these scenarios is such that we must assume that areas of the system are damaged and that live parts are exposed. The high voltages can considerably injure rescue workers. Directly working on these components can also lead to a high risk of touching live parts.

4.3 Mechanical hazards for rescue workers

4.3.1 Collapse of building parts or system parts

Fires or other technical operations can cause the building and/or system statics to fail. The collapsing building parts or falling modules can endanger rescue workers.

Hazard: injury from falling parts

Risk measure: 8

Protective goal: avoidance of injury from falling parts

Assessment: Falling system parts can cause considerable injuries to rescue workers; subframes of PV systems cannot withstand temperatures of up to 1,000°C at fires (aluminum melting point is 660°C).

The "debris zone" is the hazardous area in which falling debris can land. In damage incidents (fires, earthquakes, floods, washouts, etc.) there is danger to life in debris zones. Presence there is advisable only for the purpose of immediate rescue of people or for propping up or demolishing debris. For example, gable walls can easily topple if the remaining building structure is weakened or no longer exists.

4.3.2 Falling rescue workers

Operations may require treading on the roof and even the modules. Especially the smooth surfaces of the modules pose an increased risk of slipping or falling. The modules are generally not designed for the stress of being trod upon. The modules can also brake through partially damaged roof structures.

Hazard: falling rescue worker

Risk measure: 12

Protective goal: avoidance of falling

Remark: We must assume that roof surfaces without additional safety measures pose a risk of falling. The properties of PV modules increase this risk. The severity of injury must also be rated as high, since the fall will usually result in serious injuries.

4.3.3 Thermal voltages in the module

In case of fire, the thermal stress from (e.g.) fire penetration through the module or from cold quench water can give rise to extreme stress in the module glass, which can subsequently lead to explosion-like bursting and splintering of the glass, with a danger of injury. Mechanical stress in the glass from motion and tilting can also cause splintering during the removal of debris.

Hazard: cut injuries from glass splinters

Protective goal: avoidance of splintering or prevention of cut injuries

Risk measure: 4

Assessment: The effects depend on the given thermal propagation or the mechanical stress of the modules and will cause more serious injuries only with a low probability.

4.3.4 Explosion

Flooding of parts of the PV system (e.g. inverter or accumulator located in the basement) from flood water or quench water can cause electrolysis in the event of simultaneous DC voltage between the positive and negative terminals of the system. Hydrogen then forms that poses a danger of explosion in a closed or poorly ventilated space (electrolytic gas).

With Li ion accumulators under extreme conditions (overheating, short circuit), the danger of "thermal runaway" with a chemical chain reaction at increasing heat build-up cannot be ruled out. This can cause a fire at the battery itself, possibly explosion-like. In the event of destruction of the battery, the escape of toxic and caustic chemicals must be expected (HF). The particular hazards from accumulator batteries are being studied in a separate research project. A risk assessment cannot be made here.

Another hazard comes from the glass bursting from the heat. Glass splinters and wafer splinters can be "shot" in all directions.

Hazard: explosion

Risk measure: **4**

Protective goal: avoidance of explosive gas formation or formation of an ignitable mixture, as well as avoidance of ignition sources

Remark: Many factors must combine to create an explosive atmosphere with hydrogen. The probability of occurrence must be regarded as low. The severity of injuries from a hydrogen explosion must be specified as the maximum value for rescue workers, however.

4.4 Respiratory poisons

4.4.1 Solar module fires

Photovoltaic systems are combustible because of their polymer content (see section 3.1). 4.6 describes in detail the possible toxic emissions from PV system fires. In fires involving a PV system, the release of respiratory poisons, also in concentrations exceeding limits (maximum exposure tolerance levels) must be expected. Depending on the plastics being used, highly toxic and caustic parts (e.g. hydrofluoric acids (HF)) may occur.

Hazard: poisoning, chemical burns

Risk measure: 4

Protective goal: dilution of the concentrations of harmful substances, prevention of inhalation and skin contact (protective clothing and respiratory protection)

Remark: Building fires without PV also produce toxic fire effluents. PV components on fire contribute additionally. The effects are here regarded as merely minor, since we assume that rescue workers wear PPE.

4.4.2 Mechanical damage from electrical accumulators

Mechanical damage to accumulator cells can on the one hand lead to the escape of liquid chemicals and on the other hand, in the case of lithium ion batteries, pose the risk of thermal runaway of the accumulator. Besides a large heat build-up with an explosive flame or even explosion, toxic and caustic substances are expelled into the environment.

This is especially important in the case of the frequently occurring basement installation situations, where sufficient ventilation must be provided.

An assessment by means of a risk measure will not be provided here. The particular risks in case of damage from electrical accumulators will be analyzed in a further research project under the management of TÜV Rheinland, whose full title runs: *"Safety and reliability of photovoltaic systems with accumulator systems in particular consideration of fire risks and fire extinguishing strategies"*.

Remark:

In December 2014, the Bergische Universität Wuppertal and the Bundesverband Solarwirtschaft (BSW) published a bulletin on the use of stationary lithium ion accumulators which contained information on firefighting and technical assistance. [41] The BSW has made this bulletin available for downloading (see Appendix II, page 253).

4.5 Test series on electrical hazards in rescue operations

4.5.1 Electrical conductivity during extinguishing processes

4.5.1.1 General

Given past public discussions on the risks in firefighting at burning PV systems, this project has developed a series of tests for studying the hazardous situations in fighting fires at electrical systems with ordinary PV DC voltages.

Altogether three series of tests were performed:

1. Measurement of leakage currents at steel tubing in reference to guideline values of VDE 0132
2. Measurement of protective effectiveness of operational clothing (boots, gloves)
3. Determination of hazards from flooded spaces

The general danger in firefighting at electrical systems comes from the risk of flashovers from electrically conductive system parts or from the passage of the electrical current through water, and in particular from the quench water stream.

Guideline distances normatively apply to live electrical systems in reference both to proximities and to extinguishing measures for ruling out the danger of electric shock. By definition, PV systems belong to the low-voltage systems as per VDE 0132 (AC<1,000 V, DC<1,500 V).

Initial results from practical extinguishing spray tests in 2010 by PV consultant Dr. Bendel [42] yielded non-critical current levels primarily in the single-digit mA range. Other study results from conductivity measurements for practical verification of the normative distance recommendations for DC systems were not available to the Project Team at the time of testing, 2011. In the meantime, further series of tests have been conducted by the Oberhessische Versorgungsbetriebe AG (OVAG) in 2012 and as part of a cooperative project of the OVAG and by the Vereinigung zur Förderung des deutschen Brandschutzes e.V. (*vfdb*) in 2014, whose measurement results similarly yielded only very small values in part outside the measuring range of 0.1 mA. These measurements were considered in the assessment of the test results.

PV systems are currently designed for maximum system voltages of 1,000 V DC. Under discussion is an increase of the maximum to 1,500 V DC. The actual voltage value for a PV system depends on the string length and the performance data of the employed PV modules. In cases of small and medium-sized PV systems, as usually installed on buildings, system voltages significantly < 1,000 V are generally to be expected. For the purpose of obtaining generally valid results, 1,000 V was set as the currently maximum possible value for the performed tests.

The risk to people comes not directly from the voltage but from the electric current, however, which flows through the body because of the potential difference. This current can have physiological, physical and chemical effects, depending on the **current path through the body, the current intensity, the period of action and also the type of current**.

4.5.1.2 Normative background to assessing the current effects on humans

4.5.1.3 Current intensity and duration of action

A description of the effects and a determination of levels for the assessment of the hazards of electricity to the body as a function of current intensity and duration appears in DIN IEC/TS 60479-1 (VDE V 0140-479-1): 2007-5 – Effects of current on human beings and livestock. The limit curves given in Figure 4-2 for direct current and in Figure 4-3 for alternating current apply to the current path from the left hand to both feet for an assumed normal health condition of the person.

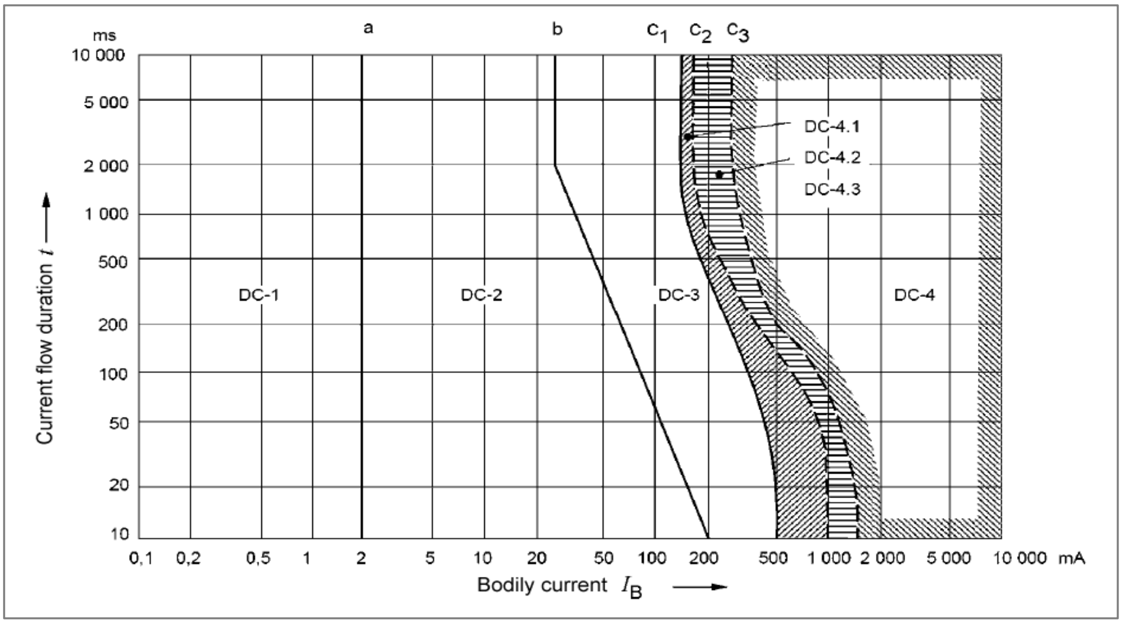


Figure 4-2: Time/current intensity sectors with effects of direct currents on humans with longitudinal current flow *(source: DIN IEC/TS 60479-1 (VDE V 0140-479-1): 2007-5)*

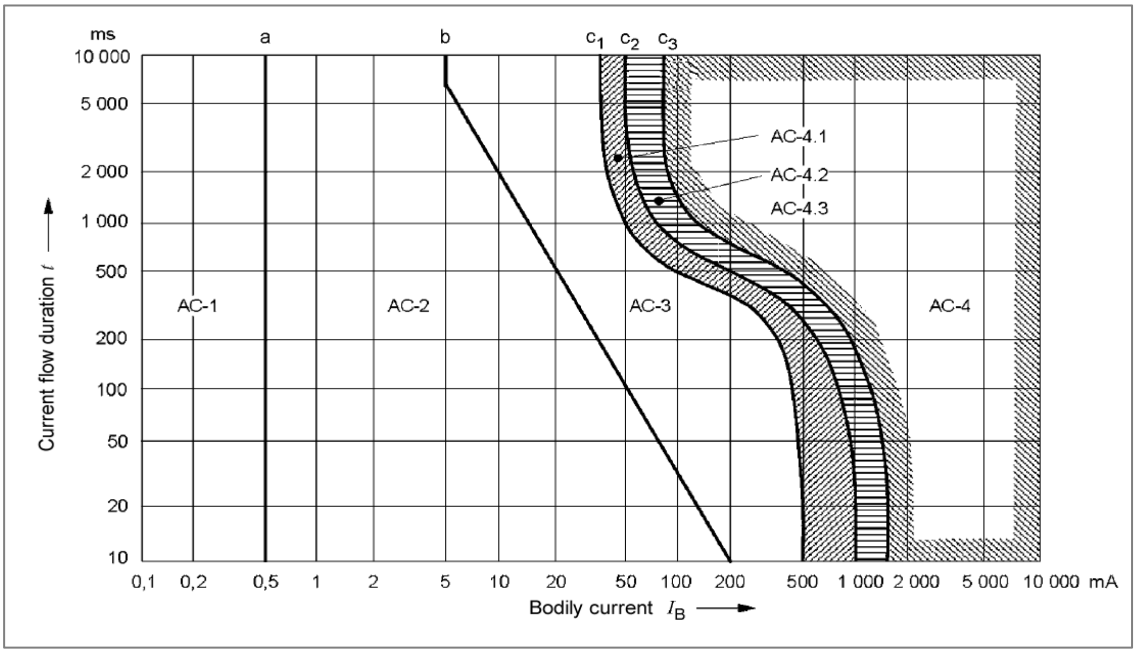


Figure 4-3: Time/current intensity sectors with effects of alternating currents (15 – 100 Hz) on humans with longitudinal current flow *(source: DIN IEC/TS 60479-1 (VDE V 0140-479-1): 2007-5)*

1. **Sector DC-1 / AC-1:** Perception is already possible, but no startle response is to be expected.
2. **Sector DC-2 / AC-2:** No damaging physiological effects are to be expected. Perception and involuntary muscular contractions are possible.
3. **Sector DC-3 / AC-3:** In this sector, severe involuntary muscular contractions are to be expected. In addition, breathing difficulties, reversible cardiac arrhythmia and muscular cramps may occur.
4. **Sector DC-41…4 / AC-4.1...4:** Pathophysiological effects like cardiac arrest, apnea and cell damage are to be expected. The probability of ventricular fibrillation increases with the current intensity and duration.

A comparison of these two graphs shows that alternating current leads at significantly lower values to more critical effects compared with direct current. The reason for this difference is that in the case of alternating current, each change in polarity will stimulate the neural and muscular structures, including the heart. The greatest hazard lies in the frequency range of 50 Hz to 60 Hz. With direct current, about four to five times the given alternating current limit value may be assumed, as Table 4-4 shows.

Table 4-4: Limit values for longer current load

Limit values for continuous electrical currents		IEC 60479-1		UL
		AC	DC	DC
Sector 1	Safe	< 0,5 mA	< 2 mA	0 - 2 mA
Sector 2	Perception	0,5 - 5 mA	2 - 25 mA	2,1 - 40 mA
Sector 3	Lock On	5 - 35 mA	25 - 150 mA	40,1 - 240 mA
Sector 4	Electrocution	> 35 mA	> 150 mA	> 240 mA

Sector 1: Possibly noticeable, no bodily reaction
Sector 2: Muscle contractions possible
Sector 3: Severe involuntary muscular reactions possible
Sector 4: Ventricular fibrillation possible

The threshold of perception for direct current lies at 2 mA. In contrast to alternating current, only the start and interruption of the current are perceptible; heat development is noticeable only with currents above 100 mA. A release threshold is not defined for direct current. The life-threatening range with direct current begins from a current of 150 mA and current flow duration of about 1 second. At such high levels even direct current poses the risk of ventricular fibrillation.

For assessing the hazard, the measurements performed considered a maximum current strength of 25 mA (DC) as the limit (sector 2).

4.5.1.4 Bodily resistance

The body impedance depends on numerous factors, in particular the current path, the contact voltage, the current flow duration, the frequency, the dampness of the skin, the size of the contact area, the applied pressure and the temperature.

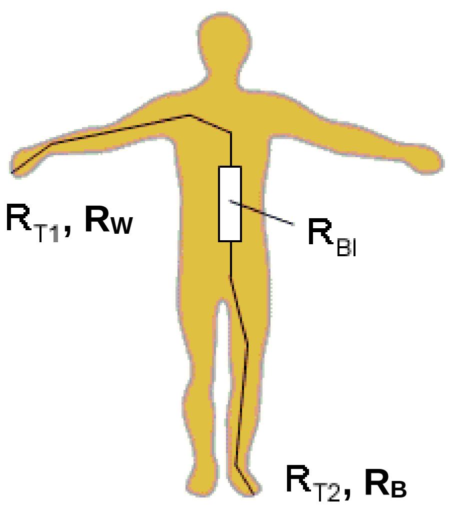
As the voltage increases, the body impedance decreases asymptotically; the skin resistance can already be penetrated at voltages > 200 V. Table 4-5 shows some statistically determined impedance values for the hand-to-hand current path.

Table 4-5: Selected values of the body impedance for current flow from hand to hand as a function of the contact voltage (*DIN IEC/TS 60479-1 (VDE V 0140-479-1):2007*-05)

Contact voltage	**Values of the total bodily resistance RT (Ω) that is not exceeded by**		
(V)	**5% of the population**	**50% of the population**	**95% of the population**
100	990	1,725	3,125
200	800	1,275	2,050
400	700	950	1,275
700	575	775	1,050
1,000	575	775	1,050

The measurements found the total impedance for the current path from a hand to a foot to lie somewhat lower (10 – 30%).

In addition to the bodily internal resistance, transitional resistance arises from clothing and the resistance of any tools present:



Total bodily resistance:

$$R_B = R_{T1} + R_{BI} + R_{T2} + R_B + R_W$$

R_B Total bodily resistance

R_{BI} Bodily internal resistance

R_{T1}, R_{T2} Transition resistance (skin)

R_B Clothing resistance

R_W Tool resistance

Figure 4-4: Total bodily resistance *(source: Brieselang.NET photo)*

For making a general statement about the hazardous situation, the experiments underlying this work assumed a very low total bodily resistance of 550 Ω.

4.5.1.5 Firefighting in the vicinity of electrical systems

To prevent hazardous currents flowing through the water stream and into rescue workers' bodies while they are extinguishing live system parts, DIN VDE 0132 – Firefighting and technical assistance in or near electrical installations – defines the recommended distances between the extinguishing agent outlet and the live system parts.

Table 4-6 shows the minimum distances during firefighting operations at electrical installations in the low-voltage range, i.e. up to 1,000 V with alternating current (AC) or up to 1,500 V with direct current (DC). [DIN VDE 0132 (VDE 0132):2008-08]

Table 4-6: Guideline values for minimum distances in the low-voltage range

Nozzle DIN 14365-CM	Low voltage (L) ≤ AC 1 kV oder ≤ DC 1,5 kV	High voltage (H) > AC 1 kV oder > DC 1,5 KV
Spray jet Full jet	1 m 5 m	5 m 10 m
Code	N-1-5	H-5-10

These distances basically refer to standardized C-multipurpose nozzles as per DIN 14365-CM with a nosepiece diameter of 9 mm and 5 bar flow pressure. The guideline values also apply to larger water extinguishing devices, however, if their nozzles comply with DIN 14365-2 as to electrical safety. The instructions on use and warnings on the extinguishing equipment must be complied with. If CM nozzles without nosepieces or other multipurpose nozzles are used, the distances must be enlarged as per VDE 0132, e.g. in the case of BM multipurpose nozzles to the minimum distance of 5 m.

To understand these normative restrictions, we consider the structure of the full jet. A full jet contains three zones (Figure 4-5). The zone of the compact water stream directly after exit of the extinguishing agent is known as the rod zone. In the following, development, zone the stream breaks up into tiny droplets. When the stream attains the quality of electrically separated, individual droplets, we speak of the spray zone (which still appears compact to the human eye)).

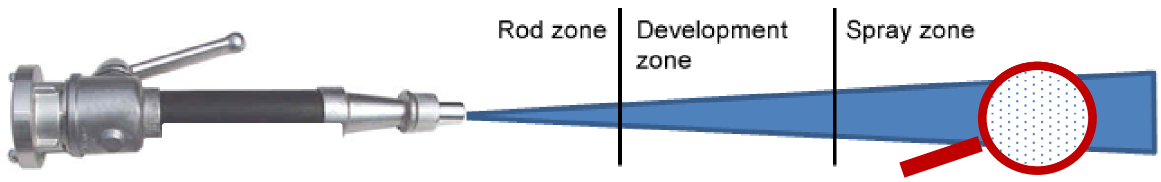


Figure 4-5: Schematic spray jet structure of a multipurpose nozzle

The guideline values for the stream pipe distances were selected so that during extinguishing operations the live electrical system parts would be struck only by the spray zone and therefore the droplet formation would prevent any continuous track. Rescue workers are therefore not exposed to any risk from hazardous leakage currents.

The length of the described development zone and the extinguishing distances to be maintained vary depending on the technical design of the nozzle.

The test procedure of standard DIN 14365 describes the test setup for measuring the voltage drops of various resistance levels in the leakage current of a nozzle with the application of an extinguishing agent to a live steel grid. Since no critical limit values are listed here, the values from Table 4-4 were used as the basis for the tests from the AP5.3.

Besides DIN 14365, EN 15182 describes a product standard that unfortunately does not address the determination of leakage currents. Merely a recommendation is made to the effect that up to 1,000 V a distance of at least 1 m be maintained at a spray jet angle of at least 30°. The new standard requires manufacturers of new types of nozzles that were not tested as to electrical safety as per the old DIN 14365, part 2, to present proof of suitability for firefighting at electrical installations. Should the manufacturer not be in a position to provide information about electrical safety, these nozzles may be used only in voltage-free electrical systems.

4.5.1.6 Test 1: Measurement of leakage currents via the quench water stream

This test includes measurement of the leakage currents of a fire department spray jet in simulated operation at a live electrical installation. Measurements with DC voltages of 1,000 V and extinguishing distances of 1 m and 5 m were performed as per standard VDE 0132 *"Firefighting and technical assistance in or near electrical installations"*. As described, the currents measured in the test are assessed as to a possible hazard to rescue workers in extinguishing operations at photovoltaic systems.

Extinguishing equipment and extinguishing agents

Water with an electrical conductivity of 630 µS/cm (20°C) was used as an extinguishing agent.

As is well known, extinguishing foam increases the electrical conductivity of water and may <u>not</u> be used for fires in live institutions. To demonstrate the practical effects, measurements with use of a foam extinguishing agent (*class A foam)* were also performed.

Nozzle types generally common in Germany, namely a C multipurpose nozzle (CM; Figure 4-6) and a C hollow jet nozzle (Figure 4-7) were used in the tests. The CM nozzle is standardized as per DIN EN 15182-3 (replaces the old DIN 14365). At 5 bar flow pressure with an attached nosepiece 9 mm in diameter, a water flow rate of approximately 120 l/min is attained. The nozzle has one setting for *full jet* (F) and one for *spray jet* (S) at 15° spray angle. The flow rate does not change. The trajectory range at full jet is approximately 15 m (figure 6).

The C hollow jet nozzle complies with nozzle standard DIN EN 15182-2. At 5 bar flow pressure the flow rate can be adjusted to 55, 120 and 215 l/min by a rotating swivel. By turning the nozzle head, *full jet* (0°) *spray jet (60°)* or *flash-over position (120°)* can be selected for the stream shape. Hollow jet nozzles differ in technical version and shape according to type and manufacturer, with the spray patterns possibly varying as well.

Figure 4-6: CM multipurpose nozzle

Figure 4-7: C hollow jet nozzle (source: Munich Volunteer Fire Department)

Performance of test

This test series (test setup as per Figure 4-8 and Figure 4-9) measured the leakage currents via the water stream when spraying live metallic electrodes (perforated plate). A current resistance of 555 Ω simulated the (smallest) bodily resistance in the worst assumable case with an adult person (rescue worker with soaked protective clothing).

Figure 4-8: Test setup with simulated PV module (perforated plate electrode) and hollow jet nozzle at a distance of 1 meter

Figure 4-9: Test setup with simulated bodily resistance for measuring the leakage currents via the extinguishing stream

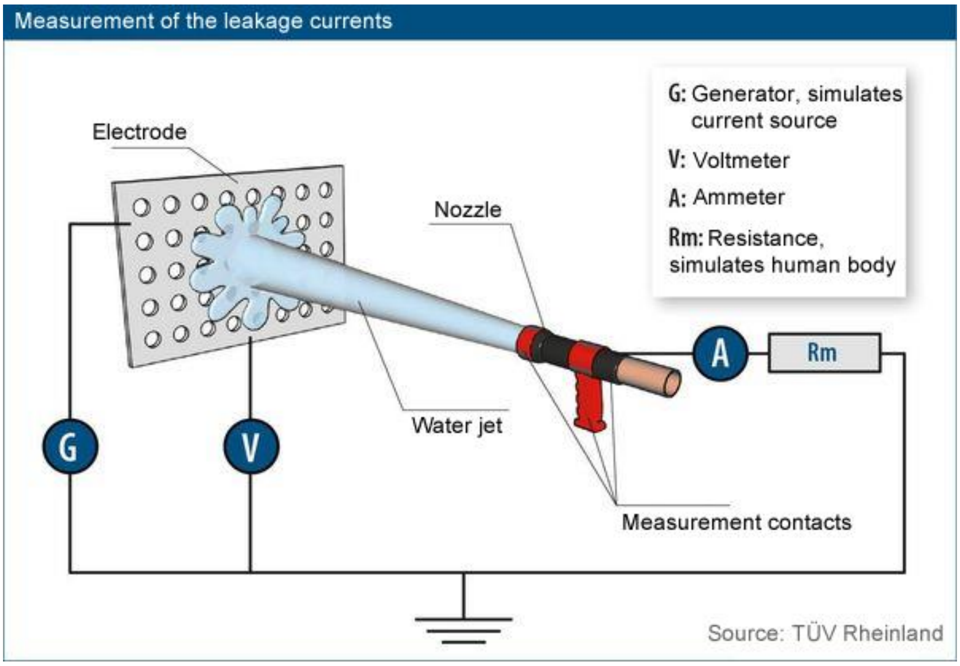


Figure 4-10: Measurement of leakage currents via the water stream: Schematic diagram (graphics: Solarpraxis AG (Harald Schütt))

The given electrical resistance in the circuit is compounded from the resistance of the extinguishing agent, the bodily resistance, the total transition resistance and any (high impedance) resistance in fault circuits and thus determines the level of a possible leakage current running through the human body.

The resistance of the extinguishing agent stream depends on the distance to the live electrode, the conductivity of the extinguishing agent and the properties of the extinguishing stream (Figure 4-10).

Measurement series with a commonly used CM multipurpose nozzle and a C hollow jet nozzle were performed. The tests were performed with different jet settings, in each case with water. For the purpose of comparison, a further series was performed with foam.

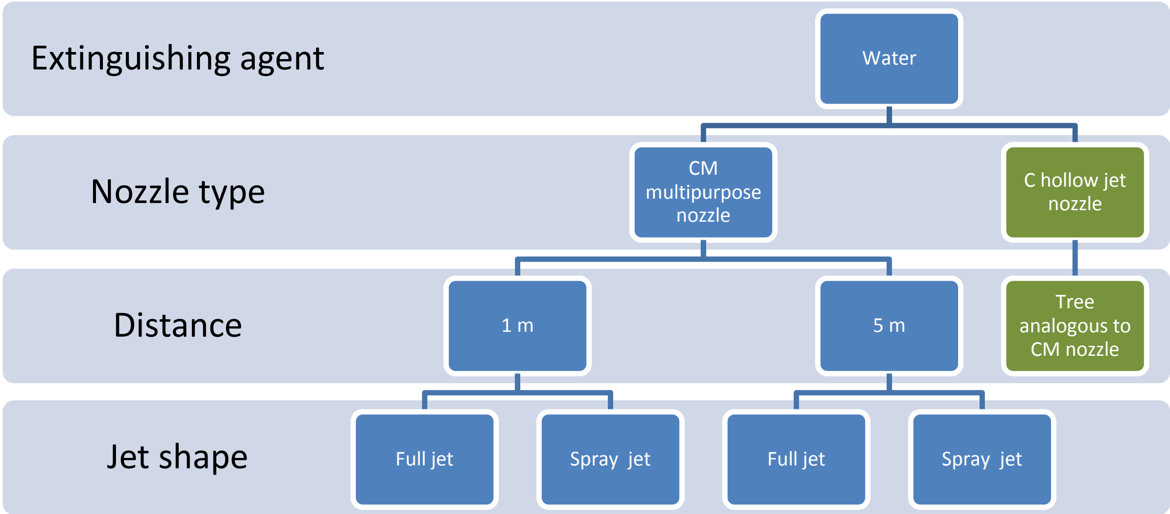


Figure 4-11: Test path for conductivity measurement with water as extinguishing agent

The level of the leakage current via the water jet depends on the voltage of the sprayed installation parts, the human bodily resistance (including transition resistance) and other types of resistance in the circuit, the conductivity of the extinguishing agent and the properties of the spray jet (Figure 4-5). The greater the distance of the electrode, the greater is the fanning of the extinguishing agent jet and the lower its electrical conductivity. The distances as per DIN VDE 0132 are such that no hazardous currents can be transmitted via the extinguishing agent jet.

Expected results

For all measurement values of the leakage current, non-critical values were expected from general experience with electrical installations.

The expectation value for full jet and 1 m distance was comparatively the highest. With increasing distance (5 m) and/or fanning (spray jet position), the leakage currents should be lower, if measurable in the first place.

Multipurpose nozzle

Figure 4-12 shows the measured leakage currents when the CM multipurpose nozzle is used with a nosepiece. The most important result of the measurements: all measured leakage currents that could flow hand-to-foot through the C body of the firefighter in the worst case lie in the non-critical range < 25 mA (Table 4-5).

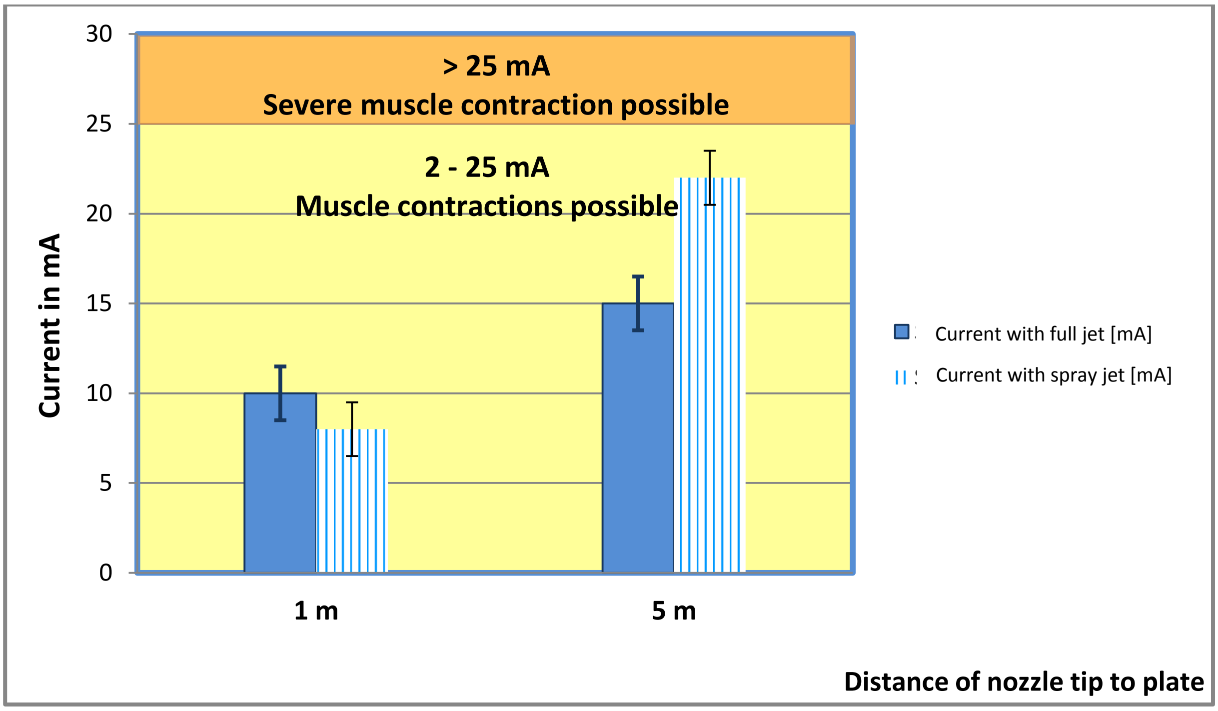


Figure 4-12: Leakage currents with C hollow jet nozzle (water)

As expected, at 1 m distance the currents at the spray jet setting (15° spray angle, striped bar) were somewhat lower than at the full jet setting (solid bar). Unexpected, on the other hand, were the larger currents measured for both stream types at a distance of 5 m compared with 1 m. At 5 m distance, the measurement values for the spray jet setting exceed the values of the full jet setting. Even given the fluctuation in measured values during the tests in the ± 2 mA range (the water stream is not a constant electrical conductor), the measured differences are significant (see discussion of the results).

Hollow jet nozzle

Figure 4-13 shows the measured leakage currents when the C hollow jet nozzle is used with a nosepiece. Here again are the most important results of the measurements: all measured leakage currents that could flow hand-to-foot through the body of the firefighter in the worst case lie in the non-critical range < 25 mA (see Table 4-5).

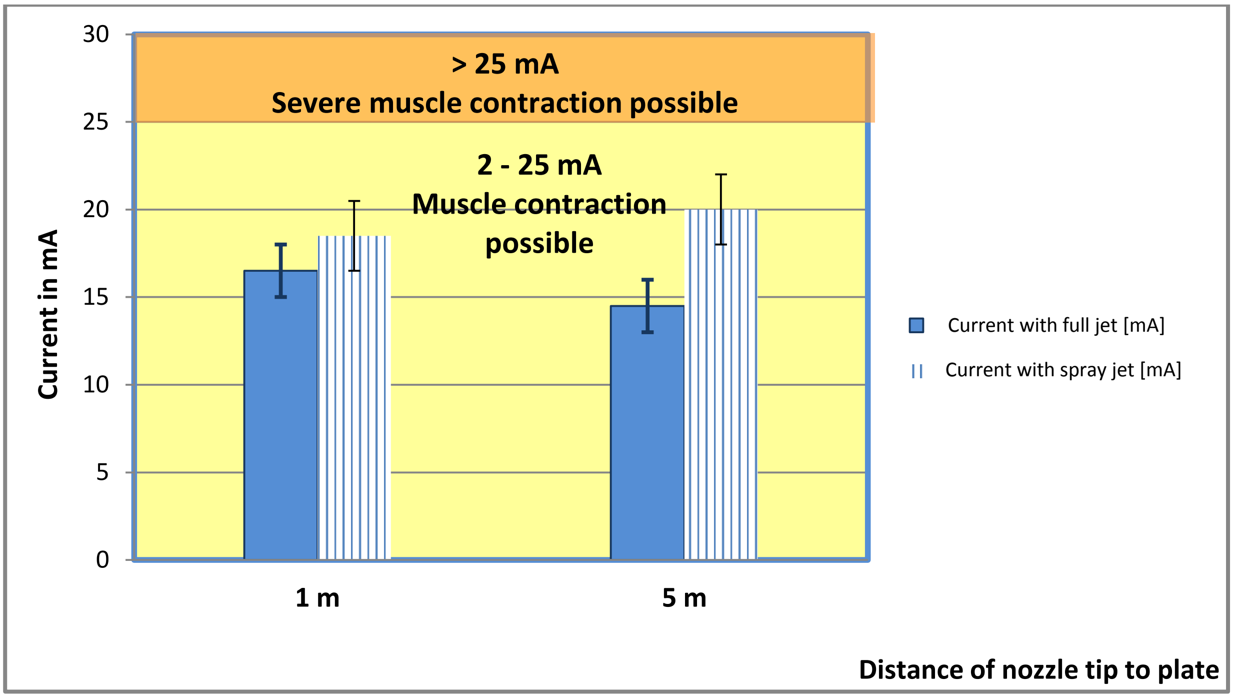


Figure 4-13: Leakage currents with C hollow jet nozzle (water)

At the full jet setting, the measured values here at a 5 m distance were, as expected, lower than at a distance of 1 m, even if quantitatively low. Surprisingly, the measurements at spray jet setting (60° spray angle, striped bar) at both distances showed in each case higher leakage currents than at the full jet setting. At a distance of 5 m the measured value for the spray jet is greater than at 1 m distance.

As expected, the comparative measurements with the use of a foaming agent showed somewhat higher currents than with water.

Discussion of the results

At the greater distance of 5 m to the live electrode, both nozzles yielded in part significantly greater measured values for the leakage currents than expected. Most likely, fault currents related to the practical test setup occurred and were also measured. Possible sources of faults (bypass function) therefore received particular attention:

1. As the test period progressed, a continuous sheet of water from the quench water run-off formed on the ground (asphalt).
2. Increasingly severe rainfall during the measurements also soaked the entire test setup, so that the desired insulated installation of the electrode and nozzle could no longer be ensured.
3. Spraying the electrode (perforated plate) caused partial run-off of the quench water at the plate along the ground, so that a low-impedance connection could be formed here under certain circumstances.
4. The greater the spray angle, i.e. the more widely the water stream fanned over the perforated plate electrode, the more conductive water tracks formed.

Figure 4-14: Run-off water forming conductive tracks to the wet ground – here full jet

Figure 4-15: Run-off water forming conductive tracks to the wet ground – here spray jet

We must therefore assume that fault circuits existed between the electrode and nozzle that decreased in impedance independently of the specific spray shape as the duration of the test progressed.

We further assume that these fault currents add to the actually occurring leakage currents and are measured along with them. Figure 4-16 shows this schematically.

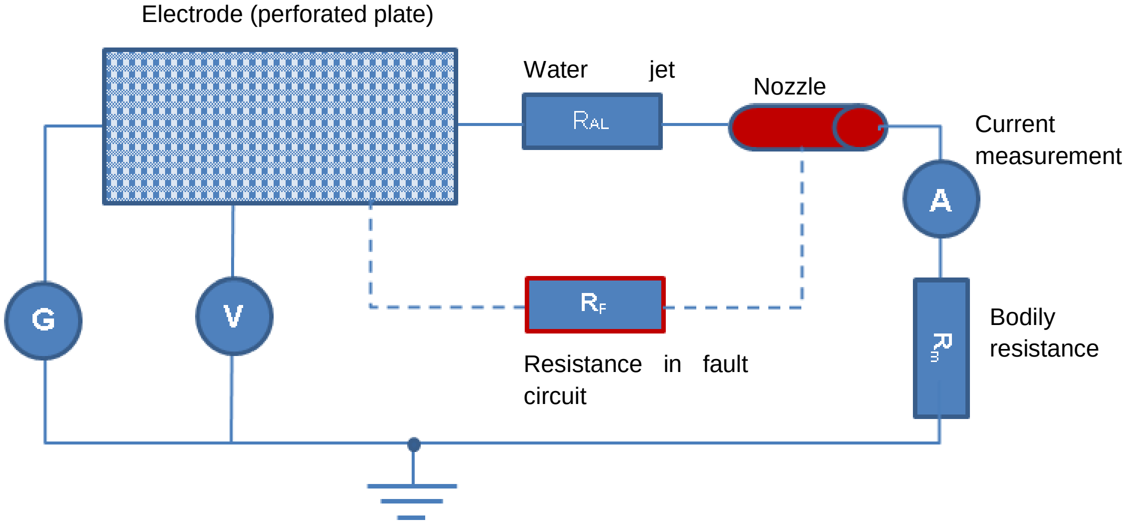


Figure 4-16: Circuit and fault circuit

Since the total resistance with a parallel connection of resistors is less than both individual resistors, the resistance R_F in the fault circuit will act more on the measured total current the lower its impedance. The effective parallel resistance between electrode and nozzle decreases and the current flow therefore becomes greater. The greater currents measured during the course of the test can thus be explained by comparison with the expected values.

Additional contributing factors are also effective, such as actually significantly greater bodily resistance and additional transition resistance from protective clothing like gloves and boots. The actual leakage currents that could flow through a firefighter must therefore be assumed to be less than the measured values generated in the present test setup, which represent a worst case scenario. In actual operations a conductive floor covering can also form with a "bypass potential," a case (involuntarily) covered by the performed tests. The results consequently lie on the safe side.

Series of tests conducted at later times (2012, 2014) by other institutions yielded significantly smaller leakage currents in the range of approximately 1 mA or less (cooperative project by OVAG and vfdb).

Another electrode type – metallic grid – and greater distance of the electrode from the ground allowed significantly less quench water to run directly onto the ground (in this case, a lawn). This test arrangement evidently allowed significantly lower fault currents to develop. Before and after each test, these currents were measured separately, which however predominantly fell below the measurement value threshold in the µA range. As a qualification, it must be noted that the possibly conductive water streaks form only directly during the test itself. In the left photo the measurement is performed with water at a spray setting of 45° – no water streaks form. The situation is different with the use of foam, for example with a spray setting of 120°, as shown in the photo on the right. Here a conductive covering forms on the ground. Foam sprayed past the electrode and also running off onto the electrode forms possible bypass connections to the spray jet.

Figure 4-17: Measurement leakage currents when extinguishing live electrical installations. Tests conducted on the premises of OVAG in 2014, cooperative project of OVAG and ***vfdb***

Figure 4-18: Measurement of leakage currents, extinguishing with foam under spray setting. Tests conducted on the premises of OVAG in 2014

<u>Conclusion</u>

All currently known measurement series pertaining to this subject yielded very low to non-critical leakage currents via the extinguishing jet in the range below 25 mA.

Given compliance with the recommended extinguishing distances of 5 m at full jet and 1 m with spray jet as per DIN VDE 0132, no leakage currents hazardous to rescue workers occurred when the water was used as the extinguishing agent.

4.5.1.7 Electrical properties of the turn-out gear

This test series investigated the additive protective effect of the turn-out gear against electric shock. Direct contact with a live DC cable was simulated. The employed turn-out gear was tested both dry and wet.

Test setup

A life-sized dummy (75 kg) simulated the human body. The dummy was covered by an electrically conductive aluminum layer and fitted with measuring contacts. The bodily resistance for the different current paths was adjusted with a resistor plate and the dummy then dressed with a complete set of firefighting protective clothing. The dummy stood on a grounded steel plate. Voltage was applied to the surface of the protective clothing by means of metal contacts (**Figure 4-19**).

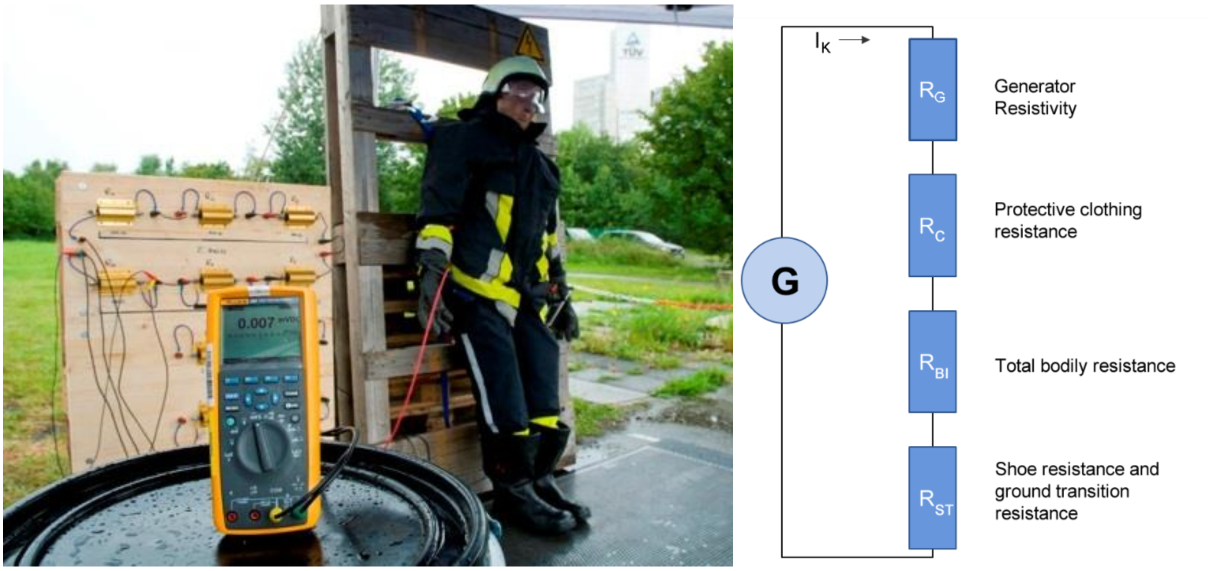


Figure 4-19: Test arrangement with dummy and schematic circuit diagram

The tests measured the currents for three different current paths. The current along the hand-to-hand and hand-to-one-foot current paths was measured at a bodily resistance of 555 Ω. The current for the hand-to-both-feet current path was measured at a bodily resistance of 430 Ω. Two contact points have been specified. The first contact point was located directly at the glove and the second at the sleeve of the protective jacket. To check the protective effect, the gloves and boots were in part left out. A DC voltage of 1,000 V was applied at the contact points.

As the substitute circuit diagram shows, resistances are serially connected here. The individual resistance values sum to a total resistance and limit the current.

In the dry state, very high resistance values are expected, whereas in the wet condition the resistances drastically decrease and the current should therefore increase. The protective boots should yield the highest value among the resistance series, so that omission of the boots would lead to a very sharp increase in the current.

In the dry state of the turn-out gear, all measured values lay in the range of measurement uncertainty. Merely very low currents under 1 µA were measured without protective boots according to the following Table 4-7 and Table 4-8:

Table 4-7: Dry clothing, hand to feet

Parameters	
Protective clothing	Dry
Gloves	On
Boots	Off
Contact point Electrode	Sleeves
Current path	Hand-feet
Bodily resistance	430 Ω
Generator voltage [V]	**Bodily current [µA]**
1000	0,54

Table 4-8: Dry clothing, hand to hand

Parameters	
Protective clothing	Dry
Gloves	On
Boots	Off
Contact point Electrode	Sleeves
Current path	Hand-hand
Bodily resistance	555 Ω
Generator voltage [V]	**Bodily current [µA]**
1000	0,45

When the turn-out gear was wet, considerable currents were measured in part depending on the current path and contact point. While the current from one hand to one foot lay in the noticeable but non-critical range, life-threatening high currents in the ampere range were measured in a hand-to-hand current path, as the following tables (Table 4-9, Table 4-10 and Table 4-11) show.

Table 4-9: Wet clothing, hand to foot

Parameters	
Protective clothing	Wet
Gloves	On
Boots	On
Contact point Electrode	Gloves
Current path	Hand-foot
Bodily resistance	555 Ω
Generator voltage [V]	**Bodily current [µA]**
1000	3,66

Table 4-10: Wet clothing, hand to hand

Parameters	
Protective clothing	Wet
Gloves	On
Boots	On
Contact point Electrode	Gloves
Current path	Hand-hand
Bodily resistance	555 Ω
Generator voltage [V]	**Bodily current [µA]**
1000	1,50

The drastic difference in resistance values were conjectured to lie in the protective boots. They were therefore removed for a further hand-to-foot measurement. The currents now measured also lay in the life-threatening range:

Table 4-11: Wet clothing without boots

Parameters	
Protective clothing	Wet
Gloves	On
Boots	Off
Contact point Electrode	Gloves
Current path	Hand-foot
Bodily resistence	555 Ω
Generator voltage [V]	**Bodily current [A]**
500	**0,85**
700	**1,21**
800	**1,40**
900	**1,57**

The following two photos (see Figure 4-20) show the effects of the currents on the contact surfaces. In a human body current marks would occur at these points due to the high heat build-up at the current entry and exit points. Burn holes from the heat appeared on the gloves.

Figure 4-20: Effects of the current on the contact surfaces, burn hole from action of current

The test results agree with the theoretical expectations. Dry turn-out gear has a very high resistance, whereas soaked clothing affords no protection against electric shock. In a current path running from one hand to the other hand and given a bodily resistance of 555 Ω, a very low resistance of about 50 Ω exists at the wet glove, where contact with a 1,000 V DC cable can cause a life-threatening current of 1.5 A to run through the human body (see Table 4-10)

The high resistance at the boots and the related protection against electric shock became evident from the tests. Despite wet clothing, hardly noticeable currents were measured with the protective boots on. Without boots, the bodily current drastically increased and at 1,000 V exceeded the hazardous limit.

A linear relationship between current and voltage can be observed. With wet clothing and an assumed bodily resistance of 555 Ω, life-threatening currents over 150 mA can already flow through the human body along a current path from hand to hand or from hand to the feet without boots at 100 V DC (see Table 4-11).

Conclusion

The measurements show that contact with a live DC cable of a photovoltaic system with complete and dry turn-out gear being worn poses no risk of electric shock.

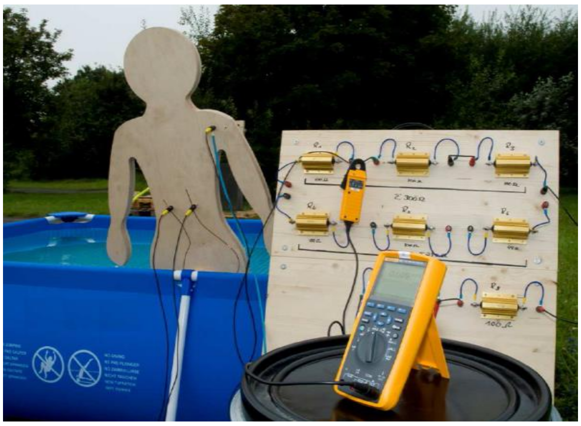
On the other hand, soaked turn-out gear affords practically no protection against hazardous bodily currents if the current path runs from one hand to the other hand.

If the current path runs from both hands to the feet, as typically occurs at the nozzle during extinguishing operations, the high resistance at the protective boots will allow non-critical currents to flow through the human body at a level that is just noticeable.

4.5.1.8 Live cable in water

The test (see Figure 4-21) served the determination of the intensity of possible currents flowing through a human body in the case of a flooded space, given the person’s contact with a live cable and simultaneous contact with a grounded part of a building.

The measurements were performed with the aid of a 3 x 2 m water-filled pool and 160 cm tall wooden dummy. Metal plates were attached to the feet and lines routed with copper wires. In the water lay a live cable, with the dummy’s shoulder connected to the ground potential.



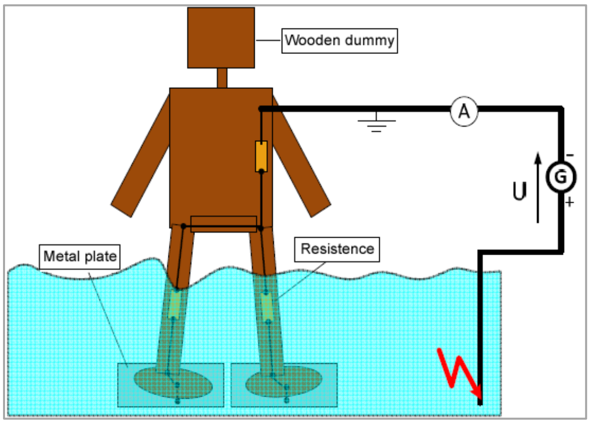


Figure 4-21: Wooden dummy in test pool and schematic test setup

Performance of test

A live cable was immersed in the pool with a water level of 60 cm and a conductivity of 630 Ω *S / cm* (at 20 °C). The voltage was adjusted to between 500 V and 900 V (DC). The wooden dummy was placed in the pool and the bodily current measured at three different distances of 0.5 m, 1 m and 2 m from the live cable. Owing to the high conductivity of the water, we expected a relatively high current flow in this experiment. Increasing the distance from the live cable should have reduced the current.

Table 4-12: Results of test 3

Water properties	
Counductivity	630 µS/cm
Temperature	20 °C
Water level	60 cm

Distance to electrode	0,5 m	
$U_{Gen, nominal}$ [V]	$U_{Gen, actual}$ [V]	Bodily current [A]
500	500	1,02
800	800,87	1,64
850	851,87	1,74
Distance to electrode	**1 m**	
500	500,33	1,02
800	801,04	1,62
850	851,54	1,72
Distance to electrode	**2 m**	
500	499,98	0,99
800	801,12	1,57
850	851,54	1,67
900	901,67	1,77

The test results show that all measured bodily currents lie in the ampere range and therefore in the life-threatening range. As expected, the dummy experiment showed a linear relationship between current and voltage, which only roughly reflects reality, given the voltage-dependence of human bodily resistance (Table 4-5). The given experimental arrangement with the given resistance values already attained the hazardous range as of a voltage of 75 V.

Increasing the distance from the live cable led only to a slight drop in current. At 800 V, the difference in current between the values at a distance of 0.5 m and at a distance of 2 m was merely 70 mA, or about 3%.

Important for the assessment is that this test considered the worst case. The ground conductor lies outside the water, so that here the entire current flows to the ground through the wooden dummy. Otherwise, only partial amounts would still flow through the human body. Given the level of the measured values even at distances of several meters, an all-clear is not possible.

Conclusion

For rescue workers in flooded basements there is a serious risk of electric shock from damaged DC cables hanging down!

Hazardous currents may flow through the body even at low voltages of around 100 V.

4.5.1.9 Concluding discussion

The studies on conductivity and possible leakage currents through nozzles have shown that when extinguishing fires near photovoltaic systems rescue workers are exposed to no serious danger from the leakage currents via the quench water exist at 1,000 V DC, if the safety distances as per *DIN VDE 0132* are maintained.

The employed nozzles had different spray patterns and accordingly different electrical properties as well. Especially different technical versions and designs of high-jet nozzles can produce significant differences in the formation of the water stream. The new standard, *DIN EN 15182*, no longer provides for electrical testing of the nozzles. For characterizing the hollow jet nozzles in terms of their electrical properties individual verifications are necessary.

The employed turn-out gear is a good insulator when dry and protects rescue workers against dangerous electric shocks. Soaked clothing no longer provides protection, so that at high voltages and a hand-to-hand current path life-threatening currents can flow through the human body. This would be the case if both terminals of the DC lines were touched at the same time. Since fire departments are required to always maintain a safety distance of at least one meter from live installation parts, this scenario is improbable, but nevertheless quite possible in practice under conditions of poor visibility and smoke.

Flooded basements pose a potentially considerable danger for rescue workers. Sagging and damaged cables from a PV system, or any other electrical home installation, can cause current to flow through the water if grounded systems are touched simultaneously. Given the high conductivity of the water, life-threatening currents in the ampere range can thus occur even at distances of several meters.

The described series of tests always considered the worst case. In real-life cases, the resistance values of the people will be significantly higher, especially given clothing or protective clothing and shoes, reducing the risk of dangerous electric shock.

4.5.1.10 Relevance for standardization

- The test series findings regarding safety and nozzle distances confirm the specifications of VDE 132. A brief summary of the test series has been forwarded to the working group of the DKE K 213 on “Firefighting at electrical installations.” In the future, other practical tests are to be extended to a voltage range of up to 1500 V DC, since this voltage limit in the module and PV system sector could be of greater interest.
- Within *DIN EN 15182*, electrical testing of the nozzles is no longer provided. The characterization of the hollow jet nozzles requires separate verifications of their electrical properties, however, as the aforementioned series of tests show. The water trajectory properties and therefore the conductivities of an extinguishing stream differ among the tested nozzles (CM multipurpose and C hollow jet).

  High-speed cameras enabled observation of the disintegration properties of the droplets on exiting the different types of nozzles. From this information we may conclude that the conductivity properties and measurements do not hold across the board for all nozzles. **Supplementation of the new standard by suitable electrical testing of the nozzles** would be appropriate and should be discussed by the corresponding standardization committee.

Recommendation for standardization:

DIN EN 15182 no longer provides for electrical testing of the nozzles. The characterization of the hollow jet nozzles requires separate verifications of their electrical properties, however, as the aforementioned series of tests show. Supplementation of the new standard by suitable electrical testing of the nozzles would be appropriate and should be discussed by the corresponding standardization committee.

4.5.2 Electrical safety situation with effects of artificial lighting

Series of tests at the Photovoltaic Institute of the Bern University of Applied Sciences, with support from the fire department, have shown that spotlights, such as those used by the fire department or the Federal Agency for Technical Relief during nighttime operations, can generally produce DC currents of significant levels in PV modules [43]. Minimum distances are therefore recommended for the spotlights to be erected. The measurements were conducted with halogen spotlights at an installed pilot plant with longitudinally oriented strings of crystalline PV modules, based on the usual PV system sizes and interconnections of roof-mounted systems on single-family houses.

A larger PV system will not lead to higher currents given the equally greater inhomogeneity of the irradiation. A more compact design (interconnection), on the other hand, can theoretically generate higher currents. Other practical studies, such as those by Underwriters Laboratories [44], led to the result of a theoretically possible electrical hazard for rescue workers from artificial lighting.

To obtain generally applicable information on a minimum safety distance, the project carried out additional series of tests covering

(1) the spotlight types commonly used by rescue workers
(2) the different types of modules mounted on German roofs
(3) the most critical case of compact design (string)
(4) the most critical case at largely normal incidence

Consideration of the worst-case combination to be defined here should yield a generally applicable recommendation including a safety supplement.

The spotlight selection considered only technologies applied in the German hazard prevention sector. The Cologne Professional Fire Department, the Cologne Volunteer Fire Department, the Porz-Langel Fire Brigade and the Siegburg section of the Federal Agency for Technical Relief supported the studies with loans of spotlights and construction of the desired combinations.

A survey of professional fire departments in Germany as well as various hazard prevention organizations found that primarily spotlights with halogen bulbs with an output of 1,000 or 1,500 W are used. These spotlights are generally mounted on extendable tripods and on light trusses on lamp poles, turntable ladders and work cranes. Depending on the version, however, use as ground spotlights is also conceivable. Halogen spotlights with an output above 1,500 W are rarely encountered. Generally several spotlights mounted on light trusses are used, typically up to 8 or 10 units per structure. Besides halogen emitters, in individual cases spotlights with halogen-metal vapor lamps (HM), high-pressure sodium lamps (HS) and high-pressure mercury lamps (HM) are used on tripods and light trusses. Here the power input generally lies at 1,000 W per lamp, and seldom higher.

The aforementioned lamp types are those most often used at the scene of a fire and designed for use under difficult conditions, although they require a very high power infeed. For this reason, spotlights with LED and xenon technologies are also being increasingly used. At present, LED spotlights with a power input of up to 150 W are in use. Xenon spotlights, on the other hand, are mostly used for 360° lighting on emergency vehicles and are rather untypical for the study.

A multi-staged study was conducted:

1. Determination of the most critical spotlight technology – module technology pairing according to the light spectra relevant in each case (worst-case pairing)
2. Studies on the homogeneity of the light cones of the spotlights
3. Measurements on compact module arrangements (approximately square form, with comparatively highest attainable homogeneity in spotlight emittance – worst-case arrangement)
4. Determination of the dependence of the generated electrical currents and voltages on the distance of the light source to the module field and on the power level of employed spotlight or spotlight combination (here with worst-case technology pairing)

4.5.2.1 Worst-case pair

All spotlights were spectrally measured, whereby it was found that the spectral composition of the light did not depend on the power category and was largely independent of the particular manufacturer; see also Figure 4-22 in the case of 5 different halogen spotlights.

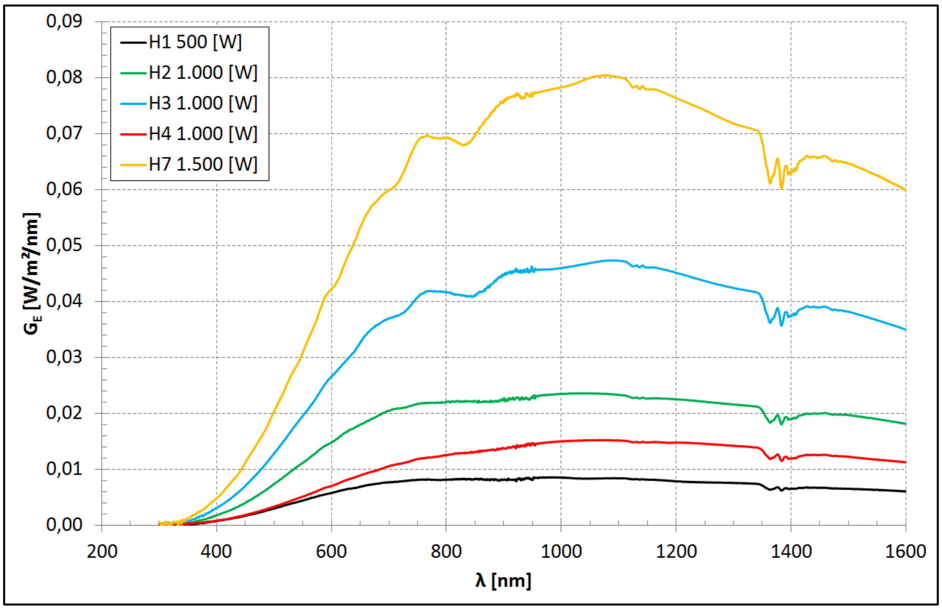


Figure 4-22: Light spectra from halogen emitters from different manufacturers and of different power categories.

By comparison, the spectral sensitivities of the different commercially available module technologies should be considered (Figure 4-23) and superimposed with the determined light spectra of the spotlight technologies. Figure 4-24 shows the results of all combinations of spotlight types and module types.

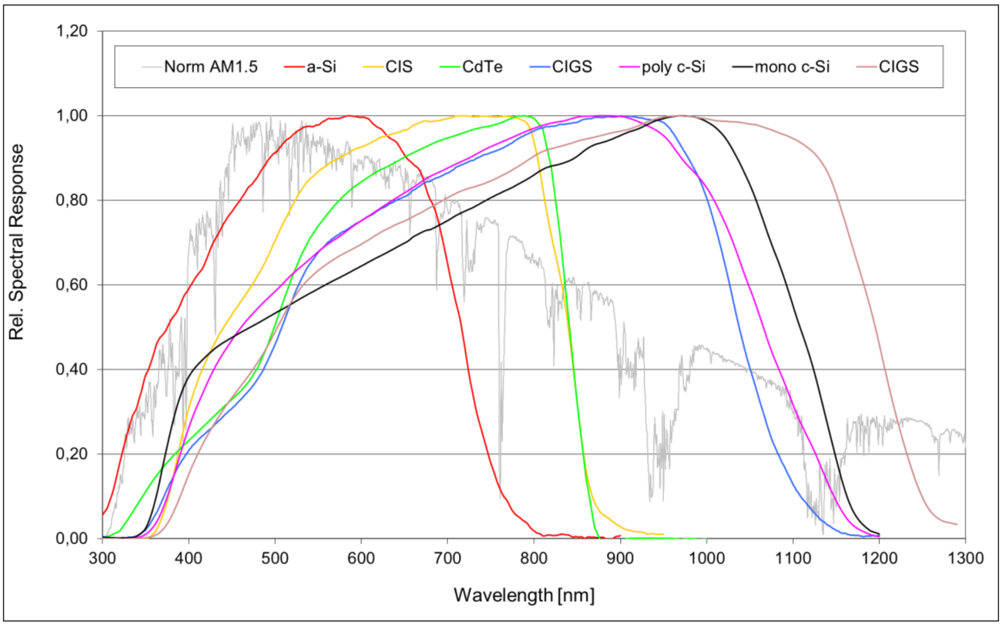


Figure 4-23: Spectral sensitivities of different module technologies

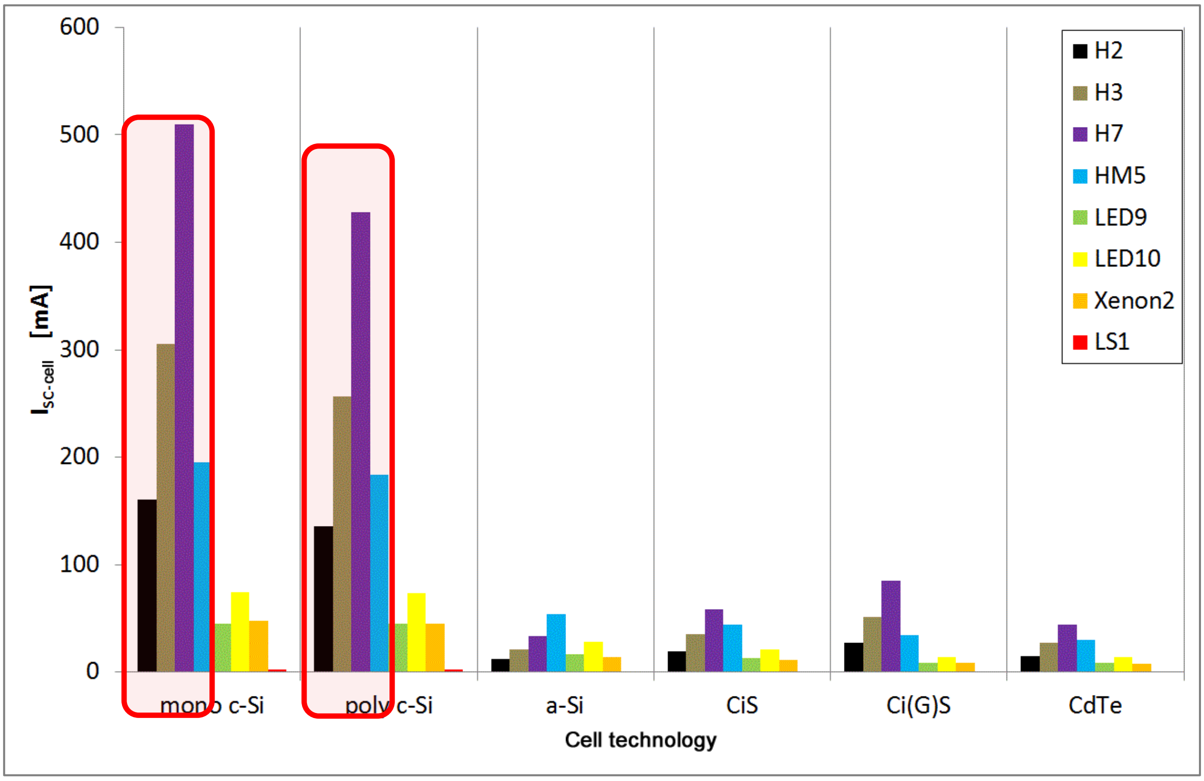


Figure 4-24: Generated short-circuit currents in different spotlight type – module type combinations

The result determined was worst-case pairing of halogen emitter and crystalline module as per the above composition – that is, precisely the pair that is most commonly encountered in practice at present. The results also indicate that the increased use of LED spotlights to be expected in the future will significantly reduce the danger potential.

Although the CIGS technology can accommodate an equally large spectral width, the measured currents are significantly lower than those in crystalline modules because of the considerably lower rated output of a thin-film module.

4.5.2.2 Homogeneity studies

The studies showed that the homogeneity of the produced light increases with the distance. On the other hand, the illumination intensity on the module sharply decreases as the distance increases (theoretically under idealized conditions in proportion to the square of the distance). The most critical case given the attainable current intensity is thus the combination of an emitter with a module, which while not practically relevant can be used to validate the worst-case scenario.

The practical testing comprised 2 series of tests:

In a first step, the generated currents and voltages were measured in a single module, in a second step in a string of 6 serially connected modules in a maximally compact design (2 x 3 modules stacked atop one another). The construction was specially manufactured by Energiebau Solarstromsysteme (Cologne) for this purpose; see Figure 4-25 and Figure 4-26.

Figure 4-25: Halogen operational emitters of THW Siegburg illuminate a compact construction of six modules

Figure 4-26: Measurement of the irradiance on the module plane produced by the emitters (above, below, on side and centered)

Tests were conducted with distances of 5 to 20 m with different lamp technologies (also combined, e.g. halogen, metal vapor). For the sake of simplicity, the short-circuit current was used for assessing the danger potential. Owing to the flat I-U characteristic of the PV module, this current is slightly higher than an assumed current flowing through the human body (with a minimum of 500 Ω) and thereby also increases the safety factor of the information.

Figure 4-27 shows the measured values of the test series with a compact string of 6 modules. The intersections with the limits laid down by IEC 60479-1 regarding effects on the human body show us the minimum distances to be set.

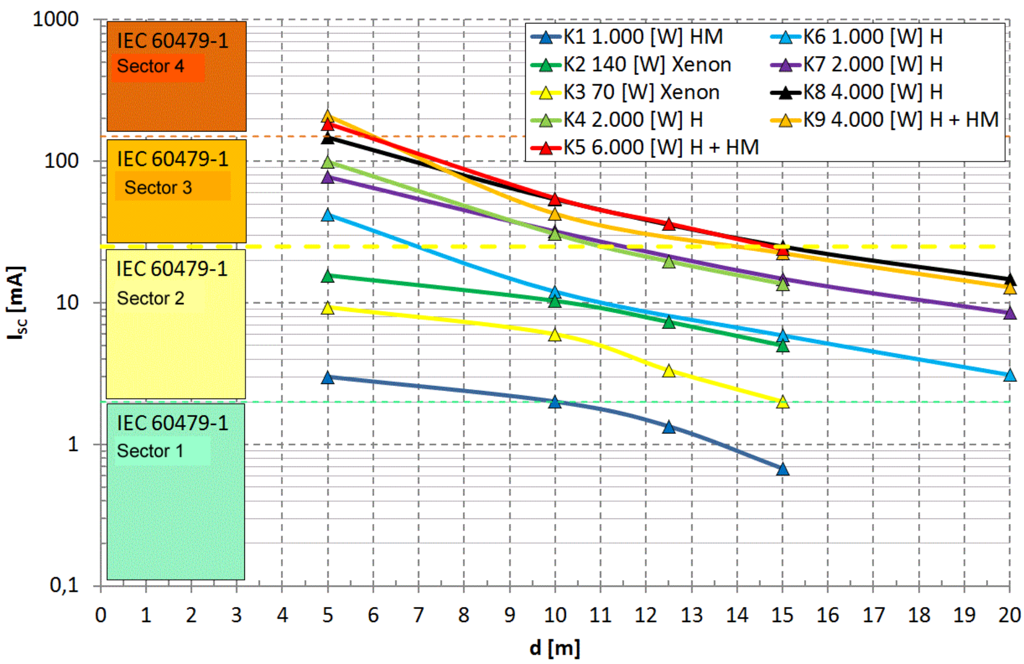


Figure 4-27: Short-circuit current measured and extrapolated with irradiation by halogen emitters of different outputs.

4.5.2.3 Recommendation for minimum distances

The analysis and extrapolation of the measured values yielded the following derived relationship between total output of the emitters and the distance to the module field with an assumed limit value of I_{sc} = 25 mA:

Basic distance with total power input of the emitters up to max. 1 kW:

$$\mathbf{d_{Pinp=1kW} = 10\ m} \qquad \mathbf{[1]}$$

Distance formula with emitter power input greater than 1 kW:

$$\mathbf{d\ P_{inp>1kW} = 10\ m + P_{inp\ [kW]} \times 1.5\ m/kW} \qquad \mathbf{[2]}$$

with
- d = minimum distance between spotlight and module surface
- P_{inp} = total emitter power input in kW

With an emitter power of 4 kW, a distance of 10 m + 4 kW x 1.5 m / kW = 16 m must therefore be maintained. The following table lists the minimum distances according to the above formula for some typically used operational emitter power levels.

Table 4-13: Examples of recommended minimum distances for commonly used emitter power levels.

Emitter power in kW (power input)	Recommended minimum distance in m
1	10
2	13
4	16
6	19
8	22

4.5.2.4 Assessment of admissibility or safety factors:

The calculation formula incorporated an additional safety factor, i.e. all actual measured values in fact lie below the distances computed with the formula. Additional safety factors were also used owing to deliberately chosen worst-case conditions; see Table 4-14:

Table 4-14: Safety factors for assessing test results

Boundary conditions in the test	Boundary conditions in operational use?
Combinations of the most critical spotlight technology used	Probably, since widespread at present. May be increasingly superseded by non-critical LED technology
Most critical module type used	Probable, since most widespread
Isc of the employed standard modules (4.7 A)	This will increase in line with the development of more powerful cells / modules
Normal incidence at module surface	Very improbable
Maximum light distribution homogeneity	Not possible
Bodily resistance R_B = 0 Ω	> 500 Ω
No shading of the modules	Partial shading from (e.g.) smoke possible

4.5.2.5 Conclusions

Summary

As in previous work, the results of the studies again show that artificial lighting is quite able to generate hazardous voltages and currents in a PV system and thus confirm the studies by BFH and UL.

Given compliance with the specified minimum distances of the illuminants and in particular the use of LED spotlights, we must assume a negligible hazard from illumination with artificial lighting, however.

In addition, the project conducted the studies with different spotlight technologies and different common power categories and with the usual distances and under defined worst-case conditions (technology, string geometry, normal incidence). In practice, these different worst-case conditions will not all obtain simultaneously; see Table 4-14.

In particular, the homogeneity of irradiation in the test arrangement at normal incidence will not be attained in practice, so that the above distance recommendation will generally include several safety factors (not further quantifiable).

The only boundary condition in the test series to be assessed as critical consists in the parameters of the employed, currently typical crystalline standard modules (2012). If modules in individual cases have considerably greater efficiency, higher currents than the values measured here and incorporated in the distance recommendation may also be generated.

This distance recommendation accordingly applies to the typical night-time (firefighting) operations at single- and multi-family houses with typical PV systems, but does not provide any guarantee for an altogether de-energized and voltage-free PV system, i.e. it provides no substitute for the necessary caution and maintaining of distance as with every electrical system.

4.6 Pollutant release in fire cases

4.6.1 Objective

A photovoltaic system operates with zero emissions independently of the employed module technology during its operating time, currently estimated to be 30 years, i.e. no toxic substances are released into the environment. Uncertainty still prevails today about the emission level of a PV system in case of fire with partial or even complete destruction of components. Different types of plastic and other combustible materials as well as, in small levels, toxic heavy metals form part of any PV system. A possible release of gaseous toxic substances under the effect of heat in a fire is therefore incontestable. The Environmental Committee in Brussels exempted all renewable energy technologies from the new regulation on the cadmium ban in the amended RoHS [45].

This section examines different issues related to fires involving PV systems. These issues comprise the possible additional hazard to firefighting personnel or other people in the vicinity of the fire source from toxic gas emissions, possible effects on the soil from massive amounts of quench water and also the possible spread of toxic gases or soot particles because of thermal and/or weather-related motions of the air beyond the immediate neighborhood.

We now examine modules and other components of a solar installation as to their typical components and therefore pollutants possibly released in case of a fire, their maximum concentrations (worst-case scenario) and their possible spread over the surroundings. We determine the risks of the employed materials for critical emissions and if necessary derive recommendations for material selections.

Figure 4-28 lists the sources of emissions to be considered in a PV system fire and their potential hazard for the different protective goals.

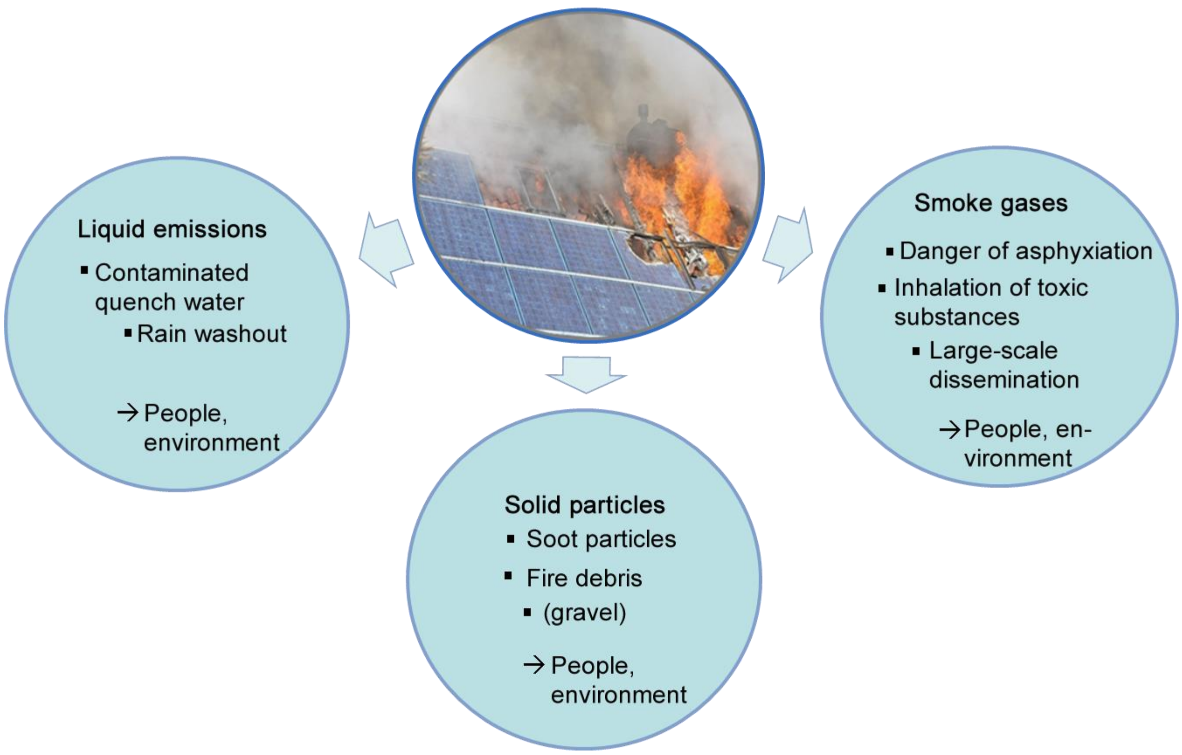


Figure 4-28: Emissions and hazards in case of fire

4.6.2 State of knowledge

According to the present state of knowledge about toxic emissions from photovoltaic systems, depending on the design, neither do intact modules produce critical gas emissions during their normal operating period nor is any release of pollutants into the soil to be expected. On the other hand, severe damage to the solar modules from hail, direct lightning strike or fire, for example, may lead to the release of pollutants in “small” amounts, e.g. [46] [47] [48].

The question whether these releases of pollutants in the event of an accident can reach levels critical for human beings and/or the environment has not been finally clarified to date. Previous studies primarily concerned thin-film modules on a cadmium telluride basis (CdTe), since metallic cadmium and cadmium compounds are classified as severely toxic in many respects: namely as carcinogenic, mutagenic and harmful to the fetus, and moreover have the dangerous property of accumulating in the body so that multiple exposure to very small doses can already cause serious health damage [49]. This must be considered when assessing the risk to firefighting personnel. The risk of absorption comes mainly from inhalation or swallowing. Cadmium is also severely hazardous to water. The possible entry into the soil through the quench water must therefore also be regarded as very critical.

The discussion about CdTe modules conducted mainly during the years 2010 – 2011 was pushed through (not wholly without self-interest) by representatives of the competing crystalline module technology, who demanded inclusion of photovoltaics in the scope of the RoHS, which would have directly pushed CdTe technology and therefore the greatest competitor out of the PV market. Several studies on cadmium telluride in PV modules were conducted, with the focus on modules manufactured by First Solar and Abound Solar.

In early 2012 the Fraunhofer Center for Silicon Photovoltaics (CSP) published a comprehensive review of completed work and its results through 2011 [50].

The conclusion drawn was that the emissions of cadmium and cadmium compounds verified in previous studies did not attain any critical concentration levels. The applicable AEGL-2 (Acute Exposure Guideline Levels values (accessible online at [51])) serve as comparable values, representing the threshold above which irreversible or long-term health damage can occur.

The practical significance of the information obtained from these studies for risk assessments in the event of actual PV system fires must be qualified, however, if we look at some of the experimental work and the conclusions drawn therefrom in detail.

For example, in 2005 a US study [47] investigated the behavior of CdTe module specimens under the effects of heat at different temperature levels from 760°C to 1,100°C. Gas emissions, mass lost, residue and Cd distribution in the fused glass residue were meticulously analyzed. We find that the diffusion of cadmium into the surrounding gas increases with the temperature, with a relatively constant emission rate of 0.5% being measured. On the other hand, the predominant share of the cadmium is encapsulated in the glass. It is conjectured that entire modules will release only about 0.4% of their cadmium content owing to the relationship of outside edges to surface area.

The measurements were performed on small specimens lying in a basin. The melted material was collected in the basin. Cadmium from the inner CdTe layer was able to escape only through the side edges; see Figure 4-29. In actual installed modules in the PV system the glass fragments, melting material can drip down and a large part of the CdTe layer or glass can be exposed together with the diffused cadmium. Theoretically it would be possible that the level of emitted gaseous cadmium under these circumstances is greater than the 0.5% measured in the lab.

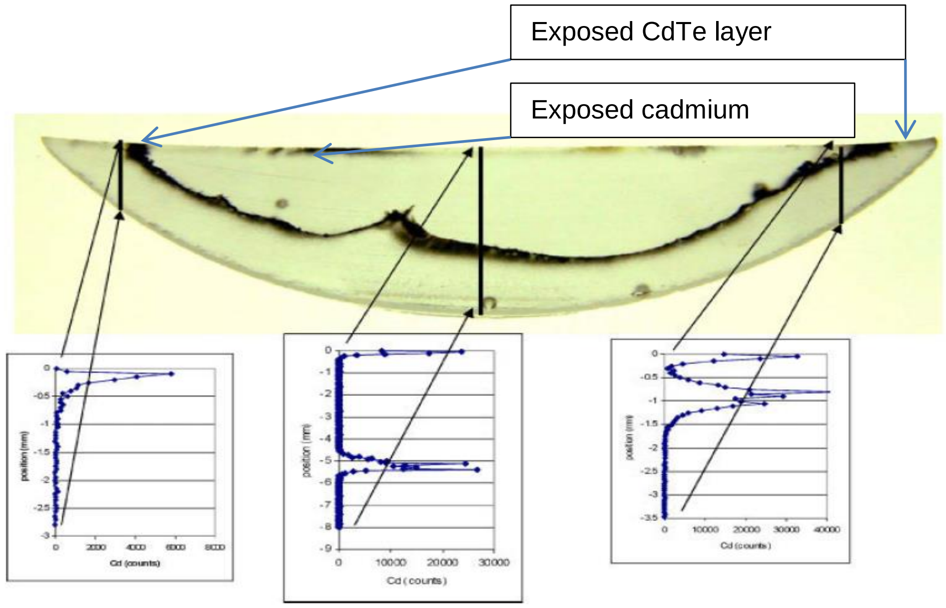


Figure 8. X-ray fluorescence microprobe analysis–vertical slice from middle of sample heated at 1000°C; Cd counts in the center and the sides of the slice

Figure 4-29: CdTe module specimen with Cd level curve within the fused and re-cooled sample, source: **[47]**

A study from 2011 on possible cadmium emissions related to rainwater flushing of fractured CdTe modules and smoke gases from PV fires [52] concluded that health risks for residents or employees and rescue workers from cadmium emissions into the soil, groundwater or air are improbable. Possible risks from deposits of the heavy metals lead and cadmium in the soil from open-space installations in or near agricultural areas were investigated by the Bavarian Agency for Agriculture [46]. While the risks from a possible washout were classified as minimal, to be on the safe side the recommendation was made that defective solar modules be quickly removed.

The first smoke gas studies were already conducted in 1994 by order of BP Solar. With the technology available at the time, 10-minute exposure levels below the applicable limits as per AEGL (Acute Exposure Guideline Levels (accessible at [51]) were found at temperatures of 800 – 900 °C for the measured concentrations and therefore classified as non-critical.

Other research studies on the release of heavy metals from PV modules on fire were conducted in 2011 and 2013 by the Federal Institute for Materials Research and Testing (Bundesanstalt für Materialforschung und -prüfung, BAM) [53], [12]. Among other things, the studies subjected small (75 mm x 75 mm) specimens from different 50 kW/m² module technologies to heat exposure and both the smoke gas composition and residue were analyzed. After about 8 minutes of such stress the module assembly failed, accompanied by a significant increase in gas emission. It was found that the specimens or fire debris still contained on the average 94% of the heavy metals from the initial specimens after the fire stress. Conversely, approximately 6% must have been released in these lab tests.
Initial values for CdTe modules were approximately 7g Cd level/m², which agrees with the specified

lower limits in the literature [54]. Given a large spread in the results, the authors recommended further studies.

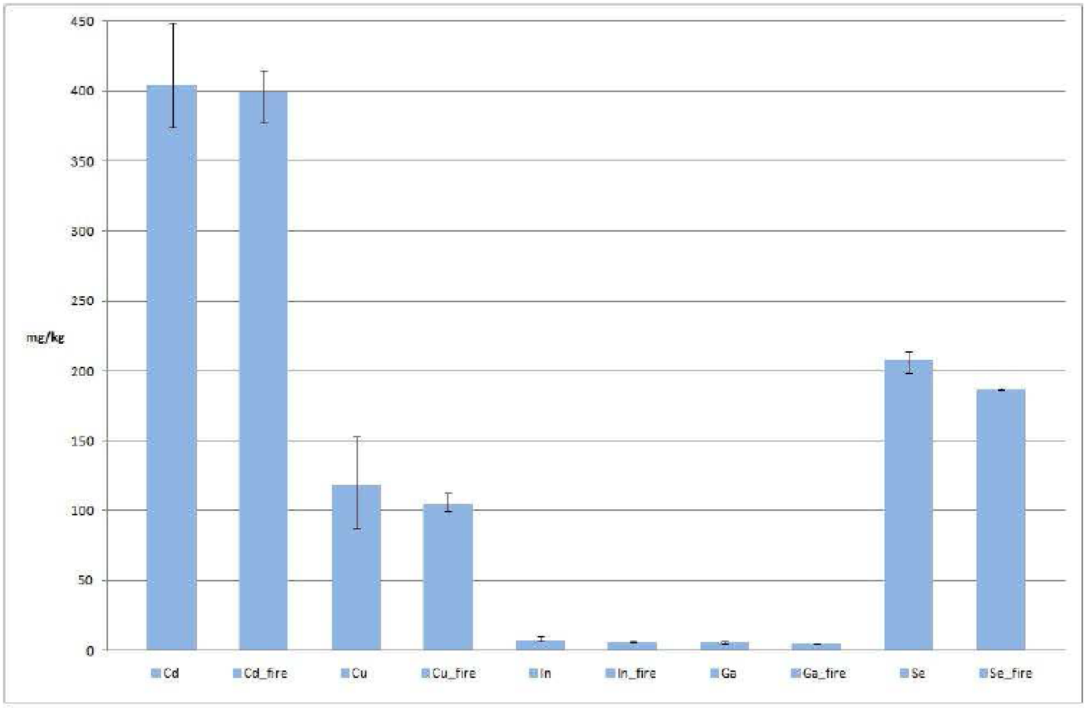


Figure 4-30: Residue analysis: Before and after fire test on CdTe and CIGS module specific (source: BAM 2013, **[12]**)

The distribution of cadmium pollutant emissions into the environment from roof-mounted PV systems on fire is the subject of an independent study conducted in 2011 by the Bavarian State Office of the Environment [55]. The distribution of outgased cadmium was then studied for different scenarios in consideration of the wind. Various installation sizes and different heat output levels were considered and in each case the cadmium concentration near the ground indicated for distances from 100 m. As a result, it was found that even in the worst case the Cd concentration at 30-600 µg/m3 lay clearly below the AEGL-2 values (1400 µg/m3; AEGL-2 10 minutes), so that a hazard to the environment can be practically ruled out.

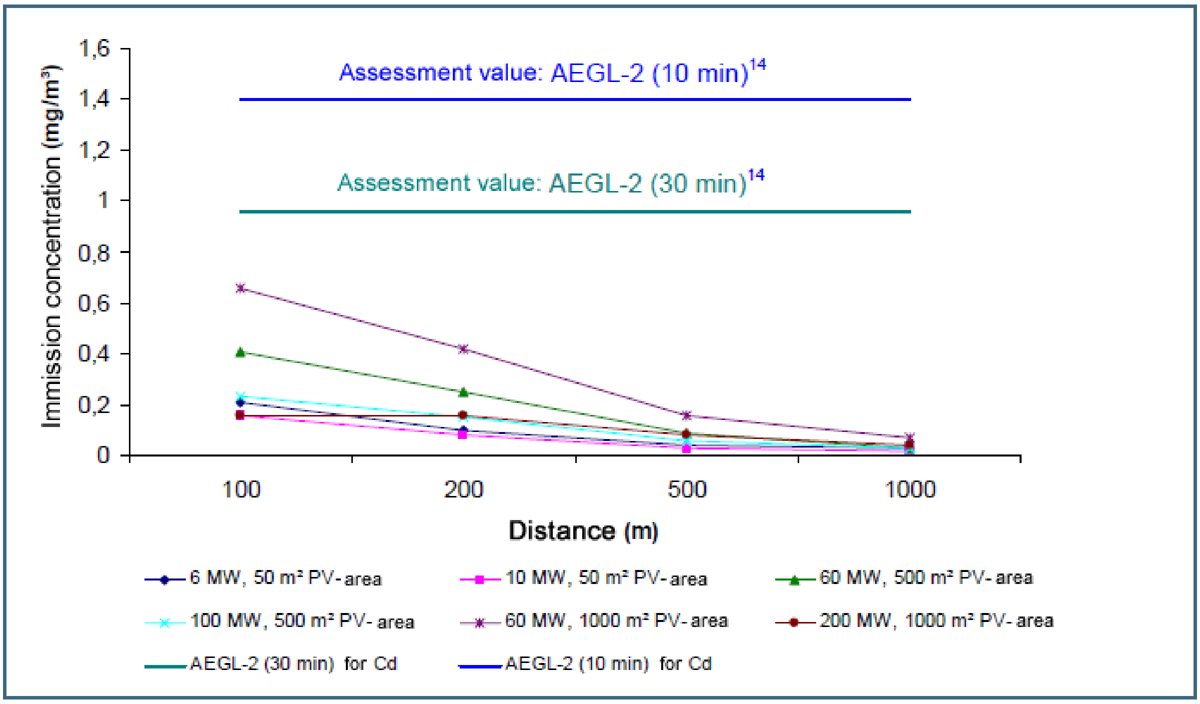


Figure 4-31: Cadmium immission concentration as a function of the distance to the fire site with a maximum cadmium content of 66 g/m (worst case)

Unfortunately, this positive result does not suffice for resolving the issue in this study. For assessing the hazard to firefighters from toxic fire effluents, considerably smaller distances of about 8 – 50 m to the emission site are relevant. Here too considerably higher concentrations occur than at distances > 100 m, depending on thermal upthrust, wind force and wind direction.

Figure 4-32 shows a typical distribution of air pollutants, here NO_2. The emission source in this case is a heavily traveled road (from a study by the Austrian Environmental Agency [56]).

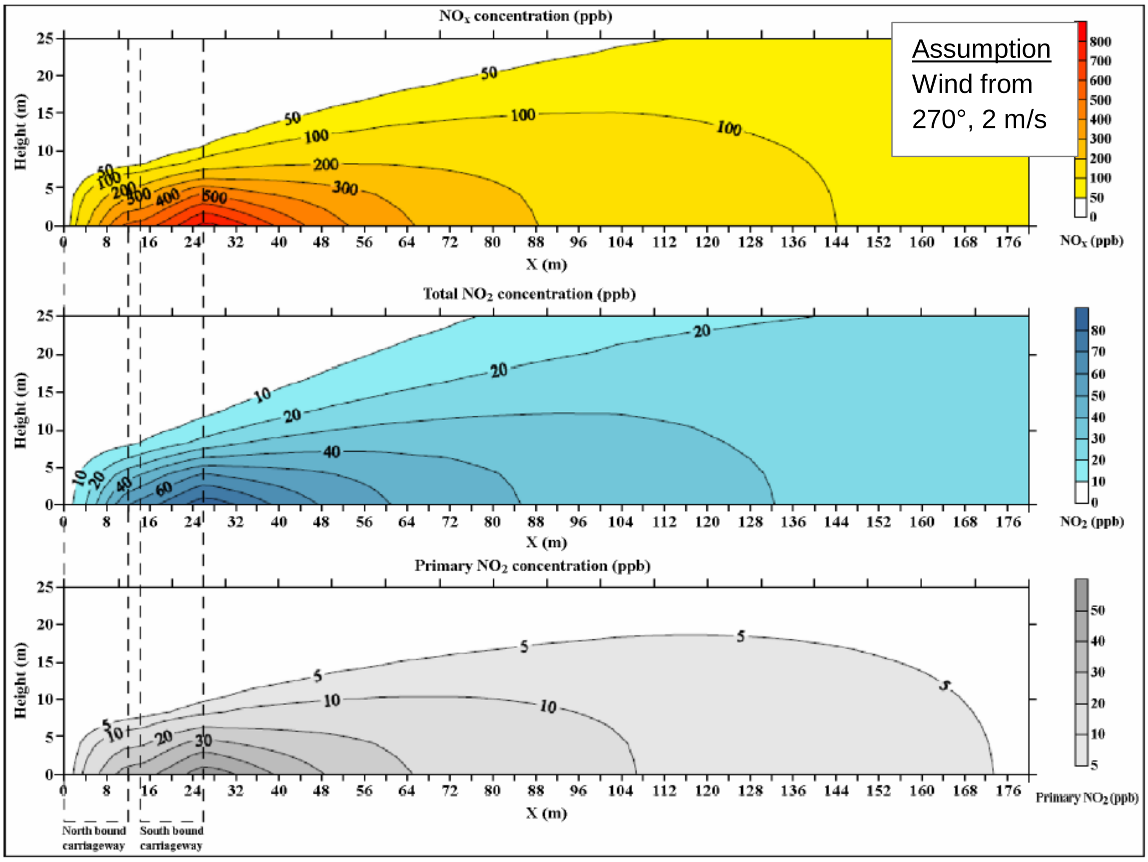


Figure 4-32: Example of pollutant concentration as a function of distance and height (source: Austrian Environmental Agency, **[56]**)

Given the rather low wind force in this example, an air pollutant concentration of approximately 10 ppb is specified on the ground along the wind direction at a 100 m distance (bottom graph), coming from a source emission of 50 ppb. In the relevant distance range of approximately 8 – 50 m, we find the overall spread of concentrations to lie between 50 and 10 ppb.

This means that in the close-up range a multiple value, in this example 5 times the value, of the pollutant concentration can exist at a distance of 100 m. From the results of the study by the Bavarian State Office of the Environment [55] we thus find ourselves well above the AEGL-2 limit for 30 minutes as well as that for 10 minutes. On the other hand, the thermal influence in the pollutant emission has a mitigating effect, bringing about greater propagation upwards in case of a fire and relieving the space near the ground.

The magnitude of this influence in practice depends on the specific fire properties and the particular environmental and weather conditions and is hardly quantifiable given the complexity of the influential factors.

Summary

Previous studies on emissions in case of damage and fire in particular show only low emission rates of toxic gases or soot levels of up to a maximum of 6% of the pollutant level in the damaged module. Most of the harmful substances were encapsulated in the fused glass part in these studies. The respective authors found that the results of smoke studies on the one hand and distribution simulations on the other posed no significant risk to humans or the environment.

Despite the positive results from previous studies, the subject of pollutant emissions in case of fire cannot be regarded as settled as non-critical for the following reasons:

Previous smoke gas studies and residue analyses were in each case performed on small specimens with side lengths of only a few centimeters. A large spread of results was obtained. Additional information should be provided by analytic lab studies on whole modules under realistic conditions in the fire lab specially equipped for this purpose.

To date no tests have been performed with incomplete combustion through quenching, for example. (To date the literature describes no studies of this scenario.)

The risk consideration for firefighters represents a special case. Rescue workers wear respiratory protection when operating in the vicinity of a PV system. An estimation of the concentrations of toxic substances at distances less than 100 m should be made in addition to the aforementioned data from the Bavarian State Office of the Environment.

Fire department crews may be exposed to pollutants for longer than 10 minutes in practice. This is also reflected by special maximum exposure concentrations for fire departments that refer to 4 hours.

Heavy metals accumulate in the body, and repeated exposure is conceivable, a fact that must be taken into account by a risk assessment. A different approach to limit considerations is therefore necessary.

4.6.3 Compositions of the modules and components

Because of their complex design, PV systems, in particular PV modules, contain numerous types of materials. For estimating theoretically possible releases of pollutants, typically used materials are analyzed and their behavior or possible chemical reactions in a fire event determined.

Table 4-15: Basic compositions of PV components

Component	Composition
Modules	
Frames	Metals, plastics
Carrier material	Glass, plastic film, metallic foil
Back rails	Metals, plastics
Solar cells	Depending on the technology: Silicon, plastic films, metallic foil, dyes, various (heavy) metals
Embedding	Cast resin, plastic films
Sealing compound	Rubber, silicone
Cell connectors	Metals, alloys
Junction boxes	Plastics, metals, diodes
Cables, plugs	Plastics, metals
Substructure	Metals, plastics
DC junction boxes	Metals, glass, plastics
Inverters	Metals, glass, plastics

In quantitative terms, the PV modules with their substructures and connecting cables as well as plug connectors make up by far most of a PV system, with the modules numbering from around a dozen in small roof-mounted systems on single-family houses to several tens of thousands in large (open-space) systems. While substructures and cables are made from rather non-critical metals and polymers that must be considered because of smoke gases, depending on the technology the PV modules contain numerous materials that in part are also classified as severely dangerous to health even in small amounts. The following considerations of materials focus on PV modules with their technology-dependent compositions.

PV modules are usually divided into three main groups based on the employed cell technologies: Crystalline modules, thin-film modules and modules with “other” (new) technologies (Table 4-16).

Table 4-16: PV technologies

Crystalline silicon (thick-film)	Thin film	Other technologies
• sc-Si (monocrystalline) • mc-Si (polycrystalline)	• **Silicon** • a-Si (amorphous silicon) µ-Si (micromorphous silicon) • **Semiconductor** • CdTe (cadmium telluride) • CIGS/CIS (copper indium – gallium selenium) • GaAs (gallium arsenide) • CZTS (copper zinc tin sulfide)	• Dye cells • Organic plastic cells • Concentrator cells (CPV, e.g. triple- junction cells)

For estimating the practical relevance of the material composition to be considered, we consider the market shares (frequency of use) of the most important module or cell technologies:

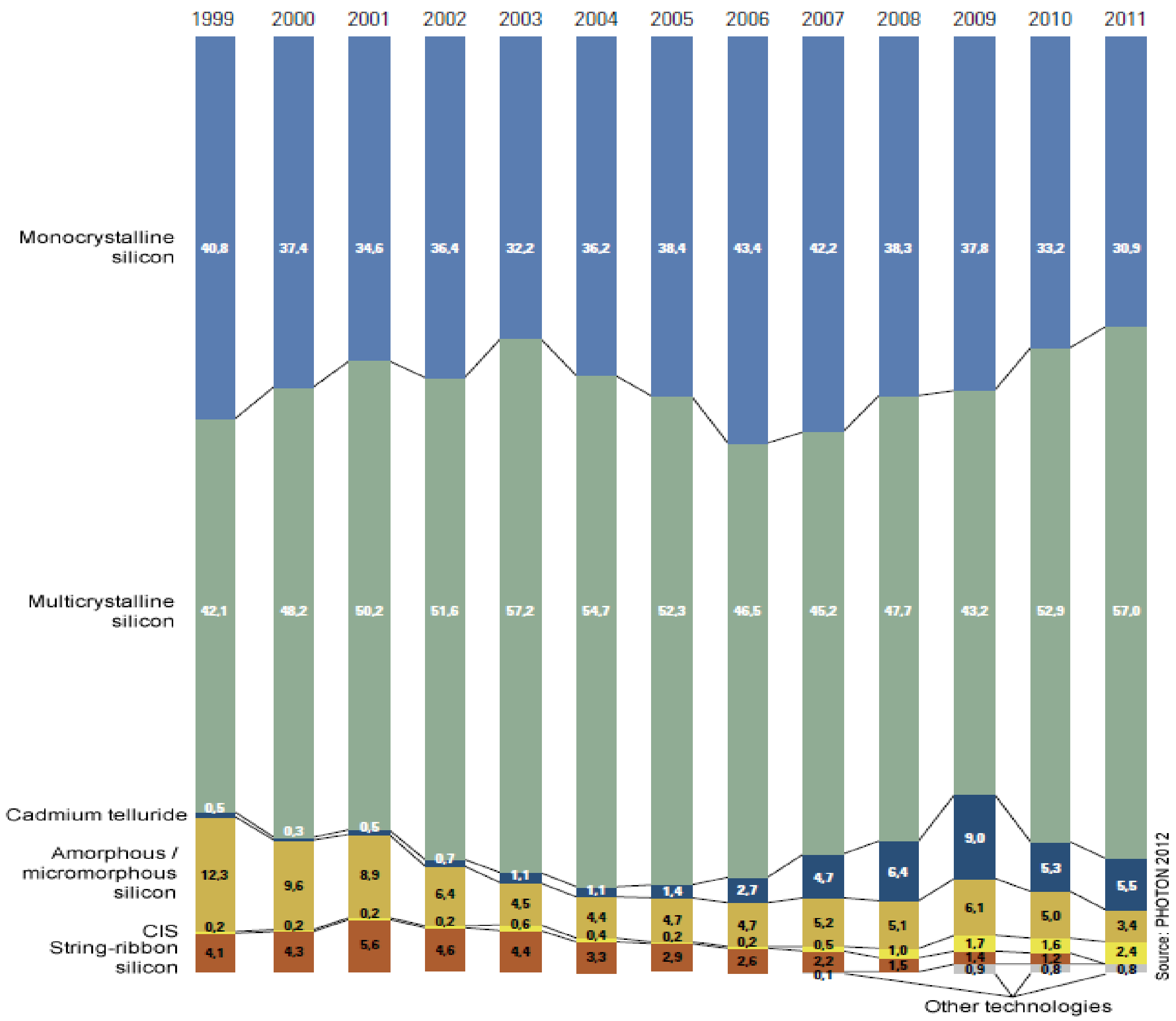


Figure 4-33: Market shares of the most common cell technologies (source: Photon Europe GmbH, April 2012)

The market share of the crystalline modules remains relatively constant between 80% and 90% as the clearly leading technology, while the total share of all thin-film technologies falls between 10% and 20%, with the trend declining over the last 3 years because of the drop in price of crystalline modules. Within the groups there are shifts with a continued predominance of cadmium telluride modules, along with an equally growing share of CIGS modules. Other cell technologies, like dye-containing or polymer modules, have so far not played any prominent role in the market.

In the following, we therefore consider typical silicon-based crystalline thin-film modules as well as proportionally the most important thin-film modules with cells made of amorphous silicon and cadmium telluride along with copper indium gallium selenium semiconductors.

<u>Crystalline standard modules</u>

The crystalline standard modules prevailing in the market are primarily manufactured as glass-film modules with aluminum frames. In addition, there are frameless modules as glass-glass versions. A crystalline standard module thus consists basically of an upper glass plate, the PV cells with attached metallic contact tabs and connectors, the cell embedding, a backsheet, the junction box and an aluminum frame. The mass fractions are dominated by glass and the frame (approx. 85 – 90%). The remainder breaks down into different plastics, silicon (cells, silicones) as well as copper and, in small amounts, other metals like silver, selenium and lead.

Current Si standard modules with an output of approx. 230 – 330 Wp are about 1.6 m² (1,650 x 990 x 40 mm) in size and weight about 18 – 19 kg.

The most important materials and their mass fractions in a crystalline standard module were compiled from studies conducted by the Institute for Ecology and Politics in Hamburg (Ökopol) from 2004 and 2007 [7] [8] as well as from an older detailed analysis by TÜV Rheinland [57] and other sources. Noteworthy is that no current analyses from the last two years were found and that studies through 2011 cited as their data source the aforementioned Ökopol studies, which we therefore use as a basis here as well.

Table 4-17: Example of the composition of a standard Si module, 215 Wp; source: **[8]**

Component	Quantity (2003) according to [Ökopol 2004]	Quantity 2007	
	%	%	kg/kWp
Glas	62,7	74,16	77,3
Frame (e.g. AlMg-Si0.5)	22,0	10,30	10,7
EVA	7,5	6,55	6,8
Solar cells	4,0	3,48	3,6
Backsheet film(Tedlar)	2,5	3,60	3,8
Junction box	1,2		
Adhesive, casting compounds	No data	1,16	1,2
Weight/kWp	103,6 kg/kWp		102,3
Cu	0,37	0,57	
Ag	0,14	0,004 – 0,006	
Sn	0,12	0,12	
Pb	0,12	0,07	
Si	No data	3%	

Compared with crystalline thick-film modules, amorphous silicon modules show no significant deviations in material composition regarding harmful substances and will not be separately considered in the following.

Table 4-18 lists the researched, typically used substances for components of a crystalline PV module. The literature did not include the connecting cable with plug. Typically they must be considered as constituting a mass fraction of approx. 3.5% and containing approx. 400 g of polymers (in the case of newer solar cables, these are usually cross-linked polyolefins, besides copper, tin and aluminum) for the conductor materials. The percentages and derived masses per m² module surface given in Table 4-18 must therefore be understood only as approximations.

Table 4-18: Materials and average mass fractions of a typical crystalline standard module, glass film (single-plate laminate)

Component	Materials	Material composition (examples)	Mass [%]	Approx. mass [g/m²]
Frame	Metal	Aluminum	8 - 10	1,060
	Plastic	Polyurethane, polyamide		
Glass	Tempered glass, annealed glass	Glass (Si, Na, Ca, Mg)	74 - 76	8,850
	Front plate, LSG	Glass, PVB film		
Cells	Crystalline	Silicon	3.6	424
Cell stringing **Connectors**	Tin-plated copper bands	Copper, tin, silver, lead, bismuth[2] (only 10-30 µm thick)	0.8	94
Backsheet	Tedlar film	PET, PVF, PA	5	590
Embedding		EVA, acrylate	6	708
Seals, adhesives	Frame sealing tape	Rubber, silicone, acrylate, PE foam, polyurethane, ethylene-propylene-copolymers	1 - 2	177
Junction boxes	Plastics, metal	ABS, PET, aluminum	1 - 2	177

Thin-film modules

Besides the technologies also based on silicon, thin-film modules use various light-absorbing semiconductor materials (cadmium telluride, gallium/indium, gallium arsenide, etc.) that are impressed on a carrier material – primarily glass, but also plastic or metallic film. Thin-film modules primarily use frameless structures (glass-glass modules or flexible modules with film covering). The design of the module types is much more varied than with crystalline modules, so that a “standard thin-film module” cannot be defined.

The glass part is much greater in glass-glass thin-film modules than in crystalline ones.

Table 4-19 and Table 4-20 below list the typical compositions of modules with CdTe cells and CIS/CIGS cells as quantitatively the most widespread thin-film technologies.

Table 4-19: Typical composition of a CdTe module (120 x 60 cm), source: **[8]**

Material	Thickness	Weight per unit area	Weight per unit power
		g/m²	G/Wp*
Glass carrier layer	3 mm	7500	71
TCO-SnO_2	<1 µm	6,9	0,07
CdS	<0,1 µm	0,483	0,005
CdTe	7µm	18	0,17
Back contact	1µm	2,7	0,03
EVA	0,5mm	500	4,8
Front glass	2 mm	7500	71
CuSn-Band		6,94	0,07
Connection box		21,7	0,2
Cable		57,8	0,6
Total		15.615	149

Table 4-20: Typical compositions of CIGS modules (three manufacturers), source: **[8]**

	Weight(g/m²)		
	Producer A	Producer B	Producer C
Si_3N_4	0,5		
Mo	4	5	
CuInGaSe	10	12	9,5
Selenium	5	6	4,5
ZnO	7	6	0,7
CdS	0,2	0	0,24
ITO			
Polyamide carrier layer			35
Glass carrier layer	7500	7500	
Front glass	7500	7500	
PIB seal	500		
Encapsulation(PVB, EVA, PU, PE)	200	500	No data
Polymer adhesive	400		
Adhesive tape		100	
Aluminium frame	3000	1800	
J-Box PP	400	100	
Polymer and copper cables	400	200	
Polyester label	1	1	
Glass total	**15000**	**15000**	
Polymer total	**1701**	**701**	
Total weight/m²	**19927**	**17730**	

The average proportionate quantities of the metallic materials relevant for thin-film modules according to the literature were extrapolated to a system size with an assumed module surface of 50 m². The approximate quantitative parts are given in

Table 4-21.

Table 4-21: Metals, materials and mass fractions of thin-film modules (CIS / CIGS and CdTe)

Cells	**Material composition**	**Mass**	
		%	g/50 m²
CIS / CIGS	Copper (incl. cable), Cu	0.8	6,000
approx. 3% market share	Indium, In	0.02	150
	Selenium, Se	0.03	225
	Zinc, Zn	0.03	225
	Gallium, Ga	0.01	75
	Arsenic, As	0.01	75
	Molybdenum, Mo	0.07	525
	Cadmium, CdS	0.001	8
CdTe	Cadmium, Cd	0.07	450
approx. 5% market share	Tellurium, Te	0.07	450

For a PV system with approx. 50 m² CdTe module area (approx. 70 modules per 1200 x 600 mm with altogether approx. 5.6 kWp), approx. 450 g cadmium must be expected according to the sources.

Roof-mounted system substructures for the most part consist of aluminum and stainless steel. Exceptions occur in the form of plastic trays (PE), e.g. for flat roofs (e.g. ConSole+ from Renusol), however. The trays are reaction-to-fire class E (as per DIN EN 13501-112010-011) according to information from the manufacturers. The trays are “normally flammable” as per existing requirements and therefore also combustible.

Construction materials of building-integrated solar systems do not differ from conventional façade and overhead glazing structures without solar elements, so that they need not be further considered here.

4.6.4 Composition of the fire effluents

Effects greatly depend on the type of fire. This applies to the production of smoke and gas as well as to the extent of damage. The produced substances and compounds were analyzed for different fire scenarios [58].

In a fully developed fire with high temperatures and oxygen supply, the organic components are largely converted through combustion to the oxidation products of carbon (C), hydrogen (H) and oxygen (O) carbon monoxide (CO), carbon dioxide (CO_2) and water (H_2O).

Bound heteroatoms like fluorine (F), chlorine (Cl) and nitrogen (N) are converted during a fire to the corresponding (highly toxic) hydrogen halides (HF, HCl) or to nitrogen oxides (NO and NO_2).

At decreasing temperature and with oxygen supplied, the products from organic materials become too numerous to mention. Partially oxidized and cracked compounds increasingly occur. In the partial oxidation of organic carbon, carbon monoxide (CO) dominates the smoke gas composition. In smoldering fires cracked compounds like plastic monomers dominate.

Below we consider the substances mentioned in the previous section in reference to the production and composition of fire effluents and smoke. Assumed is a fully developed fire scenario, characterized by temperatures above 600°C with a sufficient supply of oxygen [58].

For assessing the relevance for firefighting personnel we consider the quantities contained in the modules in addition to their toxicity.

Glass

Glass, quantitatively the main component of a typical module, does not chemically change even at high temperatures, since it already exists in an inert oxidized state. It contains no critical parts.

Metals

Aluminum can combust and change to aluminum oxide only at very high temperatures that are usually not attained in a typical fire. Aluminum can therefore be classified as inert.

Copper from supply lines and contacts burns under the considered conditions to become copper oxide, which has no toxic relevance.

Tin and lead are used in solder compounds, with the lead content making up about 40%. In a fire, these metals also convert to their metal oxides – both are toxic. Under fire conditions, lead can be released as smoke, while tin is slightly volatile.

Cadmium is used as a semiconductor material in CdTe modules, and is contained as small amounts in other cell technologies. Because of the slight oxidability of cadmium, we must assume that at higher temperatures cadmium will partially convert to cadmium oxide (CdO), which is significantly less volatile than metallic cadmium. Both cadmium and cadmium oxide have high-level toxicity. The Cd parts released in gaseous form make up about 25% of the inventory [9], while the parts released altogether as particulates and gas make up about 70% [7]. Relevant gaseous parts in the (cooled) ambient air are not to be expected. During a fire, the release of Cd/CdO particulates in the range 1 – 4 mg/m³ is at most to be expected. In the more favorable case, cadmium is chemically bound as silicate by the glass envelope. Compared with the maximum exposure concentration value of 0.4 mg/m³ (see section 4.6.5, p. 162), cadmium must be considered relevant for firefighting operations.

Arsenic (As), molybdenum (Mo), zinc (Zn), gallium (Ga), indium (In), selenium (Se)

These metals are primarily relevant to considerations of CIGS technology. In case of fire, the corresponding oxides like MoO_2 Ga_2O_3, ZnO, SeO_2 and CdO predominate. Highly volatile metals like selenium (and, as described, cadmium) can also vaporize and appear as a gas or (in a cooled state) as smoke (particles). In particular, selenium, as well as the expected selenium oxide (SeO_2), is highly volatile. **Arsenic** is a toxic, non-essential heavy metal. Arsenic and its compounds qualify as carcinogenic substances. There are also grounds for suspecting **selenium** to have cancer-causing potential. On the other hand, the acute toxicity of elemental selenium (e.g. when taken in orally) is considered very low.

Studies on heavy metal residue in the incineration of waste have found the following release rates for toxic metals [59], [60], [61].

Table 4-22: Metals released at 1,000°C in percent (solid particles in smoke gas and as gas)

Metal	Proportion released at 1000°C in %	
	Particles/gas	Gaseous phase
Se	70	70
As	60	40
In	(5)	
Ga	(10)	
Mo	(5)	
Pb	30	12
Zn	30	21
Cd	70	25
Sn	10	
Cu	10	

The specified metals are released in gaseous form and as airborne particulates. According to [59] large amounts of As and Se are released at 1,000°C. Cd and Zn enter the gaseous phase to about 25% and Pb to about 10%. The percentage not incorporated in the remaining ash, and therefore emitted in particulate form (air-borne ash), is much higher for nearly all observed metals, and in particular 70% for arsenic and cadmium. Apart from selenium, the released metals or metal compounds do not occur in gaseous form when cooled to below 200°C. The numerical values for Ga, In and Mo are estimates.

Plastics and organic materials

These include the employed sealing compounds, films, junction boxes, cables and possibly module frames as well. Quantitatively, the embedding material and backsheet are especially important.

The following maximum formation rates were used as a basis for the production of the pollutants carbon monoxide, hydrogen chloride, benzene, hydrogen cyanide, formaldehyde, styrene and hydrogen fluoride from polymers [62]. The estimated, maximum formation concentrations 10 – 20 m at close range (see Table 4-24) were derived therefrom.

Table 4-23: Maximum release rates for polymers in a fire.

Component	Polymers	mg/g polymers	ng/g polymers
CO	All	580	
HCN	PAN (25 % in ABS)	101 (25)	
HCN	Polyamides	60	
HCl	PVC	284	
Benzene	PVC	24	
PCCD	PVC		1,8
Formaldehyde	PE	7	
Styrene	PS (50 % in ABS)	710 (355)	

The share of polymers in crystalline Si modules is 5 – 10%, or 500 – 1.500 g/m². This share consists of the polymer EVA (embedding film) and PET/PVF (backsheet). If these films are used, especially emissions of CO and formaldehyde must be expected as lead substances. Added is the release of hydrogen fluoride due to the fluoride content in the PVF (if used).

Given a PV area of 50 m², altogether 25 – 75 kg of polymers are affected, which can be estimated to lead to the following maximum concentrations of selected toxic substances at close range. The maximum exposure concentration was specified here as the toxicological threshold. Section 4.6.5 will discuss the existing threshold values.

Table 4-24: Maximum concentrations at close range

Component	Concentration in mg/m³			Maximum exposure concentration mg/m³
	25 kg polymers	50 kg polymers	75 kg polymers	
CO	100	**200**	**300**	38
Formaldehyde	1,3	**2,5**	**3,8**	1,25
HF	**25**			10

The theoretically possible CO concentrations can significantly exceed toxicological thresholds at close range. The maximum expected concentrations for the components formaldehyde and hydrogen fluoride are also two to three times the permissible maximum exposure concentration.

The installed cables with plugs and boxes contribute additional polymers (in the case of older systems, possibly chlorine-containing PVC or nitrogen-containing ABS) to smoke gas formation: for a 50 m² module area this will amount to about 5 kg of polymers. These quantities do not suffice for exceeding the corresponding maximum exposure concentrations for the possibly occurring HCl, HCN, benzene or PCCD/F boxes.

4.6.5 Toxicological thresholds

4.6.5.1 Smoke gases

The currently most important assessment levels for hazardous situations are the AEGL (Acute Exposure Guideline Levels). These are incidence assessment values as per the 12th Federal Immission Control Ordinance (BIMSCHV). They have been respectively declared for different exposure times: 10 min, 30 min, 1h, 4h, 8h. For the incidence assessment values 3 levels each are defined, describing the following degrees of impact [51]:

AEGL-1/ERPG-1	Threshold for noticeable malaise
AEGL-2/ERPG-2	Threshold for irreversible or other serious, long-term health effects or escape-hindering effects
AEGL-3/ERPG-3	Threshold for life-threatening or fatal effects

Level 2 is considered relevant for pollutant concentrations.

Examples of other assessment series in Germany are the MAC (maximum allowable concentration for an 8h workday and 40h/week) and the maximum exposure concentration (German: ETW) for firefighters for 4 hours' exposure [63].

Various other assessment levels exist on the international level; we mention the ERPG (Emergency Response Planning Guidelines) and PAC (Protective Action Criteria) here as representative examples. The PAC values are a compilation of existing limits in the form of prioritized lists.

4.6.5.2 Solid pollutants

The Federal Soil Protection and Contaminated Sites Ordinance [64], Annex 2, defines test levels for the direct absorption of pollutants into the soil. Different categories are listed, such as play areas, residential areas, parks and industrial zones. For the considerations in these studies, the residential area category was used for the purpose of comparisons.

4.6.5.3 Harmful substances in quench water

For assessing the amounts of harmful substances in quench water we lack directly comparable limits. For estimating which concentrations of liquid pollutants must be qualified as critical, we applied the Sewage Sludge Ordinance for Agriculture (AbfKlärV) [65]. It specifies the thresholds for pollution of (industrial) effluent sludge containing heavy metals and other harmful substances for the purpose of protecting the environment, in particular the soil.

4.6.6 Lab tests

In connection with the BMU research project underlying the present study, experimental studies were conducted at the fire testing center of CURRENTA during June 2014 with the aim of characterizing the release of harmful substances by photovoltaic modules in case of fire.

The experimental program covered three different module types (Table 4-25). In each case both commercially available and current modules were studied. A flame was applied to the backs of the inclined modules with a gas burner, in order to simulate a possible fire emergence scenario among roof-mounted PV applications. Pollution analyses were conducted on smoke gas, fire residue and quench water samples.

Table 4-25: Module types

Type	Design	Frame	Length (mm)	Width (mm)	Thickness (mm)
Polycrystalline c-Si	Glass film	Aluminum	1,655	1,000	45*
Thin-film, CIGS	Glass film	Aluminum	1,255	980	35*
Thin film, CdTe	Glass-glass	None	1,200	600	8
* Frame thickness					

4.6.6.1 Test setup

The PV modules were mounted with profile rails arranged crosswise on a fiber cement mounting plate, located on a test platform inclined 23° relative the horizontal plane (figure 5-34). The inclination was selected as in the roof fire test as per UL 790. The modules protruded 45 cm beyond the front edge of the mounting plate and a flame was applied to their undersides in this area. The gas burner described in UL 790 served as the ignition source, producing a flame approximately 100 cm in width (Figure 4-34). The burner was positioned 10 cm below the front edge of the module, with the horizontal distance to the module front edge also being 10 cm.

On the front and back of the module five thermal elements each were arranged along the longitudinal axis of the module. The distances to the module front edge were 10, 40, 70, 100 and 130 cm. In the temperature diagrams contained in the Appendix, “MS-01” (module back) and “MS-06” (module front) designate the measuring points along the module front edge.

For the quench water tests, two extinguishing nozzles were installed in the upper part of the test setup in the interspace between the module and the mounting plate. To catch the quench water running off over the mounting plate a 1.75 × 1.50 m² steel tray was placed on the floor of the test building.

To apply the flame to module areas of similar size, for the c-Si modules the tests were performed on one module along the longitudinal direction (length: 1,655 mm), for the CIS modules on two modules along the transverse direction (total length: 1,960 mm) and for the CdTe modules on three modules along the transverse direction (total length: 1,840 mm incl. installation distance).

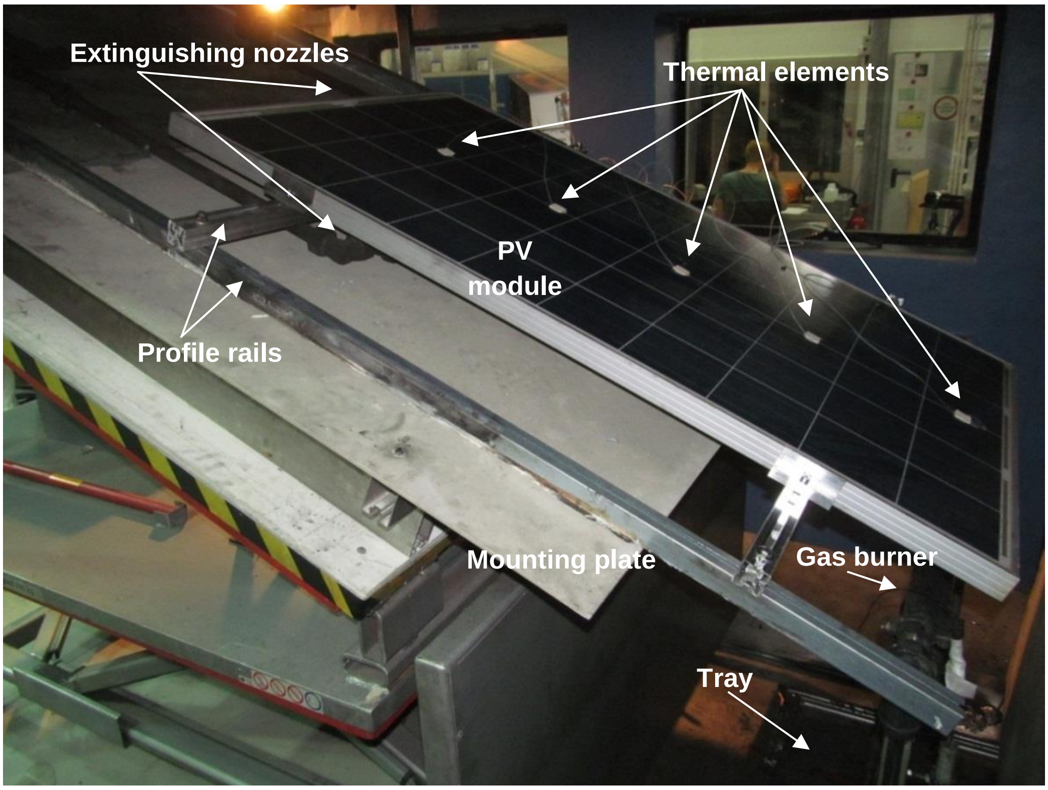


Figure 4-34: Test setup (shown here with a c-Si module)

Figure 4-35: Gas burner

4.6.6.2 Performance of test

On each module type, tests were performed with a burner output of 25 kW and 150 kW, in order to analyze the fire behavior and pollutant release of the modules at different thermal stress intensities (Figure 4-36). In addition, a further test was performed on each module type with a burner output of 150 kW, such that after six to seven minutes the fire was extinguished in each case with 20 l of quench water over a period of 45 s.

The tests were performed underneath an exhaust hood as per ISO 9705, with an exhaust flow rate of about 1 m^3/s. The following variables were measured:

- Heat release rate
- Smoke production rate
- Temperatures on front and back of the module
- Mass loss of the modules and mass of the fire residue
- Destroyed module surface
- Formation rates of the gas compounds carbon dioxide (CO_2), carbon monoxide (CO), hydrogen cyanide (HCN), hydrogen chloride (HCl), hydrogen bromide (HBr), hydrogen fluoride (HF), nitrogen monoxide (NO), nitrogen dioxide (NO_2) and sulfur dioxide (SO_2)
- Amounts of arsenic, lead, cadmium and selenium contained in the smoke gases
- Amounts of arsenic, lead, cadmium and selenium contained in the fire residue
- Amounts of arsenic, lead, cadmium and selenium contained in the quench water

In addition, two reference tests were performed with (non-combustible) calcium silicate plates instead of the modules in order to determine which smoke, CO_2 and CO formation rates the gas burner caused under the planned operating conditions. These measurement values were deducted from the actual measurement results, so that listed test results exclusively referred to the PV module emissions.

Smoke gas analysis

For determining the arsenic, lead, cadmium and selenium content, a partial stream from the waste air flow was conducted through a filter system and through a sorbent. The analysis was performed with ICP-MS. The measurement results listed in section 4 correspond to the sum of the particle-bound and to the filterable parts.

The gas compounds (except formaldehyde) were analyzed continually over time with an FTIR spectrometer connected to the exhaust tube of the extraction system. Section 4 lists the concentrations averaged over the duration of the test.

For determining the formaldehyde content, an absorption cartridge was used, with the analysis being performed with HPLC.

Fire residue analysis

The fire residue consisted of damaged, fallen-off parts of modules that accumulated during the test on the mounting plate of the test frame and in the tray placed underneath. The fire residue was first swept together and thoroughly mixed. Two samples were taken and pulverized with a granulator. The arsenic, lead, cadmium and selenium levels were determined with ICP-MS.

Quench water analysis

After mixing the quench water collected in the tray, two samples were taken and analyzed as to the arsenic, lead, cadmium and selenium levels by means of ICP-MS.

Figure 4-36: Fire test with a burner output of 25 kW (top) and 150 kW (bottom)

4.6.6.3 Test results

Appendix IX contains the full test results. Here we show selected results. Altogether 9 tests were performed, as listed in the following table:

Table 4-26: Test designation

	25 kW burner output	150 kW burner output	150 kW burner output, quench water test
Module type c-Si	1A	1B	1C
Module type CIS	2A	2B	2C
Module type CdTe	3A	3B	3C

<u>Fire behavior</u>

In the 25 kW burner output experiments, only locally limited damage occurred on all three module types. With 150 kW burner output, the modules were largely destroyed, as illustrated in the following photos.

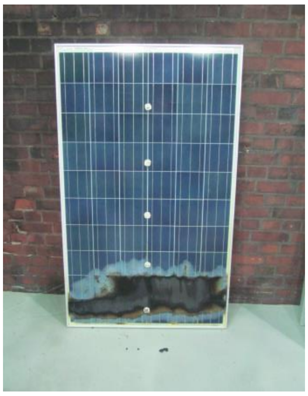



Figure 4-37: Degree of damage with c-Si and 25 kW burner output (top) and 150 kW (bottom)

Table 4-27: Comparison of selected results from the 9 fire tests

Mass loss in %	25 kW burner output	150 kW burner output	150 kW burner output, quench water test
Module type c-Si	2.3	72.5	47.8
Module type CIS	7.9	85.2	18.7
Module type CdTe	0.1	32.6	31.5

Smoke production in m² *	25 kW burner output	150 kW burner output	150 kW burner output, quench water test
Module type c-Si	41	182	73
Module type CIS	92	358	274
Module type CdTe	5	133	86

* *Smoke production in m² means the extrapolation of all produced smoke particles onto a 2-dimensional plane*

Heat release in kJ	25 kW burner output	150 kW burner output	150 kW burner output, quench water test
Module type c-Si	7,631	59,197	27,747
Module type CIS	9,699	84,712	17,506
Module type CdTe	785	15,809	9,786

The comparison shows large differences among all 3 parameters: mass loss, (total) smoke production and (total) heat release, depending on the design. Owing to the lack of a backsheet, the glass-glass module (CdTe) exhibits significantly better properties of fire behavior compared with the two other modules.

In comparing the two glass-film modules, it must be kept in mind that the CIS made a greater mass available, the incinerated mass was also greater and that consequently the thermal output was also greater.

If we relate the smoke production to the incinerated mass in each case, the difference becomes less. Altogether, the fire behavior of the CIS module type again presented a less favorable case compared with the c-Si module type (see

Table 4-28).

Table 4-28: Total smoke production in m² * standardized to 1g incinerated mass

Smoke production in m²/incinerated mass	25 kW burner output	150 kW burner output
Module type c-Si	0.13	0.11
Module type CIS	0.28	0.13

* Smoke production in m² means the extrapolation of all produced smoke particles onto a 2-dimensional plane

Chemical analyses

The following tables list the measured values for each substance referring to a specific unit. The gas analysis refers to one standard cubic meter of smoke gas, while the residue analysis refers to one kilogram of fire residue and the quemch water analysis refers to one liter of extinguishing water

Also specified are the total released quantities yielded by multiplying the measured concentration and the total volume of the smoke gas, the total mass of the fire residue or the total volume of the quench water used.

Smoke gas analysis

The concentrations as per DIN EN 45545-2:2013 were measured and averaged over the test period: Test A / B: 20 min, test C: 10 min (quenching after approx. 7 min)

Table 4-29: Average smoke gas concentrations from c-Si module

	Test 1A	Test 1B	Test 1C
Arsenic (µg/m³)	1.1	0.8	0.1
Lead (µg/m³)	50	630	1,010
Cadmium (µg/m³)	6.5	60	77
Selenium (µg/m³)	24	10	9.8
Carbon dioxide (mg/m³)	842	3,786	3,068
Carbon monoxide (mg/m³)	6	30	30
Hydrogen cyanide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen chloride (mg/m³)	n.d.	n.d.	n.d.
Hydrogen bromide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen fluoride (mg/m³)	n.d.	n.d.	n.d.

Nitrogen monoxide (mg/m³)	n.d.	n.d.	n.d.
Nitrogen dioxide (mg/m³)	n.d.	n.d.	n.d.
Sulfur dioxide (mg/m³)	n.d.	n.d.	n.d.
Formaldehyde (mg/m³)	1.0	0.9	1.8

Table 4-30: Average smoke gas concentrations from CIS module

	Test 2A	Test 2B	Test 2C
Arsenic (µg/m³)	1.5	1.6	1.0
Lead (µg/m³)	250	270	480
Cadmium (µg/m³)	12	14	34
Selenium (µg/m³)	4.8	40	8.0
Carbon dioxide (mg/m³)	615	5,817	2,751
Carbon monoxide (mg/m³)	11	237	382
Hydrogen cyanide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen chloride (mg/m³)	n.d.	n.d.	n.d.
Hydrogen bromide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen fluoride (mg/m³)	n.d.	n.d.	n.d.
Nitrogen monoxide (mg/m³)	n.d.	n.d.	n.d.
Nitrogen dioxide (mg/m³)	n.d.	n.d.	n.d.
Sulfur dioxide (mg/m³)	n.d.	n.d.	n.d.
Formaldehyde (mg/m³)	1.2	2.1	4.9

Table 4-31: Average smoke gas concentrations from Cd-Te module

	Test 3A	Test 3B	Test 3C
Arsenic (µg/m³)	0.3	0.2	0.2
Lead (µg/m³)	34	120	1,330
Cadmium (µg/m³)	9.9	37	48
Selenium (µg/m³)	4.2	4.7	2.2
Carbon dioxide (mg/m³)	42	1,453	1,495

Carbon monoxide (mg/m³)	1	63	90
Hydrogen cyanide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen chloride (mg/m³)	n.d.	n.d.	n.d.
Hydrogen bromide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen fluoride (mg/m³)	n.d.	n.d.	n.d.
Nitrogen monoxide (mg/m³)	n.d.	n.d.	n.d.
Nitrogen dioxide (mg/m³)	n.d.	n.d.	n.d.
Sulfur dioxide (mg/m³)	n.d.	n.d.	n.d.
Formaldehyde (mg/m³)	0.4	1.6	2.6

n.d. = not detectable

Comparison with toxicological thresholds

CO, CO_2:

The measured values show significant exceeding of the threshold > a factor of 10.

Hydrogen halides and nitrogen oxides:

The measured concentrations lie below the detection limit (and also below the toxicological thresholds)

Heavy metals:

The measured values lie well below the thresholds:

Pb < 0.1% GW (PAC =120 mg/m³ 60 min)
Cd < 10% GW (AEGL-2 30 min = 0.96 mg/m³)
Se < 20% GW (PAC=0.2 mg/m³)
As < 1% GW (PAC=0.58 mg/m³)

Assessment of the results

A direct comparison of the measured values with the toxicological thresholds is not possible because of the differences in exposure time. The boundary conditions vary with each fire, i.e. each fire is unique! The thresholds are used merely to estimate the order of magnitude of a possible hazard to people.

The present ventilated test arrangement ($1 m^3/s$) dilutes the pollutant concentration in the waste air to an extent not quantifiable with precision. A rough estimate of the worst case in the event of pure convection would yield approximately 10 times the concentration of the measured pollutants in the immediate vicinity (approx. 2-5 m above the fire source). This means that in the extreme case the toxicological thresholds would be approached with either cadmium or selenium given an exposure of 30 or 60 minutes.

Conclusion

Measurements of the smoke gas concentration for the components CO and CO_2 found the thresholds to be significantly exceeded. Hydrogen halides and nitrogen oxides were not present in measurable concentrations.

For the heavy metals cadmium and selenium, toxicological thresholds can be exceeded in the worst case in the immediate vicinity to the site of emission. The general public is at no risk from hazardous concentrations in the smoke gases.

Residue analysis

This section focuses on those soil pollutants that can be especially relevant to human health. They include on the one hand widespread pollution levels with risks to agriculture and groundwater and on the other hand soil impairments that can especially lead to hazards in residential areas. Of particular interest here are sensitive areas of use such as children's playgrounds and home and small gardens, Annex 2 of the Federal Soil Protection and Contaminated Sites Ordinance [64] updated in 2012 specifies test values for the direct absorption of pollutants into the soil. These test values are defined for four different categories: play areas, residential areas, parks and industrial zones. For estimating the risk of soil contamination from the toxic residue measured in lab tests, in particular lead, cadmium and arsenic, the test values from the residential area category were used.

As expected, preparation of the module residue for analysis proved to be very time-consuming, also owing to the information from other studies. Given the nonhomogeneous module remnants (Figure 4-38), the tests yield no generally applicable information, however the fire residue analysis detected lead, cadmium, arsenic and selenium in all investigated test samples of the c-Si, CIS and CdTe technologies.

Figure 4-38: Fire residue from 2 CIGS modules: Al frame, fused glass, baked plastic residue, soot and ash

The identified quantities of harmful substances vary greatly among the examined test samples of the three technologies. The following graphs show the measured values and corresponding test values as per the Federal Soil Protection and Contaminated Sites Ordinance for lead and cadmium.

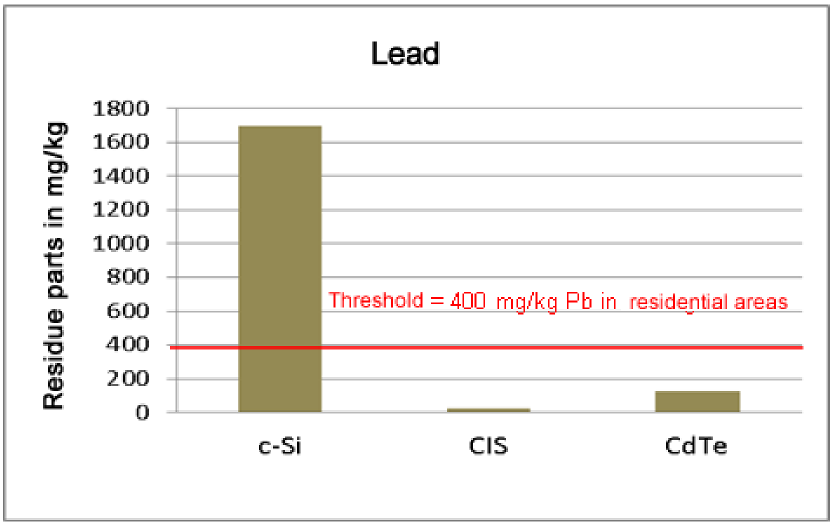


Figure 4-39: Average lead level in fire residue

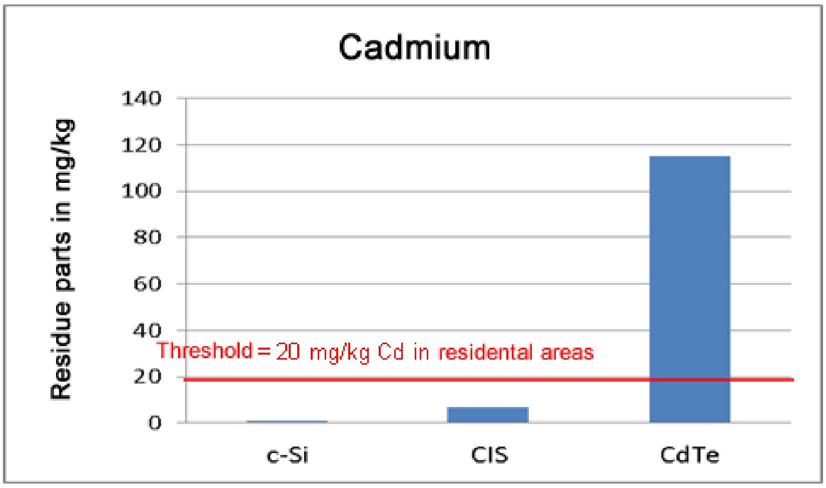


Figure 4-40: Average cadmium level in fire residue

Figure 4-39 shows that the fire residue from the crystalline module on the average exceeded the test value for lead as per the Soil Protection Ordinance by a factor of 4, while the thin-film modules exhibited non-critical levels.

On the other hand, Figure 4-40 shows that cadmium exceeded the test value by a factor of 5 in the case of the CdTe module. If the area under consideration is being used as a home garden or children's playground, the permissible test value as per the Soil Protection Ordinance decreases to 2 mg/kg, *so that particular attention must be given to the cadmium level in the soil.* In this case, the measured residue concentration from the CIS module also falls in the critical range. For the crystalline module, measurements did not show the test value to be exceeded.

For arsenic, measurements detected no critical levels.

Conclusion

Depending on the technology, the fire residue from PV modules can contain concentrations of lead or cadmium that can create critical levels of contamination in the soil.

Professional disposal of fire residue and, if necessary, soil replacement are therefore urgently recommended.

Quench water analysis

The large volume of quench water can allow detached harmful substances or suspended particles to move from the fire residue into the surroundings and the soil as well. The possible wetting of objects like parts of buildings, balconies and terraces, as well as firefighters' clothing, with contaminated quench water must be noted and kept in mind when further use is contemplated.

Investigations found no pollutant limit levels for water-based soil contamination. The risk assessment employed the Sewage Sludge Ordinance for Agriculture for the contamination of industrial sludge with heavy metals and other harmful substances [65]. The maximum permissible concentrations are given per unit of ground area (mg/m²), while the concentrations of harmful substances in the quench water are measured per unit volume (mg/m³). While a direct comparison is therefore not possible, a rough estimate could be made.

Figure 4-41 lists the measured concentrations of lead and cadmium for the individual module technologies.

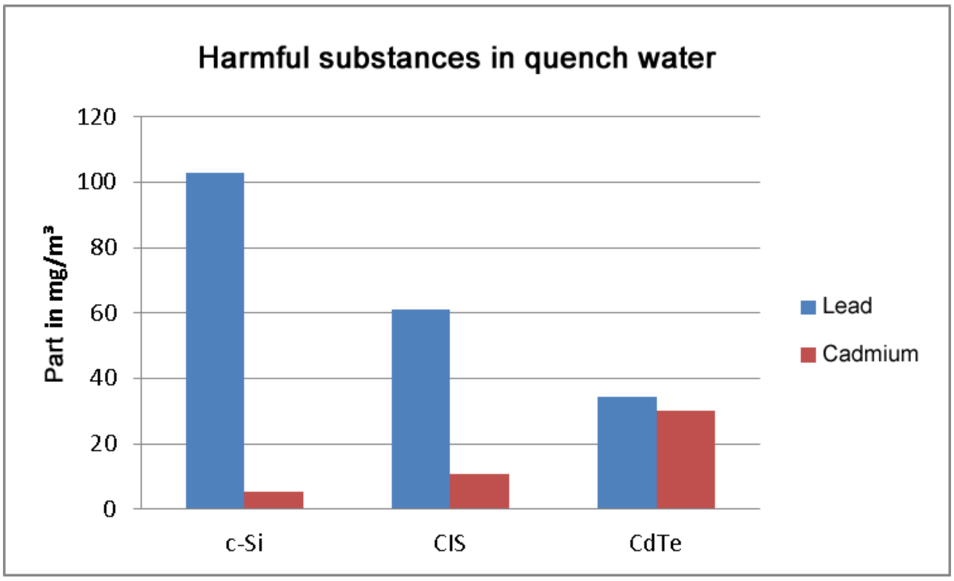


Figure 4-41: Measured concentrations of lead and cadmium in quench water

Assessment of the measurement results:

The threshold for lead is exceeded only with a 1 m³ of quench water over an area of soil less than 1 dm² (c-Si).

The threshold for cadmium is exceeded only with 1 m³ of quench water over an area of soil less than 2 m² (CdTe).

While the precondition for lead evidently should not be attained, under unfavorable conditions (e.g. runoff of the quench water over an edge) the precondition for cadmium is theoretically possible.

Conclusion

In a CdTe module fire, critical cadmium levels can enter the soil via the quench water under worst-case conditions

We therefore recommend soil sampling and analysis.

4.6.7 Summary

- PV module fires release additional contaminants into the environment in relevant quantities, depending on the cell technology and to a particular extent also on the polymers used.
- The contaminant emissions from PV modules must be rated as an additive contribution, since each roof timber fire or house fire involves a large fire load with toxic substances.
- Large-scale lab studies under ventilated conditions show no exceeding of limits in the smoke gas for investigated heavy metals and hydrogen halides (the worst case was estimated). A precise consideration of thresholds is not possible because of the uniqueness of each fire event.
- As expected, toxic heavy metals, in particular lead (c-Si) and cadmium (CdTe), were measured in fire residue in quantities potentially exceeding the thresholds among the test samples. The inhomogeneity of the residue allows no generalizations to be made.
- The measured cadmium concentration in the quench water indicates possibly critical soil contamination from CdTe modules.

5 Optimization measures for product and system safety

5.1 Fire prevention

Following the introduction in the preceding sections to determining the risks and hazard potential from electric arcs in reference to fire emergence and firefighting, we now turn to generally applicable and specific measures for reducing risks.

Of main concern are the definitions and aims of preventive fire protection that can be derived above all from the requirements in the Model Building Regulation (MBO) or the State Building Codes (German: LBO). In this regard, the clear and succinct formulation in § 14 of the MBO applies:

Structural installations shall be arranged, erected, modified and maintained so as to prevent the emergence of a fire and the spread of fire and smoke and to enable in the event of a fire the rescue of human beings and animals as well as effective fire extinguishing operations.

In sum: solar systems must comply with this standard in full!

The Model Building Regulation (MBO) is the mandatory guideline for the construction industry. Since building law is state (*Länder*) law in Germany, the 16 LBOs of the respective German states (*Länder*) apply analogously with their requirements and definitions. The preventive fire protection must be understood as the sum of all measures preventing emergence and spread of fire.

§ 61 of the MBO, article 2, sentence b) states:

Solar energy systems and solar collectors in and on roofs and on outer wall surfaces as well as those independent of buildings with a height of up to 3 m and a total length of up to 9 m are construction projects not requiring authorization.

According to the MBO, solar systems belong to technical building equipment. “Not subject to authorization” does not mean that the MBO or LBOs do not apply. On the contrary, building law (fire protection, distance spaces, regulations governing the protection of historical buildings and monuments) and regulations on building products and types of construction, statics and stability and traffic safety must be complied with. As a consequence, the sum of all measures for preventive fire protection comprises many requirements pertaining to the installation, material selection and operation of the system in general as well as specific requirements;

- Compliance with building and installation regulations, building codes of the German states
- Advising of the technical authorities on construction and on requirements relevant to fire protection
- Careful planning with technicians
- High-quality material and components
- Proper execution and inspection
- Maintenance of the systems

The following sections will address the aforementioned general points in more detail. As an example, we single out building over fire walls. Fire walls in buildings prevent the spread of fires and prevent an increase in the fire propagation potential of burning material in an attic, for example. It is therefore impermissible that solar systems bridge fire compartments and firewalls, since potentially combustible materials, such as polymer backsheets and cables, can promote fire propagation.

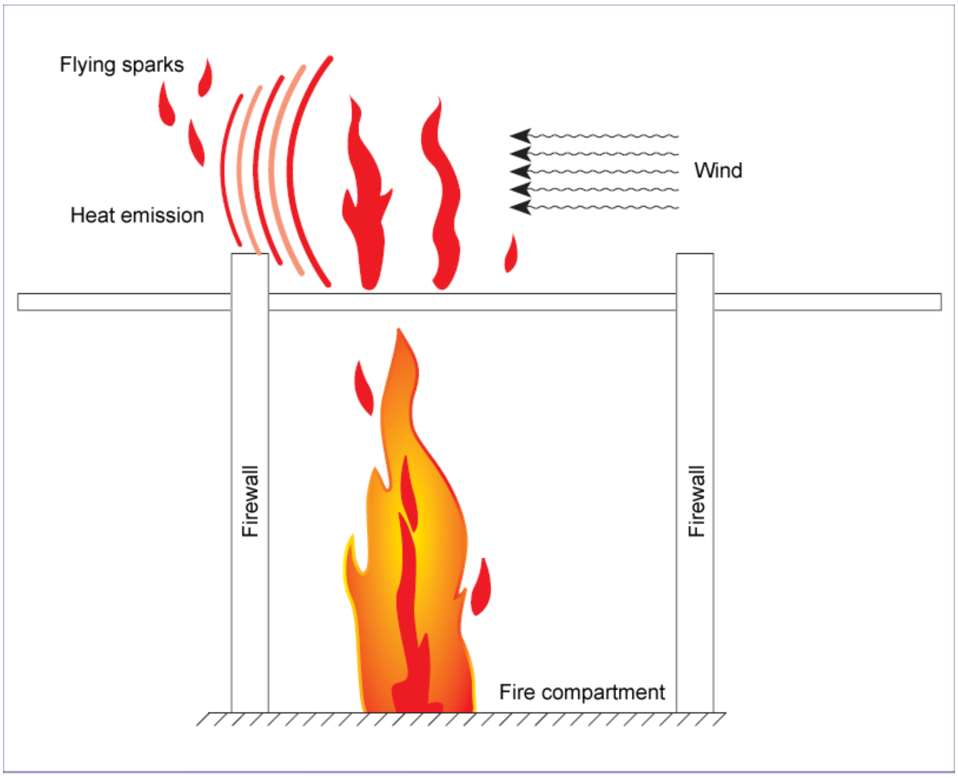


Figure 5-1: Functioning of a firewall, source: BSW

Special constructions as can be found among high-rise buildings (hotels, etc.) as per MBO § 2 also require further specifications. PV installations on facades must satisfy at least the requirement of *low flammability*, whereas for roofs *normal flammability* along with hard roofing (resistance to flying sparks and radiant heat) generally suffices.

In the matter of preventive fire protection, the building codes are supplemented by special building codes (regulation on places of public assembly, such as stadiums, regulation on places of accommodation, such as hotels, regulation on places of sale, such as shopping centers).

It must be ensured with the utmost care that no additional fire risks arise from PV installations or that such risks are reduced to a minimum. Improper installation and use of defective products as well as insufficient maintenance of PV systems can increase these risks.

In the following, this Guideline specifies in further detail the overview of existing rules and other measures for preventive fire protection and risk minimization in production and operational safety.

Conclusion

§ 14 of the MBO:

Structural installations shall be arranged, erected, modified and maintained so as to prevent the emergence of a fire and the spread of fire and smoke and to enable in the event of a fire the rescue of human beings and animals as well as effective fire extinguishing operations.

5.2 Quality assurance measures in production and their impact on risk assessment

5.2.1 Manufacturing process

Many errors and defects in the type of construction that can contribute to an increased fire risk can be avoided through improved quality control in production. To this end, TÜV Rheinland conducts regular company inspections (at least once a year) among the manufacturers, the purpose of which is to indicate any insufficient quality controls or inadequate quality assurance measures. According to a mandatory table defined for TÜV Rheinland inspectors worldwide, such defects and deficiencies fall either under the category of *recommendations* or under the category of *deviations*, with a *deviation* requiring rectification by the module manufacturer.

Manufacturers of crystalline silicon modules have undertaken a series of neuralgic production steps regarding any subsequent electric arc or fire risk. They include first of all *stringing*, in which the solar cells are generally interconnected to form a string in a soldering process. Nowadays this process is almost always fully automatic with so-called “stringers.” If important parameters like the soldering temperature and soldering time (depending on the employed cell) are not cleanly set or not exactly measured, soldering errors can occur that can lead to increased transition resistance and thereby to an increased electric arc risk.

TÜV Rheinland accordingly requires that manufacturers conduct regular (ideally inline) checks of the soldering temperature as well as regular calibrations of the sensors and measuring equipment. Proof of a regular *pull test* for the quality control of the connections at the contacts must also be provided.

Analogous problems can arise in the subsequent and in most cases manually performed connecting of the strings (*interconnection*). Here too the soldering temperature must be measured in any case and the employed measuring device calibrated.

As one of the final process steps, when the junction box is connected at the contacts the positive and negative terminals are generally fixed in place in the junction box mounted on the module. This is done either mechanically, e.g. with a clip fastener, or with a further soldering process for which the same quality requirements as mentioned above apply.

The production of thin-film modules involves the interconnection of monolithically manufactured cells generally with a longitudinal and a transverse contact strip. As with the crystalline silicon modules, the contact strips must be of the correct size. The strips are fixed in place through (e.g.) ultrasound welding or by soldering. Here too process monitoring must ensure that no disruptions in the current flow occur.

The junction box connection and the quality assurance requirements are the same as those in crystalline silicon module production.

Besides the inline tests, there are a series of useful offline tests for verifying the electrical and fire safety of the modules. They include the hot-spot test, which simulates the shading of individual cells, and the reverse-current test, which sends a current through the module in the reverse direction. In both cases critical heating levels can occur. TÜV Rheinland therefore recommends performing such tests with ready-produced modules.

It is also useful to perform incoming inspection tests on individual components of the module design, such as diodes and junction boxes, provided by other manufacturers. Diodes should undergo functional spot checks, since the failure of a diode may not be noticeable during regular operation in the field, depending on the nature of the failure.

In addition to their functionality, junction boxes can be inspected for good electrical insulation and as to whether they do not significantly increase the total series resistance. The adhesive bond of the junction box to the back of the module (often employing special glue supplied with the box) should be tested as to its adhesive properties through (e.g.) simple mechanical tensile tests. It is also recommended to check the firm seating of the box lid.

If the module design contains crimp connections, the transition resistance should be systematically measured and checked.

Another instructive aid is electroluminescence (recommended in offline mode, but should also be performed 100% inline) as well as infrared imaging (e.g. of modules in test operation), in order to detect defective or critical contact at an early stage. Electroluminescence imaging is especially useful *prior* to lamination, since cell fractures, micro-cracks, defective connections, etc., can then be detected in due time before the laminate runs through the further time-consuming and costly production stages. The imaging can also be performed for the final product, directly before delivery, however.

Mobile equipment can also detect possible electrostatic discharges at module components during individual production stages. For example, during the production process TÜV Rheinland can measure the static field charge on the backs of the modules that arises from transport of the modules from (e.g.) the box to the frame assembly. Should no suitable grounding measure (for discharging) be taken, the risk will then be that bypass diodes become damaged from a sudden static discharge on connection and are delivered to the field in defective form. While the issue of electro static discharge (ESD) must not be underestimated, it can already be avoided during production.

Generally, the introduction of new materials, as well as new suppliers of materials and components of modules, should be carefully inspected and undergo appropriate quality tests during production, since new materials often present a safety risk for the final module.

Complete traceability for the entire production process is also crucial (ideally on an *electronic* data basis), in order to connect any faults that become apparent only in the field to the corresponding conditions during the production of the defective modules. This traceability should comprise the employed materials and their suppliers as well as all process machinery, process parameters and quality tests undertaken for the corresponding batch of modules.

To ensure a constant level for all aforementioned quality tests and to minimize subjective influences in performance of the test, it is crucial that regular employee training units and sessions be conducted, documented and the acquired qualification levels summarized in (e.g.) a competence matrix. Work instructions should always be kept up to date and made locally available during the particular process steps.

Further qualification procedures are also useful, such as inline measuring procedures for checking the soldering quality between the cells (see section 5.2.3) as well as expanded requirement criteria for qualifying inflammable materials of modules and components; see example in section 3.3.

Conclusion

Trust is good, but testing is better!

A variety of options are available for internal quality control. Not to be forgotten is increased attention to supplied parts during production (such as junction boxes). For the standardization we recommend defining intensified quality assurance measures in production, on both the component and module levels. Many manufacturers already operate on a high level. A standardized quality assurance catalog makes a uniform measure of quality possible and allows the avoidance of risks through continual internal monitoring of the products.

5.2.2 Design modifications (module and system)

In the past, the further development of technologies for cell-cell connections generally led to the use of two busbars or cell connectors. An established standard today is rather three busbars (see section 3.4.1), or even wholly different types of connections, involving more than three busbars. The fact that cell connectors can detach from the cells or the connections or break up themselves as the result of thermo-mechanical load changes, production-related or purely mechanical effects, affects the probability of electric arc creation, given the number of available cell connectors. With at least three cell connectors, the risk of electric arc creation as well as the premature reduction of power loss, related to increased transition resistance in the cell design, is already reduced. The current can then flow off via the other undamaged cell connectors.

For the special case of building-integrated photovoltaics (BIPV), electric arc safety plays an even greater role. Because of the replacement of top roofing layers by PV modules, the lower layers are freely exposed and especially endangered by an electric arc event at the back of the modules. Useful recommendations for the module design in BIPV applications can be derived from the consideration of the materials which, in the event of an ignition, have fire-propagating properties given the vicinity of an electric arc. In evaluating these materials the manufacturer or distributor must explore the possibilities of the following material/component specifications:

- Selection of the junction box: There exist non-combustible junction boxes that in the event of an electric arc in the junction box at least delay, if not prevent, fire propagation into the roof interior. Manufacturers must endeavor to conduct the appropriate tests and to discuss this form of risk minimization.

- Determination of backsheets with low FSI: Safety standard IEC61730 with the ASTM 162 standard requires that the Flame Spread Index (FSI) be determined for backsheets. The specification is that backsheet be max. 100. The FSI is influenced by the exhaust temperature during a fire and the propagation speed at the sample. Tests have shown that an FSI <10 is realizable. This entails relatively severe restrictions in the spread of a fire through the individual backsheet.

We can therefore recommend that sheets with these properties (FSI < 10) should be used with BIPVs.

Glass as backing substrate: For BIPVs the option of purely glass-glass modules allows dispensing with polymer materials as rear wall insulators. Here too such a material setup can minimize the risk of arcing. Certain encapsulation materials like EVA and PVB are used in the PV industry at a rate over 90%.

Individually (not in combination), the materials are highly flammable, but can also accelerate a heat release in the final module construction.

It therefore makes sense possibly to work with fire-inhibiting materials like silicone as encapsulating materials here too in the case of building-integrated PVs.

Conclusion

Given the varied areas of application of PV modules and the various requirements (e.g. BIPVs), the selection of suitable components must aim at increasing electric arc safety.

Risks can thus be reduced if the module design is adapted to the risk situations.

Similar discussions are also being conducted regarding the use of PV modules in various climates.

5.2.3 Safety qualification of modules and components

To ensure long-term reliability of the modules and components with an eye to reducing the risk of or avoiding electric arcs, different testing and control mechanisms have been developed that can be used for the components as well as for the module production process. Individual procedures are based on normative foundations and have been adjusted or supplemented.

Stricter conditions compared with current normative requirements are in part necessary in order to readjust damage patterns observed in the field.

Long-term resistance of cell connectors

TÜV Rheinland conducted comprehensive tests on partially defective PV modules (hotspots at cell connectors, micro-cracks) from the field. Here the PV modules were variously aged. The established temperature and moisture cycles were employed as tests from the IEC qualification (Thermal Cycling and Damp Heat). The PV modules were then mechanically and dynamically stressed with current feed (forward bias at 1,2…2 Isc). This stress especially affected the cell connectors and led to sharp local temperature increases.

Significant temperature differences compared with the surrounding materials and connecting appeared especially where increased transition resistance already existed.

Figure 5-2 shows an example of a module that after approx. 2,000 dynamic load cycles (as per EN 12211/12210) produced a fire burst as the result of a short electric arc in the pressure cycle at a cell connection point. While the connection technology of these modules (here: cell connectors soldered between the cells) are not the state of the art of secure connection options, here it was possible to produce an electric arc without artificially and mechanically damage to the cell connectors.

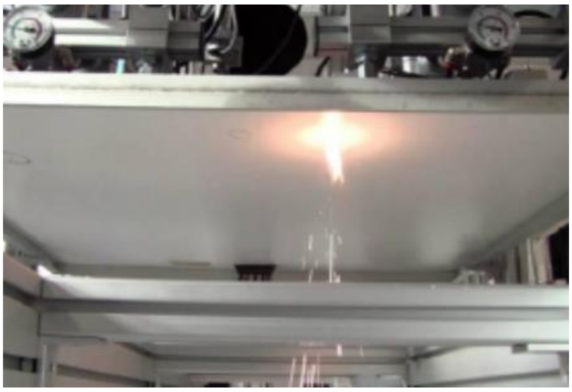


Figure 5-2: Electric arc within a PV module

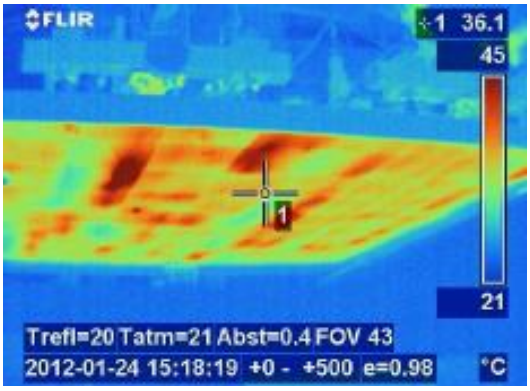


Figure 5-3: IR image

In the module shown the electric arc ignited at the moment of maximum pressure during the cycle. The entire current then flowed through the second busbar of the affected string. Here the remaining cell connector broke open in the next pressure cycle. Shortly thereafter the diodes were destroyed by the brief high voltage. The entire module current was conducted through the bypass diode. The diode was conductive, and a voltage could no longer be built up. In all tests, the modules underwent EL imaging and their IV characteristics were determined before and after the measurements, and during the stress tests the modules were observed through IR imaging.

In order to show the current flow distribution in a cell through EL imaging, an unstressed module from another manufacturer was prepared so that cell connectors were separated in a meandering pattern. The result was a zig-zagged course that the current had to follow. This induced a particular stress of the remaining intact cell connectors. After a brief mechanical stress period, no electric arcs occurred at the stressed cell connectors, contrary to expectations. The current flowed through the cell at the transition of a micro-crack lying exactly between the cell connectors. Here individual light flashes and scorching occurred along the crack; see Figure 5-4:

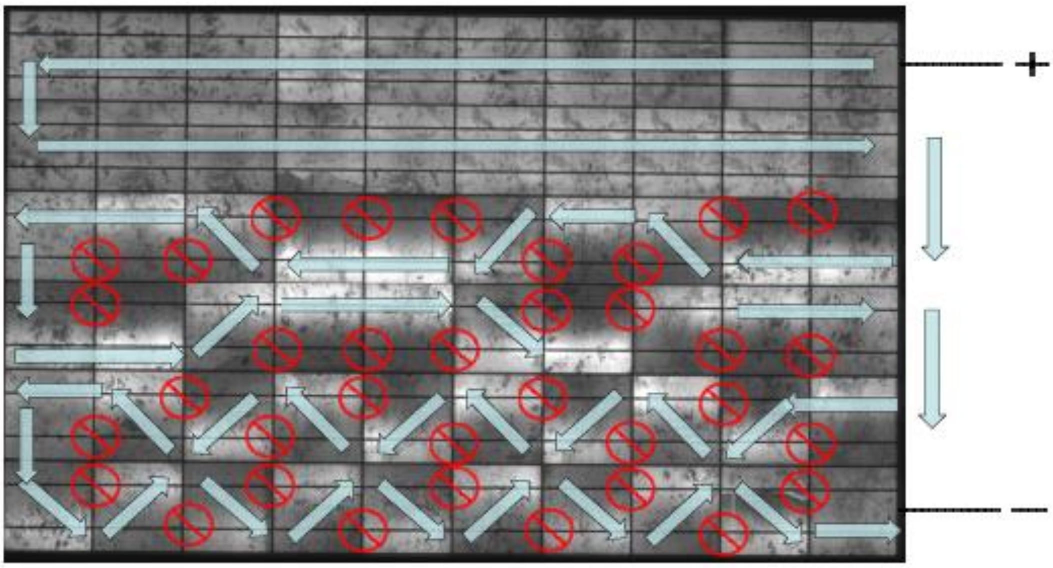


Figure 5-4: Prepared PV module with meandering transectioning of the conductor ribbons

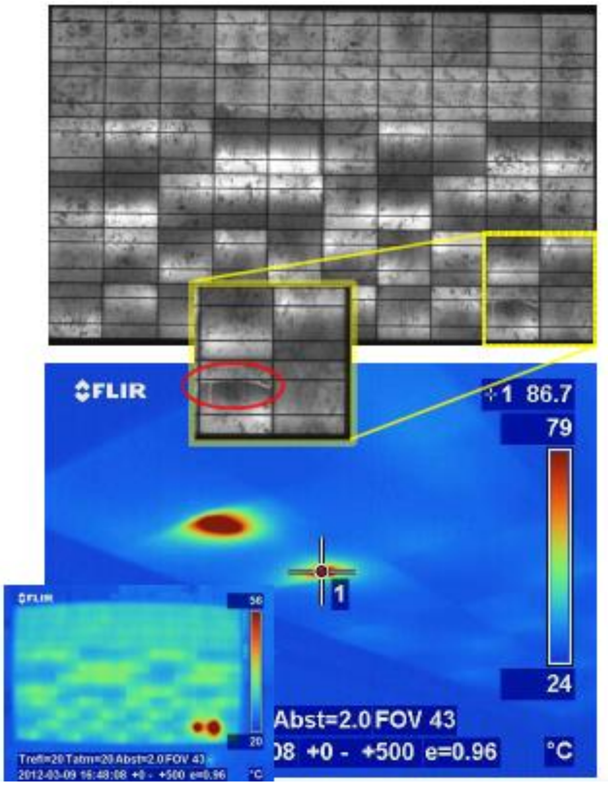


Figure 5-5: EL image with enlarged cell crack
Bottom: IR image with hotspots at the cell transitions

Figure 5-6: Marks along the cell fracture as the result of scorching and light flashes

Further tests were performed in which local scorching was induced on the backsheet of a further module and considerable temperature elevations were found at different modules. No further electric arcs occurred within 2,000 load cycles. An interesting finding in the dynamic load cycle was that temperature differences in the module of ± 10K can occur within approx. 15 s between the pressure load zero phase and the tensile load.

The following figure shows a test sequence that can indicate the reliability of contact connections. This sequence is one variant among other conceivable scenarios for subjecting modules to a particular stress through dynamic flexing. The conductor ribbons and in particular the contact connections in the module are dynamically stressed through stretching and compressing. Their sturdiness is a measure of “electric arc safety.” The dynamic stress here is based in each case on the load cycle sequence of EN 12210/12211.

Initial measurement	• Electroluminescence • Visual inspection • IV characteristic • Insulation measurement
TC 400	• Forward bias 1.2 x Isc
Intermediate measurement	• Electroluminescence • Visual inspection • IV characteristic • Insulation measurement
Dynamic mechanical stress	• Load at 2.4 kPa • 10 seconds / cycle • Total: 1000 cycles • Forward bias 1.2 x Isc • Parallel IR imaging
No mechanical stress	• Forward bias 1.2 x Isc
Dynamic mechanical stress	• Load at 2.4 kPa • 10 seconds / cycle • Total: 1000 cycles • Forward bias 1.2 x Isc • Parallel IR imaging
Intermediate measurement	• Electroluminescence • Visual inspection • IV characteristic • Insulation measurement

Figure 5-7: Test sequence for PV modules for determining electric arc susceptibility at cell connections

Before and after each stress step the modules must be examined for local temperature elevations by means of electroluminescence imaging and infrared imaging. Despite the long stressing procedure, no loss of contact or impairments from increased series resistance may occur.

We recommend random sampling for the accompanying tests during production, with new installations or modifications of materials or processes in soldering, lamination or stringing, continually through the entire production period.

Recommendation for standardization

Introduction of a dynamic mechanical test method with simultaneous current feed to the modules. A corresponding method should serve determination of the stress capacity of the cell connectors

Qualification of the soldered connection through inline measuring procedures

In addition to the methods mentioned in 5.1 for quality assurance in production, possibilities must be explored for monitoring the soldering quality at the cell connectors inline, i.e. as an integral part of production. Potential electric arc emergence sites were thoroughly discussed with the aim of reducing the risk of arcing.

Given an installed system output of more than 30 GWp in Germany, we easily recognize that the connections at contacts deserve particular attention with additional quality assurance measures. Given a module output of 200 W, around 150 million modules are installed at present with altogether about 10 billion solar cells (@ 3 Wp) and over 50 billion soldering points.
For checking cell connectors, in the following we describe a procedure developed at the Fraunhofer ISE and already presented in 1997 in Bad Staffelstein. [66]

The quality of the connection between two neighboring solar cells can be assessed without contact by means of capacitively or inductively induced currents. Figure 5-8 shows the basic principle of the inductive measurement method, in which an alternating current is pressed into the module and the current flow into the two cell connectors is registered by a current sensor. If the current splits unequally, a contacting fault exists.

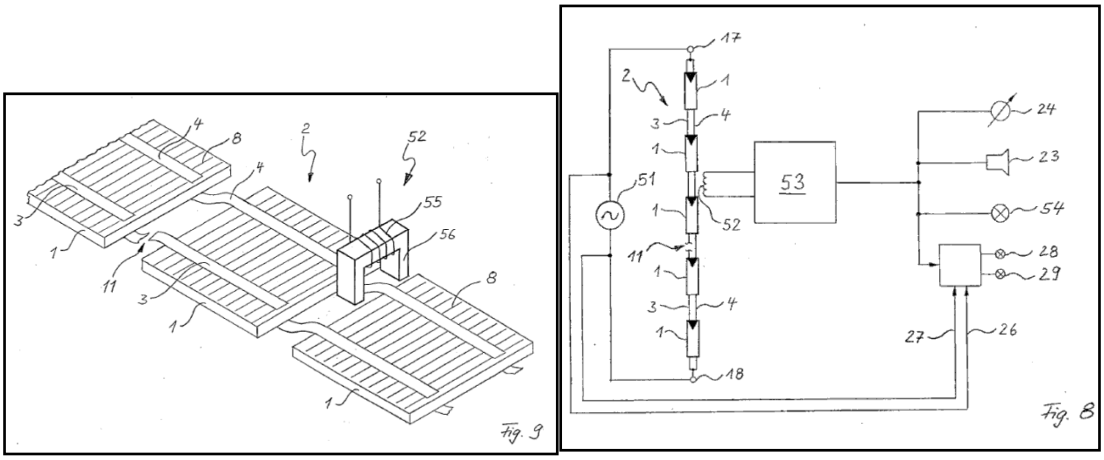


Figure 5-8: Schematic layout of the inductive measurement method for investigating connection faults between two cells.

A stress test (TC-1000 test as per IEC61215, -40°C – +85°C) indicated the suitability of the method for qualifying cell connections [28]. The increase in local transition resistance led to a reduction in performance (by approx. 50%). EL and IR imaging can reveal considerable impairment from the mechanical motions due to the temperature changes at the soldered points between or at the cells. In the EL image black cell zones represent inactive parts, while lighter areas indicate increased current density.

In practice, the module in an installation showed reduced performance, but the overall current flow was not interrupted. Nevertheless, temperature differences are discernible on the cell surfaces and cell transitions. Figure 5-9 shows that IR and EL images do not correlate 100% with one another. Consequently a detection method with higher resolution makes sense:

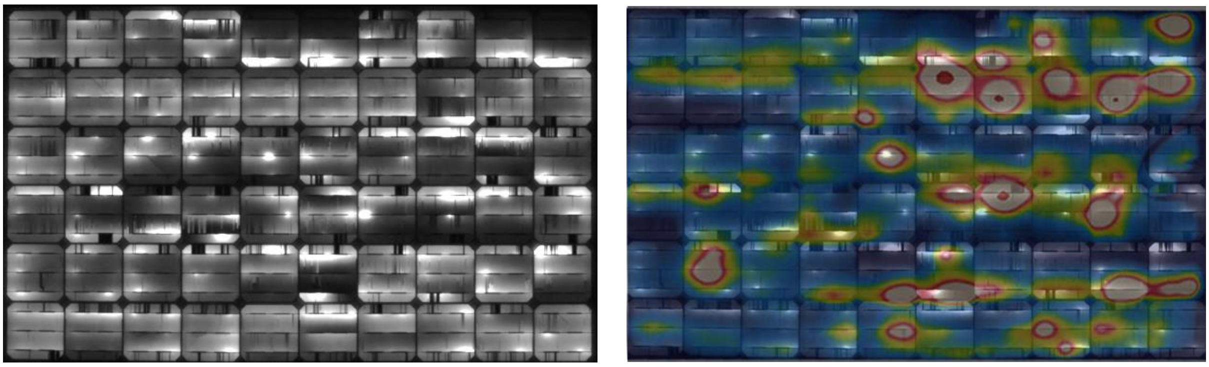


Figure 5-9: Comparison of EL and IR imaging at an aged module.

Here the cell impairment, especially at the cell transitions, is clearly discernible. A 100% correlation between IR and EL is not possible, however [28].

A series of tests employed an inductive method to measure the current carrying capacity of the cell connectors in the module shown above by coupling a high-frequency current per string via a function generator. At each of the cell transitions the busbars were measured with a sensor and their properties examined following the aging test.

The sensor basically consists of a coil with which voltages are inductively induced given the alternating field and in turn read out at an oscilloscope. Figure 5-10 shows the voltages induced in the inductive sensor by the string currents in the cell connectors (numbers designate relative sizes proportional to the string current). Here the differences in the current flows of the connectors are very clearly discernible.

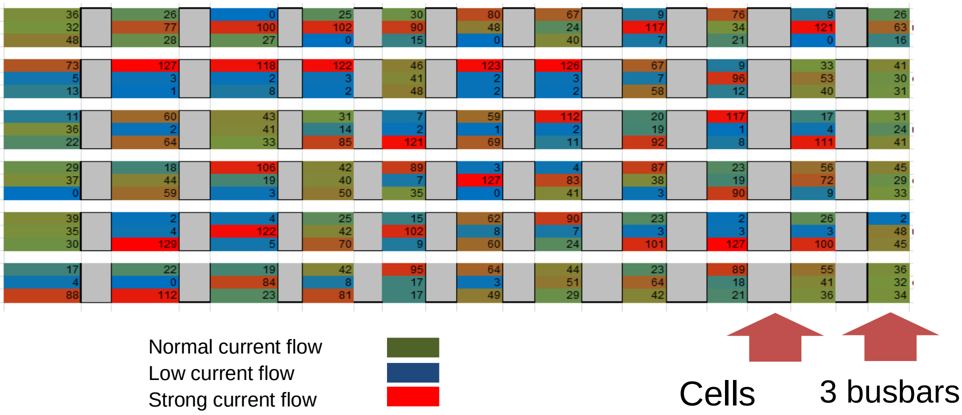


Figure 5-10: Voltage induced in the sensor by the string current in the cell connectors (relative magnitudes, proportional to the string current) **[28]**

These tests suggest using the same procedure to test and implement an inline method for module production.

Based on the inductive measurement method, parallel detecting sensors can thus be placed above a conveyor belt and during an intermediate step, for example before or after the lamination, they can be used to examine the conductivity and quality of the soldered connections as a function of position. Figure 5-11 shows this layout schematically:

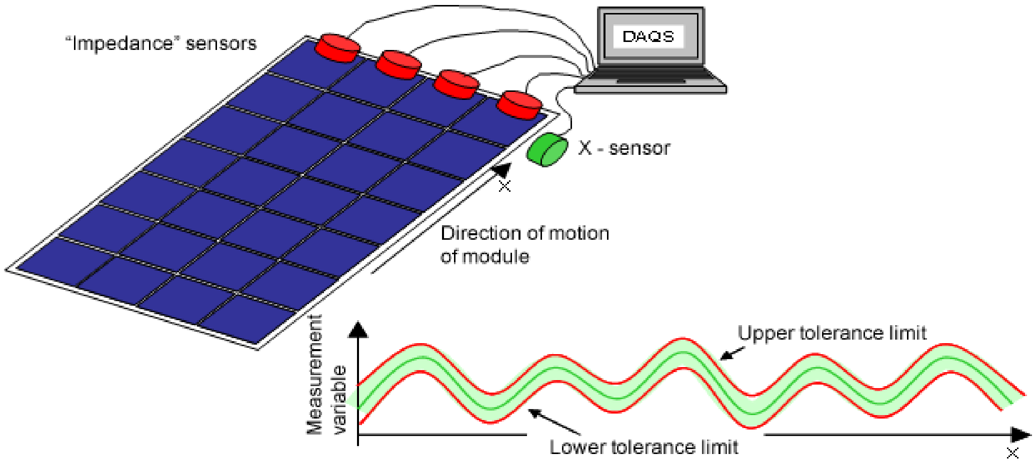


Figure 5-11: Inline method for detecting cell connection faults **[66]**]

Following the completed basic and successful tests, the following aspects are still open items and are recommended for further studies within a development project:

- Definition of permissible limits for deviations
- Correlation with other measurement procedures (EL, IR, etc.)
- Influence of lighting / current flow during the measurement
- Suitability for other cell/module technologies (e.g. back contact)
- Set up measurement stand with multiple sensors and measurement value recording
- Test combinations of different procedures
- Development of "intelligent" software (e.g. self-learning)
- Installation and testing of prototype system in a module production line
- Implementation in industrial product with industrial partner

Fire stress of components

With the application of solar modules in and on buildings, since 2012 solar modules have been declared by the DIBt as regulated building products with restrictions. These include roof-mounted, building-integrated and independent PV modules with an installation angle less than 75° and a mechanically held glass top of max. 2 m² [67]. If the modules are roof-integrated in a system, i.e. they replace the outer roof cladding, the distributor in Germany must hold a general building authority test certificate for sufficient resistance to flying sparks and radiant heat [67]. The state building codes require that building products be normally flammable if they are to be installed in buildings.

"Normally flammable" means meeting the requirements from EN 13501-1 with at least class E. This flammability classification describes a test method in which a matchstick-sized flame is applied to defined samples in order to examine the ignition.

Figure 5-12: Test method for flammability as per EN 13501-1

The usual fire classifications which the modules underwent come from the US UL 790 and describe a test method for roofs. The fire classes applied there are unfamiliar in Germany and should therefore be supplemented by appropriate categories that will provide the employed handicraft with a familiar assessment.

We therefore recommend specific labeling of the products according to the classification of the European EN 13501-1.

Since the PV modules usually do not meet the size requirements of the test method (ISO 11925-2) specified in EN 13501-1, an investigation at the overall product is not feasible. The module manufacturer can apply a corresponding declaration to the overall product if test records exist of the fire behavior both at the laminate and at other critical polymer materials. The ignition characteristics of the junction boxes, plug connectors and PV cables must be examined as per IEC 62790 (or EN 50548), IEC 62852 (or EN 50521) and prEN 50618 (or TÜV Rheinland 2PfG 1169) in a heating wire or gas flame test. Here it also assessed whether materials drip while burning or glowing.

Not considered to date are normative requirements and therefore component-oriented fire requirements for adhesive bonds. Internal as well as external lab tests must examine the bonded and adhesive joints between laminate and frame, but also with the junction box, and identify any deviations from the requirement from the European classification.

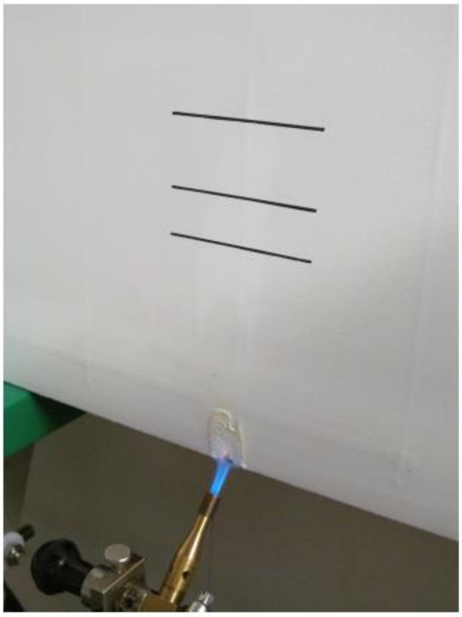


Figure 5-13: Material qualification for flammability

These tests serve material qualification but are not comparable to the EN 13501-1 classification given the test description.

Consequently, the fire behavior of the components and the module must be declared with respect to these requirements. This additional marking will help planners, architects and especially rescue workers in assessing risks of ignition.

In order to further analyze how the normative fire requirements for junction boxes are to be assessed, we conducted a series of comparisons with these specimens to determine the inflammability of box components.

The aim was to determine whether the test requirements from the established rules for module junction boxes are sufficient, so that the inflammability of materials in the event of an electric arc is sufficiently low.

A risk potential for electric arcing in a junction is generally shared by the bypass diode, introduction and connection of the main strings and the cable exit.

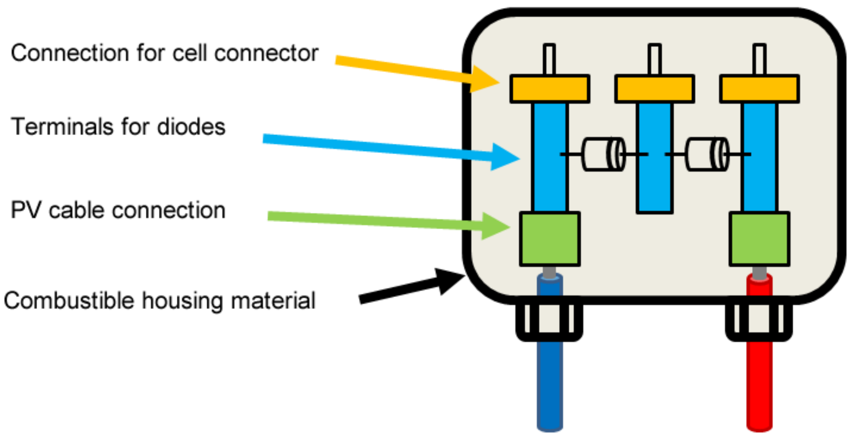


Figure 5-14: PV junction box with terminal connections

In the event of an electric arc, it must be assumed that surrounding materials will be stressed by the extremely high temperatures of the arc (> 5,000°C).

For the safety qualification it must be examined whether the surrounding materials can effect fire propagation in the event of an electric arc, i.e. whether material parts drip while burning or even continue burning on their own after the electric arc is extinguished. This is especially important if a switch or circuit breaker is used.

In this regard TÜV Rheinland has conducted studies going beyond the standard and supplementing the normative test background with realistic test arrangements. The fire tests were conducted based on the test as per EN 60695-11-20: this test is also referenced in EN 50548 for PV junction boxes. EN 60695 arranges all specimens in the upright position, however. Since modules are predominantly installed at an inclination of 20° to 60° (facade installations excepted), however, we also chose an inclined design for the test arrangement. As Figure 5-15 shows, we chose an angle between 30° and 50° in order to determine whether this arrangement would influence the fire properties of the junction box.

The purpose of this test setup was also to determine the critical character of the influence of any dripping materials on actual construction materials, such as roof membranes, insulation materials, etc., which is especially important when considering roof-integrated systems.

The test flame was applied to places where electric arcs could occur in practice in the event of a fault.

The flame impingement employed a 500 W flame as described in EN60695-11-20. Flame impingement cycles with impingements of 5 x 5 seconds with 5-second pauses in-between as described in this standard were used.

Figure 5-15: Flame impingement of lid in area of the line connections and flame impingement of the screwed cable gland of a specimen [source: TÜV Rheinland]

To determine whether the supporting surface could be ignited by dripping burning material, a thin layer of cotton wadding was placed 300 mm below the point of flame impingement, as also described in EN 60695-11-20.

The assessment of the test results was also based on EN 60695-11-20. To this end, the afterburning or afterglow time is recorded (Table 5-1) and it is noted down whether material has dripped and whether the cotton wadding underlayer ignited.

Table 5-1: Assessment criteria for test results (source: DIN EN 60695-11-20)

Criteria	**Category 5VB**
Afterburn time with flame plus afterglow time after the fifth flame impingement	≤ 60 s
Did the cotton wadding ignite from burning particles or drops from the specimen?	No
Did the specimen burn completely?	No

Table 5-2: Overview – comparison of the performed tests with normative measurements

	Applied test setup	**Normative test setup (EN 50548)**
Specimen	Complete junction box mounted on support surface	Material specimen from final sample
Inclination	30° to 50° from the vertical	Vertical
Distance from support surface	300 mm	
Surface support padding	A layer of uncompressed cotton wadding	
Test flame	500 W flame as per EN 60695-11-20, calibrated as per IEC 60695-11-3	
Flame impingement	5 times (5 s impingement + 5 s pause)	
Point of application	From the outside, in area of the connection terminal for PV cable	Bottom edge of the specimen
Assessment	5VB as per DIN EN 60695-11-20 sec. 8.4 (see table 1)	

Altogether 45 inflammability studies were conducted. Samples from eight different manufacturers and altogether 19 different junction box types underwent testing. To confirm the repeatability of the tests, if possible more than one test was performed per junction box type and material.

Results

The tests have shown that most of the specimens were able to fulfill the criteria. Merely 13 flame impingements that had to be rated as “not passed”.

One sort of material was especially conspicuous because it continued burning for a long time in the altered arrangement and its burning droplets ignited the cotton wadding and the roof membrane material. In retesting with an arrangement exactly according to EN60695-11-20 the material did fulfill its requirements, however (!).

Other tests showed that often not the housing material, but add-on parts like union nuts at screwed cable glands or seals, promoted continued burning, which presents a risk in practice.

Conclusion

The tests presented here form the basis of studies on the behavior of the junction box components under the influence of a flame or electric arc, given the surrounding building materials.

Recommendation for standardization:

The concrete practical test proposal should be considered in a future adaptation for EN 50548 and should be integrated in a comprehensive product safety concept with an eye to practical installations.

Adhesive bond between laminate and junction boxes: tensile tests

The influence of defective laminate bonds between encapsulation materials and insulating backsheets of PV modules on the corrosion process (via diffused water) at connectors plays just as large a role in the long-term behavior from a safety perspective as mechanical integrity and the influence on performance characteristics. To determine the quality level of the adhesive bond between the laminate parts, we can determine the adhesive forces through tensile tests – through measurements also before and after simulated environmental conditions.

Comparative tests at TÜV Rheinland [68] show that the quality of the laminate installed in the field greatly varies in terms of tensile strength (Figure 5-17 and Figure 5-18).

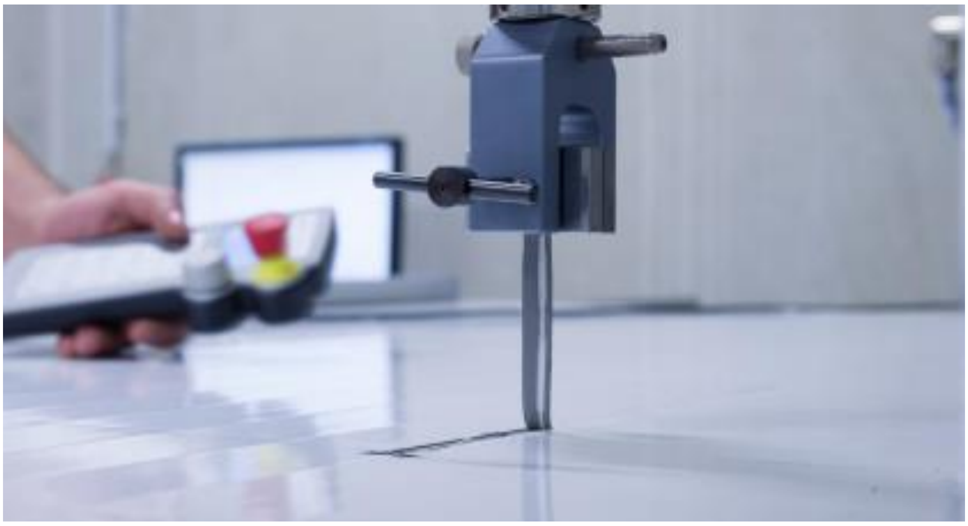


Figure 5-16: Test stand for testing the peel-off force

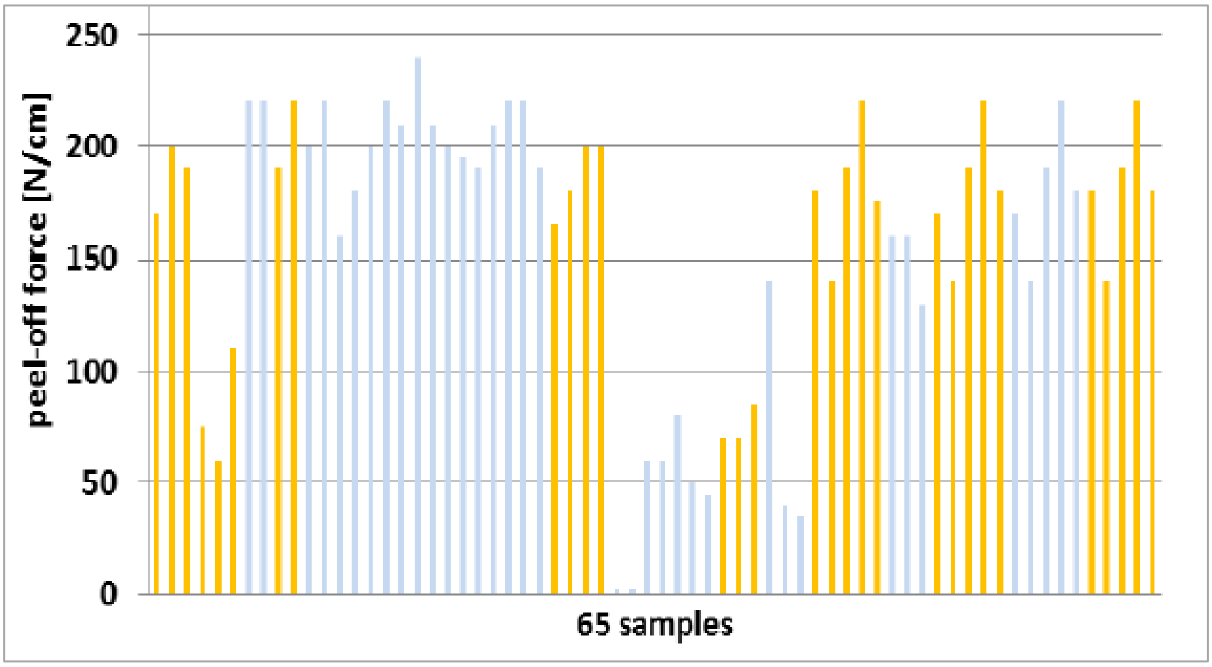


Figure 5-17: Comparison series for determining the tensile strength of laminate bonds between EVA and backsheet

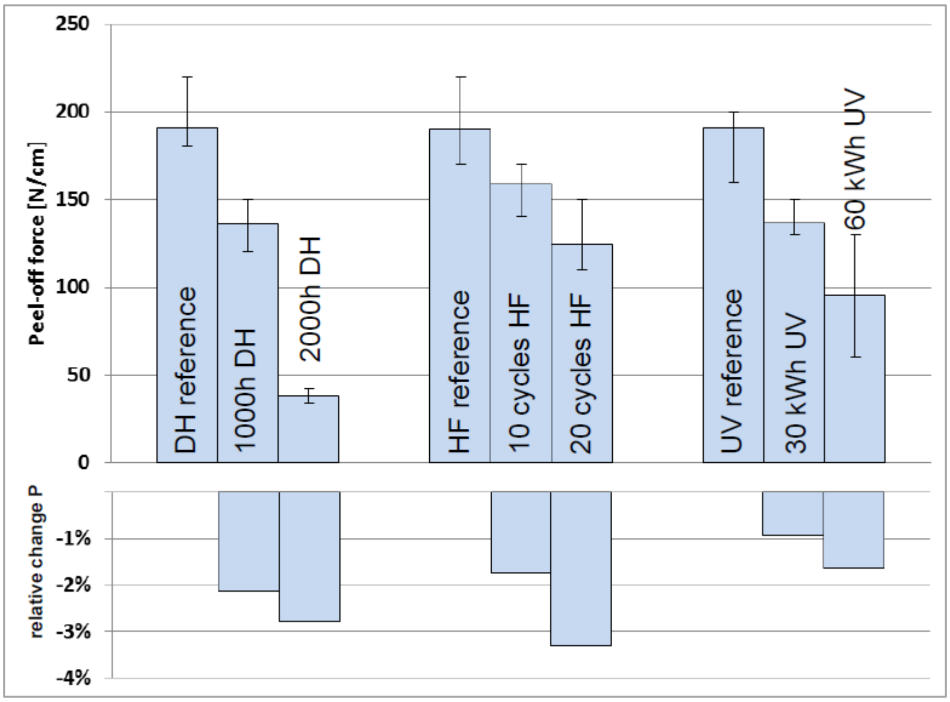


Figure 5-18: Determination of aging before and after simulated environmental conditions in the case of the adhesive force of laminate layers.

The adhesive force is influenced by aging. Environmental effects make the backsheet brittle. Besides affecting the insulation properties, this condition also accelerates contact aging.

To determine the laminate quality, generally the following mechanical properties can be investigated:

- Tension-elongation diagram of before and after aging
- Yield stress and tensile strength
- Change in the elastic modulus

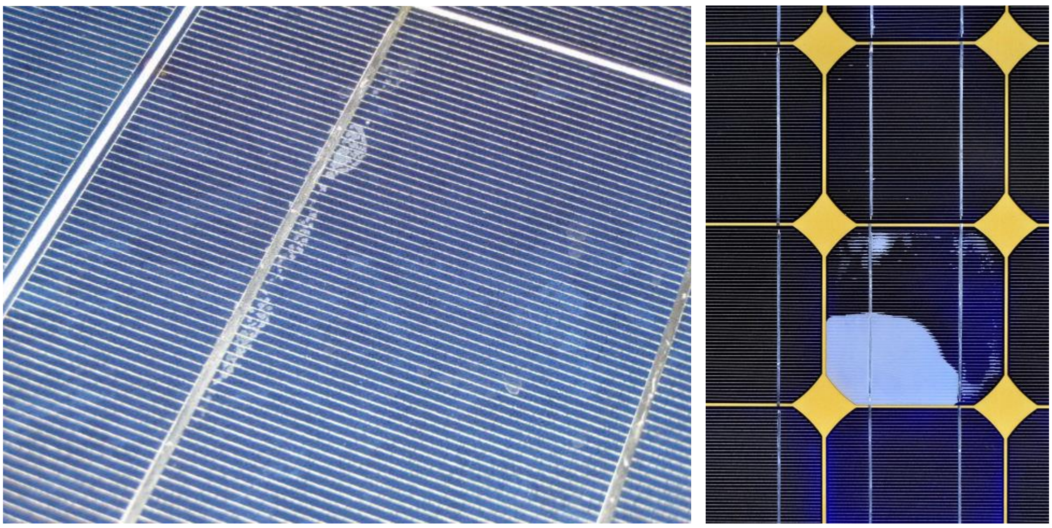


Figure 5-19: Example: delamination near a busbar.

Regarding the retention force of junction boxes, applicable standards, e.g. within the UL 1703 (standard for flat-plate photovoltaic modules), require that the connecting cables within the wiring compartment test be tested with the maximum weight of the module, but at least with 155 N. This is equivalent to stress that would occur if clearly incorrect handling in practice led to modules being improperly transported on their backs and held at the connecting cables.

This high retention force certainly deserves further discussion, since in practice stress would be explainable only by untrained installation personnel, which despite testing would be avoidable. Moreover, the wiring compartment test is defined, in which the connecting cables are pulled with 89 N along different directions. These stress requirements govern the robustness of termination test from IEC 61215 (or IEC 60068-2-21), in which the connecting cables are pulled with less than 40 N.

In the current standardization discussion for Edition 3 of IEC 61215, the test is also to be adapted to handling situations in practice, with stressing depending on the conductor cross sections (up to 155 N with 55 mm conductor cross section). A torsion test is also included that is to simulate cable twisting during installation. In addition, the new edition will also require an investigation of the retention force of the junction box (with 40 N for 30 minutes), which will stress the adhesive or adhesive bond to the backsheet. The test result is assessed according to the insulation properties (creepage distances).

With natural, vertical tension, depending on the weight of the cables and plugs, the weight is only a few grams. The existing tests refer to the sufficient retention force of screwed connections or permanent connections between the junction box and module cable, but also to the durability of the adhesive bond between the junction box and the backsheet.

From the aforementioned test sequences, the IEC test standard provides application-oriented definitions for investigating the retention force of the module cables at the junction box in spot checks during production, whether at the incoming goods inspection by the supplier or on delivery of the completed PV module.

Determination of contact resistance at critical connections in the module junction box

The currently planned modification A2 within EN 50548 and the planned first edition of IEC 62790 ("Junction boxes for photovoltaic modules") define additions pertaining to requirements relevant for fire protection. They refer primarily to the reliability of contact connections inside the junction box. For the improved qualification of the contact resistance, measurements are performed for determining the contact resistance between connection points for the module cable and for the cell connectors inside the junction box. The comparison measurements are performed before and after the temperature cycle test.

The contact resistance may altogether have an initial value not greater than 5 mΩ and after the aging tests must not be greater than 150%. For the measurement, the junction box is short-circuited to the cell connector terminals and fed 1 A (Figure 5-20).

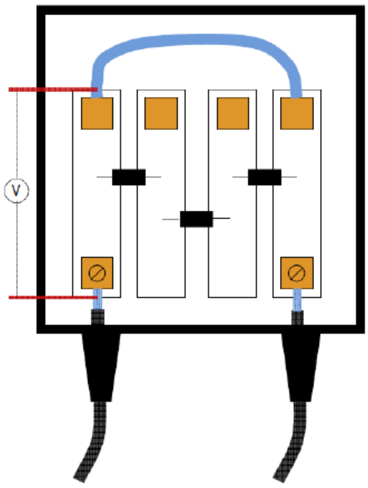


Figure 5-20: Measurement points for determining the contact resistance within the junction box standard (EN 50548:2011 + A1:2013)

Moreover, internal plug connectors (inside the junction box) must meet the applicable requirements from EN 50521:2008/A1:2012 or IEC 62852 ed. 1 (FDIS) ("Connectors for photovoltaic systems"), where the accelerated temperature cycle test here has a cycle number of 800.

An impending amendment to part 1 of the safety standard for PV modules, EN 61730-1:2007/A11:2014: *"Photovoltaic PV) Module Safety Qualification - Part 1:* Requirements for Construction," requires for Europe that components like junction boxes and connectors fulfill the aforementioned standard requirements. This has so far not been the case in the IEC version. Here people are continuing to work on improving the safety standard by means of a second edition of the IEC 61730 series.

Inflammability of backsheets

At present, IEC 61730-1 requires of backsheets a so-called flame-spread index with a maximum value of FSI 100 via the ASTM standard E 162. This value is computed from the propagation properties of the flame at the test specimen within predefined measuring marks. Besides the flame propagation speed (the faster, the higher the FSI), the temperature in the exhaust unit also determines the result.

Series of comparison tests were performed on backsheets and frontsheets according to different methods (ISO, ASTM, UL) using specimens from different sheet manufacturers.

The purpose of the studies was to determine tendencies among the materials and their properties and to allow a qualitative preselection of module materials as components of the laminate by means of a suitable development of test methods.

In the past, an estimate of fire behavior was lacking for the final product. For the tests, APA, ETFE, PPE, TPT and PA (as a conventional vapor barrier) were available as materials: Besides the aforementioned ASTM standard, we also employed the ISO standards 11925-2 (also important as a test basis for the construction material classification), ISO 5658-2 and 95/28 EC.

Table 5-3: List of specimens and applied tests.

Lab no.	Letter	Test	Dimensions	Thickness	Material	Quantity
L20056A	A	UL 94	200*50	0,43	APA	15
L20056B	A	ISO 11925-2	250*90	0,43	APA	12
L20056C	A	ISO 5658-2	800*155	0,43	APA	3
L20056D	A	95/28 EG	560*170	0,43	APA	3
L20057A	B	ASTM E 162	457*152	0,1	ETFE-frontsheet-F1	4
L20057B	B	ISO 11925-2	250*90	0,1	ETFE-frontsheet-F1	12
L20057C	B	ISO 5658-2	800*155	0,1	ETFE-frontsheet-F1	3
L20057D	B	95/28 EG	560*170	0,1	ETFE-frontsheet-F1	3
L20058A	C	ASTM E 162	457*152	0,28	TPT	6
L20058B	C	ISO 11925-2	250*90	0,28	TPT	24
L20058C	C	ISO 5658-2	800*155	0,28	TPT	6
L20058D	C	95/28 EG	560*170	0,28	TPT	6
L20059A	D	ASTM E 162	457*152	0,35	PPE	4
L20059B	D	ISO 11925-2	250*90	0,35	PPE	12
L20059C	D	ISO 5658-2	800*155	0,35	PPE	3
L20059D	D	95/28 EG	560*170	0,35	PPE	3
Climatic mem.	E	ASTM E 162	457*152	0,06	PA (vapor lock)	6
Climatic mem.	E	ISO 11925-2	250*90	0,06	PA (vapor lock)	14
Climatic mem.	E	ISO 5658-2	800*155	0,06	PA (vapor lock)	4
Climatic mem.	E	95/28 EG	560*170	0,06	PA (vapor lock)	6
Climatic mem.	E	UL 94	200*50	0,06	PA (vapor lock)	12

In summary, we can say that the fire behavior was similarly assessed for all test samples in each test. The statement on the quality of the materials is thus reflected in each test application, so that initially all methods seem equally suitable.

In the case of ISO 11925-2, not only was the individual specimen tested, but a laminate as well, with calcium silicate (CaSi) serving as a substratum, a composite material. The sheet specimen was then clamped, not bonded, to the CaSi. The results greatly deviated from those without CaSi, so that a test with individual films (consistently negative except for ETFE) is not comparable with a final-application test. CaSi support shows flame propagation similar to that with the construction material classification at the final product (module as material composite).

Films C and D show severe fire behavior, which in reality would not occur as such in the material composite, however. Thin films generally behave better. They quickly withdraw from the heat by melting. In the material composite, the PVB or EVA again determines the fire properties, which are potentially worse compared with the backsheet films, which in the case of thinner backsheets could potentially pose a problem.

All tests are suitable for making a preselection of backsheet films. They are no substitute for final-application testing of material composites, however. The ASTM standard does not suffice for making a reliable inference from the backsheet film to the module as the overall product.

Nevertheless, all standards offer the possibility of determining the quality of the individual materials. ASTM E 162 and ISO 11925-2 allow use of CaSi as a substrate, a use that based on comparisons with final specimens (module: test at backsheet film; see also 02/2011) promises a significant trend.

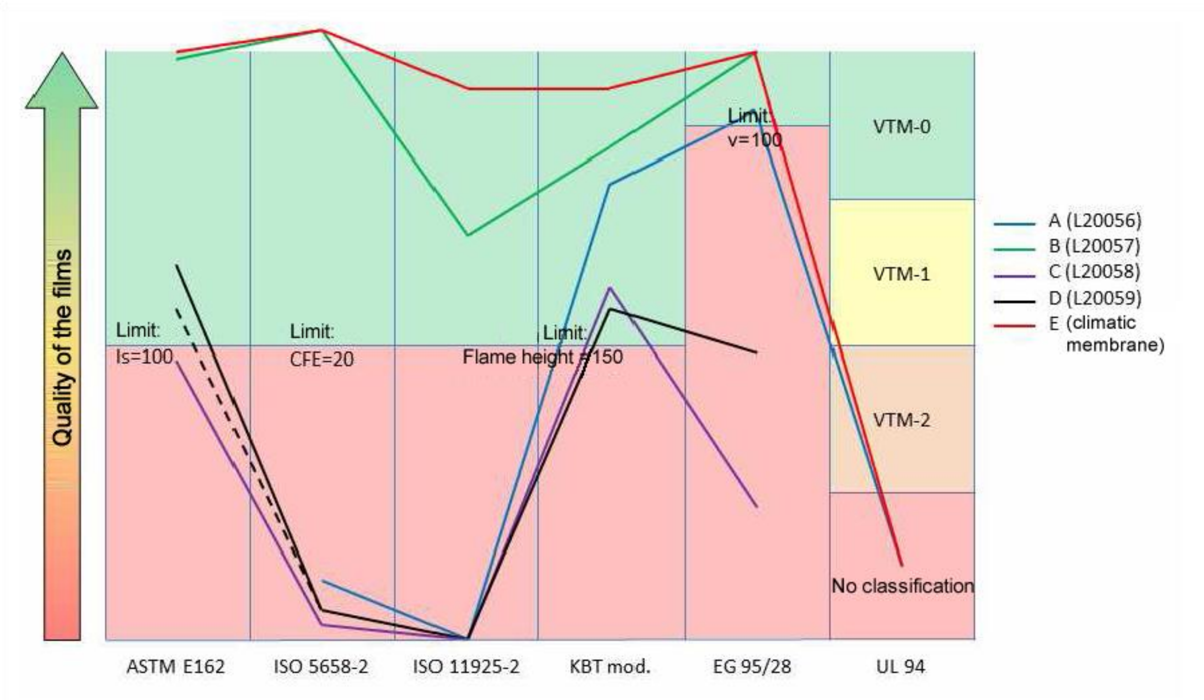


Figure 5-21: List of specimens and applied tests.

Recommendations for standardization:

We recommend including final-application tests as per the requirements in IEC 61730-1. A flame propagation and inflammability test on the individual polymer backsheet film alone is not sufficient.

Given the experience of Currenta and TÜV Rheinland in roof stress testing as per UL 790 (fire test within IEC 61730-2) on modules, we also recommend, in individual tests of backsheets, considering the later inside of the film in a flame propagation examination, since here other materials than the actually declared film core layers may sometimes be used.

These results and findings are being provided to the WG 2 standardization of the IEC TC 82 and have also been incorporated in current drafts of a revision of the IEC 61730.

5.2.4 Transport safety measures

The preceding sections have described the fire risk potential of cell cracks. In a concrete case, minor fire damage occurred along the cell crack from a current flow running diagonally through a cell (as the consequence of poorly connected cell connectors). In response to this issue, this Guideline also includes a note on transport safety and cargo safety.

Mechanical vibrations and shocks occur from transient or oscillating motions during transport, with the transport cargo being shifted from its rest position from bumps on the road or even handling.

Series of tests determined the resonance frequencies of modules (at approx. 11 Hz) under the effects of vibrations (shaking platform) during longer periods of action. In individual cases the stress sufficed to produce cell breakage and damage [69]. Other influences during transport can affect not only the mechanical cell stability, but also tension in the glass (as with oblique loads).

If incorrectly positioned during transport, module backsheets are endangered by contact with the forklift, through rod pressure, prong insertions, etc.

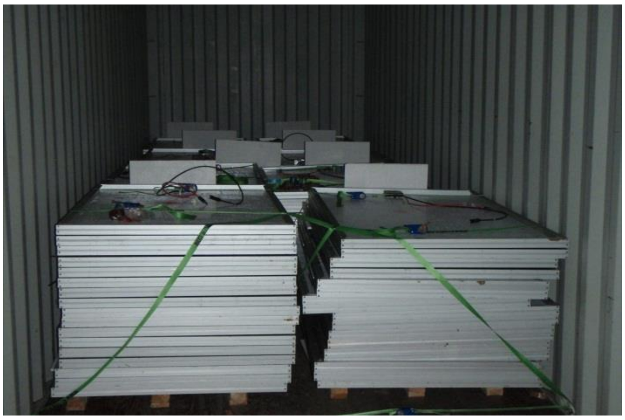



Figure 5-22: Left: incorrect handling with pressure from forklift prongs, right: improper transport of solar modules.

To reduce the risk of damage during transport as much as possible, influential factors critical to performance and safety must be avoided. The aforementioned damage to backsheets (scratches, detachment of materials) have been discovered in practice and present a considerable risk even prior to operation of the system, due to errors in transport and handling or to inadequate packaging.

We therefore recommend using only qualified packaging certified according to the international standard IEC 62759-1, for example. In accordance with this standard packaging is inspected as to its suitability for transporting PV modules.

5.3 Safe system operation

5.3.1 Prevention of electric arcs/overheating – selecting and dimensioning components

To prevent fire incidents, it is important to avoid electric arcs and local overheating in the PV system.

Here the focus must lie on the best possible quality in *component selection, planning, installation and maintenance*, despite the existing price pressure. An electric arc has a much higher probability of occurring in a poorly constructed PV system than in a high-quality one. Component manufacturers as well as planners and installation companies should take the appropriate measures and comply with the appropriate specifications.

5.3.1.1 Selection of suitable components

The first step in installing a PV system is the selection of its components. Modules, plugs, cables, inverters and other components should be selected that present the least risk of fire. This will be the case if the component manufacturer attends with the utmost care to the quality of the connection points.

Regarding **modules**, the manufacturer must minimize the number of soldering points and maximize the quality of the soldering, including inside the junction box. Spring-type terminals should be preferred over screw terminals. Carefully arranged strain relief at the module connecting cables can prevent stress at the cables leading to consequential damage at the connection to the junction box.

Plug connectors should visibly and firmly snap in and maintain a permanently low transition resistance. Generally, contemporary systems from brand names should be installed as plug connectors and collective boxes.

With screw terminal systems the danger of an unstable and therefore potentially hazardous connection is much higher than with contemporary spring-type terminals, so that the former should no longer be used.

Solar cables must be UV-resistant to a high degree and always be double-insulated, since then the risk of a parallel electric arc will be significantly less.

Inverters with integrated insulation monitoring have the effect that an (initial) fault to ground will already be noticed, practically preventing an indirect connection of both terminals via the ground potential.

5.3.1.2 Planning regarding electric arcs

The detailed planning of the PV system design can itself contribute much to fire safety. Conversely, some coarse faults should be avoided when planning the system, since they significantly increase the risks of fire emergence.

Current PV modules are equipped with bypass diodes that prevent high block voltages at the cells in the event of partial shading and thereby guard against overheating, or so-called hotspots, in the module.

These bypass diodes can fail, however. Possible causes are overvoltage during manufacture, transport or installation, but also during operation in the vicinity of a lightning strike.

Persistent or frequently alternating shading events also often lead to thermal overload and increased cycle stress of bypass diodes.

Generally the best protection against hot spots is therefore to install modules so as to avoid shading, in particular for longer periods of time, as much as possible. Especially sharply cast shadows from intense insolation are harmful and should not occur. Less critical are shadows in the morning or evening such that the sun rays are incident at a relatively flat angle, so that the currents and additional heating are relatively low.

Often safety components like **fuses and switches** are integrated in the DC part of PV systems. In the individual case it must then always be checked whether this measure is really necessary. Each additional component poses the risk of additional contact points and other sources of faults. A “sleek” system with as few components as possible has the advantage of having fewer points where damage could occur to the system.

Smaller systems with fewer than three parallel strings require no string fuses, since the modules can sustain any reverse currents that these fuses would otherwise prevent from occurring [35]. This applies to most roof systems on single or multi-family houses. If the use of fuses is nevertheless necessary, they must be able to meet the special requirements of photovoltaics, in which the rated operating current is hardly less than the short-circuit current.

The same applies to the installation of switches in the DC wiring. Power can then be switched off to parts of the system, which can be useful in repairs or other structural measures or in case of fire department rescue operations (“fire department switch”). Concerning the risk of fire emergence in a PV system, however, additional switches are simply yet another source of faults, so that it must be considered whether the protective goal could not also be achieved by protecting the DC cable against contact by routing it under plaster or through cable ducts, for example.

Should switches nevertheless be installed, they must be designed for the special requirements of photovoltaics – it is not enough to use ordinary DC switches and comply with the specifications on maximum currents and voltages, since photovoltaics presents a current-voltage characteristic different from ordinary DC voltage sources.

A fatal error that is nevertheless occasionally made is to **place system components in areas with highly inflammable materials**, such as straw, litter and sawdust.

In particular the inverters, which themselves generate heat, must never be used in such surroundings.

Other components, such as cables through such areas, can also increase the risk of fire, since heating or even a spark in the electrical installation can cause a fire.

5.3.1.3 Proper installation

The company performing the installation is especially important when it comes to setting up fire-safe PV systems. Damage has often occurred in the past due to gross deficiencies in installation.

Especially critical installation flaws occurring in the past concerned the installed **plug connectors**. Very dangerous and unfortunately occasionally occurring faults concern the incomplete insertion or coupling of plugs from different manufacturers. The latter problem can occur if different plug connector makes are mechanically compatible with one another. Notwithstanding this mechanical compatibility, the transition resistance can increase, leading to increased heating and long-term damage to the connection. In installing connections on site a suitable tool must be used to ensure the optimal contact pressure.

Other wiring problems concern **unsuitable cable routing** without sufficient fastening, running over sharp edges, disregard of minimum bending radii and construction over **fire protection compartments**.

To avoid flashovers from conductors that may conduct lightning currents (**lightning arresters)** to the components and to the wiring of a PV system, a distance of at least 0.5 m should be maintained (see also section 3.5.1). DIN EN 62305-3 (VDE 0185-305-3) contains a calculation of the (minimum) separation distance.

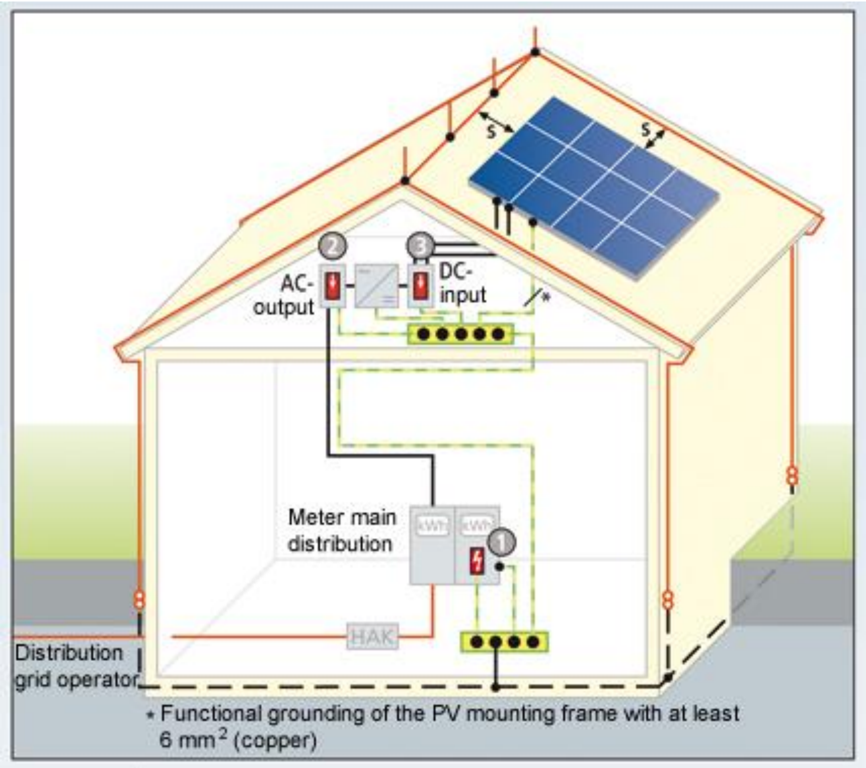


Figure 5-23: Surge protection concept for a PV system with external lightning protection with separation distance s; source: Dehn, Blitzplaner **[70]**

This does not concern the equipotential bonding conductor, however, which should always lie close to the DC cables. In addition, the size of the loops formed by the wiring must always be kept small, so that a lightning strike can at most induce surges of minimal danger.

At the same time, however, the risk of a parallel electric arc, i.e. contact between two conducts of opposite polarity, must be kept as low as possible.

Both requirements are fulfilled by routing double-insulated cables alongside one another or – ideally – routing the two main lines in two directly adjacent cable conduit systems or in conduit systems separated by a partition. The use of separated conduit systems for positive and negative is required only when laying the cables through combustible surroundings.

Occasionally installers are observed suspending modules from the cables for the sake of convenience. Even if the connection terminals of the cables typically come with strain relief, they are not designed for such stress. This practice must absolutely be avoided.

If **string fuses or DC switches** are to be used, they must be able continually to bear the system current – the current carrying capability can decrease due to heating if components are installed directly next to one another.

All specified distances must also be absolutely heeded when **installing the inverters**. While often neglected, this can have serious consequences if system components fail or even catch fire from the resulting overheating. Not permitted is mounting on combustible materials like wood.

If not already taken care of in the system planning, a professional installation company should now at the latest fully avoid installing system components in **surroundings with highly inflammable materials** (such as hay, straw, sawdust, fuels, etc.).

5.3.1.4 Acceptance inspections and regular maintenance

Besides the items to be contained in the system documentation, DIN EN 62446 (VDE 0126-23):2010-07 also describes the following tests and measurements for commissioning, as well as the recurring inspections and measurements for operation without unpredictable legal risks

(compiled on the basis of the following information: [71])

All tests should be performed during assembly and on completion in reference to IEC 60364-6 (DIN VDE 0100-600:2008-06).

Inspection of the DC system:

- Proof must be submitted that the DC system in general has been designed, selected and installed as per the requirements in IEC 60364-6 and in particular the requirements of DIN VDE 0100-712.
- The DC components are designed for operation with direct current and the highest possible voltage of the DC system as well as for the highest possible rated current.
- Protection by application of protection class II or equivalent insulation at the DC end has been implemented.
- PV string cable, PV generator cable and PV DC main cable have been selected and installed so as to minimize the risk of short-circuiting to ground and other types of short circuits; this is usually achieved by means of cables with protective insulation and reinforced insulation (often called “double insulation”).
- The wiring system has been selected and installed so as to resist expected external influences, such as wind, icing, temperature and insolation.
- For systems without string overcurrent protection, the string cables must be dimensioned greater than the theoretically possible maximum reverse current, for safety’s sake. The string

cables must be routed so as to handle the maximum additive reverse current from the parallel strings.

- Strings may be connected in parallel only given identical string polarity and approximately identical open-circuit voltage, otherwise hazardous faults not manageable by protection systems may occur.
- String overcurrent protection devices for systems must be installed and correctly designed according to the local technical connection conditions or according to the manufacturer’s instructions for protection of the PV modules.
- A direct current load-break switch at the DC end of the inverter must be installed.
- If string diodes are installed, their block voltage must be at least 2·x UOC at STC of the PV string. While unusual, protective circuits (such as surge suppressors, snubber capacitors connected in parallel) should nevertheless be considered.
- If a DC conductor is grounded, at least a simple partition must exist between the AC and DC ends. The ground connections must be protected against corrosion.
- If protection potential equalization conductors are installed, they must run parallel and in the closest possible distance from the DC and AC cables or lines and the accessories.

Surge protection:

- The areas of all wiring loops must be as small as possible in order to reduce voltages induced by a lightning strike.
- Existing protection potential equalization conductors of the PV generator frame must be grounded. These conductors must be arranged parallel to and have the closest possible contact with the DC cables.
- The module frames need not be individually grounded.

The **alternating current system** has been generally designed selected and installed as per the requirements in IEC 60364 and in particular the requirements of DIN VDE 0100-712:

- At the AC end, a device must be planned for disconnecting the inverter, by means of the upstream line fuses, for example.
- All circuit breakers and switching devices must be connected so that the PV installation is located at the “load end” and the public power supply is located at the “feed-in” end.
- Operating parameters of the inverter must be programmed according to the local technical connection conditions or according to the manufacturer's specifications.

All circuits, protective devices, switches and connection terminals are **suitably labeled**:

- Warnings about voltage after disconnection from the power supply must be attached.

- The AC main switch must be clearly labeled.
- At the interconnection point warnings must be present for the dual supply.
- A schematic wiring diagram must be posted on site.
- The protective settings of the inverter and details of the installation must be specified on site.
- Emergency shutdown procedures must be specified on site.
- All labels and markings must be permanently and suitably affixed.

Test steps:

The following part discusses the measurements required in the standard VDE 0126-23, in order to explain to the technician the necessary test steps and their technical implementation in everyday work.

1. Test of all AC circuits as per DIN VDE 0100-60
2. Inspection of the DC system
3. Continuity testing of the protection and bonding conductors
4. Polarity test of each string
5. Test of the open-circuit voltage of each string
6. Test of the short-circuit current of each string
7. Function test
8. Insulation resistance measurement of the DC circuits

While this sequence of measurements in the standard is not always the quickest way for the technician, the test steps should be logically performed in the specified order.

The measurements on the opened string should be compiled, i.e. the function test should be performed with commissioning of the inverter only after the insulation measurement.

Electric arcs in a PV system typically do not occur abruptly and without previous indications, but are usually triggered by aging phenomena (degradation). Signs are already apparent in advance. **Regular maintenance** (e.g. every 2 years) can identify critical points in due time and rectify the causes of faults.

The most important test here is a **thorough visual inspection of the system** by a professional. Much damage can be easily detected by the naked eye. They include module breakage, discoloration or deformation of modules and junction boxes, porous or abraded cables, plug connectors melted by heat and excessive dirt.
Heat build-ups can be detected especially effectively using an **infrared camera**. Both the modules and the BOS components can then be checked and excessively heated components promptly replaced.

DC switches installed in PV systems are usually operated only in the case of a fault. If the system is running normally, it is always switched on. Switches often have the property that their transition resistance significantly increases if not operated, however. This can lead to heat build-ups which in the long run can become electric arcs. For example, a switch actually intended as a safety element can certainly cause a fire if regular maintenance is not performed.

Some switch manufacturers recommend **operating their DC switches ten times in succession once a year.** Any oxide layers will then rub off and the transition resistance will significantly decrease [72]. In addition, this practice can prevent the contacts of a switch from sticking when operated.

This measure is urgently recommended for all mechanically operating DC circuit breakers.

An important goal of maintenance of a PV system is the discovery of **defective bypass diodes**. Open bypass diodes in particular are relatively difficult to detect, but the occurrence of a second fault can promote the occurrence of an electric arc. As long as the solar module is free of faults and not shaded, failure of a bypass diode will not impair the PV system. The protective function performed by the diode will no longer be available, however. Shading will then lead to intense heating of the affected module areas and to considerable yield loss.

More serious from the perspective of fire protection is the fact that an additional interruption of the current path in the module (e.g. ribbon tear-off, micro-cracks, etc.) makes the occurrence of an electric arc quite probable, however.

During maintenance, *fully alloyed (permanently conductive) bypass diodes* can be discovered with the aid of an infrared camera from approx. 300 W/m^2 irradiation owing to a slightly higher temperature of the affected module section (see Figure 5-24)

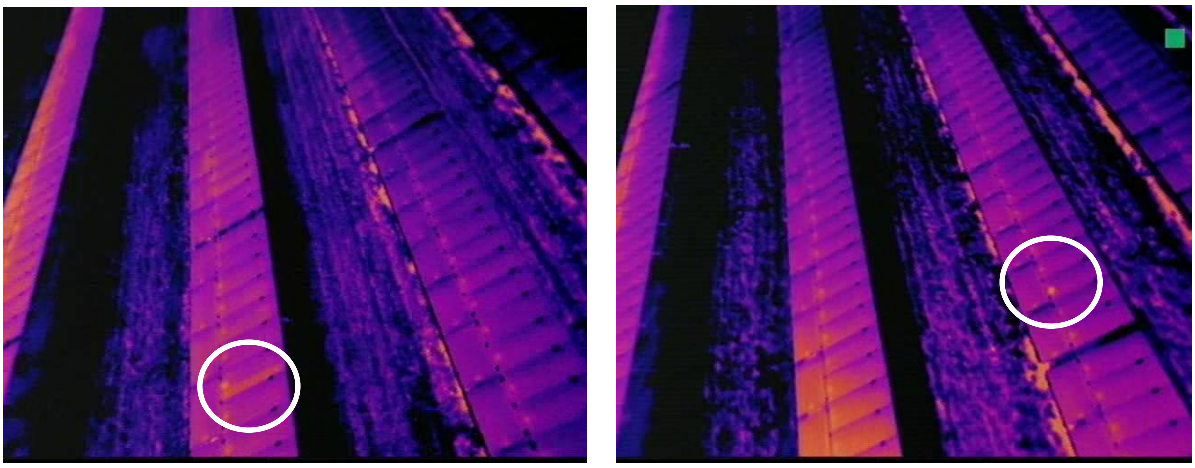


Figure 5-24: Left: heated bypass diode and affected right string, right: significantly heated bypass diode in IR overview image from drone in an approx. 5-year old open-space installation, photo: TÜV Rheinland

Another, irradiation-independent and reliable detection method is the **comparative measurement of open-circuit voltages** of the individual strings.

On the other hand, the case more relevant for fire protection, namely *partially conducting or open-circuit bypass diodes*, is more difficult to discover. If the PV connection diodes can be examined with an infrared camera, a partially conducting bypass diode can be identified from its significantly increased temperature (Figure 5-24, right).

Here too there are proposals for wire-bound measurement methods, listed in section 5.5. The search for defective bypass diodes is urgently necessary *following a lightning strike at the PV system or after a lightning strike at a lightning protection system in the immediate vicinity*.

5.3.2 Installation specifications (system planning including fire protection planning)

The planning and installation of PV systems must attend to fire protection. The corresponding fire protection requirements of the Model Building Regulation as well as any other building requirements, the professional fire protection rules and the VDE application rule VDE-AR-E 2100-712 must be complied with.

In March 2011, the German Solar Industry Association (BSW), the German Solar Energy Society (DGS), German Electrical and Electronic Manufacturers' Association (ZVEH), the Munich Professional Fire Department and the Registered Federal Association of Technical Planners and Experts in Preventive Fire Protection (BFSB) jointly issued the professional rules for the “Planning, Installation and Maintenance of PV System for Fire Protection.” These rules were also coordinated with the Consortium of the Heads of Professional Fire Departments in Germany (AGBF Bund), and are therefore recognized as state of the art.

Compiled here are the pre-existing requirements of the various rules & regulations for buildings and electrical installations. Gaps in regulations are identified and measures presented for filling them. The professional fire protection rules were developed by an interdisciplinary working group comprising fire department, fire protection and PV experts, fire protection building contractors, planners and installers.

For details on the issues, every installer and planner is advised to download the information at **www.dgs-berlin.de** (see Appendix, p. 249). It can be ordered in brochure form from the BSW at **www.solarwirtschaft.de**.

The quality of components, planning, construction and installation crucially affects the risks of operating errors that can lead to fire emergence (from an electric arc, for example).

The modules and inverters should have the corresponding **certificates**. DIN VDE 0100-712 on “Low-voltage electrical installations - Part 7-712: Requirements for special installations or locations – Photovoltaic (PV) systems” states the mandatory foundations of the installation. This standard also entails mandatory compliance of the system with protection class II.

The **plug connections** must be professionally performed. No variations in plug connections or unsuitable plug connections may be used.

Only **suitable PV string fuses** as per draft standard IEC 60263-6 should be used. Systems with one to three strings need not contain fuses. Note: Unsuitable fuses or the unsuitable design and installation of fuse holders increase the electric arc risk!

Generally **inverters with insulation monitoring** must be used. In addition, proper integration in existing or necessary **lightning and surge protection systems** is essential. The requirements of lightning and surge protection in particular according to standard supplement sheet 5 of VDE 62305-3 on “Lightning and Overvoltage Protection for Photovoltaic Power Supply Systems" should be heeded and complied with.

The modules and cables should be **professionally mounted**. PV modules should be mounted on site as per the module manufacturer's assembly instructions and with inspection of snow and wind loads as per DIN1055 parts 4 and 5 or Eurocode 1. This inspection should also occur for the mounting system, e.g. by means of system statics and for the transmission of stress to the roof structure or building.

Errors and flaws in the electrical installation can be discovered through inspections as per EN 62446 on "Grid-connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection".

The generally recognized state of the art, standards and certifications, guidelines and rules based on them, as well as instructions of the "DGS – Guidelines on Photovoltaic Systems," should be heeded. They provide the foundations for good PV system quality.

DC cables, inverters or generator junction boxes (GJB) must not be installed in the areas of stairs or exits.

Electrical components like GJBs and inverters must be installed on non-combustible supporting surfaces.

In particular, cables should be professionally selected, installed, mounted and routed. Only suitable cables compliant with the "Requirement Profile for PV System Cables" as per VDE-AR-E 2283-4, designation: design PV1-F, should be used outdoors, for example.

Mounting and strain relief according to regulations as well as permissible bending radii must be heeded. Cables must not be routed over sharp edges.

Cables should be protected against gnawing animals not only in rural areas (raccoons in urban environments).

Notes on safe installation sites for inverters

The ventilation slots and heat sinks of inverters must be free to ensure optimal cooling.

For the same reason the devices should not be installed closely above one another. Here the manufacturer's specifications must be absolutely followed.

Inverters must not be mounted on wood walls or on other combustible materials!

A metal plate serving as a shield between the inverter and a wood wall is not recommended, since the plate will conduct the release heat of the inverter, restrict the air exchange with the wood and therefore make self-ignition possible.

A structural panel of construction material class A1 (= non-combustible), such as calcium silicate with a thickness of 15 mm and protruding 10 cm all around, is best suited as a foundation. Inverters should not be mounted in areas containing combustible materials.

The devices should be protected against aggressive fumes, water vapor and fine dust. Ammonia fumes can occur in barns or stalls, for example, and cause damage to the inverter.

5.3.3 PV systems at or on buildings

Generally the installation of PV systems should not affect the protective function of roofs and firewalls. Buildings and roofs are subject to various requirements from the respective state building codes (LBOs) as well as to the Model Building Regulation (MBO) to prevent the spread of a building fire to other buildings or parts of the building (see section 5.2.1 on Fire Protection).

They include in particular the requirement of "hard roofing" for in-roof solutions as well as the use of materials with a classification of at least fire classification B2 "Normally flammable," class B2 as per DIN 4102 (old) or class E as per EN 13501 (new) for on-roof solutions. Most PV modules with glass can be assigned to class B2 or E.

The module providers should present proof of this classification with a declaration of conformity from the manufacturer.

For roof-integrated systems proof of "hard roofing" is generally provided by the manufacturer in the form of building authority test certificates. The "Information Document for the Manufacture, Planning and Execution of Solar Systems" of 7/2012 from the German Institute for Structural Engineering (DIBt) states, for example: "Solar systems must consist of at least normally flammable construction materials (§ 26 sec. 1 MBO). If such systems are arranged in or on the building envelope, outside wall surfaces as well as outside wall cladding of buildings of building classes 4 and 5 must be flame-retardant (§ 28, sec. 3, sentence 1 MBO).

Components with combustible construction materials must not be installed across firewalls (§ 30 sec. 5, sentence 1, clause 2, sec. 7 sentences 1, 2 MBO)."

In addition, the MBO defines the execution of firewalls and the distances between the so-called normally flammable materials and the firewalls. These definitions are intended to prevent fire propagation from flying sparks or heat radiation. For example, § 32 of the MBO stipulates, among other things, that dormer-like roof structures made of combustible construction materials must have a distance of at least 1.25 meters from the firewall. This applies analogously to PV modules and other components of the system.

Occasionally PV modules have been built over fire compartments, the cables pushed through fire compartments or led through firewalls without protection. Cables routed through or over a firewall must be compartmentalized according to the fire protection rules of the Regulation on Model Conduit Installation (MLAR). Otherwise there is a danger of fire propagation by virtue of the so-called wick effect of the insulation material. The employed materials must be suitable for outside applications.

The following shows an example of an economical solution for passing PV cable strings across fire protection walls by means of "fire protection bandages" (approved by the DIBT).

Figure 5-25: Fire protection bandages can prevent fire propagation across firewalls, photo: Obo Bettermann. **[73]**

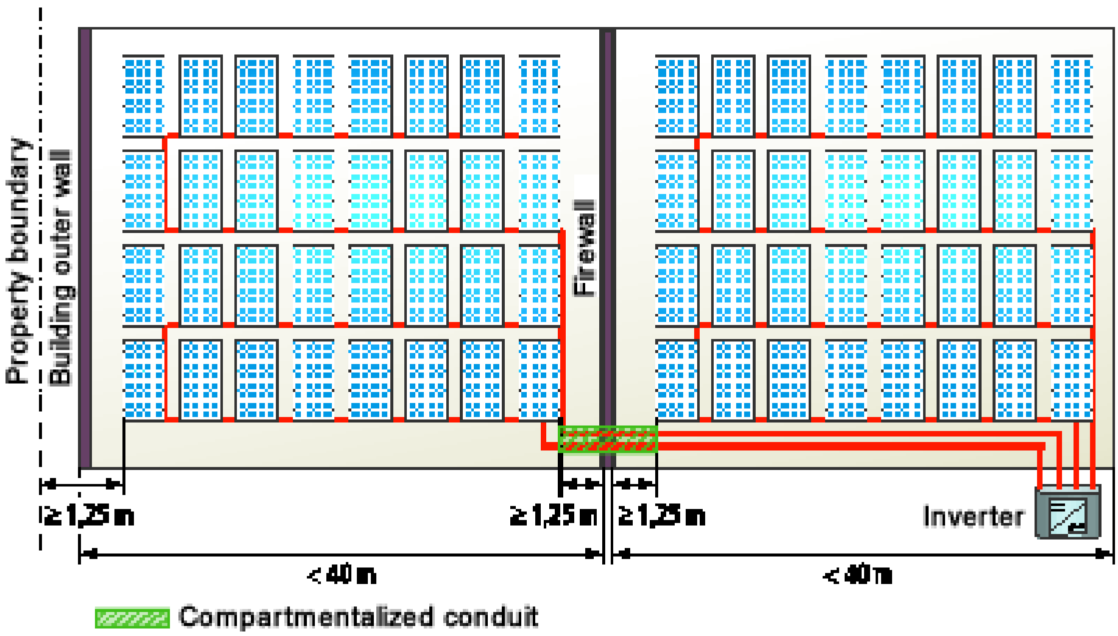


Figure 5-26: Cable routed across firewall and module distances from firewall or property boundary [source: DGS Berlin]

Firewalls must extend at least 30 cm beyond normally flammable material and therefore beyond the upper edge of the PV generator. As already mentioned, normally flammable materials may be installed only at certain distances from firewalls. For this reason, normally flammable PV modules installed above the roof covering must comply with a distance of at least 1.25 m (Figure 5-26).

Planning requirements for firefighting

In the event of a building fire, firefighters must be able to arrive at the source of the fire quickly and safely. Some such operations cannot avoid penetrating the roof structure directly from the roof and extinguishing the fire there. In this case, an electrically live system, such as a PV system, could be a hindrance, especially if it covers the entire roof surface, which should therefore be avoided.

Possible access points to the roof structure are as varied as the types of buildings. Here are examples of the most important roof variants with possible access (Figure 5-27):

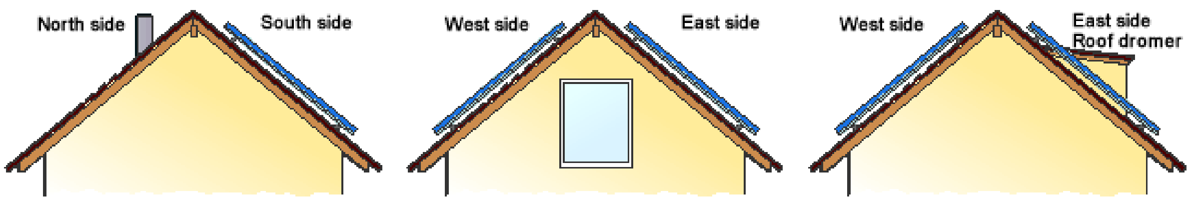
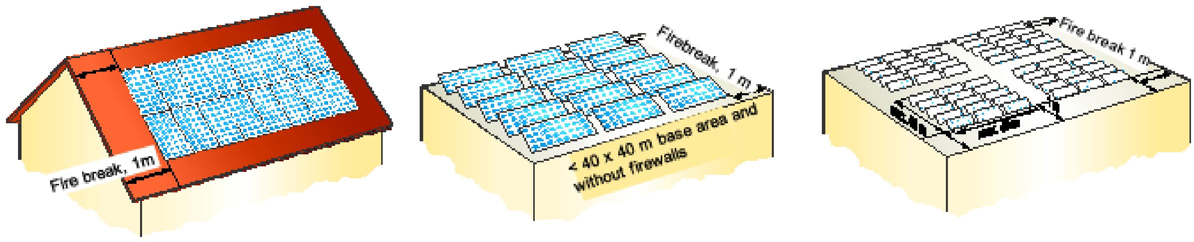


Figure 5-27: Different types of access for firefighters to a pitched roof *[source: DGS Berlin]*

In many cases firefighters can access the roof structure via the second half (often northern half) of the roof not covered by a PV generator and from there tackle the fire at a sufficient distance from live system parts. If both roof halves are occupied, as is the case with roofs facing east, other roof access options must be used.

Other possible passages are through dormer windows or gable windows. These windows must have the dimensions of a so-called “necessary window” suitable as a rescue route and be accessible to rescue workers. The minimum dimensions of such a window are a clear width of 90 cm and a clear height of 120 cm as per the Model Building Regulation.

If access to the roof structure is possible neither through roof areas at the rear nor through windows, a suitable partial area of the roof must remain free. For rescue workers a fire break of at least 1 m in width is already helpful in extinguishing operations (Figure 5-28).



a) Pitched roof occupied on both sides

b) Medium-sized roof on buildings with base area less than 40 m x 40 m

c) Large roof on building with base area greater than 40 m x 40 m

Figure 5-28: Access possibilities for firefighters *[source: DGS Berlin]*

For roofs without other access possibilities and with a base area less than 40 x 40 m, 1-meter fire breaks must be implemented on the longer side. An additional fire break is also recommended with system widths of 20 meters or more. If larger PV systems are planned, *the generator areas must be subdivided into max. 40 x 40 meter sections.* Between these sections pathways of at least 1 meter are required. Important in planning the distances to live parts is to take into account the PV modules themselves as well as the cables and other system components. Fire protection experts should participate in the planning of PV systems on special structures as defined in the building codes of the particular state and be consulted in cases of special roof shapes.

Electrical installation requirements

The VDE application rule VDE-AR-2100-712 on “Minimum requirements on the DC part of a PV system in case of firefighting or technical assistance” must be heeded during installation. Since the PV generator carries a voltage of up to 1,000 V during the day that cannot be turned off, firefighting operations can be hindered.

Firefighters must therefore follow the safety rules when extinguishing electrical installations as laid down in VDE 0132. Appropriate safety distances of one or five meters must then be maintained when extinguishing fires with a spray nozzle or jet nozzle, respectively.

Outside the building this extinguishing distance to the PV system can generally be maintained without problems. On the other hand, the safety cannot always be maintained in a firefighting assault or when rescuing people in the building, given limited visibility from smoke, for example. For this reason VDE AR-2100-712 stipulates **the avoidance of hazardous exposed DC voltages in the building in case of fire** as a protective goal in planning and installing PV systems, to allow safe rescue operations and firefighting inside the building.

To achieve this protective goal, the following minimum requirements on planning, construction and installation of PV systems as per VDE-AR2100-712 must be implemented.

- *Marking of PV systems and cable routing* is mandatory at each system. This concerns affixing the standardized information sign on the house connection box as well as affixing a general schematic for rescue workers at the delivery point of the electrical system, e.g. the house connection box or building main distributor.

- In addition, *either structural or technical installation measures* must be taken to protect against exposed hazardous voltages in the building.

- The following structural installation measures are possible:

  1. Fire-protected routing of DC cables in the building that cannot be turned off. The fire resistance of the cable system depends on the particular state building code in effect (at least F30, however). This measure can be implemented by (e.g.) in-wall routing as per VDE 0100-520 or by means of fire protection conduits and shafts as per EN 1366 or DIN 4102.

  2. Routing of the DC part of a PV system outside the building by (e.g.):

     - routing the DC cables outside the building and leading them directly into the electrical operation room or to the house connection point or

     - installing the inverters outside or at the building entry point. If the inverter is installed at the building entry point, the fire compartments in particular must be preserved and the corresponding firewalls implemented.

  3. Fire-resistant routing of PV DC cables in the building so as to prevent contact. 1 meter above arm's reach of people without aids (ladders, etc.) and routing on cable support systems as per DIN 4102-12. With this type of routing, the cable support system must be included in the function potential equalization.

Generally for the DC cable installation an unprotected zone of up to one meter about the PV generator on the roof and about the inverter in the building is permissible and must be labeled accordingly in the documentation for the rescue workers.

DC cables in the building that cannot be switched off can be routed under at least 15 mm thick mineral plaster as per the "in-wall" model cable system guideline. Routing through installation shafts and ducts made of non-combustible materials with a fire resistance capability of at least F30.

If the structural measures are not (or cannot) be implemented, one of the following technical installation measures must be implemented:

1. Installation of a DC isolator with remote triggering for disconnecting the DC main cable in the building or for disconnecting the module string or

2. use of module switch-off devices, which to date have not been authorized by a corresponding product standard in the rules & regulations, however.

Only the output DC system can then be considered as a protected zone. The continuous current-carrying capacity of the switch-off device must be designed for at least 1.25 times the $I_{SC\ STC}$ value at the connection point. On occurrence of an internal fault, the device must go to a safe state (*fail-safe principle*), e.g. disconnection in case of a fault with a separator, *otherwise the functioning of the device must be monitored daily.* If necessary, in order not to impair the functioning of the switch-off device, other devices may have to be used that prevent reverse currents from inverters or from parallel strings such as string diodes or string fuses.

On triggering by an external enable signal, e.g. from a control unit or an inverter, which must persist (fail-safe principle), the switch-off device must respond if within a period of max. 15 seconds the enable signal ceases to be applied. The device should switch on again when the enable signal returns.

Devices for disconnecting the string or PV generator must comply with the requirements on switchgear as per EN 60947-3 or EN 60947-2. Devices for switching off in or at the junction box of the module must comply with at least the requirements on temperature testing of the bypass diodes in IEC 61215 or IEC 61646. The device for switching off the module can be a semi-conductor switch without a disconnecting function, if a switch-off can be ensured given the typical failure mechanisms.

<u>For the aforementioned switch-off devices, other requirements, such as adapted service life tests and defined failure probabilities, must still be laid down in a product standard.</u>

Table 5-4: Overview of the fire protection measures of VDE AR 2102100-712

Identification and documentation	
1. Sign identifying the PV system at the house connection box or main building distribution board 2. General schematics for rescue workers 3. Supplements to existing fire department schematics	
and structural installation measures 1. Fire-protected routing of DC cables in the building that cannot be turned off. **or** 2. Routing of the DC part of a PV system outside the building **or** 3. Fire-resistant routing protected against contact	**or technical installation measures** 1. Devices for disconnecting the string or PV generator* **or** 2. Devices for shutting down the PV module* * Remark: Requirements on the devices must still be laid down in the product standards.

5.3.4 Open-space systems

Planning must give attention to suitable freedom of motion for the firefighters. Lanes between the generator sections must be left free for firefighting vehicles, especially to the inverters and transformer stations. We recommend dividing the generator tables into fire compartments and leaving the center aisles free, to rule out the risk of fire propagation.

The **system monitoring should be equipped with fire monitoring** and a **fire alarm system** should be installed. The pertinent fire department should be informed about the PV system, including cable routing, and receive schematics for operations. The fire department should have access to the fire alarm system.

Ground cables must be connected properly and routed with protection against mechanical damage, such as grass cuttings. The connections in the transformer and inverters must also be properly carried out, with protection against mechanical damage. In general, **the installation must be ground-leakage-proof and short-circuit-proof**.

Fire stress and fire hazards should be minimized by the following measures:

- Use suitable material for the substructure
- Route cables with protection against rodents
- Following the installation, leave no combustible materials behind on the premises (cartons, packaging, etc.)
- Prevent excessive vegetation underneath the PV system (mow regularly, especially underneath the PV system) and remove grass cuttings from the system
- Regular maintenance of the ventilation system for the inverter units

5.3.5 Electric arc detection

If the instructions listed in section 5.3.1 for preventing electric arcs and overheating are heeded, the probability of a PV system starting a fire is very low. Generally such a strategy qualifies as fully sufficient.

In the USA the electric arc risk must be assessed differently. PV systems are often installed with grounded PV generators, a practice that increases the risk of parallel electric arcs. Houses are often built from combustible materials like wood and roofs are fitted with bitumen tar paper.

Another approach is therefore taken: The National Electric Code 2011 [74] stipulates the installation of available electric arc detectors in building-integrated PV systems (based on the situation with certain domestic AC circuits, where this has already been the case for years).

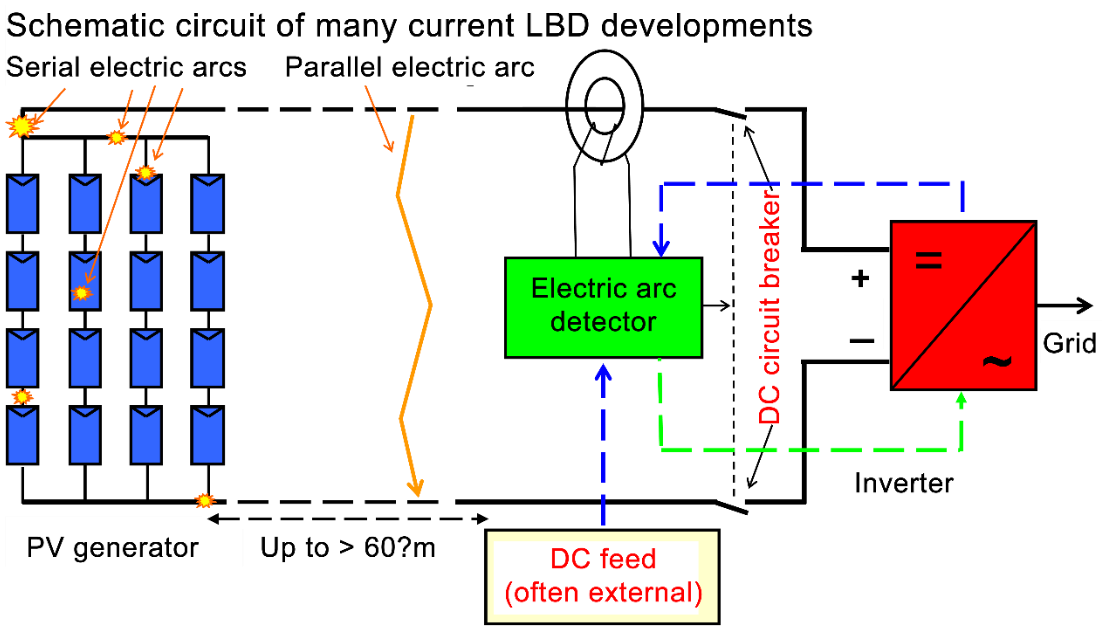


Figure 5-29: Typical schematic circuit of current LBD developments. Feed-in and shutdown by inverter (if integrated) or externally; Analysis of the disturbance currents of the electric arc in the range 1 – 500 kHz (depending on manufacturer) [6].

In Germany and Europe there exist no comparable installation regulations for electric arc detectors at present. Nevertheless, their use may be recommended, since there is no 100% protection against electric arc events.

Conceivable would be a recommendation for systems such that a fire event would pose a particular hazard to life and limb or where material values requiring special protection are present, as in public buildings like kindergartens, schools, retirement homes, hospitals or even museums or archives.

Here it is essential that the electric arc detector <u>continually</u> operate with reliability, however.

This presents a challenge not to be underestimated. It must be ensured that the electric arc detector remains fully functional over a very long time period of time, if possible during the entire service life of the PV system, without itself causing any faults in the system. Protective measures such as an integrated self-test could be helpful here.

An electric arc detector is moreover useful only if it can be assumed to **reliably detect electric arcs**. Owing to the large variety of PV systems in which the detector is to be used, this criterion is anything but trivial. Electric arcs in modules produce different noise patterns than those in serial terminals. Different cable lengths greatly differ in their dampening of electric arc signatures. Interference from inverters, switching transients, or coupled radio signals can mask or overlay the noise coming from the electric arc.

Only very robust detection algorithms tested on different systems can ensure real added utility here.

Even more critical is the subject of **faulty activation**. An electric arc detector leading to faulty activation will be hardly welcomed by system operators. When an electric arc detector causes the shutdown of a

PV system, the exact fault location is after all fully unknown. The system must then be elaborately checked in order to locate and eliminate the fault.

It is even more difficult to prove that no electric arc has occurred, and that a false alarm was the case. In cases of doubt, only a technician can do this, namely after checking each individual module, all connection points and the complete wiring.

This will generate considerable costs and create great insecurity among customers. Moreover, the danger is great that following a few such fault detections the system owner will simply override an unreliable electric arc detector in order to avoid costs and further yield losses.

Wire-bound electric arc detectors have a high potential for faulty activation:

- Discontinuities in the current can also be caused by (e.g.) passing clouds or sudden shading by (e.g.) leaves or bird droppings.

- Neighboring electronic devices or even radio signals can produce interference patterns that can be captured via the extended wiring of a PV system. These interference patterns can increase signal parts in the same frequency ranges as are typical for electric arcs.

- The inverter as a system component with its switching frequencies used for energy conversion (approx. from 1 kHz to several 10 kHz and the corresponding harmonics) can also cause interference and noise that can be misinterpreted as the effects of an electric arc.

This last point is especially difficult to tackle since each inverter produces a different interference spectrum, which is also influenced by processes like MPP tracking, partial load operation and grid services.

Constructing an electric arc detector that will function together with any commercially available inverter and under all operating conditions is therefore a very demanding affair.

Besides robust and thoroughly tested detection algorithms, *expedient switch-off concepts* (e.g. slightly time-delayed shutdowns or (following a certain waiting time in a deactivated state) multiple restarts on a trial basis before final shutdown) can also provide a remedy, if permitted by the standards.

Conclusion

Summarizing, we can say that electric arc detectors can add to safety in especially hazardous situations.

This will be the case only if the employed electric arc detector can reliably detect electric arc situations and faulty activations can be ruled out with high probability.

Careful selection of such a device is therefore essential.

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5.3.6 Batteries and charge controllers

Grid-independent PV systems with batteries and charge controllers did not form part of the research project underlying this report. Since batteries are also being increasingly used in grid-connected PV systems, however, we list here the minimum requirements for the purpose of avoiding fires.

Standard EN 50272-2:2001 (VDE 0510 part 2 or IEC 62485-2) describes in detail the safety requirements on batteries and battery systems for stationary lead and NiCd batteries.

The following discusses only the **measures for avoiding overheating and electric arc formation** in the switchgear and cable routing as well as the **measures against the risk of explosion**. These measures must also be taken with Li ion batteries.

- The rated voltage is the product of the number of serially connected cells and the rated voltage of a single cell (lead battery: 2V, nickel/cadmium battery: 1.2V). This does not correspond to the voltage during charging (higher) and discharging (lower).
- In the battery cables and in the cables of all devices connected to the DC bus, such as charge controllers, battery inverters or chargers, disconnectors for all terminals (positive and negative) must be provided. In contrast to the PV DC switches, they need not be able to disconnect at the rated current; even plugs or special clamps may be used.

  Since the operating personnel for PV systems are accustomed to disconnections under load and in order to facilitate maintenance, we urgently recommend the use of separators with load disconnection capacity when accommodating charge controllers, inverters and battery in separate housings.
- Since the battery as a voltage source can supply extremely high short-circuit currents, the cables must be routed up to the battery fuses so as to be protected against ground leakage and short circuiting. As with PV DC cables, we recommend the use of double-insulated, single-core cables. Insulated DC systems and galvanically non-separated battery inverters require fuse protection at all terminals. Grounded DC systems and galvanically non-separating battery inverters with a neutral conductor led through them require fuse protection only for the non-grounded conductor.
- During charging and especially during overcharging, gas escapes from all cells and batteries in the case of lead and NiCd batteries. This gas is produced by the overload current through electrolysis. The gases consist of oxygen and hydrogen.

  Natural or technical ventilation must keep the hydrogen concentration below 4% (volume concentration). EN 50272-2:2001 provides a detailed formula and table for calculating this volume flow. With maintenance-free lead batteries containing sealed cells and electrolytes bound in gel or non-woven material, this volume flow is five times less compared with closed cells containing liquid electrolytes. Sufficient ventilation can therefore usually be ensured here with two small openings to the outside in the battery chamber.
- Lithium ion batteries must not be overcharged to prevent gas production. Since the alcohol-containing electrolyte can escape under unfavorable conditions in the event of a fault, a minimum space is suggested for most lithium batteries.

5.4 Special fire requirements for PV systems on and at roofs

A parallel project supported by the Federal Economic Ministry of Economics and Technology (BMWi; reference number 01FS12053), TÜV Rheinland, Currenta GmbH and Co. OHG and Wuppertal University is conducting pre-normative work on fire requirements of PV systems on and at roofs.

The central objective of this project is to define fire testing methods which, adapted to the product constellation of roof-integrated and roof-mounted PV systems, capture realistic fire loads from the effects of external fires.

These test methods should be derived from the findings of test series consisting of specific aspects and applications of the combination of established European roof fire tests.

These test methods are to yield qualifying statements on fire propagation by building-integrated photovoltaics (BIPV) respectively on the influence at the underlying roof cladding by photovoltaic rooftop systems in the event of flying sparks and radiant heat.

The findings are to be incorporated into international European standardization and there significantly serve the work on a harmonized test specification.

The test series should determine the influences on BIPV on the basis of existing European fire stress tests for roofs. Above all, suitable incendiary devices, wind load parameters and additional radiation sources should be selected as crucial for the performance of tests with simulated fires.

For PV rooftop systems the effects of on-roof module installation for the scenario of a fire source lying between the PV system and roof covering (e.g. originating in flying sparks from external fires or straying fireworks) are being examined for the first time.

Here the different types of roofing in Germany and the different positioning of the incendiary devices (position and setup) are also to be characterized by means of temperature measurements.

The findings from this test series should enable the applicants to assess to what extent fire tests are required for PV systems in order to reliably prevent fire propagation into the building interior from external sources or to prevent such propagation from adding to the risks from PV rooftop systems.

The tests examined different roof structures and different PV installation systems.

For the roofing materials and roof structures the following configurations were selected, representing both the so-called “soft” and “hard” roof variants (see also section 6.2.2):

Configuration 1:

1st (= uppermost) layer: unsanded bitumen sheeting, d = 5.0 mm
2nd layer: polystyrene insulating boards, d = 80 mm
3rd position: bitumen sheeting with aluminum vapor lock, d = 5.0 mm.

Configuration 2:

1st layer: unsanded bitumen sheeting, d = 5.2 mm
2nd layer: unsanded bitumen sheeting, d = 5.0 mm
3rd layer: polyurethane insulating boards, d = 80 mm
4th layer: bitumen sheeting with aluminum vapor lock, d = 5.0 mm.

Configuration 3:

1st layer: PVC sheeting, d = 1.5 mm
2nd layer: mineral wool insulating boards, d = 80 mm
3rd layer: bitumen sheeting with aluminum vapor lock, d = 5.0 mm.

Configuration 4:

1st layer: roofing tiles including battens, d ≈ 80 mm
2nd layer: roofing membrane, d ≈ 2 mm
3rd layer: common rafter clamping felt made of glass wool, d = 200 mm.

Configuration 5:

1st layer: in-roof module, inserted in a virtual roof covering consisting of CaSi boards and roof battens, d = 50 mm
2nd layer: roofing membrane, d ≈ 2 mm
3rd layer: common rafter clamping felt made of glass wool, d = 200 mm.

In addition, for the testing a burner system was selected as the ignition initiator, which was also validated and examined as to its reproducibility in the application.

The developed burner was compared with the wood wool basket for all roof configurations. Here no PV modules were used at first.

It was possible to demonstrate that the burner produced the same heat release rates as the wood wool burning as per ENV 1187-1. Accordingly, the gas burner was also used for the other roof configurations, with PV modules.

Altogether it was found that the roof design/configuration considerably influenced the tests results!

For example, in the tests with the bitumen sheeting the roof elements and other layers burned off completely, as did the modules. This applies to both the soft and hard types of roofing. This “downgrading” of hard roofing, actually classified as B_{roof} (t1), can be explained by the upward heat dissipation significantly limited by the elevated PV module design.

Soft roofing originally already received a low classification.

The rooftop systems used in the tests for elevating the PV modules on flat roofs correspond to a worst case of systems used in practice: on the one hand flying sparks can get between modules and roof surfaces and on the other hand materials can freely drip from the modules onto the roof covering.

Figure 5-30: Left: elastomer bitumen sheet underlay, EPS insulating boards, bitumen vapor lock sheet with new gas burner. Right: PVC roof sealing sheet, mineral wool insulating boards, bitumen vapor lock sheet.

At present there also exist elevation systems preventing just this risk from flying sparks (through (e.g.) rear walls in the structure, ballast by means of gravel). In addition, non-flammable or flame-retardant underlays (e.g. protective mats) between the substructure and the roof surface can prevent or greatly limit fire propagation. For assessing suitability further tests are necessary and have been rated as appropriate.

Non-critical were the tests with PVC flat roof sheeting in conjunction with roofing tiles installed parallel to the roof. Here the destruction was limited to the area of the ignition initiator.

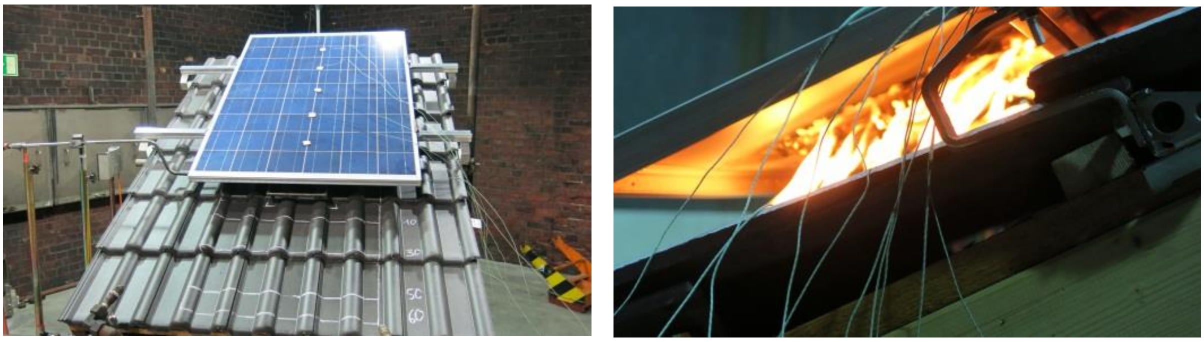


Figure 5-31: Left: roof-parallel structure with concrete roofing tiles and PV module. Right: the ignition initiator was placed between the module and the roof surface.

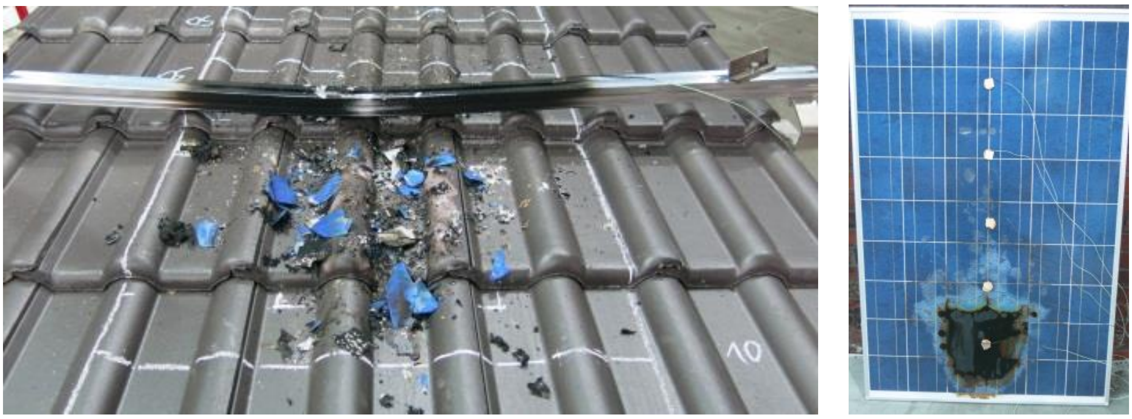


Figure 5-32: Result after test. Module was destroyed, no burn-through at the roof surface.

Nor did the tests on roof integration reveal any critical events, so that the classification criteria defined in EN 13501-5 for the structures remain in effect.

Regarding roof integration, it must be noted that other plastic elements are usually also used for the system structures in order to ensure rain-tightness with shingled modules or modules installed edge to edge. The variety of systems currently in use cannot be captured by the tests performed in this project.

The test with plaster therefore focused on a roof-integrated installation with calcium silicate boards arranged flush to one another. At the same time, regular roof underlays are used (normally flammable roofing membrane, and insulation made of flame-retardant mineral wool).

No fire propagation or ignition via or at the PV module occurred in these measurements. **For a subsequent test method to be harmonized, however, it must be clearly defined which materials (and fire classes) of the roof configuration are to be used in the test.**

Depending on the test result, it can then be decided whether a BIPV system may be used without restriction or only in combination with certain materials.

Within the project, the requirement case of **plastic trays forming a flat roof mounting system** was <u>not</u> considered (the fire case with these trays mentioned in section 3.3, p. 52, occurred only after completion of the tests).

The task of the project was to supply requirements as a recommendation for subsequent standardization work. To this end comprehensive results and positions have been formulated. A definition of test sequences and requirements could not be exhaustively discussed in this project.

For the use of roof-integrated PV systems, the **definitions and test methods of ENV 1187** can be used, a standard that has long been established for roof coverings. The tests showed that method 1 is applicable for an upper roofing system. The positioning of the incendiary device or burner must be specified as in ENV 1187-1. Here the system joints (module or module-roof connection) must be stressed each with an ignition source.

As in the usual test of roof coverings, the EN 13501-5 classification criteria can also be applied.

An appropriate test method must also require that the roofing materials, like the roofing membrane, etc., be recorded, in order to include any necessary restrictions on the use of the systems in combination with different materials. Conceivable is that the PV modules with certain substructures will correspond to poorer fire resistance classes than regular roof coverings, like tiles.

As a whole, either the wood wool basket or even the burner can be used here. Both incendiary devices are suitable.

For roof-parallel PV systems a typical roofing tile type should be defined for the tests. Alternatively, this can also be a non-combustible layer, for example calcium silicate, in order to simulate comparable substructures and roofing situations.

Here other FE studies are possible for comparing regular roof coverings with potential substitute materials for the lab tests. The use of the burner is advantageous, since owing to its size the wood wool basket cannot fit between the PV module and the roof surface. A standardization discussion must take this fact into account.

The usual roof distance in the tests should not exceed 8 cm between the underside of the module and the roof surface, unless the manufacturer can improve the fire protection with a larger distance.

In the test requirements testing should therefore generally be performed according to the manufacturer’s specifications as to the manufacturer’s assembly situation.

The same applies to elevated roof-mounted systems on flat roofs, where the two variants of ignition sources have led to great differences in the speed and extent of fire propagation!

Testing of rooftop systems especially for the setup on flat roofs with the manufacturer's particular mounting system is useful, since this type of construction alone, irrespective of the roofing layers, can itself prevent fire propagation.

On the other hand, some module manufacturers do not use their own flat-roof mounting system, but purchase such a system from an external supplier, or the installer assembles modules and systems from different manufacturers.

For modules without a corresponding mounting system a practical solution for the standardization must be developed in order on the one hand to minimize the testing labor and on the other hand to ensure the greatest possible qualification via the test method.

For all the aforementioned cases EN 13501-5 must be used as the classification basis, since the protective goal is still to prevent flames from penetrating the interior of the building.

Other parameters like duration of testing and wind speed will have to be the subject of future standardization discussions. The present project could not carry out any diversification in this regard.

With the support of five European countries, it was decided that in the fall of 2014 a New Work Item Proposal would take up the work on developing a fire test method for roof-installed PV systems.

The national committee has also decided in favor of this undertaking. The following title was chosen: "External fire exposure to roofs in combination with photovoltaic (PV) arrays – Test method(s)". The research results here will serve as the starting point of further discussions.

The standardization project is to be regarded as a joint working paper together with CEN representatives, i.e. as concerning the European standardization for technical construction matters.

Conclusion

The European test methods for roof-mounted PV systems currently present no harmonized picture regarding building codes. PV modules have so far been tested as per IEC 61730-2 with the US test method UL 790.

Because of the many standards applicable in Europe regarding the testing of inflammability and fire propagation properties of roofs, the European EN 61730 has to date not considered fire testing of PV modules!

For the purpose of study and unification, European standardization is therefore currently developing together with Cenelec and CEN a method taking into account the different modes of installation on roofs.

5.5 Commissioning and operation

Following creation of a PV system at the customer’s end, commission must take place. This should ensure proper, risk-free functioning of the system. Usually proper functioning is verified by commissioning tests documented by commissioning logs.

DIN EN 62446 VDE 0126-23 on “Photovoltaic (PV) systems – Requirements for testing, documentation and maintenance - Part 1: Grid-connected systems – Documentation, commissioning tests and inspection” primarily applies to PV systems and documents the minimum requirements for commissioning. They refer mainly to the DC part, however.

For the AC part and the overall system the usual electrical engineering norms and standards (such as VDE 0100 part 610) apply.

Commissioning is usually performed by the system installer. The latter must confirm that the system has started operation properly and can continue to be operated without risk. The system can then be transferred to the owner or operator. Following handover to the owner (subject to inspection), the latter is liable for the risks or damage caused by operation. Consequently the owner must ensure proper operation, or may entrust this task to an operator.

Figure 5-33: String measurements on generator junction boxes

Logically the operator should receive appropriate instruction prior to handover of the system. All documents necessary or helpful for operation and maintenance must also be provided to the owner.

<u>This documentation must include in particular:</u>

- System description (e.g. with general schematic)
- Wiring and circuit diagrams
- Product data sheets
- Operating instructions
- Any certificates, certificates of guarantee, etc.
- Commissioning logs
- Verification of stability, if appropriate

Also helpful are:

- Service address
- Maintenance recommendations

The owner is obligated to monitor proper operation of the system. The owner must accordingly take suitable measures, namely monitoring of the operating parameters (via status displays, etc., for example) and perform appropriate maintenance and inspections. The following sections will discuss these points in detail.

5.5.1 Acceptance inspection

Like every structural system, a PV system requires an acceptance inspection.

The inspection is to be performed formally by the owner or operator. Since the latter will usually not have the appropriate technical background, that party will often entrust this acceptance inspection to appropriate companies (specialist companies, engineering firms, test centers, etc.) or bring in specialists.

On acceptance the owner declares that the system meets the agreed specification in type and design (subject to concealed defects) and that the contractually agreed services have been rendered.

Legally, at this point at the latest full payment of the account receivable (via the contractual delivery price) to the system installer is due (in the absence of a different arrangement and of any defects).

In addition, as already described in the section on “Commissioning,” the owner assumes responsibility for operation of the system.

Consequently, acceptance has far-reaching implications for the owner and should be conducted with the utmost care, in particular in order to rule out safety risks (from e.g. electric shock or fire). A careful inspection should reliably detect any defects or deviations from the version type, quality and specified properties. An inspection can also yield demands for improvement or redelivery.

Since owners often lack the appropriate technical background for a qualified assessment of the system, it is advisable to bring in specialists. Besides technical qualification and technical orientation of the service provider(s), a certain store of experience in assessing PV systems is extremely useful. Qualified companies are sufficiently and everywhere available.

The scope of the tests and checks performed in the inspection should be adapted to the type, size and complexity of the system as well as to particular environmental conditions or a special requirement profile. For example, a building-integrated PV system has more checkpoints than a roof-parallel system. For a large-scale system with a corresponding investment volume, a more in-depth performance inspection is also advisable compared with a small system. The decision ultimately lies with the owner or investor. Claims may also come from banks or insurers, however.

Figure 5-34: Visual inspection (left at the inverter) and measurement (right at the GJB) as part of the acceptance inspection

<u>A qualified acceptance inspection should comprise the following key points:</u>

- Checking of the documentation
  - Completeness
  - Correct selection and design of components
  - Suitability of the components for the given purpose
  - Interplay of the individual components

- Comparison of the installed system against the specification
  - System parameters (design and dimensioning)
  - Orientation and alignment of the generator
  - Component selection
  - Workmanship
  - Realization of assured properties

- Comprehensive visual inspection
  - Determination of compliance with relevant standards and guidelines
  - Check for absence of defects

- Testing and measuring
  - e.g. string measurements (short-circuit current, open-circuit voltage, insulation resistance)
  - e.g. thermographic examination
  - e.g. activation of technical safety parts of system
  - e.g. U/I characteristic curve measurements
  - e.g. mechanical measurements

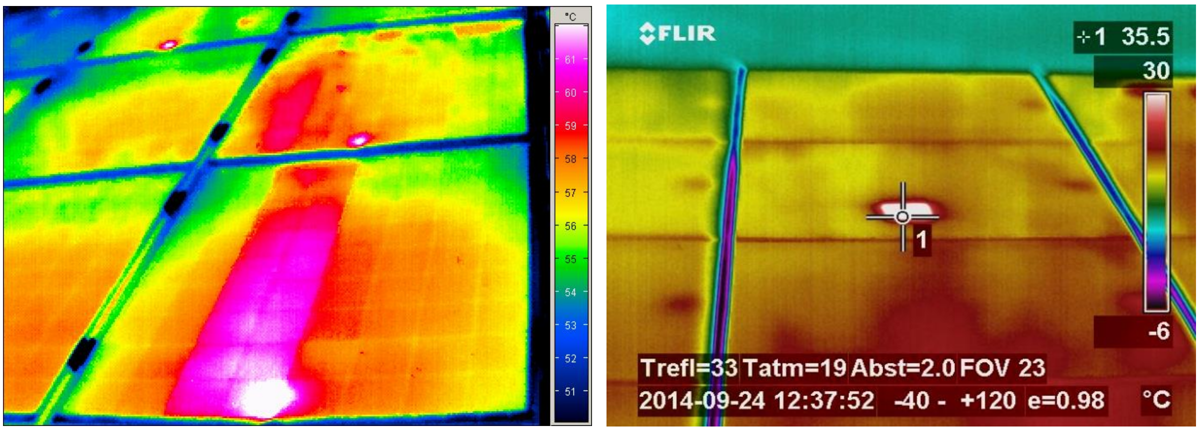


Figure 5-35: Examples of thermography at the PV generator

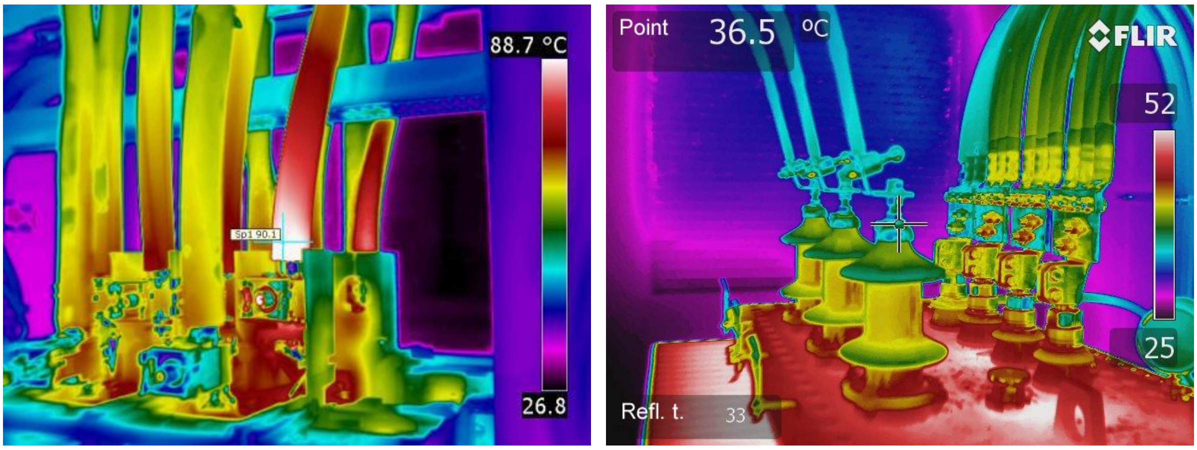


Figure 5-36: Examples of thermography in the subdistributor and at the transformer

Important is that all relevant system parts from the module to the in-feed point be considered. The system also includes (e.g.) the module substructure and the foundation or anchoring

The assessment of the system should also consider the quality of the work performed as well as the suitability of the system for long-term operation (20 years and more).

Besides the main assessment criteria, other criteria can certainly play an important role, such as:

- Easy maintenance
- Impact on people and the environment
- Realization of assured properties

Conclusion

A comprehensive and detailed system acceptance inspection significantly reduces the failure and safety risks, since defects and deficient quality can be detected and rectified.

5.5.2 Maintenance and inspection

Contrary to past statements made by some component manufacturers and system installers, PV systems are in no way maintenance-free!

They are subject to high stress from external factors, in particular climatic influences (wind, rain, hail, snow pressure, UV radiation, rapid changes in temperature, etc.).

In addition, typical aging mechanisms also occur among PV systems. As with all components and systems, malfunctions or premature failure can occur. In addition, extraordinary events or influences (e.g. marten bites, aggressive substances, extreme temperatures, lightning strikes, etc.) can lead to damage or accelerated aging. Besides yield losses, these types of damage or material changes can also cause (e.g.) local overheating, which in the worst case can lead to thermal destruction of components, to the formation of a stable DC electric arc, and even to a fire in the PV system.

Consequently regular inspections and maintenance measures are required to ensure safe and proper operation. Appropriate inspections and maintenance of the system can equally increase the system yield.

Different measures and intervals are useful depending on the type of system and stress. Besides fixed intervals, additional event-controlled inspection and maintenance are useful. They should be carried out in case of certain events (e.g. after a storm, malfunction messages, system failure, drop in yield, etc.).

The following is a list of generally applicable inspection and maintenance measures.

<u>Typical inspection measures</u>:

- Visual inspection (e.g. for external damage or material changes)
- Check of the system parameters (status displays, error messages, yields, etc.)
- Testing and measuring (here the same measures as in commissioning, or a subset thereof, come into question; often only spot checks)

<u>Typical maintenance measures</u>

- Cleaning of PV modules and meteorological sensors
- Cleaning of cooling fins and ventilation ducts or filters
- Maintenance of green areas and cutting back of plant growth
- Replacement of wear parts
- Testing and activation of safety devices (see note in section 3.3.3.2)
- Adjustment or calibration of parameters

Note that different types of qualification and equipment are required for implementing the individual points. For example, certain measures can be carried out by the operator himself. Others must be carried out by specialists (e.g. an electrician) with the appropriate qualification and equipment.

On the market many providers are available for PV system maintenance. Often so-called full-maintenance agreements are offered. Note that the measures to be implemented are often included in the agreement and also that intervals are stipulated.

Often combined maintenance and operating agreements are offered. The advantage here is that both responsibilities coincide and no interface issues arise. On the other hand, usually a control mechanism is lacking here.

Conclusion

Inspections conducted routinely and in the event of special events, as well as regular maintenance, contribute towards minimizing the failure risk in the long term and avoiding hazardous situations.

5.5.3 Switching and disconnecting devices

For carrying out inspections and maintenance, the PV generator and inverter must be electrically disconnected. Section 6.3 describes the special problems of shutdown on the module level in the event of fire department or other rescue operations.

For measuring individual strings, they must be separated. The appropriate devices for disconnection and separation are therefore required. Often they will be implemented in generator junction boxes that can be equipped with a load-break switch and disconnect terminals or fuse holders with a disconnecting function.

Figure 5-37: Generator junction boxes with load switch and disconnect terminals

In the case of string inverters, disconnection is partially integrated in the inverter. Disconnection of the strings is possible here by means of the plug connector at the inverter input.

Generally only the **load switch or load-break switch** may be operated under load. All other disconnectors may be operated only if load-free. Usually the corresponding warning labels will be attached. The accident prevention regulations must be followed (in particular the BGVA3).

Note: Reverse polarity voltages may occur from parallel connections in coupling boxes or in the inverter. The PV modules are always live when irradiated.

Figure 5-38: Fuse holder with disconnecting function

Figure 5-39: Disconnector with fuse

Figure 5-40: Load-break switch

The corresponding disconnecting devices must also be provided at the **AC end**. They are usually located directly at the inverter (central inverter), alternatively in subdistributors.

Switching and disconnecting devices also occur in the transformer station or, in the case of large systems, in the medium voltage station (Figure 5-41). Here the corresponding devices for disconnection, short-circuiting and grounding must be reserved (e.g. a grounding and short circuit kit for the transformer, see Figure 5-42).

Appropriate switching actions may at these points be performed only by specialists with switching authorization and if necessary protective equipment.

Figure 5-41: Medium voltage station

Figure 5-42: A grounding and short circuit kit for the transformer

5.5.4 Automatic system monitoring

As described in the preceding sections, it cannot necessarily be assumed that PV systems will operate over the entire operating period (usually at least 20 years, in the case of new systems the assumption is 30 years) without malfunctions and without changes in performance or yield. To limit yield losses from malfunctions, partial failure or reductions in performance as much as possible, qualified parameter monitoring as well as quick detection and reporting of faults is required.

This is usually made possible by system monitoring.

Since the system parameters are directly influenced by the irradiation conditions and the temperature level, no direct performance parameter can be derived without knowledge of these environmental conditions. Accordingly, the sensors, including the irradiation measuring devices, must be of high quality.

The devices require **regular checking and calibration** as well as systematic maintenance in order to keep measurement inaccuracies at a low level.

Performance parameters can be determined and analyzed by correlating the weather data with the system parameters. A very widespread parameter is the so-called “Performance Ratio” (PR), which specifies the ratio of supplied energy to the irradiation energy and thus serves as a measure of the efficiency of the PV system.

The error detection options depend on the type and quality of the monitoring system. For example, a detailed string current monitoring can quickly detect and localize a failure or a significant power decrease in the strings. Deviations can be detected by relative comparisons between parallel strings Problems with individual inverters (e.g. delayed start-up or intermittent failures) can also be detected in this way.

In PV power plants (very large systems) several strings are often grouped to limit the amount of data

Various solutions are available on the market. Figure 5-43 shows typical string monitoring; here the time-dependence of all string currents in different resolutions (time intervals) of an inverter can be displayed and analyzed.

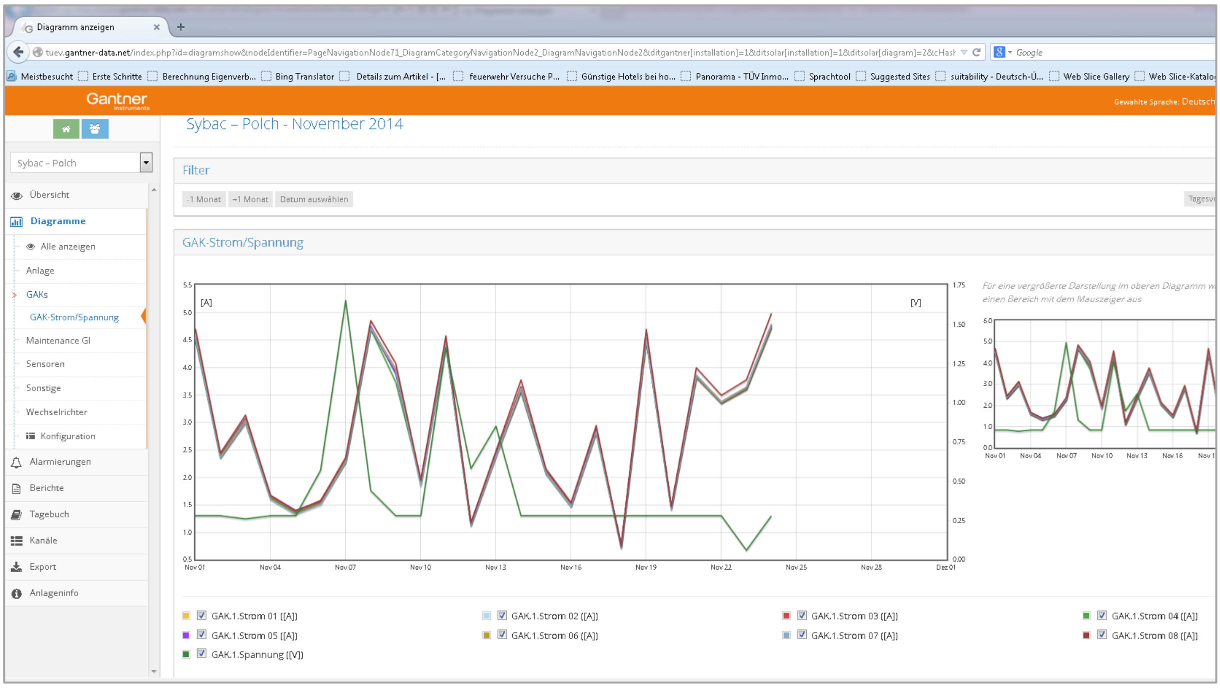


Figure 5-43: Example of online monitoring portal with string current monitoring

5.6 Devices for switching off solar modules and generators

5.6.1 Task

Solar cells generate an electric voltage as long as they are illuminated. While at very low irradiation this voltage is low, it quickly increases with increasing irradiance to full voltage. The current supplied by a solar cell is proportional to the irradiance.

Compared with batteries, solar generators cannot be switched off without additional measures. This property deviating from the usual voltage sources requires special scope both during the installation and maintenance of the PV systems and in any required rescue operations at buildings with PV systems or even at open-space systems.

Rapid growth in PV systems led around 2008 to intensified discussions on whether the absence of a switch-off feature poses an unmanageable risk to rescue workers and whether firefighters should deliberately let buildings with PV systems burn down. Ultimately, these discussions led in 2010 to a decision by the Interior Ministers' Conference of the German States to the effect that all PV modules without exception must have a switch-off feature. The standardization committees of the DKE were requested to prepare corresponding product and installation standards. A working group was organized to formulate the VDE application rule VDE-AR-E 2100-712 describing basic "measures for the DC part of a photovoltaic system for maintaining electrical safety in the event of firefighting or technical assistance" [75], [76].

Since no established state of the art yet exists in the matter of module and generator shutdown that could serve as the foundation for a product standard, this application rule describes merely technical and organizational minimum requirements for obtaining a safe system condition.

A shutdown is generally not required, but is an optional solution if structural measures (e.g. safe routing of cables, placement of cables and inverter outdoors) are implemented but are not regarded as sufficient (see also section 6.3.3: Electrical installation requirements).

The aforementioned controversial discussions of the danger potential for rescue workers have also initiated the preparation of comprehensive information material for fire departments and rescue workers as well as advanced training measures. The greater objectivity in reasoning has led fire departments to shift away from the general demand for a shutdown on the grounds that theoretically any switch-off device can fail.

Since rescue workers during an operation are hardly able to follow the "five safety rules" [77] **when handling electrical installations, they must assume (despite the possible presence of a switch-off device) that the installation is <u>not</u> de-energized.**

They must accordingly adhere to the proven basic rules of approaching electrical installations only at the prescribed distance of 1 m for live parts and 1 m for extinguishing operations with a spray jet and 5 m with a full jet.

Given over 1.5 million PV systems installed in Germany by the end of 2014, with a total output of approx. 38 GW, there remains a crucial question of whether switch-off devices can be retrofitted and whether such retrofitting can be required. Besides these technical questions, there are also legal issues as to how to incorporate protection of stock, for example.

It must therefore be assumed that in both the medium and long term rescue workers will encounter installations both with and without such switch-off devices. Since which is the case will usually be unknown, in the future rescue workers will have to treat each installation as though it cannot be switched off.

In other countries, especially the USA, other approaches prevail. Here, under the heading "Rapid Shutdown (NEC 690.12)," the current National Electric Code [78] incorporated the demand that each photovoltaic system – whether building-integrated or in an open space – can be switched off within 10 seconds. Here a residual voltage of 30 volts or a residual power of 240 VA may persist. These requirements do not relieve rescue workers of the responsibility for complying with their past safety rules.

5.6.2 General requirements on systems for switching off a solar generator or a solar module

In the past, numerous proposals for shutting down PV systems in emergency situations have already been made and tested. They have been compiled and evaluated in (e.g.) [79] and [80].

An initial class of possibilities is based on **expansive, lightproof covering of the solar generator** by means of (e.g.) extinguishing foam, tarps or even an opaque gel. These approaches have so far not been technically constructive or, from the fire department's perspective, practical. Extinguishing foam generally does not adhere to the typically inclined and smooth module surfaces, gel application is too time-consuming and tarps require practically zero wind and cannot be used with larger installations (see Figure 5-44). At a house fire possibly hazardous to people, rescue workers will always first attempt an inside attack in accordance with the proven rules of conduct and not give primary attention to covering the solar generator. These theoretical principles for shutting down solar generators are not covered by application rule VDE-AR-E 2100-712.

Figure 5-44: Tests on lightproof covering of PV modules, photo: http://pv-notaus.de/gefahren.html

The second class of systems performs an **electrical shutdown within the PV system** itself. This can theoretically occur on difficult levels from the module to the inverter, with different levels of personal protection being attainable. The required additional work also differs from measure to measure. The aforementioned application rule considers only PV systems at or on top of buildings.

A switch-off feature has to date not been required of open-space systems, but could be advantageous if (e.g.) people from a motor vehicle or plane have to be rescued from such a system (e.g. noise barrier along a highway).

The basic function required in application rule VDE-AR-E 2100-712 requires that in the event of a power failure or shutdown of the inverter the DC cables routed in a building be automatically switched off by a protective device located outside the building.

“Switched off” here means that

- the voltage must be less than 120 V
- the total of all short-circuit currents at the output end must be less than 12 mA
- the energy of the DC system at the output end must be less than 350 mJ.

Like bypass diodes, the switching devices must be able to continually conduct 1.25 times the rated short-circuit current, and they should have a fail-safe feature, i.e. in the event of a malfunction automatically enter a safe off-state. If this is not ensured (as in the case of semi-conductor switches, for example), a daily function test is necessary when cutting in the inverter in the morning, for example.

In addition, the systems must not lead to impermissible operating states such as reverse currents within generators if individual modules are switched off by a short-circuiting device either unintentionally or after a time delay.

The switch-off devices must be actively switched on by an enable signal. If this signal is not continually applied, a shutdown must occur within a maximum of 15 seconds. This enable signal may be generated only in the presence of supply voltage, but can be suppressed by other switching and monitoring devices (e.g. fire alarm systems) or even manually.

On entry of a normal operating state (e.g. recurrence of supply voltage) the switch-off device may automatically cut in again.

On stand-alone systems the enable signal must be interrupted if the system forming the stand-alone network is switched off.

5.6.3 Technical devices for switching off solar modules and generators

The application rule considers the possibilities for shutdown on the generator level and on the module level. Both the options of disconnection and of short-circuiting are included.

Figure 5-45 shows an example of a device for disconnection at the generator end or at the building entry point. Such disconnecting devices known as “*fire department switches*” must meet the requirements on switchgear as per DIN EN 60947-3 (VDE 0660-107) or DIN EN 60947-2 (VDE 0660-101).

Other requirements must still be laid down in a product standard.

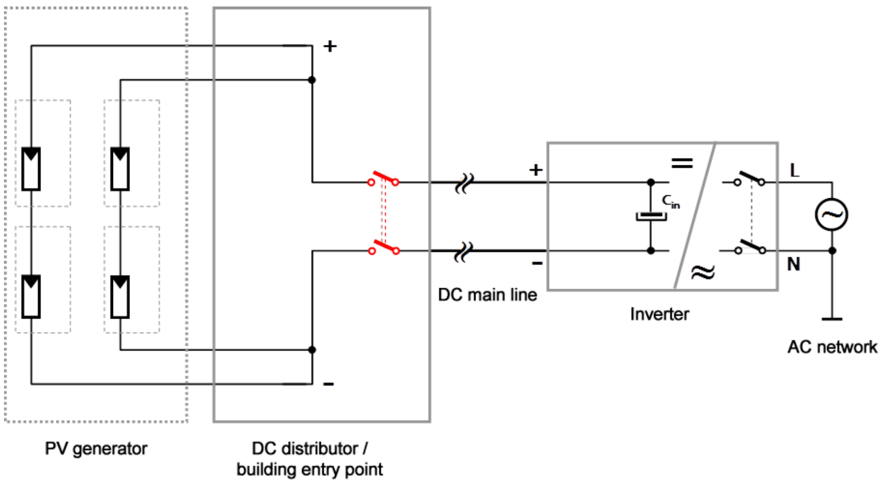


Figure 5-45: Example of device for disconnection at the generator end

Shutdown by continual short-circuiting of the solar generator as per Figure 5-46 is not permitted according to the application rule. The reason is that while the cables downstream from the short-circuit point will be de-energized, at a disconnection point in the short-circuited string the full string voltage occurs, which ultimately presents a greater hazard potential within the solar generator itself. Constant short-circuiting must therefore be avoided. Brief (15 s) short-circuiting for turning off parallel electric arcs between two live cables is permissible, although such parallel electric arcs are extremely rare.

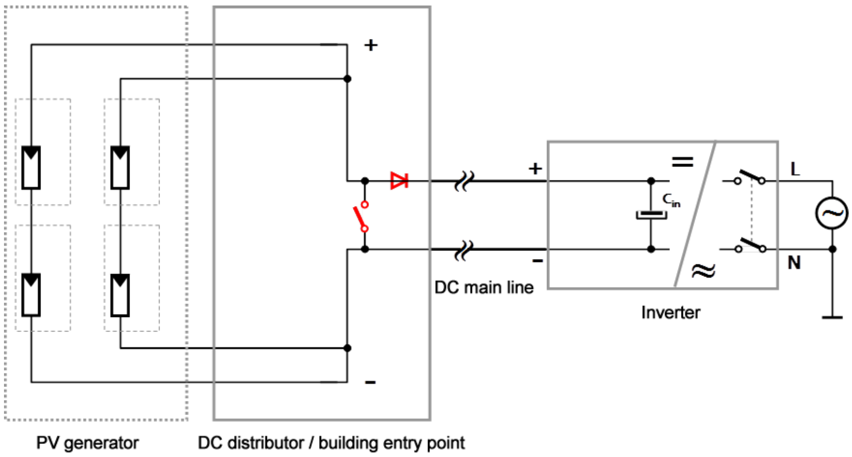


Figure 5-46: Example of device for short-circuiting at the generator end

Figure 5-47 shows a device for shutting down a solar module through disconnection. Although not expressly mentioned in the application rule, this also includes modules with integrated or allocated DC/DC or DC/AC converters providing an equivalent function. Essential here is that the switch-off device can also be a semi-conductor switch without a disconnecting function if the typical failure mechanism ensures a shutdown. If this is not ensured, a daily automatic function test is required; see above.

The requirements on such devices for shutting down a PV module must still be specified in a product standard.

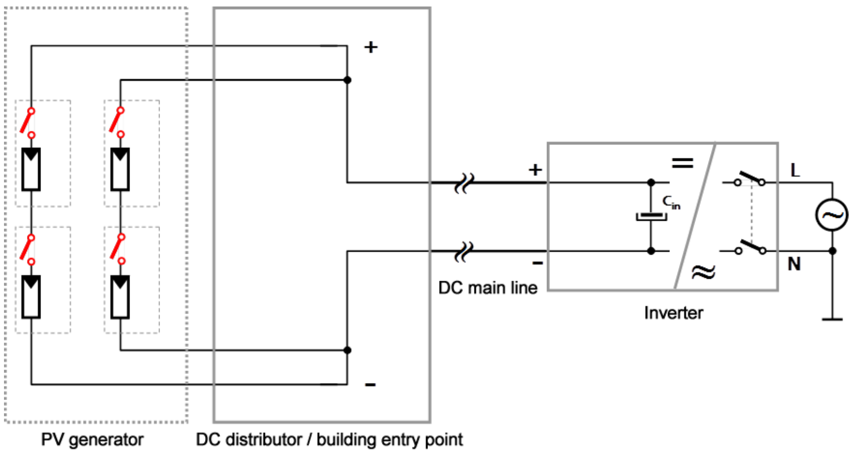


Figure 5-47: Typical device for shutdown by series switch on module level.

The device shown in Figure 5-48 for short-circuiting on the module level was in particular rejected by the module manufacturers during the public opposition proceedings on the application rule. No final result could be obtained, so that the requirements on such devices for short-circuiting a PV module must still be laid down in a product standard.

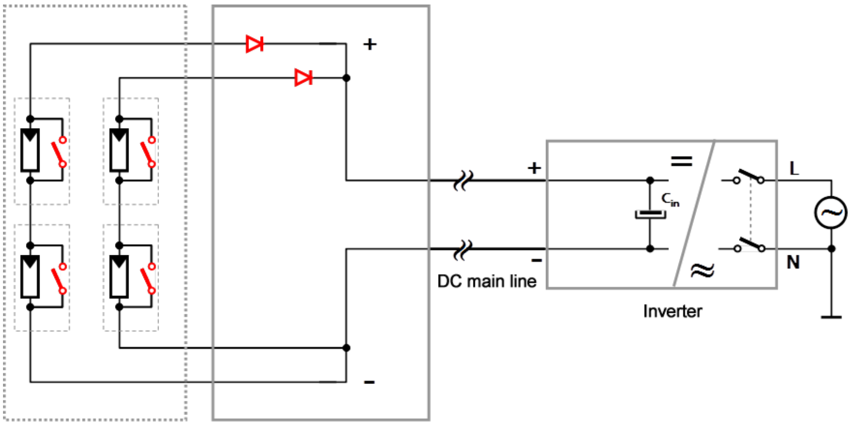


Figure 5-48: Typical device for shutdown by short-circuiting on module level.

5.6.4 Summary

The VDE application rule describes a series of measures for preserving electrical safety in the event of firefighting or technical assistance.

A shutdown of the solar generator or of the individual modules is not mandatory, but is an option.

A further conclusion from the studies on the load-break switch from 3.3.3.2 is that switches react to constantly increasing ambient temperatures with accelerated contact degradation. Planning should oversize the switches: like the DC lines, the switches should have a load capacity of at least 125% of the rated current of the system. Switches subject to elevated ambient temperatures must be designed as per the manufacturer’s derating specifications:

- All switches should be inspected once a year in order to discover any signs of overheating.
- All switches should undergo maintenance once a year and then be operated ten times.

The detailed technical requirements on such shutdown or short-circuiting systems must still be laid down in product standards. A joint research project with support from the Federal Ministry for Economic Affairs and Energy (BMWi) with reference number 0325596F is currently implementing basic pre-normative work on the subject. The partners, TÜV Rheinland LGA Products, E-T-A Elektrotechnische Apparate, Q3 Energieelektronik, Eaton Industries and SMA Solar Technology, are concerned with aging and reliability testing of these devices.

5.7 Identification marking and information commitments

Generally rescue workers must maintain the distances as per VDE0132 during extinguishing operations. If switch-off devices as per the VDE application rule VDE-AR-2100-712 are used in PV systems, the particular output DC system may be considered as a protected area. The switch-off devices and the area protected after shutdown should be separately indicated in the general plan.

Recommendation Once module switch-off devices certified as per a product standard come on the market, a separate sign with (e.g.) green border and supplemented with a module switch symbol should be used. Rescue workers will then be able to discern quickly that no hazardous DC voltage can exist at the generator.

Generally it would be a good idea if the information as to whether a PV system exists on a building would already be available at the firehouse prior to the crew's departure. Keeping this information up to date is a challenge, however. An additional problem is that not all firehouse computers have internet access. Useful would be a central database in the internet that the state authorities could access and the distribution of the address data to the pertinent administrative districts or directly to the fire department switchboards or firehouses.

The registrations of the PV systems sent to the Federal Network Agency would generally be suitable for this purpose. A corresponding request from the project group was denied by the Federal Network Agency, however.

The compilation and evaluation of all network operators' system registrations on the Web pages of the DGS: www.energymap.info (csv file with address data of all systems registered under the Renewable Energy Sources Act in Germany) would be generally suitable. A suitable online user interface for address and postal code searches would still have to be developed, however. A bigger problem lies in the deficient up-to-dateness and in the missing address data. Registration by the network operators occurs up to 18 months following commissioning.

Over 10,000 PV systems currently contain no address data. The addresses usually specify the grid connection point, which may not match the system location. All data would have to be checked or, better, the network operators compelled to properly comply with their legal obligation (Renewable Energy Sources Act § 52).

6 Measures for improving the operational safety of rescue workers

6.1 System identification

PV systems on roofs are not always visible, especially with severe smoke development. At present, no central file is available that promptly registers all installed PV systems. Quick and clear information for the fire department and other rescue workers must therefore be ensured at the actual scene of the fire.

Identification at the house connection box will enable firefighters to quickly ascertain the presence of a PV system on the building. For the purpose of identification, a warning sign Figure 6-1) as per application rule VDE-AR2100-712 must be affixed at the delivery point of the PV system, e.g. at the house connection box or building main distributor (a corresponding sticker can be obtained online from the Deutsche Gesellschaft für Sonnenenergie e.V. (DGS)).

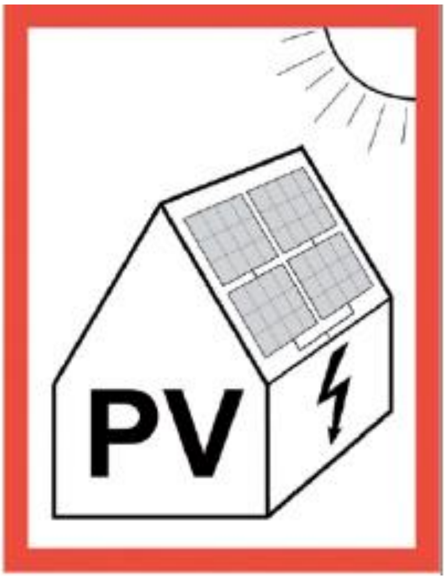


Figure 6-1: PV sign as per VDE-AR2100-712

6.2 Fire department schematic – cable routing and technical equipment

In addition, a general plan (Figure 6-2) as per application rule VDE-AR2100-712 must be present in suitable form (posted or otherwise displayed) at the delivery point of the electrical system to assist rescue workers in quickly determining the locations of live components in the building. Any fire department diagram as per DIN 14095 should be revised prior to commissioning.

The general plan must depict the types and locations of the PV system components as simply and as clearly as possible. These include

- all live cables that cannot be switched off
- live PV DC cables routed in the building and protected against fire
- location of the PV generator
- positions of all DC disconnecting devices.

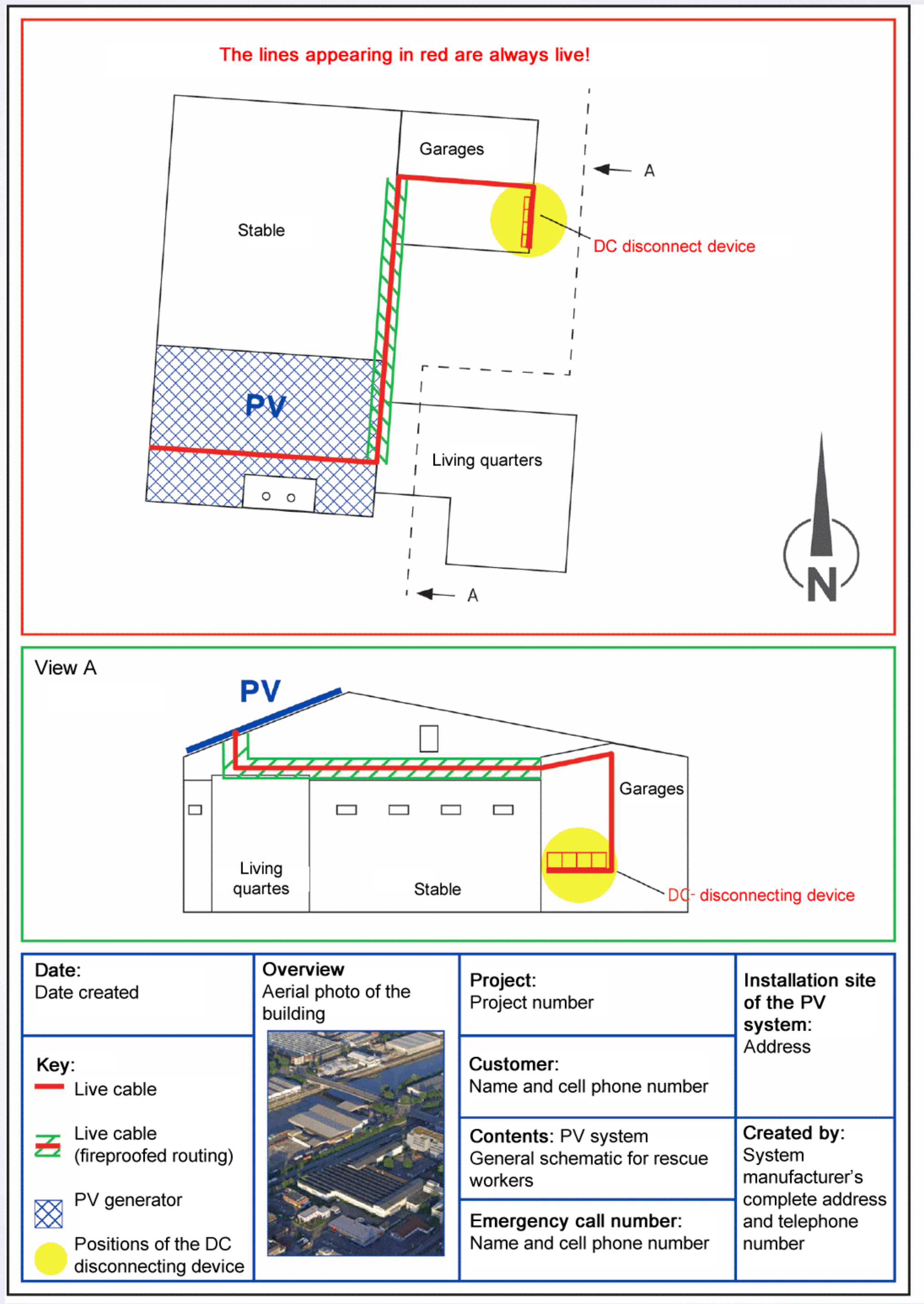


Figure 6-2: Example of a general plan for rescue workers as per VDE-AR-2100-712

6.3 Operational specification in case of fire

Section 5 already considered the variety of possible fire incident scenarios. Although these situations differ in tactical and technical procedures in the operational case, we can summarize the technical, organizational and personal protective measures as follows.

Technical measures

Technical measures should automatically bring the PV system to a safe state regardless of the malfunction. The safe state obtains if even untrained persons can work on the system without danger. Additional human intervention should not be required for attaining a safe state. **Normative technical solutions are under development.**

Organizational measures

The consideration of organizational measures did not separately address any generally common procedures in cases of fire and technical assistance, such as the use of breathing protective equipment and attention to possible debris zones.

Among all considered scenarios, basically the safety distance may be mentioned from an organizational perspective. A distinction must be made between the basic distance on the part of the rescue workers and the distance to be maintained during extinguishing operations. The brochure on “Electrical Hazards at the Scene of a Fire” (GUV-I 8677) published by the Deutsche Gesetzliche Unfallversicherung e.V. (Registered German Social Accident Insurance) requires a minimum distance to be maintained from all low-voltage systems and system components. If possible or if the situation is unclear, the safety area must be cordoned off.

Extinguishing operations are subject to differentiated safety distances as per the standard on “Firefighting and technical assistance in or near electrical installations” (DIN VDE 0132) from the Verband der Elektrotechnik, Elektronik und Informationstechnik e.V. (Registered Association of the Electrical, Electronic and Information Technology). The distances were also confirmed for PV systems in the practical testing of the research project.

Work in the area of or at a damaged PV system may be performed only by electricians. Technicians can also bring the system to a safe state so as to allow safe work. If the system or the switch elements are still undamaged, the system can be partially shut down by even untrained personnel (see BSW pocket map). Personal protective equipment as per the applicable standards must be worn for all work.

In particular, in the case of high-voltage systems, all work must be performed exclusively by specially qualified electricians.

If artificial lighting is used, safety distances as per section 4.5.2 of the research project apply as a recommendation.

Personal measures

To minimize hazards to personnel, in addition to all technical and organizational measures, knowledge about the hazards, effects and safety measures must be conveyed through training and reinforced through continual advanced training. Important in conveying this knowledge is standardized training content. It can be imparted only by technically qualified personnel. The training should comprise both a theoretical part and an on-site practical part. In addition, specialist companies can provide support to the training.

6.4 Operational specification if PV system flooded (danger of explosion)

Operations in the area of flooded PV systems require expanded organizational measures in addition to the activities already described in section 7.3. In addition to compliance with the usual safety distances, flooded areas may be entered only if no voltage is present (GUV-I 8677). To ensure the absence of voltage, an electrician should disconnect from the generator all system parts standing under water. In this way any further hydrogen production can be avoided.

Because of the possible detonating gas formation, explosion measurements must be performed as the emergency team proceeds with its work. If these measurements determine a danger of explosion or there are concrete indications of such a danger, the area cordoned off for this danger must be adapted according to the usual distances.

In addition, damage to electrical accumulators can release toxic and caustic gases (such as HF).

Selective ventilation of the affected areas can counteract these hazards.

7 Summary and outlook

This Guideline summarizes the results from over 3 years of research work by the consortium with support from other PV experts, professional associations, industrial partners, fire departments, installation companies, insurance companies and operators.

The work comprised several groups of topics:

- Fire risk assessment in PV systems, regarding both the effects of a fire from outside the system and the fire emergence risks within the PV system itself.
- Risk assessment during PV fire for rescue workers, in particular firefighters and strategies for avoiding risks
- Evaluation of possibilities for minimizing fire emergence and fire propagation risks within the PV systems
- Derivation of recommendations regarding component and system design, materials, quality assurance in manufacture, installation and operation

For the risk analysis, between 2011 and 2013 comprehensive research was conducted on actual fire damage to PV systems, including an online survey as well as surveys of professional fire departments and PV insurers in Germany. 430 cases of fire or heat damage in PV systems were investigated, in approximately half of which the PV system was considered the cause or probable cause. The studies found that in around a third of the cases the damage was caused by the PV components themselves, in another third by planning errors and in a final third by installation errors. Disproportionately many of the fire incidents occurred around mid-day or early afternoon and during the summer months, i.e. at high irradiance and therefore high current load. In these cases, defective and possibly pre-damaged components failed.

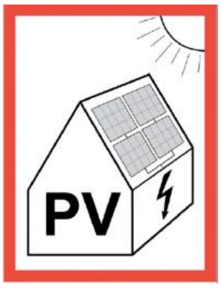
Given the findings from research and lab tests, an expert committee conducted an FMEA (“Failure Mode and Effects Analysis”). The main causal source of fault was found to be the “human factor so that the derived recommendations concern mainly quality assurance for the components as well as the planning and workmanship of the PV systems.

<u>For the standardization we recommend defining intensified quality assurance measures in production</u>, on both the component and module levels. Many manufacturers are already operating on a high level. A standardized quality assurance catalog will provide a uniform measure of quality and help prevent risks through the continual monitoring of the products.

<u>Regular testing of the systems</u> by independent third parties was deemed very purposeful. Additional safety components can further reduce the risk, but were ranked only in second place, following professional planning and construction of the systems with high-quality components.

In many cases <u>defective or prematurely aged contacts</u> of components were identified as sources of risks, both inside the modules themselves (junction boxes!) and among plug connectors and connections at contacts in collector boxes and inverters. These defects lead in the long term to overheating, which ultimately can cause scorching or an electric arc. <u>The particular surrounding materials and installation situation</u> then determine the further development of the damage. For example, inverter installations on or above a combustible supporting surface (wooden board), as often found by appraisers, can have devastating consequences in the event of a fault, as can (normally flammable) foil sheeting or wooden beams of the roof structures when BIPV modules are used.

Despite quality assurance measures, overheating or electric arcs cannot be ruled out 100%. <u>Electric arc detectors can in principle additionally reduce risks</u>, but only if they have greater detection reliability and a lower tendency to faulty activation. Owing to the electric arc characteristics and many possible interference factors, this improvement is very challenging and moreover inverter-specific. Here further development is called for. Intensive research in the project already indicated approaches that require still further development. Another open issue is the necessary robustness for guaranteeing functionality during the currently estimated 25 – 30 years' operating time of the PV systems.



The project declared information on the presence of a PV system on a building to be a basic factor for firefighters' operational safety, a requirement to be implemented by a defined marking by means of a warning sign at the entrance area or at the house connection box.

Risks for firefighters come especially from the DC voltage produced at the generator field, voltage that persists even after disconnection from the grid at the DC end as long as light is impinging upon the modules.

At present no established state of the art exists for module and generator shutdowns and consequently no product and installation standards exist as yet. The standardization committees of the DKE have thus far developed an application rule (VDE-AR-E 2100-712) describing the technical and organizational minimum requirements for obtaining a safe system state in case of an emergency. A shutdown is generally not required, but is an optional solution if structural measures (e.g. safe routing of cables, placement of cables and inverter outdoors) are not regarded as sufficient.

Since rescue of people always has priority for emergency teams in tense situations under time pressure, compliance with the "five rules of safety" when dealing with electrical installations will hardly be possible. Despite the possible presence of a switch-off device, they will have to assume that the system is not de-energized.

This hazard can be counteracted by maintaining a minimum distance of 1 m, as is generally recommended for electrical installations. In particular, in cases of fire incidents with very restricted visibility, unclear situations in the building and the possible necessity of rescuing people, damaged DC cables pose an electrical hazard of high degree for the rescue workers. The risk-reducing routing of PV system cables inside or on top of the building therefore deserves particular attention. They should be routed as much as possible outside the building or through fire-protected conduits.

Series of conductivity tests have confirmed that if the specified minimum distances – 5 m with full jet and 1 m with spray jet – are maintained, then no danger to the rescue workers from hazardous electric currents via the extinguishing water jet will occur. To be kept in mind is the use of approved nozzles and water as an extinguishing agent, since foam additives will increase conductivity. The measurements moreover made clear that wet turn-out gear practically no longer provides protective insulation. Flooded basements with electrical installations such as inverters or electrical accumulators (batteries) pose a danger to life in the case of a fault! In addition to the risk of electric shock, caustic and explosive gases (electrolytic gases) can form. Good ventilation is therefore essential.

Studies on emissions during fires have found contamination levels added to the CO and CO_2 levels usually produced in house fires. Possible exceedances of toxicological limits among the heavy metals like lead and cadmium released depending on the technology were found only in the immediate vicinity of the fire site and only under very unfavorable conditions. On the basis of our research of the literature, our own fire tests and a propagation simulation, we can rule out any hazard to the environment from gaseous pollutants related to burning PV modules. Fire residue can contain toxic heavy metals like lead and cadmium in amounts exceeding the limits (soil thresholds for residential areas). In the event of damaged CdTe modules, quench water may introduce critical amounts of cadmium into the soil. While the measurement results cannot be generalized, they indicate a risk potential. We therefore regard the proper disposal of fire residue as crucial. In the event of more extensive fire damage to CdTe modules, we recommend soil examinations in the immediate vicinity.

Comprehensive series of tests with artificial lighting (spotlights) have confirmed that under certain conditions operational spotlights can generate dangerously high currents in the modules. The project arrived at a generally applicable and simple distance formula that will enable firefighters to quickly determine the minimum distance for the employed spotlight power and thereby avoid electrical hazards from DC currents during night-time operations.

During its runtime the project increasingly used PV systems with accumulators. The state subsidies for these systems particularly in the small system segment and the rapid development of accumulator technologies lead us to expect increasing dissemination over the coming years. This research project was able to assess the new installation situations and risks only in individual cases.

A further research project headed by TÜV Rheinland will analyze the particular properties and risks from electrical accumulators in cases of damage. The full title runs: *Safety and reliability of photovoltaic systems with accumulator systems with particular consideration of fire risks and fire extinguishing strategies*.

In conclusion from the studies conducted in this and other parallel research projects, we may state that the fire emergence risk in PV systems is very low given planning in accordance with fire protection, use of high-quality components and proper installation. While overheating from contact aging during the operating time cannot be ruled out, it usually occurs only over longer periods of time. In the worst case an electric arc can occur. Direct current electric arcs are not self-extinguishing and therefore pose no risk of fire propagation. Regular inspections and maintenance can prevent more serious damage, as can inspection following special events such as storms or earthquakes. For special installation situations, electric arc detectors with switch-off devices can provide additional safety. These devices still require further development in terms of reliability and longevity.

PV systems pose no special danger for firefighters if the safety distances are maintained, as is the case with any other live electrical systems. An elementary and effective protective measure for firefighters is an easily visible sign indicating the presence of a PV system on the building.

8 Supplement

I. List of professional publications from the project

- *Fire Safety at PV Systems – Fire Prevention and Fire Fighting*, 15.02.2011, Photon PV Safety Conference, San Francisco – USA, F. Reil.

- *Normanforderungen zur Brandsicherheit sowie erweiterte Maßnahmen zur Brandvorbeugung und –bekämpfung*, 18.02.2011, 1st PV User Conference, Cologne, F. Reil.

- *Normanforderungen zur Brandsicherheit sowie erweiterte Maßnahmen zur Brandvorbeugung und –bekämpfung*, 18.03.2011, Argesolar Practice Workshop, Saarbrücken, F. Reil.

- *German Research Project: Fire Safety Risks at PV Systems and Risk Minimization*, 12.04.2011, Photon PV Safety Conference, Berlin, F. Reil.

- *Brandschutz an PV-Anlagen – Aktuelle Normanforderungen und Forschungsaktivitäten*, 14.04.2011, PV Components Workshop, Cologne, F. Reil

- *Normanforderungen für den Brandschutz von PV-Anlagen und Ausblick*, 17.05.2011, Bauzentrum München, Munich, F. Reil

- *Normanforderungen für den Brandschutz von PV-Anlagen und Ausblick*, 25.05.2011, Bauzentrum München, Munich, W. Vaaßen

- *Technische Möglichkeiten zur Abschaltung von Solargeneratoren im Schadensfalle – eine Übersicht und Bewertung*
  04. 03 2011, 26. Symposium on Photovoltaic Solar Energy,
  Bad Staffelstein, pages 594 – 599, Dr. H. Schmidt

- *Übersicht und Bewertung der verschiedenen Abschaltlösungen,*
  08.06.2011, DGS Workshop on "Photovoltaics and Fire Protection," Munich,
  Dr. H. Schmidt

- *Determination of Fire Safety Risks at PV Systems and Development of Risk Minimization Measures*, September 2011, EUPVSEC 2011, Hamburg, F. Reil, W. Vaaßen, A. Sepanski, B. van Heeckeren, F. Gülenc, Dr. H. Schmidt, R.Grab, G. Bopp, H. Laukamp, S. Phillip, H. Thiem, A. Richter, A. Krutzke, R. Haselhuhn, M. Halfmann, F. Volkenborn, Prof. Dr. H. Häberlin

- *Brandrisiken in PV-Anlagen und Erstellung von Sicherheitskonzepten,* November 2011, VDI Technical Form – PV and Fire Protection – A Smoldering Conflict, Düsseldorf, A. Sepanski, F. Reil, W. Vaaßen

- *Brandschutz an PV-Anlagen-Aktuelle Normanforderungen und Forschungsaktivitäten*, October 2011, TRLP Inverter Symposium, Cologne, F. Reil

- *Qualitätskontrolle von PV-Anlagen im Systemhaus*, January 2012, Fire Protection Workshop, Cologne, A. Richter

- *Statistische Schadensanalyse an deutschen PV-Anlagen*, January 2012, Fire Protection Workshop, Cologne, H. Laukamp

- *Lichtbogenversuche an Modulen und Komponenten*, January 2012, Fire Protection Workshop, Cologne, A. Sepanski

- *Elektrische Gefährdung der Feuerwehren durch PV-Anlagen (Messung elektrischer Leitfähigkeiten)*, January 2012, Fire Protection Workshop, Cologne, H. Thiem
- *Gefährdung beim Löschangriff an PV-Anlagen bei Mond- und Kunstlicht*, January 2012, Fire Protection Workshop, Cologne, Prof. Dr. H. Häberlin
- *Baustoffklassifizierung und Entflammbarkeitsuntersuchungen an PV-Modulen*, January 2012, Fire Protection Workshop, Cologne, F. Reil
- *Anforderung an die Qualitätssicherung*, January 2012, Fire Protection Workshop, Cologne, J. Althaus
- *Brandschutz bei BIPV,* January 2012, Fire Protection Workshop, Cologne, F. Reil
- *Brandschutzgerechte Installationen,* January 2012, Fire Protection Workshop, Cologne, R. Haselhuhn
- *Lichtbogenerkennung – Normüberblick und technische Anforderungen,* January 2012, Fire Protection Workshop, Cologne, S. Philipp
- *Sicherheitskonzepte zum Schutz vor elektrischem Schlag,* January 2012, Fire Protection Workshop, Cologne, S. Philipp
- *Fire Protection and Safety Concepts*, January 2012, 2nd Inverter and PV System Technology Forum, Berlin, H. Schmidt
- *PV Systems - a Fire Hazard? - Myths and facts from German experiences*, 2012, 27th EU PVSEC, H. Laukamp, G. Bopp, R. Grab, H. Häberlin, B. van Heeckeren, S. Phillip, F. Reil, H. Schmidt, A. Sepanski, H. Thiem, W. Vaaßen
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- *Risikoanalyse von PV-Systemen mit der FMEA-Methodik,* 2nd Workshop on PV Fire Protection, 24.01.2013, Freiburg, Dr. H. Schmidt:
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- *Bestimmung von Brandrisiken an PV-Anlagen und Ableitung von Maßnahmen zur Risikominimierung*, Berlin Science Days, Berlin, 27.11.2012, F. Reil:
- *Baulicher Brandschutz an PV-Anlagen*, NRW Consumer Protection, Siegburg, 23.11.2013, F. Reil
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- *Comparison of Different DC Arc Spectra – Derivation of Proposals for the Development of an International Arc Fault Detector Standard*, IEEE PVSC Publication, Tampa, USA, 2013
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- *Qualität in der Photovoltaik – Werterhalt und Ertragssicherung durch Wartung*, EnergieAgentur NRW, Düsseldorf, 2013
- *Zusammenfassung Schadensfallerhebung und -analyse,* Results of an Extensive Collection of Data on Damage Incidents, Fire Protection Workshop, Cologne, January 2014, H. Laukamp, Dr. H. Schmidt, Fraunhofer-Institut für Solare Energiesysteme ISE
- *Lichtbogendetektion in PV-Anlagen,* Fire Protection Workshop, Cologne, January 2014, R. Grab, Fraunhofer-Institut für Solare Energiesysteme ISE, Prof. Dr. H. Häberlin, L. Borgna, Berner Fachhochschule Technik und Informatik, BFH-TI
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- *Installationsempfehlungen und Diskussionsstand der zukünftigen PV Installationsnorm IEC 60364-9-1,* Fire Protection Workshop, Cologne, January 2014, G. Bopp, H. Laukamp, Fraunhofer-Institut für Solare Energiesysteme ISE
- *Neuartige Methoden zur Qualitätssicherung und Fehlersuche,* Brandschutz-Workshop, Cologne January 2014, *N.Bogdanski, TÜV Rheinland Energie und Umwelt GmbH, Dr. H. Schmidt, Fraunhofer-Institut für Solare Energiesysteme ISE*
- *Emissionen von Solarmodulen im Brandfall, Brandschutz-Workshop*, Cologne, January 2014, A. Sepanski, TÜV Rheinland Energie und Umwelt GmbH
- *Elektrische Risiken für Einsatzkräfte, Rückblick und neue Ergebnisse*, Fire Protection Workshop, Cologne January 2014, Horst Thiem, Berufsfeuerwehr München, M. Reichard, A. Sepanski, F. Reil, TÜV Rheinland Energie und Umwelt GmbH

- *Emissionen von Photovoltaikmodulen im Brandfall,* 11th Workshop on Module Technology, Cologne, November 2014, A. Sepanski, TÜV Rheinland Energie und Umwelt GmbH, B. Bansemer Currenta GmbH

Two television reports from *Bavarian Broadcasting* (*Geld+Leben* broadcast in 2011) and ARD (*Plusminus*) covered the debate on fire protection at PV systems. The present research project was also mentioned in the ARD broadcast.

In its broadcast *hitec* in December 2011, the German-language TV station *3SAT* intensively documented the conductivity measurements and referred to the work of the research project. The project homepage contains a link to the segment. The subject was also treated in the *WDR* program *Kopfball*, with very intuitive explanations of the topics covered in section 5.5.

II. Document download

- Brochure on “Brandschutzgerechte Planung, Errichtung und Instandhaltung von PV-Anlagen” (Planning, Installation and Maintenance of PV systems for Fire Protection): http://www.dgs.de/fileadmin/bilder/Dokumente/PV-Brandschutz_DRUCK_24_02_2011.pdf

- DIBT paper on “Hinweise für die Herstellung, Planung und Ausführung von Solaranlagen” (Information for the Manufacture, Planning and Implementation of Solar Systems) https://www.dibt.de/de/Fachbereiche/Abteilung_I.html

- BSW Solar, Information Sheet for Rescue Workers – Operations at Stationary Lithium Solar Energy Accumulators – Information for Firefighting and Technical Assistance http://bsw.li/1u5Yqz5

III. Websites

- Project homepage: http://www.pv-brandsicherheit.de
- Homepages of the project partners:
    - TÜV Rheinland Energie und Umwelt GmbH: www.tuv.com/PV
    - Fraunhofer Institut Solare Energiesysteme: www.ise.fraunhofer.de
    - Deutsche Gesellschaft für Sonnenenergie, Landesverband Berlin-Brandenburg e.V: http://www.dgs-berlin.de
    - Munich Fire Department / Fire Technology: http://www.muenchen.de/rathaus/Stadtverwaltung/Kreisverwaltungsreferat/Branddirektion-Muenchen.html
    - Currenta GmbH & Co. OHG: Analysis: http://www.analytik.currenta.de
    - Energiebau Solarstromsysteme GmbH: http://www.energiebau.de
    - Bern University of Applied Sciences: http://www.bfh.ch
      Photovoltaics Lab of Bern University of Applied Sciences: http://www.pvtest.ch
- Deutsche Gesellschaft für Sonnenenergie: http://www.dgs.de
- Bundesverband Solarwirtschaft: http://www.solarwirtschaft.de
  Guidelines on planning and installation of photovoltaic systems and other professional publications:
  http://www.dgs-berlin.de/de/publikationen/photovoltaikleitfaden.html
- German Federal Network Agency: http://www.bundesnetzagentur.de
  Photovoltaic system registry:
  http://www.bundesnetzagentur.de/cln_1411/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/ErneuerbareEnergien/Anlagenregister/Anlagenregister_node.html

IV. Survey

The survey on incidents of overheating and fire related to PV systems continues to be available online. The data continue to be collected in 2015. We appreciate your support.

You can reach us online at: http://www.pv-brandsicherheit.de

V. List of figures

VI. List of tables

VII. List of abbreviations

Abbreviation	Description
ABS	Acrylnitrile-butadiene-styrene copolymer
AEGL	Acute Exposure Guideline Level
a-Si	Amorphous silicon (thin-film module)
AR	Anti-reflective layer
ASTM	ASTM International (originally American Society for Testing and Materials)
Forward bias	Voltage applied across a P-N junction in the forward direction
BBodSchgV	Bundes-Bodenschutz- und Altlastenverordnung (Federal Soil Protection and Contaminated Sites Ordinance)
BIMSCHV	Federal Immission Control Ordinance
BMU	Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety)
BMWi	Bundesministerium für Wirtschaft und Energie (Federal Ministry for Economic Affairs and Energy)
CdTe	Cadmium telluride
CPS	Concentrated Solar Power
DIN	Deutsches Institut für Normung e. V. (German Institute for Standardization)
ETW	Einsatz-Toleranz-Werte (maximum exposure concentration)
EL	Electroluminescence
ERPG	Emergency Response Planning Guidelines
EVA	Ethylene-vinyl-acetate
EN	European Norms
FSI	Flame Spread Index
FTIR	Fourier transformation infrared spectrometer
GAK (GJB)	Generatoranschlusskasten (generator junction box)
HPLC	High Performance Liquid Chromatography
NN (msl)	Normalnull (mean sea level)
IR	Infrared (thermography)
IEC	International Electrotechnical Commission
ISO	International Organization for Standardization
IEC	International Electrotechnical Commission
c-Si	Crystalline silicon (thick-film module)
CIS	Copper indium diselenide
LBO	Landesbauordnung (state building code)
ICP-MS	Inductively Coupled Plasma Mass Spectrometry
Mpp	Maximum Power Point
ML	Mechanical Load

µ -Si	Micromorphous silicon
MBO	Musterbauordnung (Model Building Regulation)
PA	Polyamide
PAC	Protective Action Criteria
PET	Polyethylene terephthalate
PSA	Persönliche Schutzausrüstung (personal protective equipment)
PVB	Polyvinyl butyral
PVF	Polyvinyl fluoride
STC	Standard Test Conditions
IV	Current x voltage diagram (also I/U characteristic)
UL	Underwriters Laboratories
VFDB	Vereinigung zur Förderung des Deutschen Brandschutzes (Association for the Promotion of German Fire Protection)
WT	Wet Leakage

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IX. Appendices

a) FMEA results

Results of the FMEA analysis of fire risks in PV systems, Dec. 10, 2012, Frankfurt

Component involved / location	Potential faults	Potential causes	Actual status: Probability of occurrence	Actual status: Probability of fire emergence (significance)	Actual status: Probability of detection	Actual status: RPN	Improved status: Possible remedial measures	Improved status: Probability of occurrence	Improved status: Probability of fire emergence (significance)	Improved status: Probability of detection	Improved status: RPN	Comments
DC plug												
PV connectors	*Plug connector scorched*	*Plug not fully inserted*	4	7	8	224	*Training of the installers*	3	7	8	168	
							Plug design: Snap tabs, touch & feel, color ring, etc.	2	7	7	98	
							Acceptance inspection (DIN 0126-23)	4	7	7	196	
							Acceptance inspection (revised methods, e.g. IR)	4	7	6	168	*Develop new measuring methods*
							Regular repeat inspections (DIN 0126-23)	4	7	7	196	
							Regular repeat inspections (revised method, e.g. IR)	4	7	5	140	
							Electric arc detector	4	4	7	112	*If functioning reliable*
		Plug mechanically damaged or corroded due to improper installation, weather conditions, animal bites, production faults	4	7	7	196	*Training of the installers*	3	7	7	147	
							Acceptance inspection (DIN 0126-23)	4	7	7	196	
							Regular repeat inspections (DIN 0126-23)	4	7	5	140	
							Electric arc detector	4	4	6	96	
							Insulation measurement	4	7	5	140	
		Plugs poorly crimped at the factory (also within distributors, inverters, etc.)	3	7	7	147	*QA measures at manufacturer*					
							Acceptance inspection (visual, IR, new measuring procedures)					

			Actual status				Improved status					
Component involved / location	Potential faults	Potential causes	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Possible remedial measures	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Comments
		*Plugs poorly crimped **at the factory** (also within distributors, inverters, etc.)*	3	7	7	147	*Regular repeat inspections (visual, IR, new measuring procedures)*					
							Electric arc detector					
		Plugs poorly crimped on site	7	7	7	343	*Training of the installers*	4	7	7	196	
							Plug design: Contacts connected without tool	3	7	7	147	
							Regular repeat inspections (DIN 0126-23)	7	7	5	245	
							Electric arc detector	7	4	6	168	
		*Plugs from **different manufacturers** (fakes) combined*	7	7	9	441	*Training of the planners/ installers*	4	7	9	252	
							Suitability for standardized, compatible plugs	1	7	9	63	
							Normative exclusion of incompatible connections	2	7	9	126	
AC plug												
AC plug	*Plug scorched*	*Screw contacts insufficiently tightened*	3	6	5	90	*Training of the installers*					
							Acceptance inspection (visual, IR, new measuring procedures)					
							Regular repeat inspections (visual, IR, new measuring procedures)					
		Impermissibly rigid cable at unsuitable plug	5	5	4	100	*Training of the installers*					
							Acceptance inspection (visual, IR, new measuring procedure)					
		Impermissibly flexible cable without suitable conductor sleeves	5	4	7	140	*Training of the installers*					

			Actual status				Improved status					
Component involved / location	**Potential faults**	**Potential causes**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Possible remedial measures**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Comments**
		Impermissibly flexible cable without suitable conductor sleeves	5	4	7	140	*Acceptance inspection (visual, IR, new measuring procedures)*					
Screw terminals (DC)												
Screw terminals in field distributors, inverters (DC end)	*terminals scorched*	*Screw contacts insufficiently tightened, cables unsuitably introduced*	7	7	6	294	*Training of the installers, torque wrench*	4	7	6	168	
							Acceptance inspection (DIN 0126-23)	7	7	5	245	
							Acceptance inspection (improved, e.g. with IR or contact resistance measurement)	7	7	3	147	
							Regular repeat inspections (DIN 0126-23)	7	7	4	196	
							Regular repeat inspections (improved, e.g. with IR)	7	7	3	147	
							Preferred use of spring-type terminals (where possible)	3	7	3	63	
							Structural modifications of generator junction boxes	5	7	4	140	*e.g. simpler, straight-line introduction of cables*
							Electric arc detector	7	4	6	168	
		Undersized, too tightly packed (ambient temperature, derating), no potential separator plates, etc.	5	8	7	280	*Improve planning*	3	8	7	168	
							Acceptance inspection (DIN 0126-23)	5	8	5	200	
							Improved acceptance inspection (e.g. resistance measurement, IR)	5	8	4	160	
							Inspection by third party (PV expert)	5	8	2	80	
		Cable insulation also clamped in	5	7	8	280	*Training of the installers*	5	7	8	280	*Not helpful in this case*
							Acceptance inspection (DIN 0126-23)	5	7	8	280	

			Actual status				Improved status					
Component involved / location	**Potential faults**	**Potential causes**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Possible remedial measures**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Comments**
		Cable insulation also clamped in	5	7	8	280	*Expanded acceptance inspection (with thermal camera)*	5	7	4	140	
							Structural modification of the terminal strip (alignment)	4	7	6	168	
		Improper workmanship of aluminum lines	7	8	6	336	*Training of the installers*	5	8	6	240	
							Acceptance inspection (DIN 0126-23)	7	8	5	280	
							Expanded acceptance inspection (with thermal camera)	7	8	3	168	
							Inspection by third party (PV expert with aluminum background)	7	8	3	168	
							Electric arc detector	7	7	6	294	*Large cross sections -> large output ->consequence: parallel electric arc*
Screw terminals (AC)												
		Screw contacts insufficiently tightened, cables unsuitably introduced	6	6	6	216	*Training of the installers, torque wrench*	4	6	6	144	
							Acceptance inspection (DIN 0126-23)	6	6	5	180	
							Acceptance inspection (improved, e.g. with IR orcontact resistance measurement)	6	6	3	108	
							Regular repeat inspections (DIN 0126-23)	6	6	4	144	
							Regular repeat inspections (improved, e.g. with IR)	6	6	3	108	
							Preferred use of spring-type terminals (where possible)	3	6	3	54	
							Structural modifications of generator junction boxes	5	6	4	120	*e.g. easier, straight introduction of lines*
							Electric arc detector					*Electric arc in copper lines only at very high temperature, effect unclear*

			Actual status				Improved status					
Component involved / location	Potential faults	Potential causes	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Possible remedial measures	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Comments
Screw terminals in field distributors, inverters (AC end)	*terminals scorched*	*Undersized, too tightly packed (ambient temperature, derating), no potential separator plates, etc.*	5	7	7	245	*Improve planning*	3	7	7	147	
							Acceptance inspection (DIN 0100-600)	5	7	5	175	
							Improved acceptance inspection (e.g. resistance measurement, IR)	5	7	4	140	
							Inspection by third party (PV expert)	5	7	2	70	
		Cable insulation also clamped in	5	6	8	240	*Training of the installers*	5	6	8	240	
							Acceptance inspection (DIN 0100-600)	5	6	8	240	
							Expanded acceptance inspection (with thermal camera)	5	6	4	120	
							Structural modification of the terminal strip (alignment)	4	6	6	144	
		Improper workmanship of aluminum lines	7	8	6	336	*Training of the installers*	5	8	6	240	*Not helpful in this case*
							Acceptance inspection (DIN 0100-600)	7	8	5	280	
							Expanded acceptance inspection (with thermal camera)	7	8	3	168	
							Inspection by third party (PV expert with aluminum background)	7	8	3	168	
							Electric arc detector	7	4	5	140	*Electric arcing with copper*
Soldered connections												
Soldered joints within the module (cell connector, cross connector)	*Soldered points scorched, possibly electric arcs in the module*	*Poor soldering, aging from mechanical / thermal stress*	7	6	9	378	*QA improvement at manufacturer (24h)*	2	6	9	108	
							Regular repeat inspection (DIN 0126-23)	7	6	8	336	

			Actual status				Improved status					
Component involved / location	**Potential faults**	**Potential causes**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Possible remedial measures**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Comments**
		Poor soldering, aging from mechanical/ thermal stress	7	6	9	378	*Regular, improved repeat inspections (with IR)*	7	6	3	126	*If the sun is shining*
							Electric arc detector	7	4	7	196	
Diodes												
Bypass and string diodes	*Diodes short-circuited or open*	*Overvoltage from static discharge during module production and installation*	4	4	9	144	*QA measures, training of installers*					
							Surge protection at the diodes					
		Overvoltage from electrical storm or switching operations in the system	6	4	8	192	*Regular lightning strike*	4	4	8	128	
							Surge protection at the diodes, voltage-proof diodes	3	4	8	96	
							Expanded repeat inspections (IR, new measuring procedures)	6	4	4	96	
		Long-term failure from thermal overload and temperature cycles with variable shading	4	4	9	144	*Use of "cool" technologies*					
							Regular repeat inspections (visual, IR, new measuring procedures)					
Module												
Module	*Open circuits, insulation flaws*	*Torn-off cell connectors (straps)*	4	6	8	192	*Manufacturer's design modifications, QA measures*	2	6	8	96	
							Regular repeat inspections (IR, new measuring procedures)	4	6	4	96	
							Electric arc detector	4	4	7	112	
		Cell breakage	2	3	8	48						
		Glass breakage	6	5	2	60	*Improved mounting technology*					

			Actual status				Improved status					
Component involved / location	Potential faults	Potential causes	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Possible remedial measures	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Comments
		Glass breakage	6	5	2	*60*	*Repeat inspections (visual, IR, new measuring procedure)*					
							Electric arc detector					
		Damage to the backing film from mounting error, aging (delamination) or vandalism	5	4	7	*140*	*Training of the installers*					
							Insulation monitoring through inverter					
							Acceptance inspection (visual, IR, new measuring procedures)					
							Regular repeat inspections (visual, IR, new measuring procedures)					
		Cell damage such as micro-cracks, snail tracks, etc.	8	2	6	*96*	*Avoidance of causes through design and QA measures*					
							Regular repeat inspections (visual, IR, new measuring procedures)					
DC fuses												
DC fuses	*Overheating, deficient switching characteristics*	*Use of unsuitable fuses, e.g. AC fuses or insufficient voltage or current parameters or unsuitable installation*	6	8	7	*336*	*Improved planning, selection of suitable components*	*2*	*8*	*7*	*112*	
							Dispense with DC fuses if possible	*1*	*1*	*1*	*1*	*Note: Only if possible (2 or 3 strings)*
							Acceptance inspection (as per DIN 0126-23)	*6*	*8*	*4*	*192*	
							Acceptance inspection by third party (PV expert)	*6*	*8*	*2*	*96*	
AC fuses												
AC fuses	*Overheating*	*Overheating by excessive bundling, high ambient temperatures (derating), etc.*	6	6	5	*180*	*Improved planning selection of suitable components*	*3*	*6*	*5*	*90*	
							Acceptance inspection (as per DIN 0100-600)	*6*	*6*	*3*	*108*	

			Actual status				Improved status					
Component involved / location	**Potential faults**	**Potential causes**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Possible remedial measures**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Comments**
		Overheating by excessive bundling, high ambient temperatures (derating), etc.	6	6	5	*180*	*Regular repeat inspections (as per DIN 0105-100)*	6	6	2	*72*	*Brown discoloration also discernible*
Cable (DC and AC)												
Cable (DC and AC)	*Mechanical damage, insulation flaws, electric arcs*	*Long-term damage from weather conditions (UV radiation,humidity, temperature cycles, etc.)*	7	7	4	*196*	*Selection of suitable components*	4	7	4	*112*	
							Protected cable routing	3	7	4	*84*	
							Cable routing in separated protected tubing	3	5	4	*60*	
							Insulation monitoring through inverter	7	7	2	*98*	*Actually already state of the art*
							Regular repeat inspections (as per DIN 0126-23)	7	7	3	*147*	
							Electric arc detector	7	7	4	*196*	*Parallel and ground electric arcs*
		Damage from negligent installation	7	5	4	*140*	*Training of the installers*					
							Acceptance inspection (visual, insulation measurement)					
		Electrical overload due to cross section or heaped routing	5	5	6	*150*	*Improved planning, selection of suitable components*					
							Acceptance inspection (visual, IR)					
DC switch												
DC switch within or outside the inverter		*Not DC suitable*	3	8	6	*144*	*Improved planning, selection of suitable components*					
							Acceptance inspection (visual, IR, new measuring procedures)					
		Rated voltage and current insufficient	6	8	6	*288*	*Improved planning, selection of suitable components*	2	8	6	*96*	

			Actual status				Improved status					
Component involved / location	Potential faults	Potential causes	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Possible remedial measures	Probability of occurrence	Probability of fire emergence (significance)	Probability of detection	RPN	Comments
		Rated voltage and current insufficient	6	8	6	*288*	*Acceptance inspection (as per DIN 0126-23)*	*6*	*8*	*3*	*144*	*Contact holder Switches must be actuated*
Inverter												
Inverter		*Ventilation clogged /out of order*	6	4	5	*120*	*Selection of a cleaner location*					
							Fail-safe behavior of the inverter					
							Regular maintenance /cleaning					
							Regular repeat inspections (visual, IR, new measuring procedures)					
		Ambient temperature too high	5	4	5	*100*	*Improved planning, selection of suitable components*					
							Ventilation measures					
		Internal electrical defects	4	4	8	*128*	*Good design, high manufacturing quality*					
							Surge protection					
							Metallic housing					
							Electric arc detector /module shutdown					
Moisture												
General installation	*Corrosion from moisture*	*Unsuitable protection class (IP xx) / deficient air exchange*	5	4	6	*120*	*Improved planning, selection of suitable components*					*Select the correct protection class for the given installation site*
							Acceptance inspection (visual, IR, new measuring procedures)					
		Cable introduced into PG cable glands from above	4	4	3	*48*	*Training of the installers*					

			Actual status				Improved status					
Component involved / location	**Potential faults**	**Potential causes**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Possible remedial measures**	**Probability of occurrence**	**Probability of fire emergence (significance)**	**Probability of detection**	**RPN**	**Comments**
		Cable introduced into PG cable glands from above	4	4	3	48	*Acceptance inspection (visual, IR, new measuring procedures)*					
Fire hazard												
General installation		*Mounting on combustible surface (e.g. wooden board or chipboard) or insurroundings containingeasily combustible objects (e.g. straw, hay, fuels, etc.)*	6	6	5	180	*Selection of a suitable location*	1	6	5	30	
							Compliance with pertinent VDE and building codes	2	6	5	60	
							Compliance with the manufacturer's specifications	3	6	5	90	*If appropriate*
							Acceptance inspection (as per DIN 0126-23)	6	6	3	108	
							Regular repeat inspections (as per DIN 0126-23)	6	6	3	108	*Change in use of the space possible*
J box soldered connections												
Soldered connections inside the junction box	*Soldered points scorched, possibly electric arcs in the module or in the junction box*	*Poor soldering, aging from mechanical / thermal stress*	5	7	9	315	*QA improvement at manufacturer*	2	7	9	126	
							Regular repeat nspection (DIN 0126-23)	5	7	9	315	
							Expanded regular repeat inspections (with IR)	5	7	3	105	
							Electric arc detector	5	4	8	160	

b) Laboratory tests on PV module emissions

1. Subject and purpose of investigation

In connection with the BMU research project on “Assessing Fire Risks in Photovoltaic Systems and Developing Safety Concepts for Risk Minimization,” experimental studies were conducted at the fire testing center of CURRENTA during June 2014 with the aim of characterizing the release of harmful substances by photovoltaic modules in case of fire. The experimental program covered three different module types (table 1). A flame was applied to the backs of the inclined modules with a gas burner, in order to simulate a possible fire emergence scenario among roof-mounted PV applications. Pollution analyses were conducted on smoke gas, fire residue and quench water samples.

Type	Design	Frame	Length (mm)	Width (mm)	Thickness (mm)
c-Si	Glass film	Aluminum	1,655	1,000	45*
CIS	Glass film	Aluminum	1,255	980	35*
CdTe	Glass-glass	None	1,200	600	8
* Frame thickness					

Table 1: Investigated module types

2. Test setup

The PV modules were mounted with profile rails 40 mm high and arranged crosswise on a fiber cement mounting plate, located on a test platform inclined 23° relative the horizontal plane (figure 1). The inclination was selected as in the roof fire test as per UL 790. The modules protruded 45 cm beyond the front edge of the mounting plate and a flame was applied to their undersides in this area. The gas burner described in UL 790 served as the ignition source, producing a flame approximately 100 cm in width (figure 2). The burner was positioned 10 cm below the front edge of the module, with the horizontal distance to the module front edge also being 10 cm.

On the front and back of the module five thermal elements each were arranged along the longitudinal axis of the module. The distances to the module front edge were 10, 40, 70, 100 and 130 cm. In the temperature diagrams contained in the Appendix, “MS-01” (module back) and “MS-06” (module front edge) designate the measuring points on the module front edge.

For the quench water tests, two extinguishing nozzles were installed in the upper part of the test setup in the interspace between the module and the mounting plate. To catch the quench water running off the mounting plate, a 1.75 × 1.50 m² steel tray was placed on the floor of the test building.

To apply the flame to module areas of similar size, for the c-Si modules the tests were performed on one module along the longitudinal direction (length: 1655 mm), for the CIS modules on two modules along the transverse direction (total length: 1960 mm) and for the CdTe modules on three modules along the transverse direction (total length: 1840 mm incl. mounting distance).

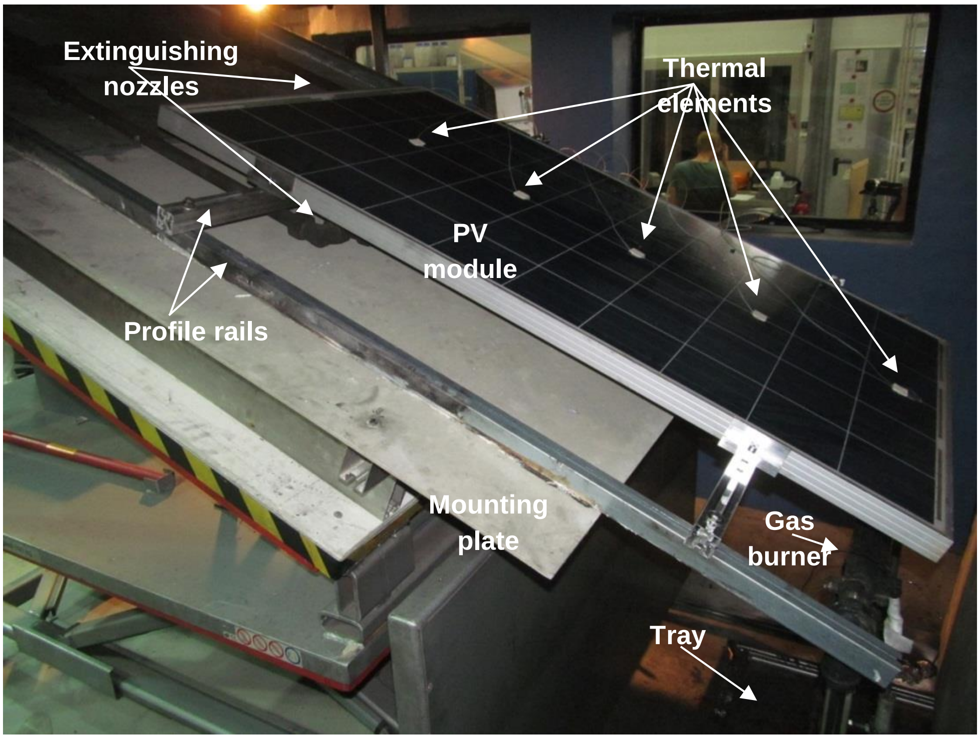


Figure 1: Test setup (shown here with a c-Si module)

Figure 2: Gas burner

3. Performance of test

On each module type, tests were performed with a burner output of 25 kW and 150 kW, in order to analyze the fire behavior and pollutant release of the modules at different thermal stress intensities (figure 3). In addition, a further test was performed on each module type with a burner output of 150 kW, such that after six to seven minutes the fire was extinguished in each case with 20 l quench water over a period of 45 s.

The tests were performed underneath an exhaust hood as per ISO 9705, with an exhaust flow rate of about 1 m³/s. The following variables were measured:

- Heat release rate
- Smoke production rate
- Temperatures on front and back of the module
- Mass loss of the modules and mass of the fire residue
- Destroyed module surface
  - Formation rates of the gas compounds carbon dioxide (CO_2), carbon monoxide(CO), hydrogen cyanide (HCN), hydrogen chloride (HCl), hydrogen bromide (HBr), hydrogen fluoride (HF), nitrogen monoxide (NO), nitrogen dioxide (NO_2) and sulfur dioxide (SO_2)
- Amounts of arsenic, lead, cadmium and selenium contained in the smoke gases
- Amounts of arsenic, lead, cadmium and selenium contained in the fire residue
- Amounts of arsenic, lead, cadmium and selenium contained in the quench water

In addition, two reference tests were performed with (non-combustible) calcium silicate plates instead of the modules in order to determine which smoke, CO_2 and CO formation rates the gas burner caused under the planned operating conditions. These measurement values were deducted from the actual measurement results, so that the test results listed in section 4 exclusively referred to the PV module emissions.

Smoke gas analysis

For determining the arsenic, lead, cadmium and selenium levels, a partial stream from the waste air flow was conducted through a filter system and through a sorbent. The analysis was performed with ICP-MS. The measurement results listed in section 4 correspond to the sum of the particle-bound and to the filterable parts.

The gas compounds (except formaldehyde) were analyzed continually over time with an FTIR spectrometer connected to the exhaust tube of the extraction system. Section 4 lists the concentrations averaged over the duration of the test.

For determining the formaldehyde content, an absorption cartridge was used, with the analysis being performed with HPLC.

Fire residue analysis

The fire residue consisted of damaged, fallen-off parts of modules that accumulated on the mounting plate of the test frame and in the tray placed underneath during the test. The fire residue was first swept together and thoroughly mixed. Two samples were taken and pulverized with a granulator. The arsenic, lead, cadmium and selenium levels were determined with ICP-MS.

Quench water analysis

After mixing the quench water collected in the tray, two samples were taken and analyzed as to the arsenic, lead, cadmium and selenium levels by means of ICP-MS.

CURRENTA analyzed the arsenic, lead, cadmium and selenium levels in its Elemental Analysis department, smoke gas samples and formaldehyde levels in its Air Analysis department and fire residue pulverization in its Environmental Analysis department.

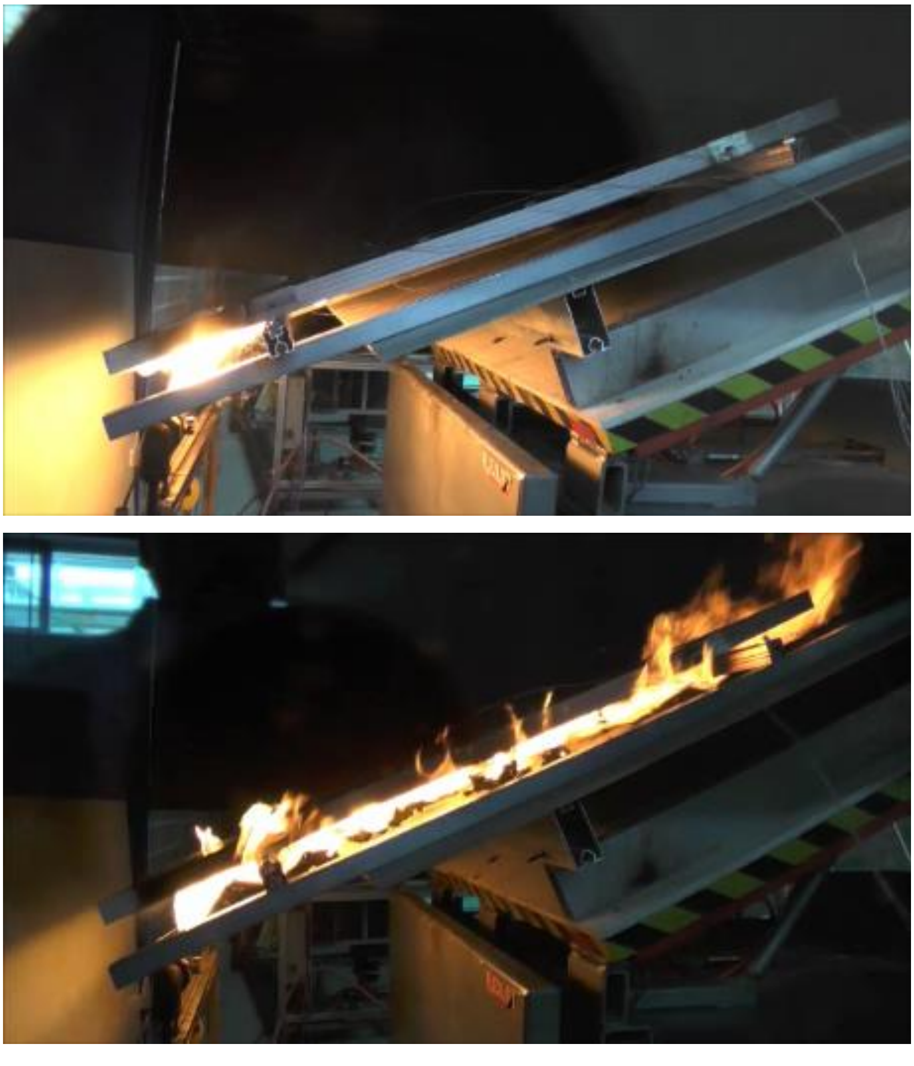


Figure 3: Fire test with a burner output of 25 kW (top) and 150 kW (bottom)

4. Test results

Altogether nine tests were performed, as listed in the following table:

	25 kW burner output	150 kW burner output	150 kW burner output, quench water test
Module type c-Si	1A	1B	1C
Module type CIS	2A	2B	2C
Module type CdTe	3A	3B	3C

Table 2: Test designation

In the 25 kW burner output experiments, only locally limited, primarily surface, damage occurred on all three module types. At 150 kW burner output, the modules were destroyed over wide areas; the test documentation appears in the appendix to the report.

The results of the chemical analysis are specified in the following as masses of the respective analytes relative to one standard cubic meter of smoke gas, one kilogram of fire residue or one liter of quench water. Also listed are the total released quantities yielded by multiplying the measured concentration and the total volume of the smoke gas, the total mass of the fire residue or the total volume of the quench water used.

n.d.: not detectable

n.i.: not investigated

4.1 Module type c-Si

Heat release, smoke development and damage to the specimen

		Test 1A	Test 1B	Test 1C
Test duration	(s)	1,200	1,200	600
Maximum heat release rate	(kW)	29.2	246.6	272.9
Average heat release rate	(kW)	6.4	49.3	46.2
Total heat release	(kJ)	7,631	59,197	27,747
Maximum smoke production rate*	(m^2/s)	0.12	0.78	2.05
Average smoke production rate*	(m^2/s)	0.03	0.15	0.12
Total smoke production*	(m^2)	41	182	73
Initial mass of specimen	(g)	19,978	20,022	19,882
Residual mass of specimen	(g)	19,525	5,502	10,375
Mass loss	(g)	453	14,520	9,507
Mass loss	(%)	2.3	72.5	47.8
Mass of fire residue	(g)	143	12,798	n.i.
Burned mass	(g)	310	1,722	n.i.
Destroyed area	(m^2)	0.54	1.53	0.97

***** *The smoke production is given in m^2, i.e. the area projected by the sum of all smoke particles onto a 2-dimensional plane*

Table 3: Fire-technological parameters for module type c-Si

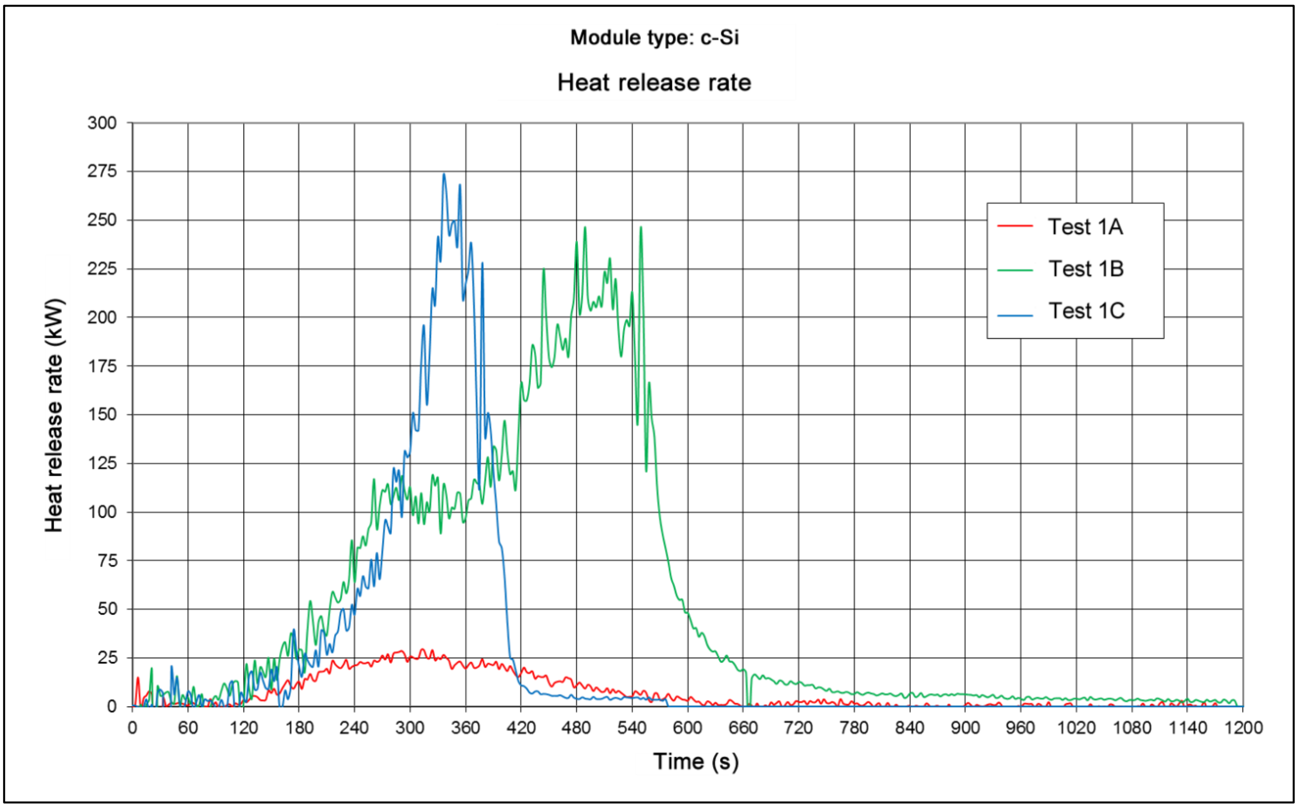


Figure 4: Module type c-Si heat release rate

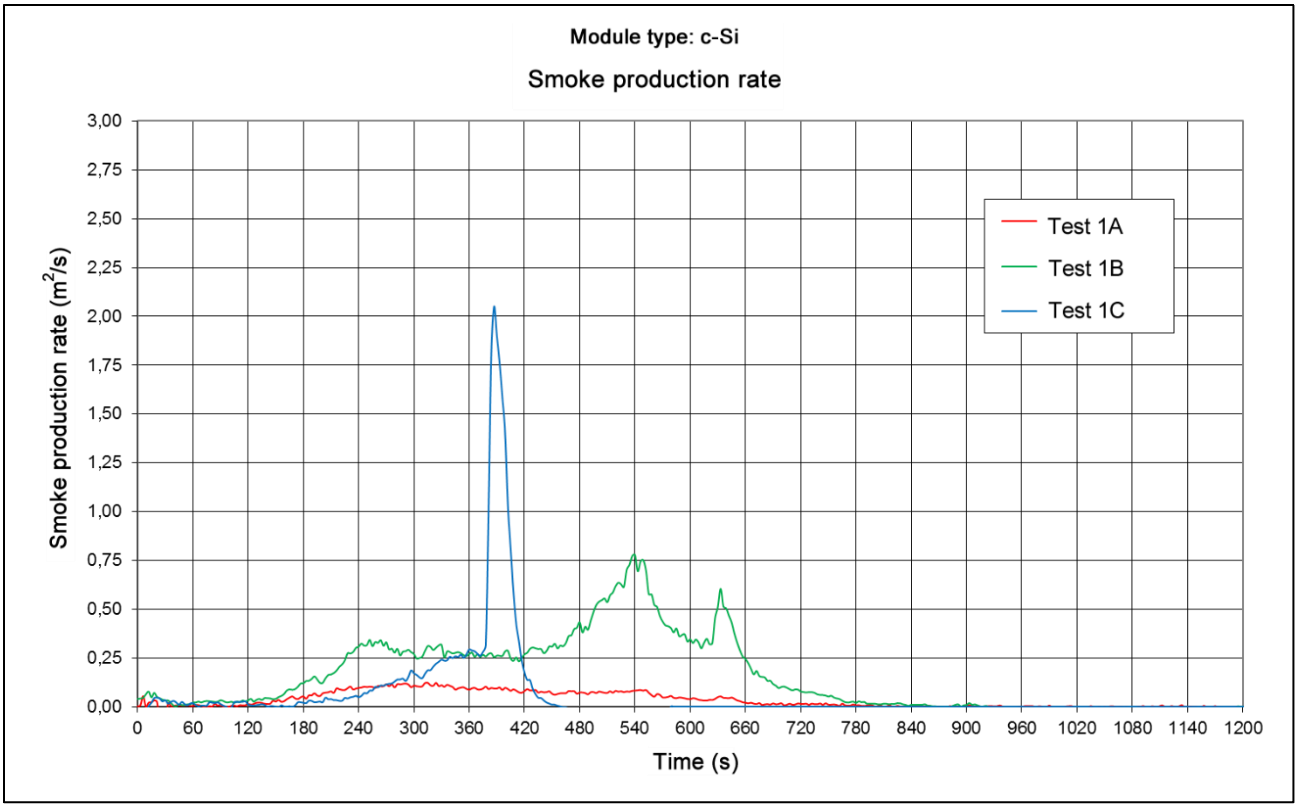


Figure 5: Module type c-Si smoke production rate

Smoke gas analysis

		Test 1A	Test 1B	Test 1C
Arsenic	(µg/m³)	1.1	0.8	0.1
Lead	(µg/m³)	50	630	1,010
Cadmium	(µg/m³)	6.5	60	77
Selenium	(µg/m³)	24	10	9.8
Carbon dioxide	(mg/m³)	842	3,786	3,068
Carbon monoxide	(mg/m³)	6	30	30
Hydrogen cyanide	(mg/m³)	n.d.	n.d.	n.d.
Hydrogen chloride	(mg/m³)	n.d.	n.d.	n.d.
Hydrogen bromide	(mg/m³)	n.d.	n.d.	n.d.
Hydrogen fluoride	(mg/m³)	n.d.	n.d.	n.d.
Nitrogen monoxide	(mg/m³)	n.d.	n.d.	n.d.
Nitrogen dioxide	(mg/m³)	n.d.	n.d.	n.d.
Sulfur dioxide	(mg/m³)	n.d.	n.d.	n.d.
Formaldehyde	(mg/m³)	1.0	0.9	1.8

Table 4: Module type c-Si smoke gas analysis – measurement values (time-averaged)

		Test 1A	Test 1B	Test 1C
Arsenic	(mg)	1.3	1.0	0.1
Lead	(mg)	61	760	600
Cadmium	(mg)	7.9	72	46
Selenium	(mg)	29	12	5.8
Carbon dioxide	(g)	1,020	4,543	1,822
Carbon monoxide	(g)	7	36	18
Formaldehyde	(g)	1.2	1.1	1.1

Table 5: Module type c-Si smoke gas analysis – computed total release

Fire residue analysis

	Test 1A		Test 1B		Test 1C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg/kg)	48	30	11	9.1	n.i.	n.i.
Lead (mg/kg)	4,800	6,400	700	2,700	n.i.	n.i.
Cadmium (mg/kg)	0.3	2.5	0.4	1.4	n.i.	n.i.
Selenium (mg/kg)	0.5	110	0.3	20	n.i.	n.i.

Table 6: Module type c-Si fire residue analysis – measurement values

	Test 1A		Test 1B		Test 1C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg)	6.9	4.3	140	120	n.i.	n.i.
Lead (mg)	690	920	9,000	35,000	n.i.	n.i.
Cadmium (mg)	0.04	0.36	5.1	18	n.i.	n.i.
Selenium (mg)	0.07	16	3.8	260	n.i.	n.i.

Table 7: Module type c-Si fire residue analysis – computed total release

CURRENTA

Quench water analysis

		Test 1A		Test 1B		Test 1C	
		Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic	(µg/l)	n.i.	n.i.	n.i.	n.i.	0.9	1.2
Lead	Lead(µg /l)	n.i.	n.i.	n.i.	n.i.	76	130
Cadmium	(µg/l)	n.i.	n.i.	n.i.	n.i.	4.9	5.7
Selenium	(µg/l)	n.i.	n.i.	n.i.	n.i.	13	3.6

Table 8: Module type c-Si quench water analysis – measurement values

		Test 1A		Test 1B		Test 1C	
		Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic	(mg)	n.i.	n.i.	n.i.	n.i.	0.02	0.02
Lead	(mg)	n.i.	n.i.	n.i.	n.i.	1.5	2.6
Cadmium	(mg)	n.i.	n.i.	n.i.	n.i.	0.10	0.11
Selenium	(mg)	n.i.	n.i.	n.i.	n.i.	0.26	0.07

Table 9: Module type c-Si quench water analysis – computed total release

4.2 Module type CIS

Heat release, smoke development and damage to the specimen

		Test 2A	Test 2B	Test 2C
Test duration	(s)	1,200	1,200	600
Maximum heat release rate	(kW)	41.7	184.1	186.3
Average heat release rate	(kW)	8.1	70.6	29.2
Total heat release	(kJ)	9,699	84,712	17,506
Maximum smoke production rate	(m^2/s)	0.34	0.92	2.94
Average smoke production rate	(m^2/s)	0.08	0.30	0.46
Total smoke production	(m^2)	92	358	274
Initial mass of specimen	(g)	39,165	39,099	39,124
Residual mass of specimen	(g)	36,075	5,805	31,806
Mass loss	(g)	3,090	33,294	7,318
Mass loss	(%)	7.9	85.2	18.7
Mass of fire residue	(g)	2,758	30,547	n.i.
Burned mass	(g)	332	2,747	n.i.
Destroyed area	(m^2)	0.45	2.36	2.34

Table 10: Fire-technological parameters for module type CIS

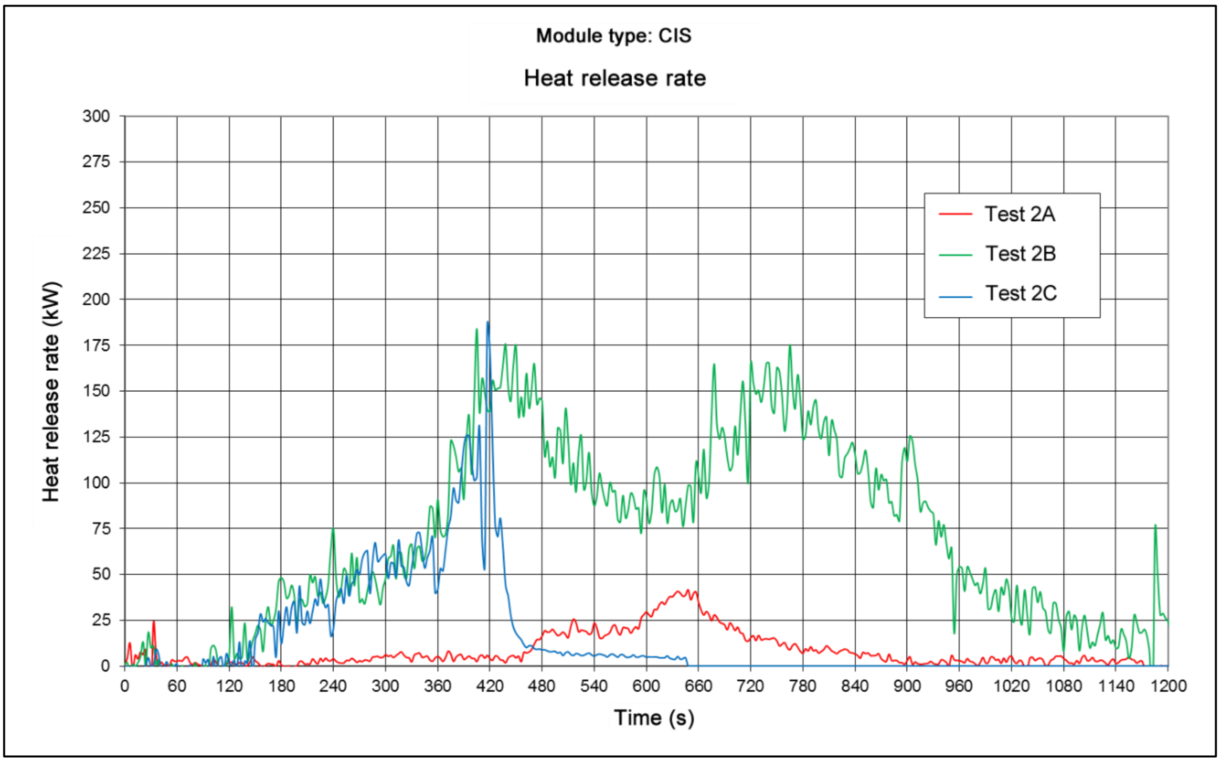


Figure 6: Module type CIS heat release rate

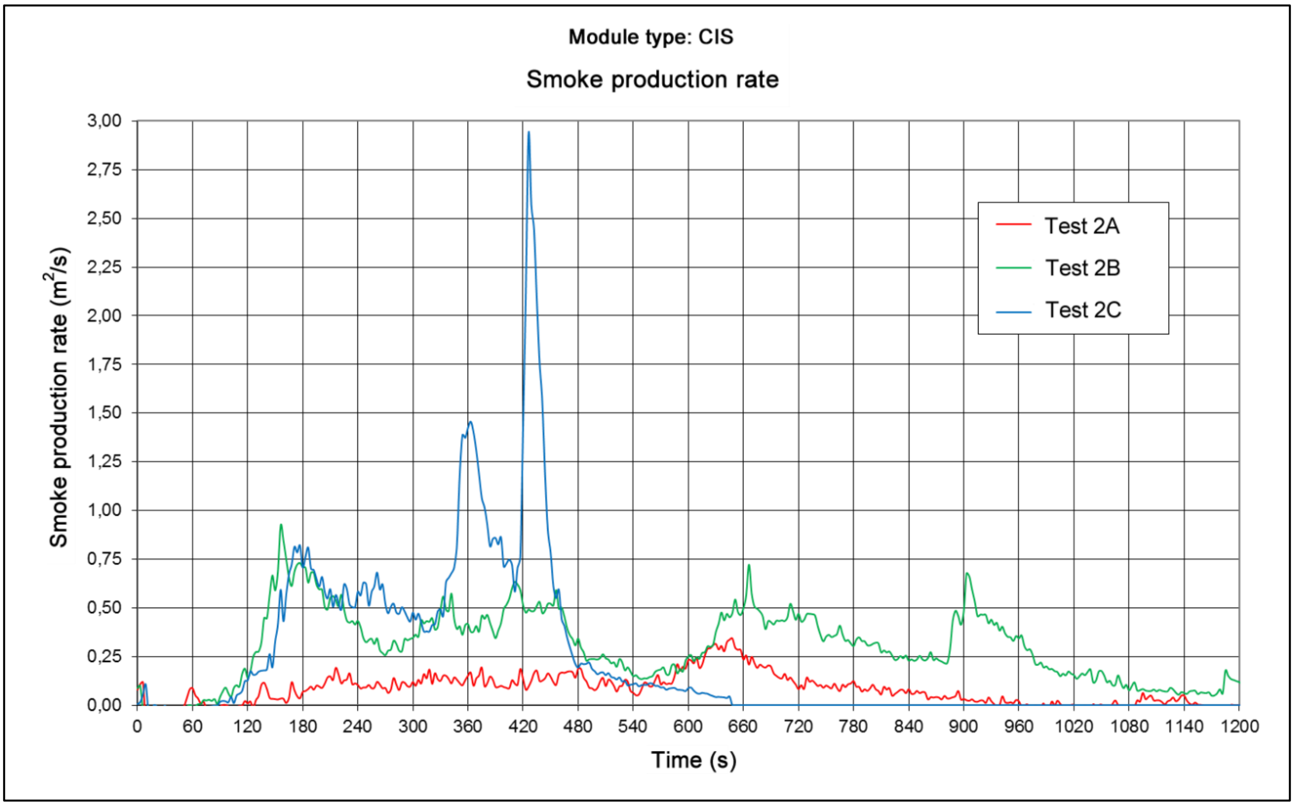


Figure 7: Module type CIS smoke production rate

CURRENTA

Smoke gas analysis

	Test 2A	Test 2B	Test 2C
Arsenic (µg/m³)	1.5	1.6	1.0
Lead (µg/m³)	250	270	480
Cadmium (µg/m³)	12	14	34
Selenium (µg/m³)	4.8	40	8.0
Carbon dioxide (mg/m³)	615	5,817	2,751
Carbon monoxide (mg/m³)	11	237	382
Hydrogen cyanide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen chloride (mg/m³)	n.d.	n.d.	n.d.
Hydrogen bromide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen fluoride (mg/m³)	n.d.	n.d.	n.d.
Nitrogen monoxide (mg/m³)	n.d.	n.d.	n.d.
Nitrogen dioxide (mg/m³)	n.d.	n.d.	n.d.
Sulfur dioxide (mg/m³)	n.d.	n.d.	n.d.
Formaldehyde (mg/m³)	1.2	2.1	4.9

Table 11: Module type CIS smoke gas analysis – measurement values (time-averaged)

	Test 2A	Test 2B	Test 2C
Arsenic (mg)	1.9	1.8	0.6
Lead (mg)	310	300	290
Cadmium (mg)	15	16	20
Selenium (mg)	5.9	45	4.8
Carbon dioxide (g)	760	6,492	1,634
Carbon monoxide (g)	14	265	227
Formaldehyde (g)	1.5	2.3	2.9

Table 12: Module type CIS smoke gas analysis – computed total release

CURRENTA

Fire residue analysis

	Test 2A		Test 2B		Test 2C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg/kg)	1.7	2.2	1.7	2.5	n.i.	n.i.
Lead (mg/kg)	23	26	23	29	n.i.	n.i.
Cadmium (mg/kg)	5.9	5.9	6.0	7.4	n.i.	n.i.
Selenium (mg/kg)	350	260	360	110	n.i.	n.i.

Table 13: Module type CIS fire residue analysis – measurement values

	Test 2A		Test 2B		Test 2C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg)	4.7	6.1	52	76	n.i.	n.i.
Lead (mg)	63	72	700	890	n.i.	n.i.
Cadmium (mg)	16	16	180	230	n.i.	n.i.
Selenium (mg)	970	720	11,000	3,400	n.i.	n.i.

Table 14: Module type CIS fire residue analysis – computed total release

Quench water analysis

	Test 2A		Test 2B		Test 2C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (µg/l)	n.i.	n.i.	n.i.	n.i.	0.7	0.9
Lead (µg/l)	n.i.	n.i.	n.i.	n.i.	61	61
Cadmium (µg/l)	n.i.	n.i.	n.i.	n.i.	12	9.5
Selenium (µg/l)	n.i.	n.i.	n.i.	n.i.	240	700

Table 15: Module type CIS quench water analysis – measurement values

	Test 2A		Test 2B		Test 2C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg)	n.i.	n.i.	n.i.	n.i.	0.01	0.02
Lead (mg)	n.i.	n.i.	n.i.	n.i.	1.2	1.2
Cadmium (mg)	n.i.	n.i.	n.i.	n.i.	0.24	0.19
Selenium (mg)	n.i.	n.i.	n.i.	n.i.	4.8	14

Table 16: Module type CIS quench water analysis – computed total release

Module type CdTe

Heat release, smoke development and damage to the specimen

		Test 3A	Test 3B	Test 3C
Test duration	(s)	1,800	1,200	600
Maximum heat release rate	(kW)	15.3	66.5	88.2
Average heat release rate	(kW)	0.4	13.2	16.3
Total heat release	(kJ)	785	15,809	9,786
Maximum smoke production rate	(m^2/s)	0.08	0.23	0.87
Average smoke production rate	(m^2/s)	0.003	0.11	0.14
Total smoke production	(m^2)	5	133	86
Initial mass of specimen	(g)	35,583	35,540	35,527
Residual mass of specimen	(g)	35,552	23,942	24,334
Mass loss	(g)	31	11,598	11,193
Mass loss	(%)	0.1	32.6	31.5
Mass of fire residue	(g)	2	11,035	n.i.
Burned mass	(g)	29	563	n.i.
Destroyed area	(m^2)	0.03	0.32	0.82

Table 17: Fire-technological parameters for module type CdTe

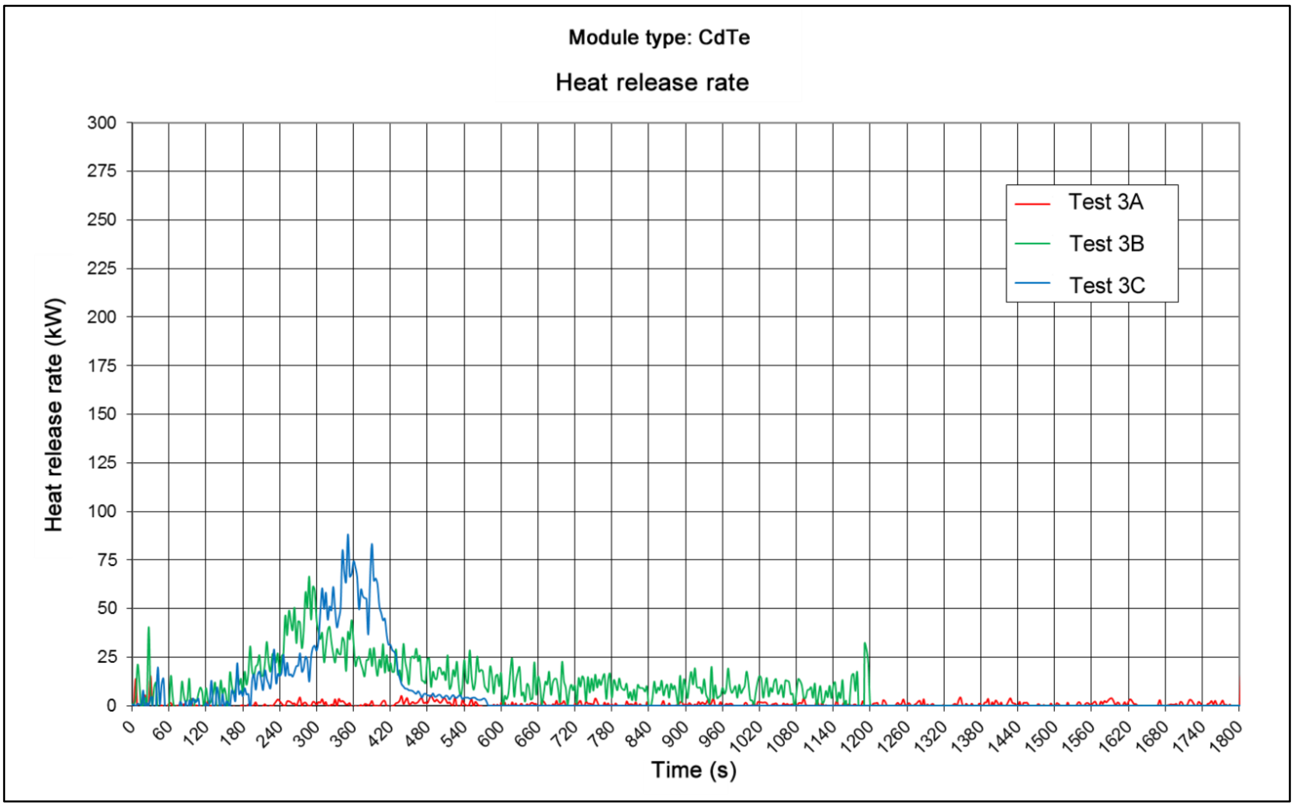


Figure 8: Module type CdTe heat release rate

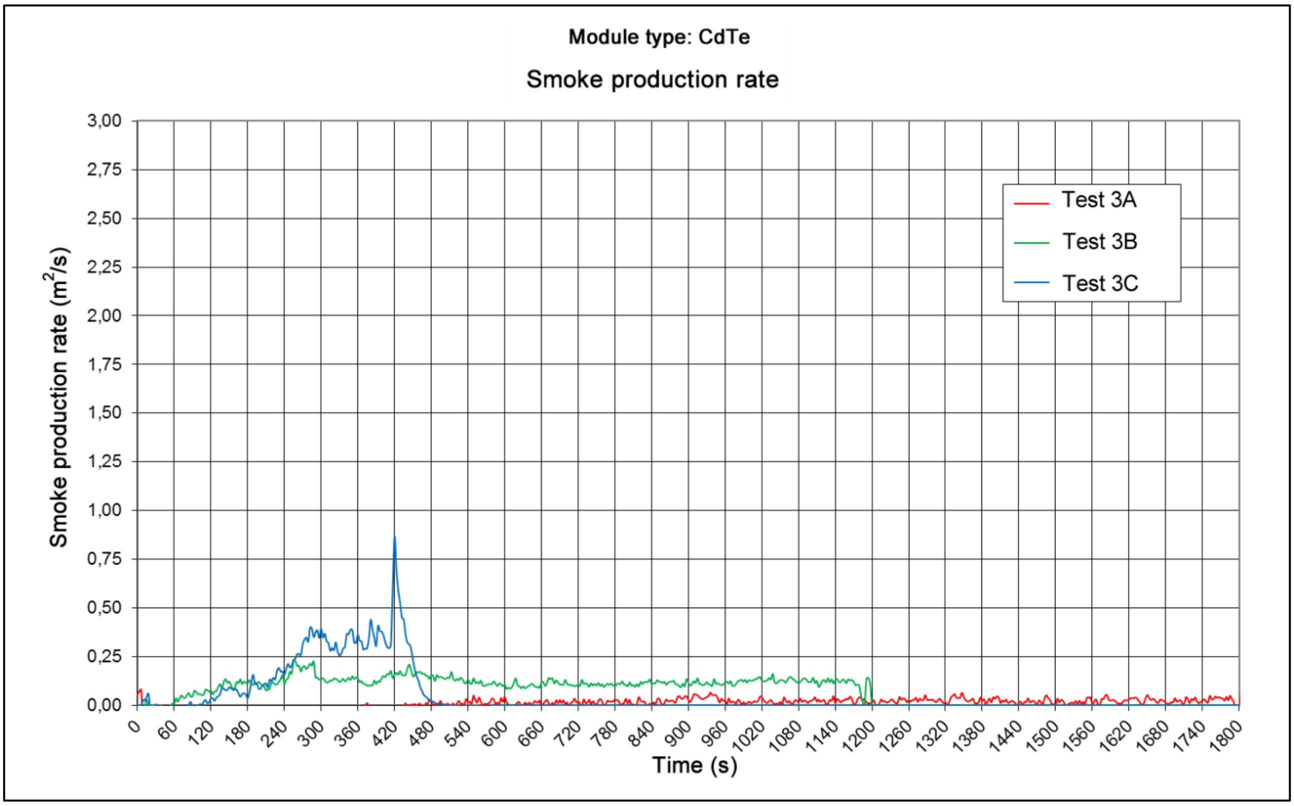


Figure 9: Module type CdTe smoke production rate

Smoke gas analysis

	Test 3A	Test 3B	Test 3C
Arsenic (µg/m³)	0.3	0.2	0.2
Lead (µg/m³)	34	120	1,330
Cadmium (µg/m³)	9.9	37	48
Selenium (µg/m³)	4.2	4.7	2.2
Carbon dioxide (mg/m³)	42	1,453	1,495
Carbon monoxide (mg/m³)	1	63	90
Hydrogen cyanide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen chloride (mg/m³)	n.d.	n.d.	n.d.
Hydrogen bromide (mg/m³)	n.d.	n.d.	n.d.
Hydrogen fluoride (mg/m³)	n.d.	n.d.	n.d.
Nitrogen monoxide (mg/m³)	n.d.	n.d.	n.d.
Nitrogen dioxide (mg/m³)	n.d.	n.d.	n.d.
Sulfur dioxide (mg/m³)	n.d.	n.d.	n.d.
Formaldehyde (mg/m³)	0.4	1.6	2.6

Table 18: Module type CdTe smoke gas analysis – measurement values (time-averaged)

	Test 3A	Test 3B	Test 3C
Arsenic (mg)	0.6	0.2	0.1
Lead (mg)	64	140	800
Cadmium (mg)	19	43	29
Selenium (mg)	7.9	5.4	1.3
Carbon dioxide (g)	79	1,674	897
Carbon monoxide (g)	2	73	54
Formaldehyde (g)	0.8	1.8	1.6

Table 19: Module type CdTe smoke gas analysis – computed total release

Fire residue analysis

	Test 3A		Test 3B		Test 3C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg/kg)	2.2	8.2	0.6	0.9	n.i.	n.i.
Lead (mg/kg)	17	160	52	200	n.i.	n.i.
Cadmium (mg/kg)	2.0	7.4	120	110	n.i.	n.i.
Selenium (mg/kg)	300	250	2.8	3.6	n.i.	n.i.

Table 20: Module type CdTe fire residue analysis – measurement values

	Test 3A		Test 3B		Test 3C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg)	0.004	0.02	6.6	9.9	n.i.	n.i.
Lead (mg)	0.03	0.3	570	2,200	n.i.	n.i.
Cadmium (mg)	0.004	0.02	1,300	1,200	n.i.	n.i.
Selenium (mg)	0.6	0.5	31	40	n.i.	n.i.

Table 21: Module type CdTe fire residue analysis – computed total release

Quench water analysis

	Test 3A		Test 3B		Test 3C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (µg/l)	n.i.	n.i.	n.i.	n.i.	1.4	1.4
Lead (µg/l)	n.i.	n.i.	n.i.	n.i.	35	34
Cadmium (µg/l)	n.i.	n.i.	n.i.	n.i.	7.1	53
Selenium (µg/l)	n.i.	n.i.	n.i.	n.i.	73	47

Table 22: Module type CdTe quench water analysis – measurement values

	Test 3A		Test 3B		Test 3C	
	Specimen 1	Specimen 2	Specimen 1	Specimen 2	Specimen 1	Specimen 2
Arsenic (mg)	n.i.	n.i.	n.i.	n.i.	0.03	0.03
Lead (mg)	n.i.	n.i.	n.i.	n.i.	0.70	0.68
Cadmium (mg)	n.i.	n.i.	n.i.	n.i.	0.14	1.1
Selenium (mg)	n.i.	n.i.	n.i.	n.i.	1.5	0.94

Table 23: Module type CdTe quench water analysis – computed total release

c) PV passport

PV Passport No. ______-______-______

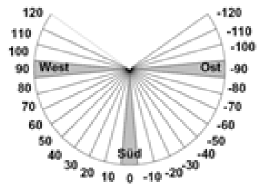
PHOTOVOLTAIC SYSTEM

Installed system capacity

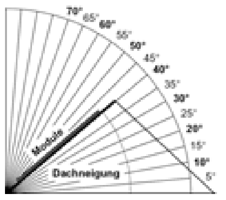
Nominal output of all modules ________ kWp

Alignment and roof pitch

Alignment



Roof pitch



Please circle the appropriate degree

System operator / Contractor

(First and last name or name of company)

Street, house number

Postal code, city

Location of system (if different from above)

Building/property owner (first and last name or name of company)

Street, house number

Postal code, city

Photo / description of system

(Type of building, sloped roof, flat roof, contiguous system or divided into sections, rooftop/integrated, ...)

Commissioning, metering system

Date of commissioning: __________________

Feed-in / reference meter No.: __________________

Meter reading at handover________________ kWh

PV measuring device, meter No.: ________________

Meter reading at handover________________ kWh

Demand and yield forecasts

Expected electricity yield: _____________ kWh/year

Of which, expected direct consumption: _________ %

☐ No forecasts have been made

Feed-in management pursuant to EEG

☐ Effective power reduction ☐ Remote control capability

Storage system in place (see storage passport)

☐ no ☐ yes :________kWh

PV PASSPORT ISSUING BODY

This PV passport was issued by:

Company

Authorized person (first name, last name)

Street, house number

Postal code, city

The signee confirms that all information contained in this PV Passport and in Annexes 1 – 4 applies to the PV system that is described above and handed over to the buyer [1)2)]

Date, signature of system builder/system vendor

www.photovoltaik-anlagenpass.de

This seal confirms that the issuing company is registered with the BSW and ZVEH "PV Quality Group" (*Qualitätsgemeinschaft Photovoltaik*); see Internet site for benefits and list of installers.

Company stamp

PV Passport Seal with Registration number

1) The PV Passport is only complete with Annexes (1) to (4)
2) While this PV Passport was compiled with greatest possible care, a guarantee for the attested characteristics cannot be given in terms of liability regardless of negligence.