PV FIRE HAZARD - ANALYSIS AND ASSESSMENT OF FIRE INCIDENTS

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ABSTRACT: This paper addresses an investigation of heat damages and fires of PV systems. Information on damage cases was collected by an online-questionnaire, online research, literature research, by questioning technical experts and from an insurance company´s files. Some 180 cases of fire and heat damage were found, where PV systems caused fires affecting the PV system or its surroundings. A statistical analysis or these cases is given. Main reasons for fires were component failures and installation errors. Especially in larger systems improper handling of aluminum cables caused several fires. DC-switches were found to be critical and therefore laboratory testing was conducted. This testing of aged DC switches found increased resistance and potential thermal damage. Operating the switches several times reduced the resistance markedly. Inspection of older PV systems showed that bypass-diodes are reliable and pose a low risk for reverse currents into strings. Recommendations to further improve system safety are given.

Keywords: safety, reliability, building integrated PV, system design

1 INTRODUCTION

The work presented is part of a project to address issues of PV system safety and reliability, fire protection, building codes aspects and fire fighter issues [1], [2]. It aims at improving PV systems´ safety by investigating fire incidents as well as heat damages with PV systems involved. We wanted to identify “hot-spots” for fire hazards in order to develop safety and reliability improvements.

Information on damage cases was collected by internet and literature research, by asking technical experts and insurance companies and via an online-questionnaire. Additionally, system inspections to identify ageing behavior and long term failure rates have been conducted.

2 STATISTICAL ANALYSIS OF FIRE INCIDENTS IN PV SYSTEMS

Collection period for incident reports covered the years 1995 – 2012. The evaluation was limited to cases in Germany. In total some 400 incident reports were found. Some 180 out of these reports found that the PV system caused the fire.

Please note: For most incidents only a fraction of information was available. Thus, each topic of analysis may be based on a different number of events.

2.1 Severity of damage and number of cases

The following table and the chart in figure 1 below indicate the numbers of cases with a certain damage level.

Table 1: Number of incidents with a certain damage

fire from outside - PV system affected	220
fire from PV - building destroyed	10
fire from PV - building damaged	65
fire from PV - PV system damaged	49
fire from PV - component damaged	55

At the time of closing the survey some 1.3 mio. systems with a total capacity of approx. 30 GWp were installed in Germany. Considering the number of damaged buildings in one year (see section 2.5) and relating it to the number of installed PV systems, an annual risk of approximately $30*10^{-6}$ can be estimated that a building is damaged due to a fire caused by its PV system.

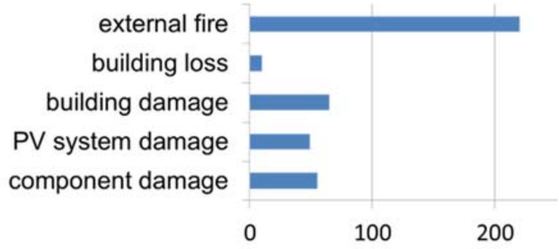

Figure 1: Number of identified incidents and severity of effect on surrounding

The following analysis focuses on the 180 cases where the cause of a fire originated within the PV system.

2.2 Influence of mounting type – building integration

Are there any parameters which significantly impact the severity of damage? Of the available information one parameter was apparent. Figure 2 shows the impact of mounting type.

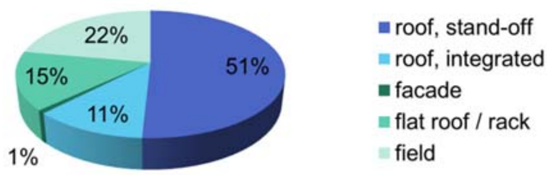

Figure 2: Distribution of fire reports depending on mounting type

The fraction of each mounting type roughly correlates with the market share of each market fraction as given by the German solar industry association BSW [3]. Only roof integrated systems stand out. They together with other BIPV systems account for about 1 %

of the whole market. Looking closer at the incidents where building damage had been reported – these are 54 cases – yields the picture in Figure 3. Roof-integrated PV generators account for some 20 % of building damage! Thus, roof-integrated PV systems had a fire risk which is 20 times higher as for regular stand-off mounted PV generators.

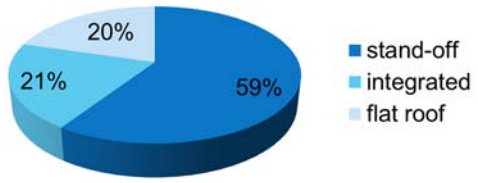

Figure 3: For cases of damaged buildings only: distribution of fire reports depending on mounting type

This can easily be explained by the fact that buildings with stand-off system are typically covered by a "hard roof" (i.e. tiles), which shields the building from external fires. For BIPV systems, however, a fire within the PV system is already inside the building.

This clearly indicates that BIPV systems should receive very careful planning and thorough installation and possibly special protection for critical components! (cf. section 2.3)

2.3 Location of Component where Fire Started

Is there a pattern in incidents which indicates options for easy improvements? Do some components stand out as frequent cause for fire? Figures 4 and 5 show the section and the component, respectively, where the origin of a fire could be located.

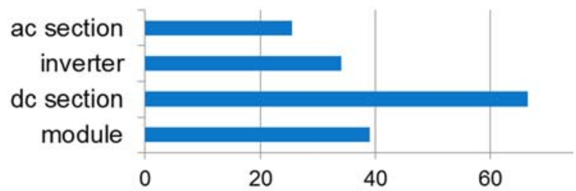

Figure 4: Counts of system section where fire started. AC section includes all components from inverter output terminals to the point of coupling to the grid. DC section includes all components from string connectors at modules to inverter input terminals.

Dominant section in terms of fire risk is the DC section, i.e. string and array cabling and array junction boxes. The main system components, PV modules and inverters, account for roughly half the fire incidents. Surprisingly inverters have been found nearly as often as modules, which are used in far higher numbers. Aside from inverters, the AC section of systems is far more often involved in fires than expected, considering that the components used are regular AC components with a long-term evolution.

The next figure shows the component causing the fire with the best available resolution. We wanted to see, if there are key components with an abnormal fire risk.

Apparently, the inverter is a "hot-spot". Why this? Findings presented in the next sections indicate that there are two main reasons: product defects and installation errors, which cause the high rate of fires from inverters.

Another "hot-spot" is module junction boxes. Here, we assume that product defects in combination with deficient manufacturing quality assurance are the major cause of fires. A survey of field failures of PV modules in the US found failing connectors to account for some 6 % of failures of fielded modules [3].

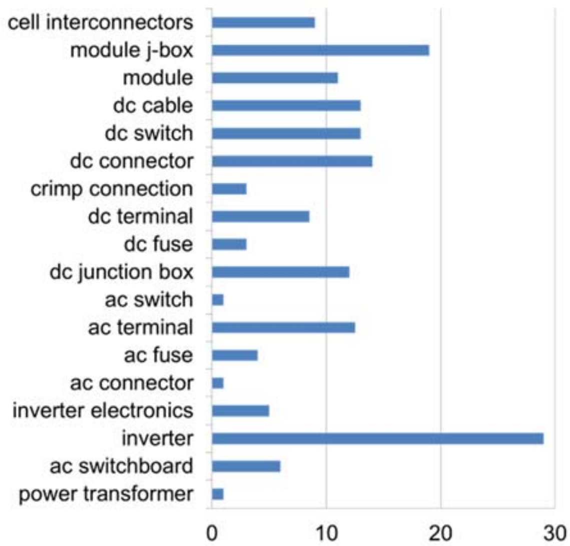

Figure 5: Counts of component where fire started with best available resolution

Other causal components are fairly well distributed. However, it appears that all sorts of connections are sensitive, especially those produced in the field. Furthermore, "dc switch", "dc terminal", "dc junction box" and „ac distribution" often mean use of screw terminals. The authors believe that screw terminals are a potentially weak spot in PV systems and should be replaced by other connection technologies. Tightening screws can be forgotten and good contact quality needs controlled torque according to the terminal manufacturer´s specifications. Which installer regularly uses a torque control screwdriver?

DC switches showed a special failure pattern and are discussed in more detail in section 3.

2.4 Cause of Incident

For some 110 incidents a likely cause could be identified. The distribution of these causes is shown in Figure 6.

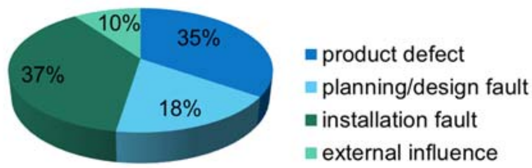

Figure 6: Distribution of identified causes of fire incidents. Installation fault describes poor workmanship.

Installation faults and product defects are the main reasons for damage. They caused roughly 35 % of damages, each.

The following paragraphs will address in detail faults and errors found responsible for burning marks and fires.

Product defects

Module manufacturing errors have been known for several manufactures. A couple of manufacturers seem to have had either poor designs or series production deficiencies. Poor quality assurance in the factory had been suspected as underlying cause of these failures [3].

Similarly, some inverter types appear to have some design flaws. However, only anecdotal evidence is available. Our fire incident survey brought up only a few cases where information on inverter type was available, so no statistical evaluation was done.

These **mechanical design errors** had been noted:

- frameless thin-film modules mounted too tight to each other → restraints occurred, mechanical tensions, glass breakage → electric arcs
- mounting rails tightly next to module junction boxes (j-box) caused shearing forces → damage to j-box → electric arc
- weather exposed array junction boxes – no rain or sun protection - developed stress on contacts due to high internal air temperatures and humidity from water vapor diffusion → increasing contact resistance → electric arc
- array junction boxes and inverters mounted on wooden panels or above combustible material → fire spread quickly and damaged building interior
- missing fire retarding seal at building entrance of rooftop PV array cabling; → electric arc penetrated from roof into building → building heavily damaged

Following a list of **design errors in electrical installations** are given with their respective result:

- multiple, bundled (=grouped) laying of cables without current derating → overheating of cables → fire in cable trunk
- underrated cables → overheating → charred contacts
- underrated DC-switch → overheating → electric arc
- neglected simultaneous maximum power dissipation from fuses (coincidence factor of 1, different from standard AC loads) → overheating of cabinet → contact degradation → fire
- AC fuse at DC circuit → fuse did not interrupt current → electric arc
- DC wiring laid over sharp metal edge → insulation damaged → short circuit → electrical arc
- unsuitable terminals used to connect aluminum conductors → increased contact resistance →fire
- cabinets for indoor use used outdoors → water penetration → contact degradation → overheating → charred terminals → loss of power

Figure 7: "Watertight" IP 65 array junction boxes after 15 years operation; the left one shows water droplets from condensed vapor.

- cabinets for outdoor use, but without condensation drainage provided → water accumulation → contact corrosion → loss of power (see Figure 7)
- Inverters have been installed at unsuitable places expose to weathering or in an unsuitable way – on or near combustible material. Damages range from defective inverters to burnt down barns.

Poor workmanship and its consequences

- DC connector not properly plugged → plug molten down → string interrupted; in some case building damaged
- DC connector not at all or poorly crimped → arc and building damage
- screw terminal not fastened → arc and generator junction box destroyed; in one case building destroyed
- wire insulation partly inserted into terminal → poor contact → overheating → fire in cabinet
- fuse not latched into holder → arc → junction box damaged
- insufficient or lacking preparation of Aluminum conductors → poor contact → fire → inverter station destroyed. Several cases were reported.
- lacking strain relief of cables → is likely cause for contact failure and fire in AC distribution cabinet
- cross mating of DC connector parts of different manufacturers → overheating of hundreds of contact pairs in a large PV System → expensive repair
- module wires were used as handle → wires slightly pulled out of j-box contacts → arc in j-box

External influences

- rodents and martens eating wire insulation -> short circuit -> arc
- lighting strike > damaged (shorted) bypass diodes -> reverse current -> damaged j-box
- craftsman working on a roof drilling long screws into (hidden) DC cables -> short circuit -> arc

Besides the above mentioned errors more a subtle design flaws may also have cause fires in transformer stations of large PV systems. Transformer stations for utilities in Germany are typically designed for "utility loads". Utility loads dwell at part load most of the time and reach nominal power for only short periods in the evening [5]. Thus regular transformer stations are underrated for long term continuous full power around noon as they are encountered in PV systems.

Poor workmanship may be attributable to tough working conditions for installers (see next section) as well as extensive employment of unskilled labor. Unskilled labor reportedly has been widely used due to lack of skilled personal and to achieve low installation cost.

2.5 When did incidents occur?

Annual incident numbers increased markedly during the last years (see Figure 8). The number of annual incidents correlates well with German installed capacity of about seven GWp in 2010, 2011, 2012 each [3], considering that faults show up in the next sunny season. This observation is supported by Figure 9. Most incidents occurred during installation or the first year of operation. This fact supports the finding that most fire incidents were caused by product defects and poor workmanship. Poor workmanship might partially be caused by tough working conditions triggered by sharp feed-in-tariff (FIT) drops in winter 2011 (see Figure 10).

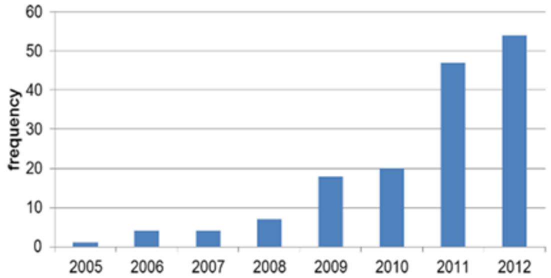

Figure 8: Number of incidents over years; the frequency of damage correlates well with the annually installed PV capacity allowing for one year delay.

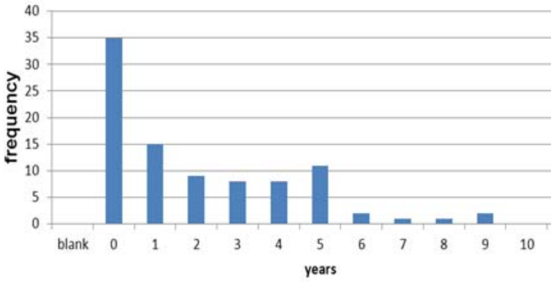

Figure 9: Number of incidents over operation system age. The peak in the first year is striking.

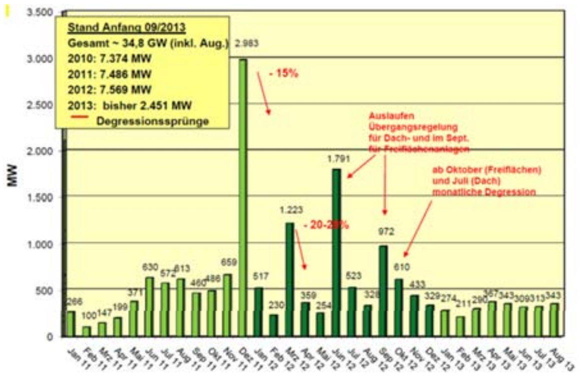

Figure 10: Newly installed capacity in Germany in MWp per month from 01/2011 - 08/2013 [6]. Red arrows indicate a drop in feed-in-tariff. These drops caused a peak in installed capacity the month before, each time.

We assume that the rush of clients to take advantage of the older FIT is partly responsible for the high rate of early failures.

In the 2012 EEG amendment the FIT adaption scheme was changed to a monthly reduction. Thus, the exceptionally high work peaks should no longer occur.

3 DC SWITCHES

3.1 Field experience

As mentioned before DC switches had been found in several incidents as cause of a fire [2].

In many more PV systems inspectors found switches with marks of severe overheating (see Figure 11). At the site of a PV fire started by a DC switch the authors found among six "surviving" switches two more switches with charred terminals – out of a total of 15 switches. When we contacted suppliers of these switches, a major retail company mentioned hundreds of product replacements due to charred terminals. One manufacturer told us they were aware of a problem and they had changed the switch design and replaced "FASTON" terminals by screw terminals. Another manufacturer told us they had received little negative feedback from the field. (However, their switches had been built into the mentioned retailer´s products.)

Figure 11: DC switch with charred terminals after six years of operation. This damage can be easily detected even by lay persons, if the contacts are visible.

Figure 12 shows the site of a fire which destroyed a generator junction box (j-box). The investigator identified the DC switch as cause of the fire [7]. Actually, the inspector found "lack of maintenance" as final cause of the fire. The switches´ manufacturer required annual operation of the switch to clean contacts [8] After the fire all array junction boxes – about 130 boxes - were inspected. In some 10 % of the boxes switches with charred terminals were found.

Figure 12: An array junction box had been destroyed by a fire. The j-boxes were fully exposed to sunlight and weathering. We assume that this exposure has contributed to contact degradation (photo: Freiwillige Feuerwehr (fire department) Bühl).

3.2 Laboratory testing

To understand the degradation of switches and the need for maintenance we investigated some six year old switches recovered from the site of a PV fire started by a

DC switch [2].

Five of the original switches could be recovered. Switches 1-3 were rated for 25 A, switches 4-5 for 16 A. The switches were tested in the lab for contact resistance and for electric losses from contact resistance. We followed the manufacturer´s recommendation and operated the switches for ten cycles. Figure 13 shows the result of the test. Initial total contact resistance varied between about 10 mΩ and 28 mΩ. At rated current this corresponds to about 8 W (25 A switch SW-2), respectively 3 W (16 A switch SW-4) and 17 W (25 A switch SW-3) losses. After “maintenance”, losses at rated current ranged between 2 W (SW-2) and 6 W (SW-3).

The fifth switch was different. The lower part of the switch did not respond to the switching operation.

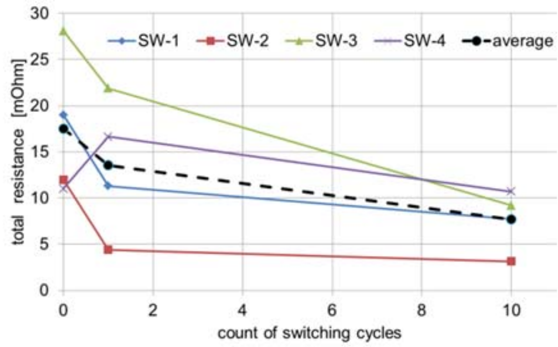

Figure 13: Total contact resistance of a DC switch with several contact layers as function of switching cycles

Operating the switches ten times reduced contact resistance and losses in average by a factor of about two.

Cause of overheating was first thought to be poor FASTON connectors. Disassembling the switch SW-5 provided clues that indicate that the prime heat source was located within the switch and not at the connectors (see Figure 14). Isolation materials within the switch are completely carbonized. The axis had shrinked and also was carbonized. It was broken and had left a section of the switch “open”, another one “closed”. Probably, degraded contacts caused internal losses and subsequently internal overheating.

The axis broke exactly when the switch was operated by firemen during the fire. Thus, the safety device failed when it was needed.

Overheating is caused by resistive heating at the switching contacts. The phenomenon of contact degradation is well known among contact manufacturers and attributed to minor movements under thermal cycling (“fretting”). Contact degradation is probably accelerated by high ambient temperatures like those encountered in both reported fire cases - in an uninsulated attic or an unshaded generator junction box on a roof.

To broaden the data basis a similar experiment was conducted for DC switches installed in PV systems at Fraunhofer ISE´s premises. These switches employ a different operation principle compared to the ones mentioned before. Figure 15 shows a view into the open switch.

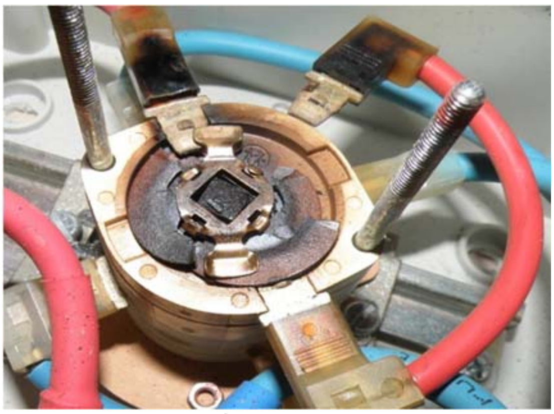

Figure 14: Interior of a switch with charred contacts. The switch´s axis had been weakened from repeated internal overheating and broke, when fire fighters switched off the system.

Eight switches of the same type were tested under regular operation in a PV system. They are rated at 16 A and loaded to 8 A at maximum. Switches had been commissioned some ten years before the testing and probably not been operated since, except for Fas2. Switch Fas2 had been open most of the time and been closed about a year ago.

Figure 15: DC switch with four contacts tested in operation at Fraunhofer ISE. Three contacts are connected in series for one pole, one contact switches the second pole.

The result of the resistance measurement is shown in Figure 16. The initial contact resistance could not be determined, because the switches are built into locked enclosures. To open the enclosure we had to switch off the systems.

This type of switch, though of a different construction, shows a similar behavior as the former type. Repeated switching reduces contact resistance significantly.

Associated losses at rated current vary from about 13 W (worst case) to 1.3 W (minimum). Marks of overheating were not observed, probably because the switches were operated at maximally half the rated current.

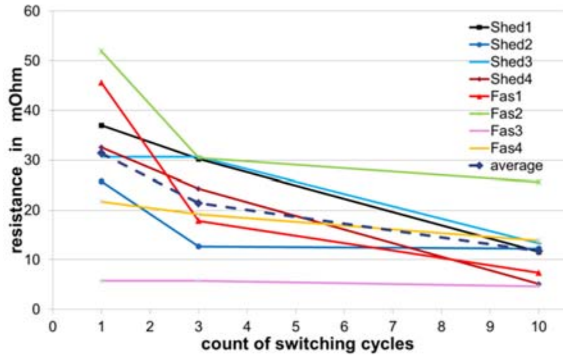

Figure 16: Total contact resistance of eight DC switches as function of switching cycles. Fas2 had been open for years and might therefore have degraded more than the other switches.

3.3 Rating of DC switch

Current design requirements for DC switches are scarce. IEC 60364-712ed.1 simply requires a switch disconnector between array and inverter. No further clues are given for proper rating of this switch.

Concluding from the aforementioned fire cases, additional information for component selection should be requested:

- a derating factor taking into account the switch´s real ambient temperature to be expected under the prospective mounting situation
- another derating factor taking into account the irradiance condition to be expected, including irradiance enhancements effects [9]. Regular irradiance enhancements effects of up to 1500 W/m² have been reported. This corresponds to doubling internal resistive losses and accelerated contact degradation.
- Maintenance requirements for switches.

4 SYSTEM INSPECTIONS

One major fault scenario for fire hazard is reverse current from multiple parallel strings into one string. This may overload modules and string wiring in the faulty string. A recent investigation found that with crystalline silicon technology under regular operation conditions, no reverse current will flow, not during snow cover of one string and not during any other string shading [10]. Shorted strings, e.g. from installation errors or bypass diode failures, however, can cause reverse currents. When strings are electrically shorter by more than 10 % than the rest of the array in parallel, critical reverse currents may occur (Figure 17).

As can be seen from Figure 18 open circuit operation of the array is most critical for this fault constellation. If the inverter is operating and keeping the system at MPP, strings may be shorted by 25 % without destructive reverse currents into the faulty string [10].

Thus to assess the risk of fire from reverse currents the main question is: how reliable are bypass diodes?

To answer this question we inspected PV systems to identify faults and failures. The inspection focused on older module types from various manufacturers, but included recent module types. We inspected about 1 MWp with about 7100 modules and about 16700 bypass diodes. System age ranged between 17 and 6 years, average module age was about ten years.

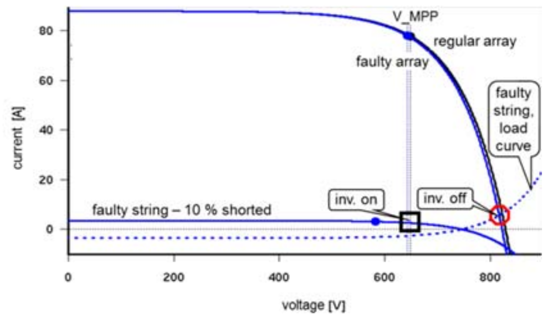

Figure 17: I-V curves at STC of an arbitrary array of 25 strings in parallel (upper/black curve) and of the same array with a faulty string with 2 out of 20 modules shorted (second upper, blue curve). Each string comprises 20 modules. I-V curve of the faulty string is the lower blue curve, and its load curve is dashed blue. While the inverter is running, the faulty string operates at V_mpp and gives a positive contribution to array current. When the inverter is switched off, the operating point of the faulty string is shifted to the intersection of the faulty array´s I-V curve with the faulty string´s load curve at "inverter off". The faulty string draws about twice its short – circuit current. This scenario corresponds to six bypass diodes shorted out of in total 60 bypass diodes in that string.

We looked especially for "hot-spots" in Modules and for shorted bypass diodes (BPD) using a thermography camera. The camera was used to identify thermally abnormal modules, where bypass diodes seemed to carry current (see Figure 18).

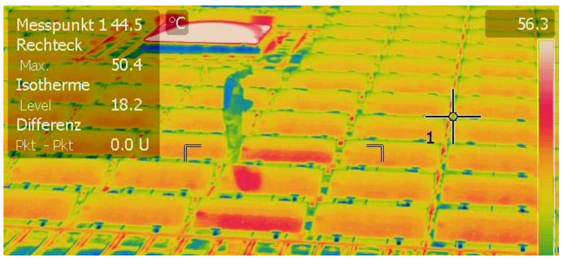

Figure 18: Infrared view of a module field. Two modules show an abnormality with slightly elevated temperature of a substring, each. The red blot in between is a reflection of the technician´s body.

These modules were examined closer and the voltage drop across the diode was measured. If the voltage drop was around 0.6 V (bipolar diode) the diode was assumed to be ok. If the voltage was below 0.1 V, the diode was assumed to be shorted. The inspection took place on sunny days with high irradiance.

The most frequent fault we found, were "hot-spots" at intra-module soldering between cell interconnect ribbon and module bus bar – 6 modules were affected (Figure 19 and Figure 20).

One (!) shorted BPD was spotted among the 7100 modules. This corresponds to a short circuit failure rate of $6.1*10^{-6}$/a.

Thus, "old" modules employing bipolar diodes appear to be quit robust against this kind of bypass diode failure.

In some 20 more modules a bypass diode was active without an apparent cause.

Figure 19: Close-up view of poor soldering. Without thermal imaging camera it is very hard to detect.

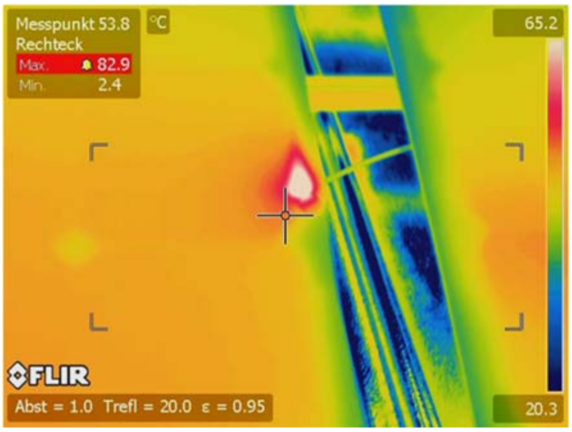

Figure 20: The thermal imaging camera easily detects the faulty solder connection

However, modules employing Schottky diodes as bypass diodes may be different, because Schottky diodes are much more sensitive against overvoltage. In a new 5 MWp system – not covered in the former paragraph on older systems – bypass diodes in about 1500 modules had been damaged by a lightning strike. All diodes involved failed with a short circuit.

Some 25 string fuses were later found to have tripped. Probably, when the sun came out the day after the thunderstorm, massive reverse currents into heavily damaged strings occurred.

A similar observance of many shorted bypass diodes was made in two other systems after lightning strikes. All three systems showing that massive damage did not have a lightning protection system, sometimes not even a grounding system.

Thus, for PV systems exposed to lightning strike risks a lightning protection system is recommended to protect the bypass diodes and reduce outage time due to bypass diode failures.

5 CONCLUSIONS, RECOMMENDATIONS

PV systems are generally a safe technology. Nevertheless, like any electrical installation they constitute an additional risk of fire. This risk was in the order of magnitude of 30 fires annually for 1 000 000 PV systems. However, BIPV systems, especially with roof integrated PV generators, bear a fire risk which is much higher. Thus, BIPV systems need special precaution and risk awareness of the installer.

Several approaches contribute to reduce the fire risk: About a third of fire incidents were caused by installation errors. Thus, everything that eases the installation process also helps to reduce the likelihood of installation errors and a resulting fire.

Specifically, installers can reduce the fire risk by simple measures as:

- adhere to manufacturer´s requirements
- use the right crimping tools for string connectors
- use terminals without screws, e.g. cage clamp terminals
- observe specific requirements and components for aluminum conductors
- use DC connectors of the same manufacturer - no cross combinations
- if screw terminals are used: use screwdrivers/wrenches with torque control, or, even better
- use newly available connection technologies, which do not require a tool (“click-on” connectors)
- conduct initial verification, i.e. inspection and testing

To identify long-term degradation and product defects like poor soldering, which eventually could lead to a fire, yield monitoring and regular inspection is recommended. In several cases of module failure from heat damages, output power had decreased over time before the fire.

Inspections can easily reveal overheating marks on modules, switches, connectors and terminals. These marks can be detected also by lay persons.

Verification of insulation resistance helps to detect damaged or degraded cable and module insulation.

Inspection of the whole system including all electrical connections with a thermal imaging camera eases detection of critical components significantly.

Inspection should be done annually and in combination with maintenance operation of DC switches. Suggested verification interval is four years as for commercial electric installations in Germany.

To limit the potential damage to a building it is strongly recommended to separate polarities at the building entrance and to use fire-retarding sealing for each polarity. This prevents an arc entering the building. Here the requirement for small induction loops in the wiring should be put secondary.

In critical applications, employment of arc detectors should be considered for a reduced fire risk.

PV systems at sites exposed to a high risk of lightning strike should be protected by a lightning protection system. This reduces the likelihood of massive bypass diode damage and thus the likelihood of overheating from reverse currents.

Last, not least, avoiding financing schemes with sharp drops in feed-in-tariff relieves pressure on installers and thus improves the fire safety of PV systems.

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