Technical Risks in PV Projects

Report on Technical Risks in PV Project Development and PV Plant Operation

Merged Deliverable D1.1 and D2.1 (M12)
Version 2.0

Funded by the Horizon 2020 Framework Programme of the European Union

www.solarbankability.eu

Document information

Deliverable name	**Report on technical risks in PV project development D 1.1** **Report on technical risks of PV plant operation D 2.1**
Lead beneficiary	EURAC TUV-RH
Due delivery date from Annex I	1/3/2016
Actual / forecast delivery date	14/3/2016 Update 27/2/2017
Dissemination level	Public | ~~Restricted~~ | ~~Confidential~~

Document validation

Name	Organisation	Date	Visa
David Moser– WP1 leader	EURAC	11/03/2016	OK
Ulrike Jahn – WP2 leader	TUV - RH	11/03/2016	OK

Document history

Version	Date	Modifications	Name
0.1	22/12/2015	First draft	David Moser
	24/1/2016	First review	Caroline Tjengdrawira
0.2	25/1/2016	Second draft	David Moser
0.3	01/02/2016	Third draft	David Moser
0.4	10/02/2016	Fourth draft	David Moser
0.5	19/02/2016	Fifth draft	Magnus Herz
	2/03/2016	Second review	Caroline Tjengdrawira
0.6	4/03/2016	Sixth draft	David Moser

	11/03/2016	Third review	Ioannis Thomas Theologitis
	14/03/2016	Final review	Caroline Tjengdrawira
0.7	15/03/2016		David Moser, Magnus Herz, Ulrike Jahn
2.0	23/2/2017	Update	David Moser, Ulrike Jahn, Mauricio Richter

Foreword

The photovoltaic (PV) sector has overall experienced a significant growth globally in the last decade, reflecting the recognition of PV as a clean and sustainable source of energy. Project investment has been and still is a primary financial factor in enabling sustainable growth in PV installations. When assessing the investment-worthiness of a PV project, different financial stakeholders such as investors, lenders and insurers will evaluate the impact and probability of investment risks differently depending on their investment goals. Similarly, risk mitigation measures implemented are subject to the investment perspective. In the financing process, the stakeholders are to elect the business model to apply and be faced with the task of taking appropriate assumptions relevant to, among others, the technical aspects of a PV project for the selected business model.

The Solar Bankability project aims to establish a common practice for professional risk assessment which will serve to reduce the risks associated with investments in PV projects. The risks assessment and mitigation guidelines are developed based on market data from historical due diligences, operation and maintenance records, and damage and claim reports. Different relevant stakeholders in the PV industries such as financial market actors, valuation and standardization entities, building and PV plant owners, component manufacturers, energy prosumers and policy makers are engaged to provide inputs to the project.

The technical risks at the different phases of the project life cycle are compiled and quantified based on data from existing expert reports and empirical data available at the PV project development and operational phases. The Solar Bankability consortium performs empirical and statistical analyses of failures to determine the manageability (detection and control), severity, and the probability of occurrence. The impact of these failures on PV system performance and energy production are evaluated. The project then looks at the practices of PV investment financial models and the corresponding risk assessment at present days. How technical assumptions are accounted in various PV cost elements (CAPEX, OPEX, yield and performance ratio) are inventoried. Business models existing in the market in key countries in the EU region are gathered. Several carefully selected business cases are then simulated with technical risks and sensitivity analyses are performed.

The results from the financial approaches benchmarking and technical risk quantification are used to identify the gaps between the present PV investment practices and the available extensive scientific data in order to establish a link between the two. The outcomes are best practices guidelines on how to translate important technical risks into different PV investment cost elements and business models. This will build a solid fundamental understanding among the different stakeholders and enhance the confidence for a profitable investment.

The Solar Bankability consortium is pleased to present this report, which is one of the public deliverables from the project work.

Other Publications from the Solar Bankability Consortium

Description	Publishing date
Snapshot of Existing and New Photovoltaic Business Models	August 2015
Technical Risks in PV Project Development and PV Plant Operation	March 2016
Review and Gap Analyses of Technical Assumptions in PV Electricity Cost	July 2016
Minimizing Technical Risks in Photovoltaic Projects	August 2016
Financial Modelling of Technical Risks in PV Projects	September 2016
Best Practice Guidelines for PV Cost Calculation	December 2016
Technical Bankability Guidelines	February 2017

Proceedings from the Project Advisory Board and from the Public Workshops

Description	Publishing date
1st Project Advisory Board closed meeting	June 2015
2nd Project Advisory Board closed meeting	December 2015
First Public Solar Bankability Workshop - Enhancement of PV Investment Attractiveness	July 2016
3rd Project Advisory Board closed meeting	February 2017
Solar Bankability Final Workshop - Improving the attractiveness of solar PV investment	February 2017

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Acknowledgements

The Solar Bankability Consortium would like to extend special thanks to the Members of the Project's Advisory Board for their input and support: 123 Ventures, Deutsche Bank, Grünstromwerk, HSH-Nordbank, KGAL, SEL Spa, SMA, Solarcentury, Triodos Bank, WHEB group.

Project Information

EC Grant Agreement Number: No 649997

Duration: March 2015 until February 2017 (24 months)

Coordinator: EURAC Institute for Renewable Energy (IT)

Project Partners: 3E N.V. (BE), ACCELIOS Solar GmbH (DE), SolarPower Europe (BE), and TÜV Rheinland Energy GmbH (DE)

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Glossaries & Abbreviations

CPN	Cost Priority Number
GHI	Global Horizontal Irradiance
EPC	Engineering Procurement and Construction
EL	Electroluminescence
FiT	Feed-In Tariff
FMEA	Failure Modes and Effects Analysis
IEA	International Energy Agency
IR	Infrared imaging
LCOE	Levelised Cost of Electricity
O&M	Operation & Maintenance
PLR	Performance Loss Rate
POA	Plane of Array
PPA	Power Purchasing Agreement
PR	Performance Ratio
PV	Photovoltaic
PVPS	Photovoltaic Power Systems
RCE	Retail Cost of Electricity
RPN	Risk Priority Number
STC	Standard Test Conditions

Executive Summary

Historical performance data for PV systems on which to base technical risks assessments and investment decisions are difficult to be accessed by all market players, such as investors, PV plant owners, EPC contractors, etc. Reasons for this difficulty are that most PV systems have been operational for only a few years (GWs cumulative installations in many countries was only reached after 2010) and a tendency among system operators and component manufacturers to keep available performance data as confidential. In addition, performance data are in most cases not available for PV plants with low nominal power (e.g. residential-commercial market segments up to 250 kWp) as the cost of monitoring is still perceived as an added cost. Finally, although description of failure and corrective measures is common practice in the field of operation and maintenance (at least in paper form), this is not often carried out with the sufficient level of details to derive meaningful statistical analysis due to missing cost information and lack of a common approach in the assignment of failures to a specific category. For the PV industry to reach mature market level, a better understanding of technical risks, risk management practices and the related economic impact is thus essential to ensure investors' confidence.

The Solar Bankability project is an EU-funded project under the Horizon 2020 Work Programme. The project aims to establish a common practice for professional risk assessment, which will serve to reduce the risks associated with investments in PV projects. One objective of Solar Bankability is to improve the current understanding of several key aspects of risk management during the project lifecycle, from the identification of technical risks and their economic impact, to the process of mitigating and allocating those risks among project parties, to transferring those risks through insurance, warranties, preventive maintenance, etc. To achieve this, in Solar Bankability we have started building upon existing studies and collecting available statistical data of failures with the aim to i) suggest a guideline for the categorisation of failure, ii) introduce a framework for the calculation of uncertainties in PV project planning and how this is linked to financial figures, and iii) develop a methodology for the assessment of the economic impact of failures occurring during operation but which might have originated in previous phases.

The risk analysis has the aim to assess the economic impact of technical risks and how this can influence various business models and the LCOE. ***This report presents a first attempt to implement cost-based Failure Modes and Effects Analysis (FMEA) to the PV sector and to define a methodology for the estimation of economic losses due to planning failures, system downtime and substitution/repair of components***. The methodology is based on statistical analysis and can be applied to a single PV plant or to a large portfolio of PV plants in the same market segment. The quality of the analysis depends on the amount of failure data available and on the assumptions taken for the calculation of a Cost Priority Number (CPN) – which is an indicator that will be explained later on this report (see chapter 2 and chapter 5). The overall results can be linked to the cost of periodic and corrective maintenance and form the basis to estimate the impact of various risk scenarios in PV business models. Furthermore, the uncertainty for the calculation of the energy yield related to technical risks is also reported.

The methodology described in this Deliverable can only be applied to the failures with a direct economic impact to the business plan either in terms of the reduced income due to downtime or the costs for repair or substitution. The technical risks included in the risk matrix which cannot be described with an exceedance probability or with a CPN are very important and have to be considered as they might have an impact on the CPN value of other component failures. For example, the technical risks related to monitoring system, spare parts, normative and documentation, insurance reaction time, operation and maintenance contract, video surveillance, detailed field inspection (IR, EL, etc), just to name a few, can reduce or increase the time to detection or the time to repair/substitution and might have an impact on the detection costs. A thorough analysis has being carried out in relation to mitigation measures and was published in the project report “Minimizing Technical Risks in Photovoltaic Projects”, available since August 2016. In the Solar Bankability project, “year 0 risks” related to uncertainties were further analysed in the project deliverable “Review and Gap Analysis of Technical Risks throughout PV Project Lifecycle and their Uses in PV Investment Cost Calculation” (D3.1), available since August 2016, while “Risks during Operation” with a CPN were integrated in risk scenarios as developed in the project deliverable “Report on Financial Model Evaluation” (D4.2), available since October 2016.

1) Introduction on Technical Risks

Historical performance data for PV systems on which to base technical risks assessments and investment decisions are difficult to be accessed by all market players, such as investors, PV plant owners, Engineering Procurement and Construction (EPC) contractors, etc. Reasons for this difficulty are that most PV systems have been operational for only a few years (GWs cumulative installations in many countries were only reached after 2010) and a tendency among system operators and component manufacturers to keep available performance data as confidential. In addition, performance data are in most cases not available for PV plants with low nominal power (e.g. residential-commercial market segments up to 250 kW_p) as the cost of monitoring is still perceived as an added cost. Finally, although description of failure and corrective measures is common practice in the field of operation and maintenance (at least in paper form), this is not often carried out with the sufficient level of details to derive meaningful statistical analysis due to missing cost information and lack of a common approach in the assignment of failures to a specific category.

For the PV industry to reach mature market level, a better understanding of technical risks and risk management practices is thus essential to ensure investors' confidence. One of the objectives of Solar Bankability is to improve the current understanding of several key aspects of risk management during the project lifecycle, from the identification of technical risks and their economic impact, to the process of mitigating and allocating those risks among project parties, to transferring those risks through insurance, warranties, preventive maintenance, etc. To achieve this, Solar Bankability has started building upon existing studies and collecting available statistical data of failures with the aim to i) suggest a guideline for the categorisation of failure, ii) introduce a framework for the calculation of uncertainties in project planning and how this is linked to financial figures, and iii) develop a methodology for the assessment of the economic impact of failures occurring during operation but which might have originated in previous phases.

Description of typical failures at PV module level was subject to extensive studies within the first phase of the IEA PVPS Task 13 “Performance and Reliability” and the results were presented in the deliverable “Review of Failures of PV Modules” (Köntges et al., 2014). In the document, the most common failures of PV modules are described together with the measurement methods to assess impact on the performance and safety; the importance of visual inspection is highlighted. While the types of failures are highly dependent on the design (or failure of the design) of the PV module and on the environment in which the module is deployed, statistical evaluation of what has been reported can help understand some of the most common failures. Hasselbrink et al. recently summarized data for returns from a fleet of >3 million module-years (Hasselbrink et al., 2013). The study found that 0.44% of front contact modules were returned after an average deployment of 5 years, with the majority (~66%) of these returned because of problems with laminate cell/ribbon/solder failures (primarily cell interconnections). The second most common reason (~20%) for returns was because of problems with the backsheet or encapsulant (e.g. delamination). Thus, the vast majority of the returns were associated with failures that can usually be identified visually. More analyses are needed to understand if the lower rate of return associated with other types of failures are due to the low detectability by visual inspections (e.g. hotspots, cracked cells, PID, etc.) leading to a biased conclusion.

Modules that have failed and been returned to the manufacturers are not the only factor to be considered; modules are usually observed to degrade slowly in the field. Jordan et al have summarized ~400 reports in the literature on the subject of the degradation rates for crystalline silicon modules (Jordan et al., 2012). The degradation is dominated by a loss of short-circuit current. In most cases, the researchers observed that this decrease in short-circuit current is associated with discolouration and/or delamination of the encapsulant material. Thus, both statistics on returns of modules and statistics on slow degradation appear to be correlated to mechanisms that can be observed visually. The systematic use of visual inspection would enable the collection of a large dataset of failures. In the PVPS Task 13 framework, a standardised method and format for collecting the data was developed and the data collection is ongoing.

Regarding the determination of reliability at inverter level, it involves taking a look at the failure rate (including the bathtub curve of failure), the infant mortality rate, the useful life of a solar inverter and the meantime between failures (MTBF). The vast majority of PV system failures are believed to be inverter-related (Ristow et al., 2008). Interestingly, a 1994-1997 study on 126 PV systems found that 75% of the failures were due to inverters with an MTBF of 1.65 years. Module MTBF was 552 years for residential and 6666 years for utility scale system, i.e. one would expect one module of every 552 or 6666 to fail every year, respectively. Another study between 1996-1997 (SMUD's PV Pioneer Program, 332 PV systems) found that 90% of the failures were due to inverters (Maish, 1999). The MTBF of inverters are thus not comparable with the values for modules and inverters must be replaced one or more times during the course of the PV system service life.

The failure modes that mostly affect PV inverters are related to units exposed to high thermal and electrical stress as well as the thermal management system itself. Electronic components such as bus capacitors, electronic switches (e.g. IGBTs) and printed circuit boards (PCBs) are found to be responsible for the majority of PV inverter failures reported in literature. Furthermore, maximum power point tracking (MPPT) schemes are also identified as an important factor impacting the overall reliability of PV inverters (Petrone et al., 2008).

Research results show that electrolytic capacitors suffer from increasing leakage current over time due to corrosion effects. However, state-of-the-art film capacitors suffer almost no change in the leakage current, even over long periods of time (Flicker et al., 2012). IGBTs are subject to repeated stress conditions due to repeated on-off power cycles and ambient temperature changes. Damage from such over-current conditions could potentially be cumulative impacting the PV inverter lifetime (Kaplar et al., 2011). A fan failure could cause the inverter to overheat affecting its overall lifetime and reliability. However, it is shown in literatures that even under extreme operating conditions, state-of-the-art fans used in PV inverters may work without failing during at least twelve years (Ma and Thomas, 2011). Typical estimated life expectancy of integrated circuits (ICs) and optical components is around ten years (Ma and Thomas, 2011). However, this will strongly depend on the quality of the materials used and on the design topology. For example, new developments with high quality materials used for special applications like, for e.g. micro-inverters, are designed to work under extreme conditions and are claimed to have longer lifetimes.

Current trends in PV industry appear to push the limits of inverter reliability (Flicker, 2014). High ratios of the sum of the peak power of the installed PV modules to the installed rated power of the inverter, kW_p/kW_{ac}, ratios are more common on recent PV installations. One of the main advantages of higher kW_p/kW_{ac} ratios is the more stable power output profile due to the reduced variation during daytime peak hours. However, high kW_p/kW_{ac} ratios result in the PV inverters operating at maximum power for many hours during the day, thus being subjected to increased stress. Higher DC operating voltages are known to significantly increase the stress conditions for switching components and capacitors. For micro-inverters, they are more subjected to extreme diurnal temperature cycling which leads to increased stress on the components. Moreover, there are much larger numbers of micro-inverter units than standard inverters in utility-scale PV plants (i.e. approximately 3500 units per MW); each of these micro-inverters can potentially fail which can be a serious issue. Moreover, the large numbers of micro-inverters also poses a challenge for O&M activities. In addition, not all micro-inverters are offered with the similar warranties duration as the PV modules they are directly connected to.

Over the last years, significant improvements on PV inverters reliability have been made. Amongst others, reliability of capacitors has improved significantly by replacing electrolytic capacitors by metal film or foil capacitors. However, the current trends in PV industry keep pushing forward the limits of inverter reliability: the higher kW_p/kW_{ac} ratios, higher DC operating voltages, the micro-inverters and continuous pressure to reduce unit costs are seen as the main challenges for future of inverter reliability (Flicker, 2014; Klise et al., 2014).

The price pressure and continuous search for reducing costs lead to pushing the limits, use of new technologies, new components and reduced dimensions, which in the past repeatedly caused early-stage troubles and temporarily increased failure rates. Based on past due-diligence it is found that many failures occurring in the field are related to non-electronic parts of the PV inverter, e.g. failure of contactors, the malfunction of protective equipment under demanding environmental conditions, such as very high and very low ambient temperatures, high humidity, water (or snow) ingress, excessive soiling and lightning strikes. Many failures are associated with new technologies, still lacking an extended track record in the field and often suffering from unexpected failures.

Extensive work was carried out in the USA in the framework of the PVROM project (Klise et al., 2014) where a rigorous data collection, analysis and feedback mechanism is developed and considered a best practice for PV plant owners and operators looking to go beyond simple data collection and immediate incident response. The PVROM project was formally launched in 2013 with the aim of increasing the data sample collected from and shared by industry partners. The database allows for detailed analysis of component failures and indicators such as the average active repair time, mean downtime and maintenance actions. The database builds on the commercially available software tool XFRACAS for failure reporting and corrective actions (Hamman, 2014). Collins et al described (Collins et al., 2009; Stein et al., 2010) the minimum data necessary for reliability and availability analyses of PV systems as: incident occurrence date/time, Bill of Material part number, part serial number, part commissioning date (in-service date), incident description, incident category, service response date/time, service completion date/time, restoration to service duty date/time, and estimated energy lost (kWh), and also reported how an incident tracking utility can be used for real time data entry.

Ideally, during the process of failure detection and correction, an automatic ticketing system should be in place. This is not always common practice and the collection of a high number of failure data for statistical analysis should also consider existing failure reports, which might come in paper form and might not include all the necessary information.

2) Description of FMEA and Cost-based FMEA Approach

The typical approach in risk analysis in technical projects is to apply a classic Failure Modes and Effects Analysis (FMEA) where the various risks, belonging to a certain phase and component, can be prioritized through their Risk Priority Number (RPN). In the FMEA, each identified risk is evaluated for its severity (S), occurrence (O) and detectability (D); numbers are used to score each of these evaluation parameters. Typically, the RPN is then obtained by multiplying these three factors with the following formula:

$$\mathbf{RPN = S_{RPN} \times O_{RPN} \times D_{RPN}}$$

Technical risks are those that arise from the PV module, inverters, and other mechanical and electrical components, as well as system engineering, energy prediction, and installation. Some risks are confined to specific phases of development, such as construction risk, while others persist throughout the entire cycle from planning through operation, such as default risk.

In the classic FMEA typical numbers are used on a scale from 1 to 10 for each evaluation parameter. An example for severity is given in Table 1; as it can be seen, in this particular approach, the plant performance losses are ranked lower than safety issues. A similar rating can be used for occurrence, also on a scale from 1 to 10, but it is not useful as one cannot distinguish between 10 occurrence figures (defined as probabilities) in a PV risk analysis. For the detectability, the ranking depends on the quality of the monitoring system as well as on the scope and frequency of the conducted tests and inspections. Using those rating figures for S_{RPN}, O_{RPN} and D_{RPN}, the risk priority number (RPN= S_{RPN} x O_{RPN} x D_{RPN}) will result in a value between 1 and 1000 using the formula above.

Table 1: Definition of Severity in classic FMEA approach

Severity	Criteria	Ranking
None	No effect, Performance loss < 0.5%	1
Low	Performance loss < 1 %	2
	Performance loss < 3 %	3
Moderate	Performance loss < 5 %	4
	Performance loss < 10 %	5
High	Performance loss < 25 %	6
	Performance loss > 25%	7

Safety risk without performance loss	Safety risk without performance loss	8
Safety risk with performance loss	Safety risk with performance loss	9
Death, fire, total loss	Safety hazard	10

In Solar Bankability, the role of the FMEA was to focus on the most important failure risks with respect to their impact on electrical and financial performance.

The classical implementation of FMEA was proposed as a first attempt to prioritise risks; here the performance and safety risks were considered together. The resulting spread of the FMEA results is an indication for the uncertainty of this evaluation and after discussion among partners the FMEA can be conducted again to consolidate and gauge the results. Consequently, the Top Failure ranking list can be evaluated by external experts in a second round FMEA to further refine the results.

In the second FMEA approach, performance and safety risks were treated separately, introducing and testing a rating score on a logarithmic scale for severity and occurrence in the search to obtain the cost-related priority number. The proposed performance-safety FMEA would deliver two RPN numbers for one failure - a Performance RPN and a Safety RPN. This approach was used to rate some examples of top failures and seemed to work for well-defined failures of certain components (e.g. modules) and certain phases. But for the whole risk matrix including all components and different project phases this approach failed to generate meaningful cost-related priority numbers.

An example of FMEA rating of PV module failures is given in the diagram below (Figure 1). The rating of the technical risks was based on the statistics of failure reports from TÜV Rheinland and included the expertise of groups beyond the project team. This FMEA rating resulted in a top-down list of technical risks for a component as long as the uncertainties are low and conditions are clearly defined.

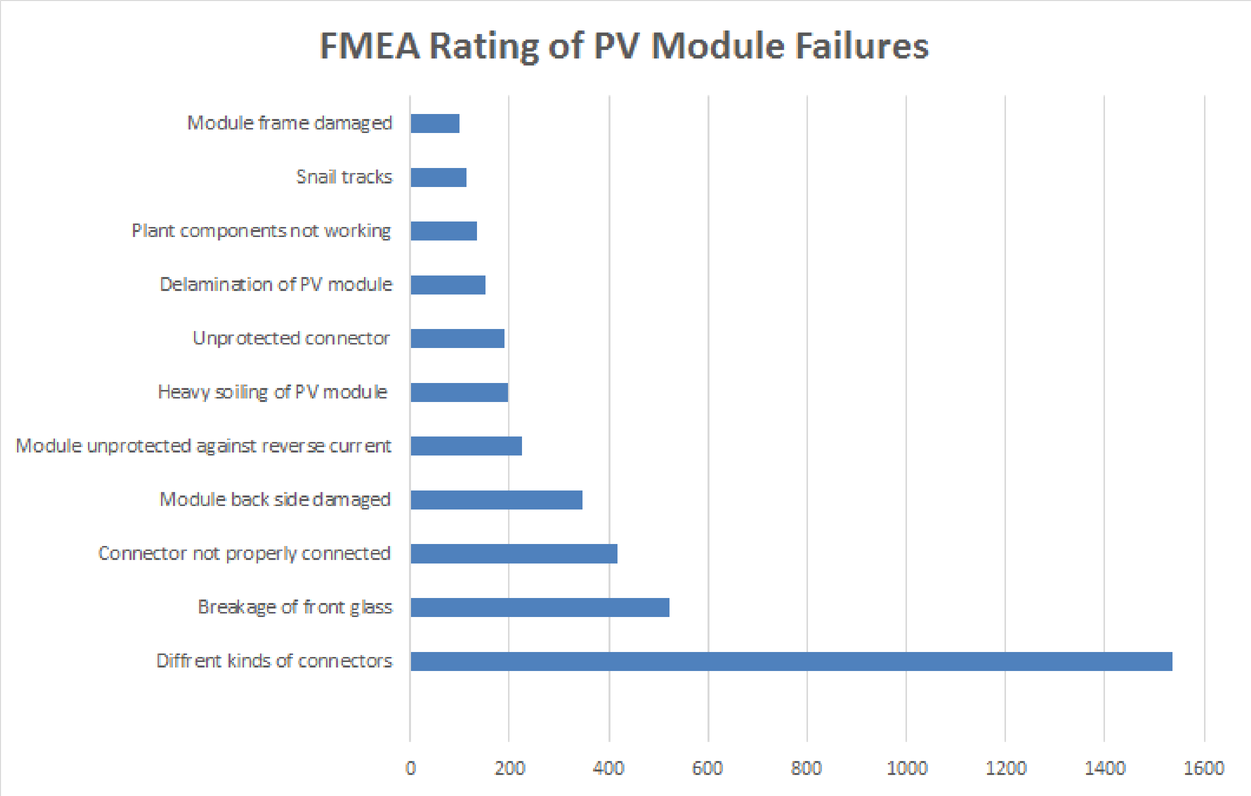


Figure 1: Example of rating of PV module failures based on classic FMEA

From the above two analysis for methods to prioritise failures and critical issues on photovoltaic plants, the classical FMEA methodology was deemed to be inadequate since it did not provide a framework for the calculation of the economic impact. To consider the failure just from a technical point of view is in fact not enough to achieve the objective of the Solar Bankability project. Many literatures have discussed the approach of cost priority FMEA in the automotive or wind turbine markets. The cost-based approach works with a special coefficient called the CPN (cost priority number) which corresponds to RPN (risk priority number) in the classic FMEA. This approach appeared to be more in line with the objective of this project and thus we have elected to implement the cost-based FMEA in Solar Bankability. Since - to the best of our knowledge - no analysis on this approach has been carried out for photovoltaic plants, we have also developed the definition of Occurrence, Severity and Detectability for the analysis of PV System as described in Chapter 5.2).

3) Risk Matrix: Procedure and PV Value Chain Description

One of the main objectives of the Solar Bankability project is the definition of technical risks along the overall PV value chain for each component in the PV plant. The value chain has been divided into five phases, taking into consideration the efficiency and lifespan of the PV plant:

I. Product testing / development

II. PV plant planning / development

III. Transportation / installation

IV. Operation / maintenance

V. Decommissioning

More detailed definitions of the five phases are given in this chapter.

It is important to categorise a technical risk not only in terms of when it occurs/generated but also which component is affected by the failure. Therefore, the following components have been selected:

A. Module

B. Inverter

C. Mounting structure

D. Connection and distribution boxes

E. Cabling

F. Potential equalization and grounding, lightning protection system (LPS)

G. Weather station, communication and monitoring

H. Transformer station and MV/HV (medium voltage/high voltage)

I. Infrastructure and environmental influence

J. Storage system

K. Miscellaneous

Based on the value chain and the components defined above, the so-called "*Risk Matrix*" was developed (Figure 2). Due to the structure of the matrix, each technical risk can be assigned to a certain project phase and component. A short description of the most critical risks, which have been qualitatively prioritised within the Solar Bankability project, can be found in Appendix 2.

		I	II	III	IV	V
	Components / Project Phase	Product testing / development	PV plant planning / development	Installation / Transportation	Operation / Maintenance	Decommissioning
A	Modules					
B	Inverter					
C	Mounting structure					
D	Connection & Distribution boxes					
E	Cabling					
F	Potential equalization & Grounding, LPS					
G	Weather station & Communication & Monitoring					
H	Transformer station & MV/HV					
I	Infrastructure & Environmental influence					
J	Storage System					
K	Miscellaneous					

Figure 2: Structure of the risk matrix developed in the Solar Bankability project

3.1) Product Testing / Development

During the production line, raw materials (PV cell, frame, electronics etc.) may get damaged due to machinery errors or mishandling. Thus, inspection during production helps to control the quality of the final products by identifying the problematic source, fixing it, and also provide the mean to directly detect the defect item. Moreover, the conformity of the process with the related standards leads to a production line with higher yield and fewer defect rates.

Quality assurance measures of PV plant components, e.g. pre-delivery and receiving inspections, are influential factors on the product quality. The implementation of a quality system in the factory to ensure a high-level product quality and the technical characteristics as specified (e.g. in the data sheet) are strongly dependent on the manufacturer’s philosophy which ultimately determines the level of detail and compliance of the quality measures in the factory.

An extended factory inspection at the manufacturer’s site shall put a focus on the quality assurance measures, incoming goods inspection and material handling procedures. A particular focus is also given to the power measurement and data control, traceability and calibration procedures.

3.2) PV Plant planning / Development

The expertise of the EPC contractor is one of the most important factors during the PV project planning phase since they are responsible for the design, procurement, construction and commissioning of the PV plant. Great performance losses can occur during the operation of the plant because of an incorrect or non-optimised plant design. The selection process and criteria of an EPC contractor is therefore one critical step in ensuring having a competent contractor. It is recommended, for PV planning, to select qualified/certified EPCs who can prove their expertise with training and confirmed references[1].

Similar recommendations apply to the residential sector and in general to the installation of small scale PV systems where experienced EPC contractors may not be involved. This becomes increasingly more important as the degree of complexity of the business case increases due to the need to include considerations on direct self-consumption or direct line power purchasing agreements (PPAs).[2] This type of schemes requires knowledge on load profiles and might not be of straightforward implementation for PV installers of small-scale systems.

The selection of the PV technology and components is a key parameter for the performance of the plant. Wrong choices in planning, due to lack of knowledge, or low-quality components, in order to reduce the cost, can cause unexpected loss of production or potential safety issue. The location of the PV plant is a crucial point for the component selection and all the environment parameters such as humidity, altitude etc. must be taken into account for the operational points of the components. For PV plants installed in the urban environment, yet there are other factors that need to be considered such as shading from near objects, quality of the roof/facade accessibility, etc. The compromise between cost and quality should, in any case, respect at least the minimum requirements for the reliability of the plant.

For the overall evaluation of a PV project, performance simulation is an essential part for the assessment of the expected energy yield. The related uncertainty of the simulation depends upon a great number of factors (Chapter 5.1). Distinctive elements are the meteo-data, uncertainty of the 3-dimensional plant model (horizon uncertainty of the far-shadings, near shading), losses related to PV modules and electrical equipment, slow degradation etc. Careful mitigation of these parameters can provide better assessment of the profitability of the plant.

The quality and reliability of the installation could be ensured by conducting the necessary studies for it, such as:

1. The static study of the mounting structure in combination with the suitability of the site.
2. External lighting protection and protection against voltage surges studies
3. Grounding system (earth-resistance), step & contact voltage protection studies
4. The electrical installation study

[1] http://pvtrin.gr/en/home/index.html
[2] See deliverable August 2015 – “Snapshot of Existing and New Photovoltaic Business Models”, http://www.solarbankability.org/results.html

5. Environmental study / decommissioning study

All the studies should be in compliance with the latest international (such as IEC) and European standards (such as the CE directives).

3.3) Transportation / Installation

The global transport of products and the influences of transportation on the PV module performance is a risk often not considered. Traceability of the impacts on existing failures or failures originated during transport is not always possible during shipping processes. Moreover, the link or impact of transport damage (e.g. solar cell cracks) on the system performance is not clearly documented.

It is currently known that:

1. The quality state of the module is unclear when delivered (traceable real power, micro cracks)
2. The origin of failures is not detectable
3. The degree of damages / power losses is not known.

The above is attributed to the fact that the quality condition of outgoing goods is unclear and/or the packaging and handling requirements are not properly specified or followed.

The inspection of the modules for possible defects on site is essential not only to identify any damaged modules but also for the evaluation of the degradation of the modules after a certain period of time e.g. one year. To ensure the original product quality at construction site, transparent product quality and certified logistics processes are recommended (Pieterjan Vanbuggenhout et al., 2011).

During the installation the warranty and functionality of the components should be guaranteed by qualified/certified PV installers. Any damage caused by the installation company or a sub-contractor is not responsibility of the owner. More details are given in the project deliverable "Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation" (Jahn et al., 2016). Most common failures or improper practice are defined by Keating et al. (T.J. Keating et al., 2015):

Table 2: Most common failures and improper practice

Component	Failure 1	Failure 2
Site	Deformation of the land	Roof damage – not adequate sealing methods
PV modules	Mechanically broken module	Loose module clamps

Inverters	Wrong installation	Wrong configuration
Mounting structure	Damage of the insolation	Incomplete structure
Cabling	Tighten or loose cables	Exposure to physical damage
Grounding	No existing potential equalization	Wrong combination of material
Monitoring	Wrong installation of sensor	Wrong configuration

These mistakes mostly occur because of lack of know-how, short available time for the installation, wrong planning etc.

After the completion of the installation and before the commissioning of the PV plant, as-built files must be delivered to the owner. These files are necessary for the safe and proper maintenance of the plant and troubleshooting. If what is reported in the planning documentation differs from the installation, or in the worst case scenario, no documentation is available, proper intervention within the PV plant cannot be guaranteed.

3.4) Operation / Maintenance

During the plant operation, the most vital parameters are the production and the performance of the PV plant. Accordingly, the correct monitoring of these two elements is essential for long-term plant operation assessments. Thus, measurement accuracy and monitored data of plant performance should be prioritised and regularly validated. Furthermore, loss of data will lead to wrong assessment of the plant performance and alternative solutions or measures of recovering the loss of data should be considered in advance.

The lifetime and performance of the components are directly influenced by their maintenance. For the electrical and electronic equipment the maintenance protocol and guidelines stated in the installation manual or instruction from the manufacturer must be closely followed. PV modules do not require specific maintenance aside from periodic cleaning since the electricity production can be negatively influenced if the surface is covered by soiling or snow. The losses due to soiling depend upon how much soil and dirt the surface of the module has accumulated. In addition, the inspection of the PV modules for degradation or other defects such as hot-spots, lamination etc. must be included in the O&M contract of the plant. This means that periodic maintenance should go beyond visual inspection (T.J. Keating et al., 2015). For small size systems (e.g. residential systems), close monitoring should be considered as a cost-effective measure compared to periodic maintenance and/or inspection.

After the installation, it is important for all market segments to have a clearly assigned party responsible for the plant O&M. In many cases the EPC contractor typically performs the O&M of the PV plant for at least the early years for the plant operation (during the EPC warranty or Defects Liability Period). In this case, damage or power loss caused by the wrong installation should be repaired by the EPC. In other cases, especially for non-utility scale PV systems, procedures are unclear where PV plant owners, as non-experts, may not be aware of the technical risks and related economic losses. In any case, the O&M procedures should be clearly defined so that ownerships and responsibilities of the O&M tasks are assignable and traceable. This risk must be considered during the PV planning phase.

3.5) Decommissioning

3.5.1) Disposal of PV Modules

The European law regulation for the collection and treatment of photovoltaic module waste across Europe – the Waste Electronics and Electrical Equipment (WEEE) Directive, entered into force in August 2012. The EU member states were given 18 months to adapt this directive into national laws with a deadline of 14th February 2014. One of the most important innovations of this directive for the PV industry is the definition of 'Producers', which includes all firms or individuals established in European countries selling, reselling or importing PV modules. In the directive, the Producers are responsible for the environmentally sound disposal and recycling of solar modules in all the EU Member States where they operate. These obligations, however, are likely to differ significantly from country to country. Nevertheless, most EU member states having relevant markets for photovoltaic had announced new regulation during the year 2014.

A waste law bringing PV modules that are made or sold in Germany under mandatory producer responsibility rules came into force on 24th October 2015. Under the new WEEE legislation, known as ElektroG, PV modules are classified as household equipment. Therefore, producers of PV modules must provide a legally binding financial guarantee on their annual sales of PV modules in the country.

In France the adaptation of the WEEE came into force on 23rd August 2014 by the "Decree 2014-928". The law applies to French-based companies, which manufacture or import PV modules for the French market.

The British government has introduced its interpretation of the European Union's WEEE Directive for the disposal of PV modules on 1st January 2014. For the U.K. photovoltaic market, the regulations require all importers of PV panels into the U.K. to register with a Product Compliance Scheme, which demands that all producers take full financial responsibility of the waste disposal of the PV panels they supply to the market, in addition to reporting all important data, such as numbers supplied and locations distributed to.

In Italy the disposal of waste electrical and electronic equipment (EEE) is regulated by Legislative Decree No. 49 of March 14th, 2014. The photovoltaic modules are considered WEEE components since April 12th, 2014 and therefore their recovery and recycling at end of life is subject to regulation.

On 14th of December 2015 the GSE (Gestore Servizi Energetici) published the "operational guidelines for the management and disposal of photovoltaic panels" provided in accordance with Art. 40 of legislative decree 49/2014. These guidelines provide operating instructions on how to guarantee complete waste management by photovoltaic panels in tariff and apply to the beneficiaries of the various Conto Energia.

The report "Study on photovoltaic panels supplementing the impact assessment for a recast of the WEEE directive"[3] showed the economic impact of recycling solar modules and predicted the potential of cost reduction thought economy scale. Nevertheless country norms, general literature and scientific articles tend to focus currently on decommissioning's potential of solar module. Unexplored remains the economic potential of decommissioning photovoltaic plants, including solar cables, inverters, aluminium, etc. Technical risks related to the disposal of PV modules are linked to possible unclear procedures to the recycling or to the content of harmful materials over certain limits, which might lead to higher costs for the safe disposal of the PV modules.

3.5.2) Decommissioning of PV Plants

Numerous scientific articles on Life Cycle Assessment (LCA) of PV installations can be found on the literature. The energy-based approach analyses every single system component from production to decommissioning. The main environmental impact is connected to the production, transport and installation of PV modules. However, the electrical materials and cabling also have an important role in terms of energy impact. Energy PayBack Time (EPBT) and Energy Return On Energy Invested (EROEI) are essential parameters to evaluate the energy sustainability of PV installations. However, it is no possible to generalise or categorise these parameters on installation typology or market segment, as they are strongly depending on country energy mix, solar radiation, energy price, etc.

From the first known intervention at the end of March 2009 about the disassembly of Chevantogne generator to the recent final report of the activity of the IEA PVPS Task 12 (Frischknecht, 2016), many installations have been studied. The procedure to calculate the lifetime environmental impact includes inventory analysis, impact assessment and interpretation. The data collection portion of the LCA is defined as Life Cycle Inventory (LCI). It consists of detailed tracking of all the flows of raw materials, energy by type, water and emissions to air, generated during the production and the lifetime of the "system of interest".

[3] http://ec.europa.eu/environment/waste/weee/pdf/Study%20on%20PVs%20Bio%20final.pdf

Table 3: LCI (Life Cycle Inventory) of mounting structures of PV modules.

Installation type		on-roof	on-roof	in-roof	in-roof	ground	ground	
Company		PhönixSon nenstrom AG	Schletter	Schletter	Schweizer	PhönixSonne nstrom AG	Springerville	
type of mounting system		TectoSun	Eco05+EcoG	Plandach5	Solrif			
framed (f) or unframed (u) modules		f	f+u	f+u	u	f	f	
Products	**Unit**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**	**Comment**
mounting structure	m2	1	1	1	1	1	1	m2 module area
Materials/fuels								
steel	kg	0	0	0	0	11.5	4.01	
stainless steel	kg	0.49	0.72	0.28	0.08	0.17	0	
aluminum	kg	0.54	0.97	1.21	1.71	1.26	0	
concrete	kg	0	0	0	0	0	8.03	
EPDM	kg	0	0	1.41	1.41	0	0	EPDM underlayer, thickness 1.14 mm
roof tiles (avoided)	kg	0	0	-40	-40	0	0	ceramic roof tiles
total without EPDM/roof tiles	kg	1.03	1.69	1.49	1.79	12.93	12.04	

The table above shows the amount of raw materials used in different types of PV installation (on-roof, in-roof and on ground) for several sample plants. The data has been collected from different solar module mounting structure operators and literature in the year 2006. For a correct calculation of LCI and decommissioning cost, a more elaborate approach is necessary. An example of the study by the IEA PVPS Task 12 (Frischknecht, 2016) considers a wider representative of PV installations in different European countries. The LCI comparison (Table 4) lists the PV plant raw material. Every single voice has to be actualised through the current material costs. While the disposal value of steel, aluminium, even of solar modules can be calculated, the estimation of the cost-related to "plant dismantling" is more complicated. Examples of cost of decommissioning for the whole plant were given in studies carried out in the US. Value of labour cost and recycled materials were estimated to find a net cost of decommissioning between 105 and 73 $/kW. (Table 5 for California and Table 6 for Maryland).[4,5]

In business models the cost of decommissioning is usually not considered[6] as the assumption is that the value of recycling of materials should balance the costs of dismantling the plant.

[4] http://webapp.psc.state.md.us/intranet/Maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C160000-199999%5C172702%5CDecommissioningPlan31July15rev1(redactedversion2).pdf accessed on the 12th February 2016

[5] http://www.planningdocuments.saccounty.net/DocOpen.aspx?PDCID=13854 accessed on the 12th of February 2016

[6] Feedback from the Project Advisory Board

capacity		93 kWp	280 kWp	156 kWp	1.3 MWp	324 kWp	450 kWp	569 kWp	570 kWp	
type of module		single-Si laminate	single-Si panel	multi-Si panel	multi-Si panel	multi-Si panel	single-Si panel	multi-Si panel	multi-Si panel	
type of mounting system:		Slanted roof integrate	Flat roof mounted	Flat roof mounted	Slanted roof mounted	Flat roof mounted	Flat roof mounted	Open ground	Open ground	
location		Switzerla nd	Switzerla nd	Switzerla nd	Switzerla nd	Germany	Germany	Spain	Spain	
Products	**Unit**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**	**Comment**
photovoltaic installation	unit	1	1	1	1	1	1	1	1	Refers to capacity above
electricity yield	kWh/ m^2*a	131	155	120	128	141	136	238	198	3.85 MJ converted solar energy per kWh
Components/fuels										
electricity consumption	kWh	7.13E+00	2.15E+01	1.19E+01	1.03E+02	2.48E+01	3.45E+01	3.60E+01	3.60E+01	Erection of plant
diesel consumption	MJ	0	0	0	0	0	0	7.66E+03	7.67E+03	
inverter weight	kg	123	2420	1590	6600	2600	3535	4675	4675	This amount is replaced every 15 years.
mounting system	m2	6.84E+02	2.08E+03	1.17E+03	1.01E+04	2.55E+03	3.38E+03	4.27E+03	4.27E+03	
photovoltaic module	m2	7.05E+02	2.14E+03	1.21E+03	1.04E+04	2.63E+03	3.48E+03	4.29E+03	4.40E+03	Including 2% replaces during life time and 1% rejects
Electric installations (excluding inverter)										
copper	kg	7.06E+01	3.18E+02	3.03E+02	3.87E+03	3.77E+02	3.81E+02	7.41E+02	7.41E+02	Drawn to wire
brass	kg	5.46E-01	1.02E+00	6.82E-01	7.50E+00	1.36E+00	1.36E+00	1.36E+00	1.36E+00	
zinc	kg	1.09E+00	2.05E+00	1.36E+00	1.50E+01	2.73E+00	2.73E+00	2.73E+00	2.73E+00	
Steel	kg	2.24E+01	4.12E+01	2.81E+01	2.90E+02	5.29E+01	5.29E+01	5.29E+01	5.29E+01	
nylon 61	kg	6.28E+00	1.18E+01	7.84E+00	8.63E+01	1.57E+01	1.57E+01	1.57E+01	1.57E+01	
polyethylene1	kg	6.07E+01	3.15E+02	2.80E+02	3.73E+03	4.12E+02	4.17E+02	7.09E+02	7.09E+02	
polyvinylchloride1	kg	8.69E-01	2.61E+01	2.17E+01	2.36E+02	4.17E+01	4.35E+01	4.49E+01	4.49E+01	
polycarbonate1	kg	5.46E-02	1.02E-01	6.82E-02	7.50E-01	1.36E-01	1.36E-01	1.36E-01	1.36E-01	
epoxy resin1	kg	5.46E-02	1.02E-01	6.82E-02	7.50E-01	1.36E-01	1.36E-01	1.36E-01	1.36E-01	
Transport	tkm									
lorry	tkm	4.23E+03	1.82E+04	9.64E+03	8.34E+04	2.10E+04	2.96E+04	3.51E+04	3.52E+04	500 km modules
transoceanic freight ship	tkm	1.69E+04	7.28E+04	3.86E+04	3.34E+05	8.14E+04	1.18E+05	1.41E+05	1.41E+05	2'000 km modules
van	tkm	8.91E+02	4.12E+03	2.24E+03	1.80E+04	4.72E+03	6.62E+03	7.96E+03	7.98E+03	100 km system

Table 4: LCI of photovoltaic plants in Europe.

Component	Disposal Costs	Labor Costs	Value of Recycled Materials	Net cost	Note
Fence	$20,000	$30,000	$10,000	$40,000	
AC and DC electric wiring	$15,000	$120,000	$90,000	$45,000	Entirely reusable copper/aluminum wire; assumes market value of scrap Cu from LME
Transformer + Switchgear	$30,000	$15,000	$75,000	-$30,000	Lifetime of transformer and switchgear >> 20 years; significant reclamation value
PV-Module	$0	$90,000	$0	$90,000	Cost of solar module removal labor = similar to cost of installation
Aluminum Module Support	$5,000	$30,000	$150,000	-$115,000	Commodity price for scrap aluminum from LME
Wooden Beams	$0	$30,000	$0	$30,000	Wood can be scrapped or buried
Steel posts	$0	$60,000	$50,000	$10,000	Concrete removal offset by recovery of steel at scrap commodity price from LME
Concrete and residual waste	$75,000	$75,000	$0	$150,000	
			Net sum	$220,000.00	

Table 6: Decommissioning cost of 3MW installation in Maryland

Component	Disposal Costs	Labor Costs	Value of Recycled Materials	Net cost	Note
Fence	$200,000	$200,000	$100,000	$300,000	
AC and DC electric wiring	$150,000	$500,000	$900,000	-$250,000	Entirely reusable copper/aluminum wire; assumes market value of scrap Cu from LME
Switchgear	$100,000	$100,000	$100,000	$100,000	Lifetime of transformer and switchgear >> 20 years; significant reclamation value
PV-Module	$0	$700,000	$0	$700,000	Cost of solar module removal labor << cost of installation
Steel Module Support	$50,000	$200,000	$500,000	-$250,000	Commodity price for scrap steel
Wooden Beams	$0	$200,000	$0	$200,000	Wood can be scrapped or buried
Steel posts	$0	$500,000	$400,000	$100,000	Concrete removal offset by recovery of steel at scrap commodity price
Concrete and residual waste	$600,000	$500,000	$0	$1,100,000	
Permitting and Monitoring	$0	$100,000	$0	$100,000	Obtaining permits required for decommissioning and monitoring decommissioning activities
			Net sum	$2,100,000.00	

Table 8: Decommissioning cost for a 20MW installation in California

3.5.3) Decommissioning of Electrical Storage Systems

The number of PV plants with electrical storage systems will rise in the future to follow business models that exploit the benefits of direct self-consumption but also to make sure that PV plants can provide further flexibility to the grid by applying logics of primary frequency and reactive power control. The number of storage systems installed is at present very low and consequently the experience in decommissioning is also limited. Nonetheless, some procedures have already been prepared and described for various batteries based on different chemistry so that used batteries can be recycled at the end of their lifetime.

In the example of cobalt oxide lithium-based batteries can be used to produce an alloy that can be further refined into cobalt, nickel and other metals. Cobalt can be further transformed into high grade lithium cobalt oxide, which can be resold to battery manufacturers. A slag containing calcium oxides and lithium is left as main by-product. Tesla states that by recycling these type of batteries, a minimum of 70% of CO_2 emissions can be saved at the recovery and refining of these metals[7]. This in turn can substantially reduce the carbon footprint for the manufacturing of Lithium-ion batteries.

For lead-based batteries, the lead is melted and re-cast into ingots or other lead products, battery acid is used in the production of gypsum, the plastic is reprocessed into new plastic.

[7] https://www.teslamotors.com/it_IT/blog/teslas-closed-loop-battery-recycling-program

4) Risk Description: Examples

In the following chapter, five selected sample components and the corresponding failures will be described in detail. Such a method aims to show the process of weighing risks as developed in the Solar Bankability project. The complete list of the failures can be found in Appendix 2 where each failure is defined. An agreed definition of failures is in fact beneficial for the industry as it should lead to a commonality in terminology and an improved failure data collection.

1. Module – Delamination failure
2. Inverter – Overheating failure
3. Mounting structure – Module clamps incorrectly installed
4. Cabling – Different types of connectors
5. Connection and distribution boxes – Missing protection against electric shock

The selection of the failures is according to their frequency of detection and their impact in the PV plant. The failure description is divided into five sections:

1. Brief and detailed description of the failure

In this section we provide a clear definition of the failure so that it can be used regardless of the expertise of the user. Our aim is for this failure list to be an important step towards a standardised nomenclature for defects to a certain extent.

2. Root cause related to the PV plant phase

This section lists the different root causes which could lead to the failure and thus must be considered in the failure evaluation. For e.g. module glass breakage could be due to defective glass or mishandling of module during transportation or installation.

3. Detection methods

Each failure is detected by different techniques and equipment. Incorrect detection methods or mistakes in the failure detecting process could result in longer time for the failure to be identified and rectified and thus most effective (time and cost) detection method should be always preferred.

4. Cost Priority Number (CPN)

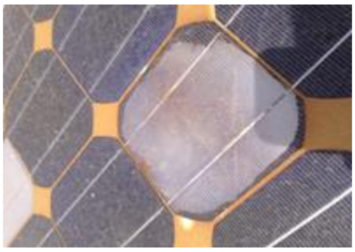
For every risk a CPN is assigned for the assessment of the failure. The CPN was developed as part of the project and is described in detail in Chapter 5. This parameter is important for the evaluation of the risk with regards to its economic impact. The CPN given in the following tables is for base scenario given in Chapter 6.

5. Action

Taking into consideration all the previous points, this section is a proposal of the recommended actions after the detection and evaluation of the failures.

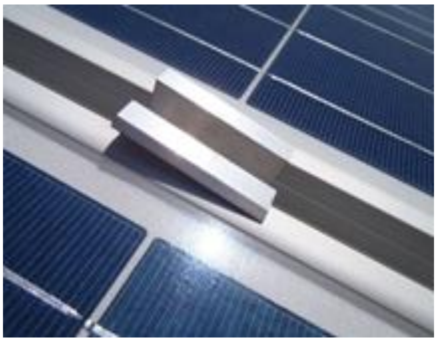
The description of the calculation of the CPN can be found in Chapters 5 and 6 and the values for the applied base scenario are documented in Appendix 4.

Component	**Module**			
Defect	**Delamination**			
Brief description	Delamination resulting from the loss of adhesion in bright, milky areas that stand out in colour from the remaining cells.			
Detailed description	The adhesion between the glass, encapsulant, active layers, and back layers can be compromised for many reasons. Delamination is more frequent and severe in hot and humid climates. Typically, if the adhesion is compromised because of contamination (e.g. improper cleaning of the glass) or environmental factors, delamination will occur, followed by moisture ingress and corrosion. Delamination at interfaces within the optical path will result in optical reflection and subsequent loss of current power from the modules. Delamination on cells leads to decrease in short-circuit current (I_{sc}) and can even result in reduced insulation of the component and increased safety risk.			
References	Review of Failures of Photovoltaic Modules, IEA (Köntges et al., 2014) . Study of Delamination in acceleration tested PV modules – Neelkanth G., Mandar B.			
Normative References	IEC 61215	IEC 61730		IEC 61446
Causes	Installation: Mishandling	Product defects: Material defect Module assembly processing issue		Maintenance: Environmental influence & degradation
Detection	Visual inspection			
CPN [€/kWp]	Time to detect in [h]	Time to repair/substitution [h]	Repair / substitution time [h]	Power loss [%]
	8760	744	2	1
3.59	C_{det} (average cost of detection/component) [€]	C_{sub} (average substitution cost/component) [€]	C_{rep} (average repair cost/component) [€]	C_{transp} (average transport costs per component) [€]
	0	108	0	10
Action	Modules with large delamination area must be replaced.			

		
Delamination of a module	Delamination	Browning and delamination of a module

Component	**Inverter**			
Defect	**Overheating**			
Brief description	During temperature derating, the inverter reduces its power to protect components from overheating.			
Detailed description	Temperature derating protects sensitive inverter components from overheating. When the monitored components reach the maximum operating temperature, the inverter shifts its operating point to a lower power. During this process, power is reduced step-by-step. In the extreme case, the inverter switches off completely. As soon as the temperature of the threatened components falls below the critical value, the inverter returns to the optimal operating point. Temperature derating can occur for various reasons, e.g. when installation conditions interfere with the inverter's heat dissipation.			
References	UEN103910			
Normative References	IEC 62116	DIN VDE 0126	EN50530	
Causes	Installation: Improper installation	Product defects: Fan failure	Maintenance: Fan or dust is blocking heat dissipation	
Detection	Visual inspection, inverter monitoring, datalogger			
CPN [€/kWp]	Time to detect in [h]	Time to repair/substitution [h]	Repair/substitution time [h]	Power loss [%]
	8760	744	4	20
1.64	C_{det} (average cost of detection/component) [€]	C_{sub} (average substitution cost/component) [€]	C_{rep} (average repair cost/component) [€]	C_{transp} (average transport costs per component) [€]
	0	0	377	10
Action	The filters and in general heat dissipation path should be cleared of obstruction			
				
Soiled air filter	Soiled air filter	Ventilation failure		

Component	**Mounting**			
Defect	**Module clamp not fixed correctly**			
Brief description	Inadequate fastening or damage of the module or frame by the clamp.			
Detailed description	The most common mistake in module clamping, is their improper installation that can lead to the damage of the module and sometimes to its detachment from the mounting structure. In addition the installation of wrong clamps can cause problems such as damage of the frame, glass breakage etc. The installation manuals of the module and mounting structure from the manufacturer must be closely followed to avoid such failures.			
References	Module and mounting structure installation manuals			
Normative References	EN 1999-9	EN62446	EN 1090-3	
Causes	Installation: Improper installation	Product defects: Wrong combination of clamps - modules	Maintenance: Corrosion	
Detection	Visual inspection			
CPN [€/kWp]	Time to detect in [h]	Time to repair/substitution [h]	Repair/substitution time [h]	Power loss [%]
	8760	744	48	0
-	C_{det} (average cost of detection/component) [€]	C_{sub} (average substitution cost/component) [€]	C_{rep} (average repair cost/component) [€]	C_{transp} (average transport costs per component) [€]
	0	0	0	0
Action	All module clamps and damaged modules must be replaced.			

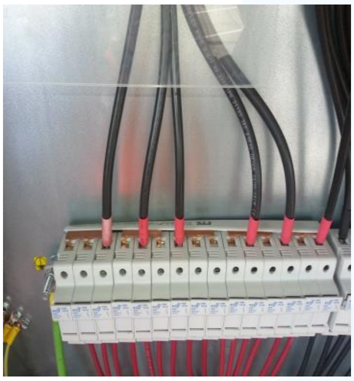
		
Improper installation	Wrong combination of clamps and modules	Damaged PV module due to clamping

Component	**Cabling**			
Defect	**Different types of connectors**			
Brief description	Different interconnectors are combined. Problems of compatibility of materials as well as corrosion may happen during the lifetime of the PV plant.			
Detailed description	The practice of connecting different types of connectors is a significant issue, with direct consequences e.g. burnt connectors, electrical arcing. One of the most common failures is that no current will flow through the connection. However, this is not typically the case and the problems instead do not manifest themselves right away. Usually the ill-fitted pair of connectors will connect together and pass electricity without any easily noticeable problems or losses. However, over time the misalignment of connectors and material scheme can lead to losses or connector failure.			
References	Declaration TÜV Rheinland, G. Volberg			
Normative References	EN 62548	EN 62446		
Causes	Installation: Different types	Product defects: Insulation	Maintenance Corrosion:	
CPN [€/kWp]	Time to detect in [h]	Time to repair/substitution [h]	Repair/substitution time [h]	Power loss [%]
	8760	744	0.5	0
0.39	C_{det} (average cost of detection/component) [€]	C_{sub} (average substitution cost/component) [€]	C_{rep} (average repair cost/component) [€]	C_{transp} (average transport costs per component) [€]
	0	1.5	0	1
Detection	Visual inspection			
Action	If compatibility cannot be met, connectors should be changed.			

Different types of connectors

Different types of connectors

Different types of connectors

Component	**Connection and distribution boxes**			
Defect	**Missing protection against electric shock**			
Brief description	The protection against electric shock detached or is missing.			
Detailed description	The distribution and connection boxes, in order to provide effective protection against direct contact hazards, must possess a degree of protection according to the standards. Moreover all the removable parts of the equipment (door, front panel, etc.) must only be removed or opened by means of a key or tool provided for this purpose, after complete isolation or disconnection of the live parts in the enclosure. The metal enclosure and all metal removable screens must be connected to the protective grounding conductor of the installation.			
References	Schneider Electric, Electrical Installation Wiki			
Normative References	IEC61140	IEC60364-4-41	IEC62548	
Causes	Installation: Wrong planning or incomplete installation	Product defects: Material failure	Maintenance: Corrosion	
Detection	Visual inspection			
CPN [€/kWp]	Time to detect in [h]	Time to repair/substitution [h]	Repair/substitution time [h]	Power loss [%]
	8760	744	1	0
0.11	C_{det} (average cost of detection/component) [€]	C_{sub} (average substitution cost/component) [€]	C_{rep} (average repair cost/component) [€]	C_{transp} (average transport costs per component) [€]
	0	10	0	2
Action	The protection against electric shock must be intact for each terminal.			
				
Missing protection	Live parts are exposed	Live parts are exposed		

5) Quantification of the Economic Impact of Technical Risks

In the Solar Bankability project the risk analysis has the aim to assess the economic impact of technical risks and how this can influence various business models and the LCOE. As seen in Chapter 2, the classical FMEA analysis with RPNs, although important, is clearly inadequate and needs to be expanded to include a method to assess the cost impact of each risk. In the project we therefore developed a cost-based FMEA by introducing a Cost Priority Number (CPN) which would include cost consideration directly in the risk assessment. To do so, it is important to understand what the needs are from the LCOE and from the business model analysis point of view. A CPNs ranking could prioritize risks which have a higher economic impact. However, it might not be applicable to each type of risk as some risks might have an impact i) on the energy yield in the form of added uncertainty, ii) on risks occurring during operation but originating in an early phase of the value chain (failure precursors), and iii) on the CPN of other risks.

Examples of technical risks with impact on the energy yield in the form of added uncertainty are: incorrect power rating of PV modules, estimation of soiling, incorrect assumptions of module degradation and simulation parameters. Technical risks becoming failures during operation but originated in an early phase are defined as precursors and are for example: uncertified components in the production line during the “Product testing” phase or module mishandling during the “Transportation/Installation” phase.

We have therefore organised the analysed risks into two broad categories based on the timeframe they are likely to occur:

· **Year 0 risks**: risks which are present during the development phase and have an impact on the utilization factor (e.g. irradiance estimation, degradation, miscalibration of flasher, etc.) and/or on the CAPEX (e.g. higher cost of components).

· **Risks during operation**: risks which can occur during operation and the occurrence of which may not be constant year after year but presents peaks along a certain timeframe.

Year 0 risks have an effect on the business models and LCOE in terms of uncertainty (i.e. error bars) and hence the exceedance probability (e.g. P50, P90, etc.), on CAPEX, utilisation factor, degradation, etc. Risks during operation have an effect on the business models and LCOE depending on which year they are more likely to occur. In the Solar Bankability project, the “Year 0 risks” is further analysed in the deliverable “Review and Gap Analysis of Technical Risks throughout PV Project Lifecycle and their Uses in PV Investment Cost Calculation” (D3.1) (Caroline Tjengdrawira and Mauricio Richter, 2016), while “Risks during Operation” is integrated in risk scenarios as developed in the deliverable “Report on Financial Model Evaluation” (D4.2) (von Armansperg et al., 2016) .

For the analysis of the technical risks, the high challenges of obtaining reliable detailed statistics for each plant component on the likelihood of failures over the lifetime of the PV plant is universally acknowledged. For some components such as inverters, the data may be more readily available due to the PV plant monitoring practice. For other components, the failure statistics may be not straightforwardly available, or such data may not exist altogether.

Keeping these challenges in mind, we have relied on data from the consortium to perform our first cost-based FMEA exercise. This input data are statistically significant and based on a large evidence base. As the first step, we have analysed this data, organised and consolidated them and established a list of different failures associated with the selected PV components along the different PV plant phases. These risks were qualitatively prioritised in the risk matrix as described in Chapter 3.

5.1) Technical Risks during Project Planning Phase

The technical risks identified before the operational phase (Testing / Planning / Transportation & Installation) can be defined as Year 0 risks in the LCOE calculation – and consequently in a business model - if they have an impact since the beginning of plant operation. Other technical risks can be defined as root cause of failures occurring during operational phase. In this section, only Year 0 risks are considered. For each of these risks it is important to understand how the variability and associated uncertainty are calculated and how the values are distributed in terms of probability. These aspects are essential for the calculation of the exceedance probability of the energy yield and how this is influenced by the overall uncertainty (see Figure 3, the exceedance the exceedance probability of the energy yield is given with an uncertainty of 5 and 10% calculated based on a normal distribution of the energy yield.). A reduction in the uncertainties can lead to higher values of energy yield for a given exceedance probability and hence a stronger business case. (Reich et al., 2015) estimated the combined overall uncertainty of the energy yield to fall in a

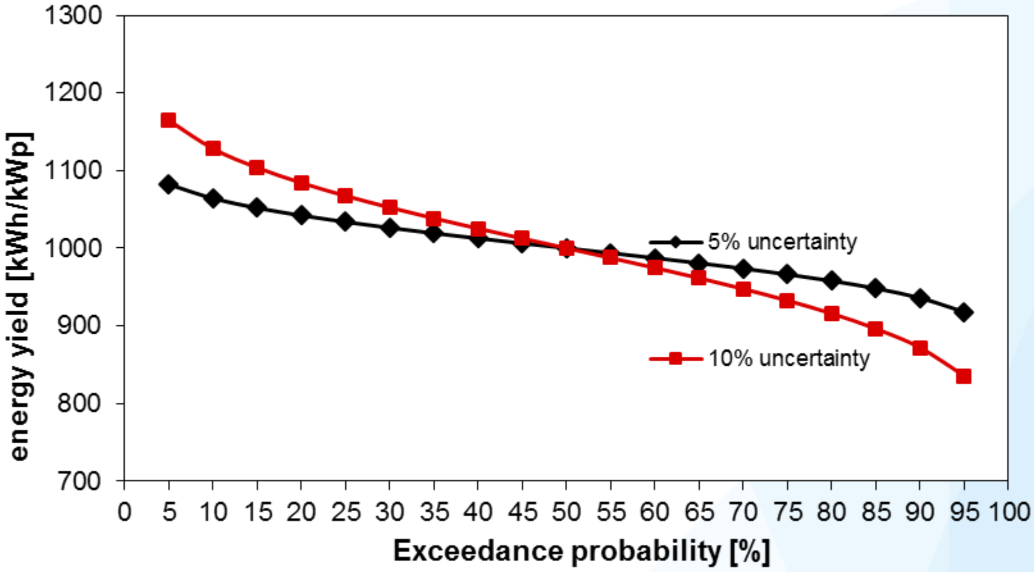


Figure 3: Exceedance probability for energy yield assuming different uncertainties calculated with a normal probability distribution function

range between 5 and 11%; in this study, the uncertainty on various effects such as irradiation, shading, soiling, inverter losses, etc. were taken into account. In another study, (Muller et al., 2015) have calculated the variation of the overall uncertainty of the energy yield over the lifetime of a PV plant and compared the findings with data from a portfolio of 26 systems located in Germany and Spain. These efforts show the importance of having a common framework that can assess the impact of technical risks on the economic performance of a PV project. In the coming years, as the availability of measured data will exponentially increase, it will be important to build large databases to increase the confidence level of the statistical analysis and thus reduce the perceived risks from investors.

5.1.1) Uncertainties in the Long-Term Insolation Estimation

LONG-TERM INSOLATION DATA SOURCES

Different sources of long-term insolation data are available worldwide: measured data from meteorological institutions, interpolated values (e.g. Meteonorm (METEOTEST Genossenschaft, 2014)) and estimates from satellite derived images (e.g. SoDa HC-3, SolarGIS, SatelLight, PVGIS, NASA, etc.). These databases not only use irradiation data obtained by different methods, but also often covering different periods. As shown by e.g. (Richter et al., 2015) and (Müller et al., 2014), given the long-term variations of irradiance, the time period used to estimate the irradiation for a typical year often has an important influence that has to be accounted for.

Significant differences can be observed when comparing the databases between each other or against reference meteorological observations. Consequently, the insolation uncertainty depends to a large extent on the source of the data and the reference period used. An example to illustrate this is a case study on the insolation data for a site in Belgium, illustrated in the two following figures. In Figure 4, different databases (coloured lines) providing satellite derived yearly global horizontal irradiation (GHI) are compared against each other and against the reference ground measurements from the Royal Meteorological institute of Belgium (black line). It can be seen for this site that the GHI yearly values are clearly under-estimated by the HC-1 (SoDa) satellite-derived source while the other databases appear to provide closer values to the reference ground measurements. In Figure 5, databases providing the mean GHI are compared. The comparison of the mean values provided by these databases against the 10-year centred moving average of the meteorological station (dashed grey line) highlights the effect of the time period used to estimate the irradiation for a typical year.

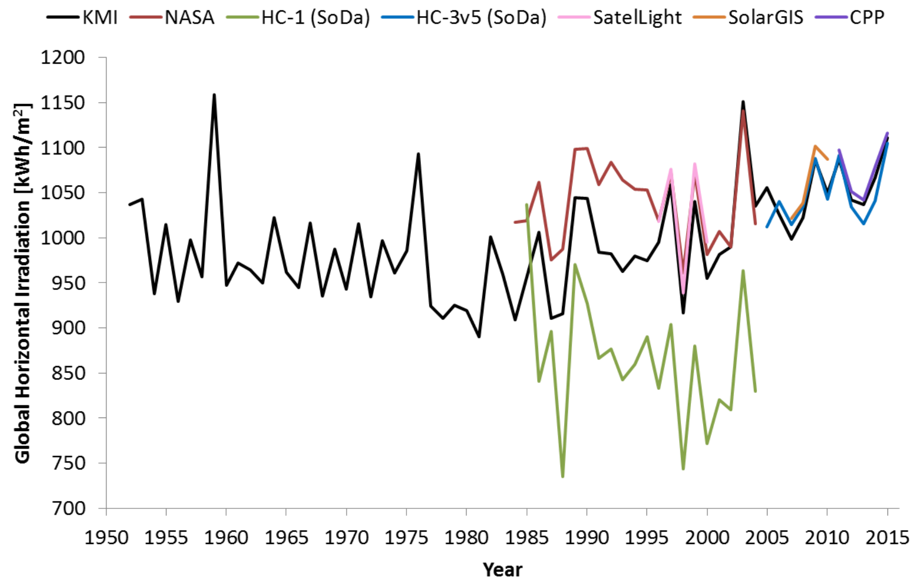


Figure 4 : Comparison of different databases providing satellite derived yearly global horizontal irradiation (GHI) values in Uccle (near Brussels, Belgium) with ground-measured data (black line) from the royal meteorological institute of Belgium (KMI for its acronym in Dutch)

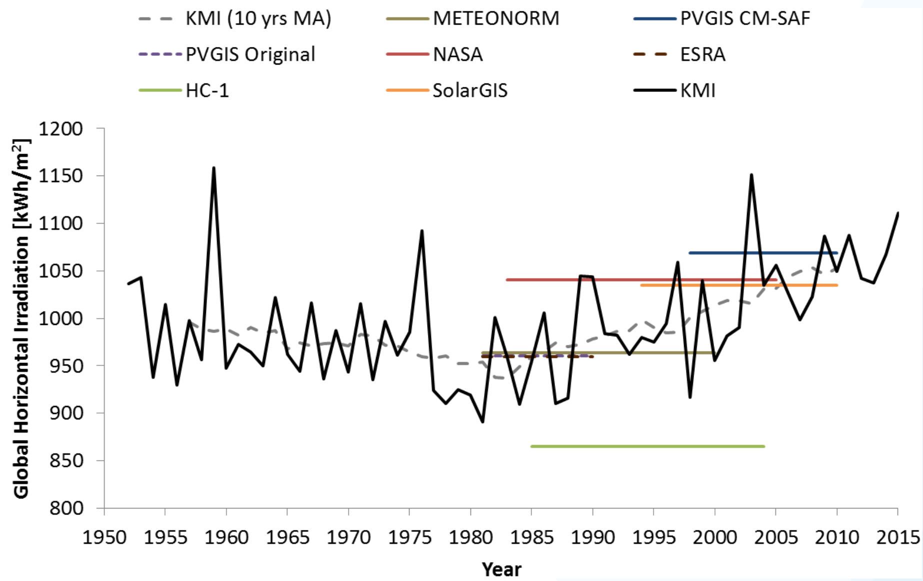


Figure 5 : Comparison of different databases providing mean global horizontal irradiation values in Uccle (near Brussels, Belgium) with ground measured data from the royal meteorological institute of Belgium (KMI for its acronym in Dutch) – The dashed grey line represents the 10 year centred moving average (MA) of KMI data.

Often, different databases are combined in order to reduce the uncertainty in the solar resource estimation. If ground measurements are available for a short period (e.g. one year), this data can be combined with long-term satellite estimations using of the Measure-Correlate-Predict (MCP) methodology, described in, for e.g., (Christopher Thuman et al., n.d.) or (Gueymard and Wilcox, 2009). The MCP method is a widely established and recognised methodology for wind resource assessments and its application is gaining ground for solar resource assessment. The purpose of the MCP methodology is to combine the data of short period of record but with site-specific seasonal and diurnal characteristics with a data set having a long period of record with not necessarily site-specific characteristics. Upon completion of a year of ground measurements, a linear regression or other relationship is established between measured data at the target site, spanning a relatively short period, and the satellite data, spanning a much longer period. The complete record of the satellite data is then used in this relationship to predict the long-term historical climate at the target site. Assuming a strong correlation, the strengths of both data sets are captured and the uncertainty in the long-term estimate can be reduced.

The application of the MCP methodology for long-term solar resource assessments is being studied by the Solar Bankability consortium in WP3[8]. The results of the analysis is be reported in the project deliverable D3.1 published in June 2016.

ANNUAL INSOLATION VARIABILITY

The annual insolation variability or “year-to-year variability” is defined as the ratio of the standard deviation (σ) to the average global horizontal irradiation (GHI) over a long-term period (typically more than 10 years) (K. Scharmer and J. Greif, 2000), (Richter et al., 2015). In average, the standard deviation of the yearly sums of GHI is mostly in the range of 4% to 6% as shown for example, by (Richter et al., 2015) and (Suri et al., 2007). Table 9 presents an overview of the variability (σ) of GHI as extracted from Meteonorm (METEOTEST Genossenschaft, 2014) for some representative weather stations located across Europe. The 90% exceedance probability (P90 scenario) is also provided. The σ90 in Table 9 is calculated by multiplying σ with 1.328, i.e. the conversion factor between the standard deviation and a single-sided P90 deviation considering a Student’s t-distribution with a sample size of 20 years (period covered by the irradiation database).

Table 9: Variability of the annual GHI for different sites in Europe

Weather station	Variability (σ) of GHI	σ90
Athens – Observatory (WMO nr: 167140)	5.4%	7.2%
Bern-Liebefeld (WMO nr: 66310)	4.6%	6.1%
Cabauw (WMO nr: 63480)	5.7%	7.6%
Dublin – Airport (WMO nr: 39690)	5.1%	6.8%
Hamburg (WMO nr: 101410)	6.6%	8.8%
Helsinki-Airport (WMO nr: 29740)	4.6%	6.1%

[8] PV Investment Costs Elements, led by 3E

Lisbon (WMO nr: 85350)	3.9%	5.2%
London Weather C. (WMO nr: 37790)	7.1%	9.4%
Paris Monsouris (WMO nr: 71560)	5.8%	7.7%
Roma/Ciampino (WMO nr: 162390)	4.0%	5.3%
Uccle(WMO nr: 64470)	6.4%	8.5%
Wien / Hohe Warte (WMO nr: 110350)	6.1%	8.1%

For risk assessments, the annual insolation variability may become the main source of uncertainty when analysing the risk associated with the cash flow during a single year (Vartiainen et al., 2015). However, when calculating the lifetime accumulated income, this uncertainty has a relatively small effect since the years with less irradiation are generally compensated for by other years with more irradiation.

LONG-TERM TRENDS

Research has revealed that the irradiation in several places across Europe showed a dimming period followed by a significant brightening trend starting from around 1990 (Müller et al., 2014; Wild et al., 2005; Martin Wild, 2009). In one case, a study of long-term GHI measurement records from 8 stations in Germany found a brightening trend of +3.3 % per decade, starting from around 1984 (Müller et al., 2014). The Solar Bankability project team performed a similar analysis using the long-term GHI measurement records from 32 meteorological stations of the Royal Meteorological Institute of The Netherlands (KNMI) covering the period from 1958 to 2015 (Figure 6). The trends shown in Figure 6 (i.e. red and blue lines), were found by calculating the slope for each possible combination of 10 years (moving window). The point at which the slope reversal occurred was defined as the beginning of the brightening trend. Note that before 1990 not enough data was available and therefore no conclusions from a previous dimming trend can be derived from this data. However, since around 1990 a clear brightening trend is observed with a slope of +2.63% per decade.

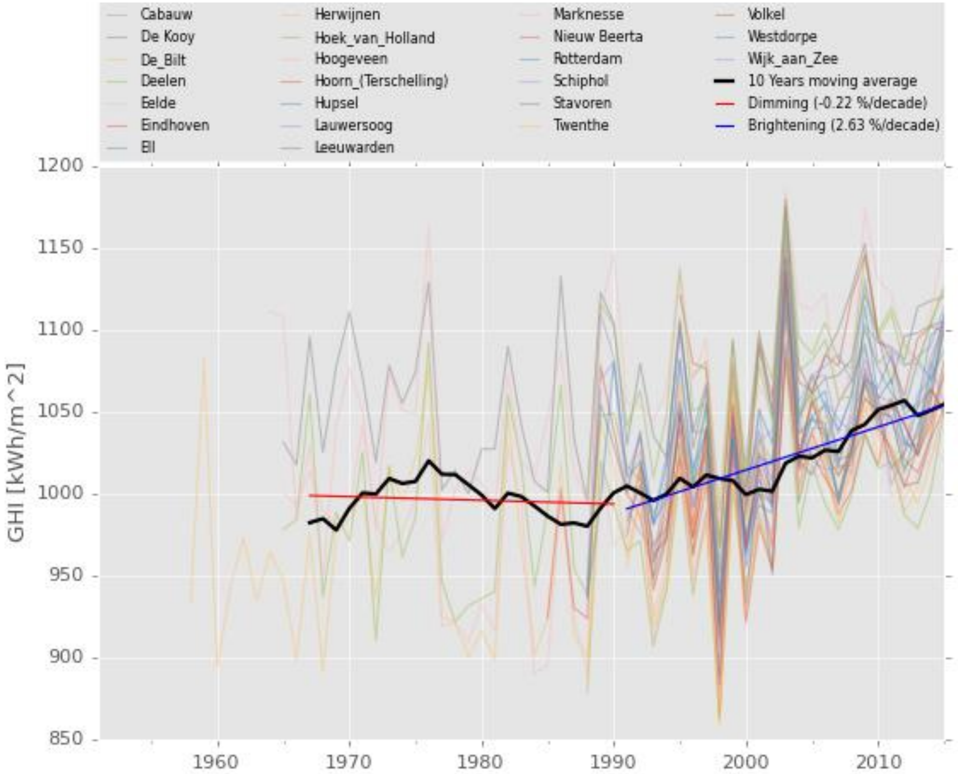


Figure 6 : Annual GHI from 32 meteorological stations from the Royal Meteorological Institute of The Netherlands (KNMI for its acronym in Dutch). The dark black line represents the mean 10 years moving average irradiation. The red and blue lines represent the dimming and brightening trends respectively, calculated as the linear regression of the mean 10 years moving average.

PROJECTIONS OF FUTURE TRENDS

Unfortunately, there is no certainty on the future development of the observed solar insolation trends. Some studies have analysed different scenarios to assess the impact of these trends on long-term solar resource assessments. For example, in (Müller et al., 2014) the results of analysing three different scenarios show that using the 10 most recent years to estimate the future irradiance for the subsequent 20 years is the best estimator even in the case of a complete trend reversal. Moreover, the authors in (Müller et al., 2014) concluded that when using the average global horizontal irradiance from the past to predict the average of the subsequent 20 years, the observed long-term trends create and additional uncertainty of about 3%.

Although it could be expected that irradiation in the coming years remains at a higher level than the overall mean, long-term yield estimates are often based partly on historical irradiation data from before 2000. As a result, the actual irradiation may be underestimated. Moreover, the annual variability that is calculated based on this long-term period may be overestimated impacting negatively the P90. Figure 7 shows the resulting annual variability (σ) of GHI considering different reference periods. Results show that in average for the 32 sites in The Netherlands, the annual variability of GHI (σ) considering the last 20 years is ± 4.37%. In contrast, this value decreases up to ± 2.3% when considering only the last 10 years as recommended for e.g. by (Müller et al., 2014). When calculating a P90 scenario as presented in Table 9, the σ90 becomes ± 5.8% for the 20 years reference period compared with ± 3.18% for the shorter reference period of 10 years.

Note that a conversion factor of 1.328 and 1.383 between standard deviation and single-sided P90 deviation was used considering a Student's t-distribution with a sample size of 20 and 10 years respectively.

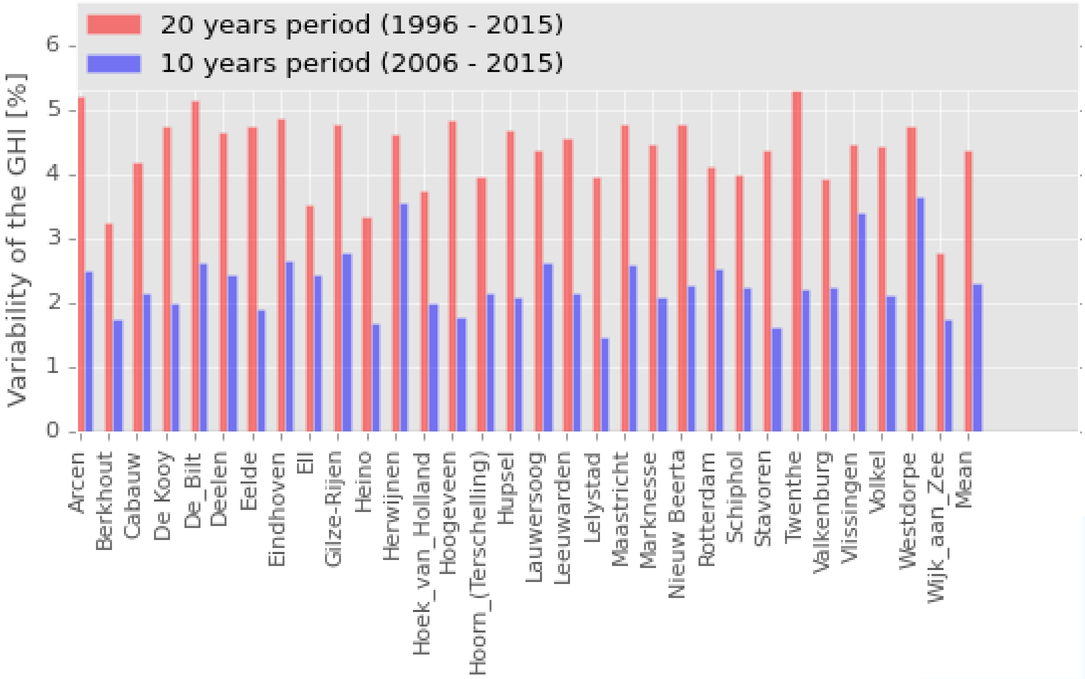


Figure 7: Annual variability (σ) of GHI for the 32 meteorological stations from the Royal Meteorological Institute of The Netherlands (KNMI for its acronym in Dutch).

For a better understanding of this uncertainty introduced by the observed long-term trends, the project team is investigating the application of an autoregressive integrated moving average model (ARIMA) to the analysed dataset from the 32 meteorological stations from the KNMI in The Netherlands. Results of this analysis was reported in the project Deliverable D3.1 published in June 2016 (Caroline Tjengdrawira and Mauricio Richter, 2016).

5.1.2) Uncertainties in Degradation and Models Available

PV modules producers provide warranties on the performance losses occurring in at least 20-year lifetime. Here uncertainty arises:

i) from the investor's side there is a need for standardized procedures on how to monitor and assess the process of degradation during and at the end of module lifetime in order to indisputably verify warranty fulfilment;

ii) from the manufacturer's side, there is the need to collect as much field data as possible in order to verify the real degradation rate of their products, under different climatic conditions, and fine tune the existing accelerated ageing tests.

The assessment of module degradation is also an essential contribution to the procedure for the estimation of module energy rating, i.e. performance assessment based on the energy output under real operating conditions ((Huld et al., 2013) and (Dirnberger et al., 2015)) rather than on the power output measured in laboratory under Standard Test Conditions (STC). For this reason, the energy rating is considered more representative of the module outdoor performance and it will be used in the future as a tool to classify module performance in several standard climatic zones (Huld et al., 2013). The increasing gain of importance within the PV research community is testified by the currently on-going implementation of an ad-hoc standard (IEC 61853) – already partly published (IEC 61853-1:2011, 2011).

The factors and mechanisms behind module degradation are well known. PV modules are affected by continuous cycles of temperature, humidity, irradiation, mechanical stress, spotted soiling. All of these can induce corrosion of the metallic cell interconnections, delamination, discolouration and breakages of the module, cracks of the cells, hot spots, bubbles and other failures (Köntges et al., 2014; Ndiaye et al., 2014; Quintana et al., 2002; Sharma and Chandel, 2013). In addition to material degradation a PV module or array under outdoor operating conditions is exposed to other factors directly affecting its electric performance. These are diffuse soiling, snow, shading, modules and cell mismatch. It is therefore more appropriate to speak about the performance loss rate (PLR) rather than degradation rate. The PLR of a PV module or system depends on:

- the technology, i.e. the photovoltaic material, the quality of the components and the assembling process;
- the local climatic conditions;
- the experimental and analysis methodology used for its assessment.

Several studies have been conducted on this topic. (Jordan and Kurtz, 2013) collected nearly 2000 PLRs from studies from the last 40 years, calculating an average −0.7%/year and median −0.5%/year performance loss rate for crystalline silicon technologies, and an average −1.5%/year and median −1%/year for thin-film technologies. The distributions of the degradation rates result in positively skewed curves with long tails at high PLRs. In general, PLRs for crystalline silicon technologies resulted more concentrated around the median, while thin-film technologies showed more dispersed values, with a minimum of −4.2%/year. Another study on the same database (Jordan and Kurtz, 2012) found short-circuit current (Isc) and, in lesser extent, fill factor (FF) as the largest contributor to power degradation in crystalline silicon technologies, especially in hot and humid climates. As for thin-film technologies, the FF was reported to play a major role particularly for humid climates. (Skoczek et al., 2009) analysed the long-term performance of 204 crystalline silicon-based modules installed in the 1980s representing 53 module types from 20 producers. The continuous exposure time ranged between 19 and 23 years. Results showed an average −0.8%/year PLR, with 82.4% of modules respecting the typical manufacturers' warranty of 90% of the initial power after 10 years and 80% after 25 years.

In general, the assessment of the PLR can exploit measurements performed indoor (Carr and Pryor, 2004; Polverini et al., 2013; Sharma and Chandel, 2013) and outdoor (Kahoul et al., 2014; Kamei et al., 2014; Makrides et al., 2014; Munoz et al., 2011; Ndiaye et al., 2014). For the latter, the electrical parameters can be recorded in dedicated test sites mainly built for research purposes and equipped with I/V curve tracers that acquire data with a frequency not lower than 10 min

(Kahoul et al., 2014; Munoz et al., 2011; Ndiaye et al., 2014). Another category of outdoor measurements involves the use of electrical records from systems continuously kept at Maximum Power Point (MPP), performed using also commercial inverters (Kamei et al., 2014; Makrides et al., 2014). This last kind of studies is particularly interesting to plant owners and installers, since it can be performed on any kind of PV plant connected to the grid, just provided that a reliable irradiance measurement is available.

In general, the calculation of the PLR from field measurements involves the adoption of a performance metric and of a statistical method. The first consists of an analysis technique to calculate representative performance estimators on a selected time scale (usually monthly). Amongst these, the Array Performance Ratio (PR_a) and Array PVUSA ($PVUSA_a$) indexes are the most commonly used (Jordan and Kurtz, 2013). The statistical methods are mathematical algorithms applied on the time series of performance estimators in order to extract a trend. The most common is linear regression but also classical series decomposition (CSD), locally weighted scatterplot smoothing (LOESS), and autoregressive integrated moving average (ARIMA) are used.

The calculation of the PLR is more accurate when the more the applied performance metrics, statistical methods and filtering techniques succeed in minimizing seasonal oscillation and eliminate outliers (Makrides et al., 2014; Phinikarides et al., 2014). An improved method based on the use of the array generated power metric (P_{max}) corrected for irradiance, temperature and spectral effects to STC was applied by (Belluardo et al., 2015), associated to suitable filtering technique and linear regression, with the aim of decreasing the overall uncertainty in the estimation of the PLR. This method was named after its metric, $P_{max,STC,}$ and was compared to other methods based on the two widely-recognized metrics PR_a and $PVUSA_a$, to which the same filtering technique and linear regression were applied. The comparison was performed on the base of the PLR and of the associated uncertainty (see Figure 8).

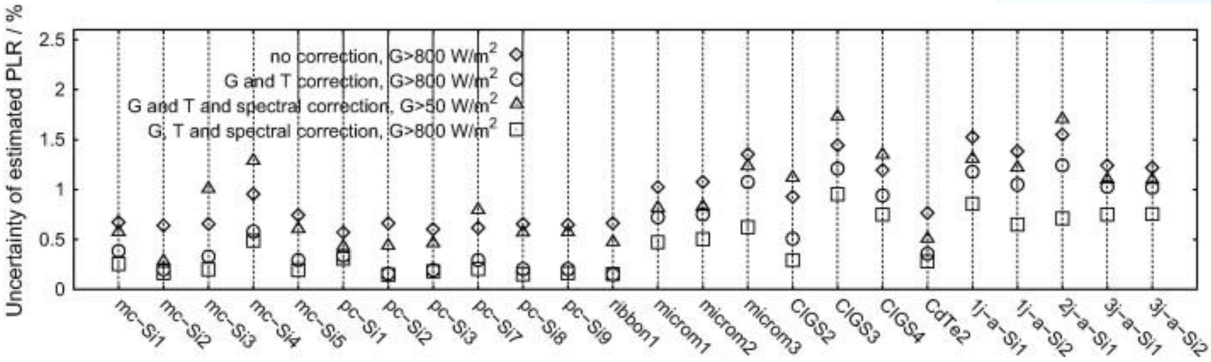


Figure 8: Improvement in uncertainties of the PLR using different filtering and correction techniques.

The probability distribution of degradation will have an effect on the calculation of P50/P90 parameters due to the unknown distribution type. High value of degradation will have in fact a strong impact especially on the P90 value over the course of the years. The subject has in fact seen an increased interest in recent years resulting in more than 11000 degradation rates in almost 200 studies from 40 different countries. In a recent study, (Jordan et al., 2016) found median degradation for crystalline silicon technologies in the 0.5–0.6%/year range with the mean in the 0.8–0.9%/year range. Hetero-interface technology (HIT) and microcrystalline silicon (μc-Si) technologies, exhibit degradation around 1%/year. Several studies showing low degradation for copper indium gallium selenide (CIGS) have emerged. Higher degradation for cadmium telluride technology (CdTe) has been reported. Significant deviations for beginning-of-life measurements with respect to nameplate rating have been documented over the last 35 years (see Chapter 5.1.4 for results from factory inspections). Therefore, degradation rates that use nameplate rating as reference may be significantly impacted. Studies that used nameplate rating as reference but used solar simulators showed less variation than similar studies using outdoor measurements, even when accounting for different climates. This could be associated with confounding effects of the measurement uncertainty and soiling that take place outdoors. Non-linearities for the worst performing modules have been documented even if the majority of modules exhibit a fairly linear decline. Modelling non-linearities, whether they occur at the beginning-of-life or end-of-life in the PV life cycle, has an important impact on the levelised cost of electricity.

5.1.3) Uncertainties in Parameters Used in Power Calculation

Different models are used in the industry to estimate the amount of energy that a PV system can produce. These models are based on different modelling approaches and assumptions made for the calculations. In addition, most of the input parameters (e.g., irradiance, temperature, PV array orientation, module and inverter performance, user-defined values for additional losses such as soiling, mismatch, cabling, etc.) have inherent uncertainties and could impact the final estimated amount of energy. These uncertainties are introduced at different stages throughout the energy conversion chain.

PV MODULE MODEL (DC POWER CALCULATION)

Plane-of-Array (POA) irradiance estimation

The conversion of the Global Horizontal Irradiance (GHI) to the plane-of-array (POA) Irradiance encompasses two major steps: first, the GHI is split into its components, i.e., horizontal diffuse irradiance and horizontal direct irradiance, by the use of a decomposition model. Subsequently the diffuse, direct and ground reflected irradiance components are transformed to the POA and recombined again in order to obtain the global irradiance in the POA.

As reported in (Richter et al., 2015), a normalized root mean square error (NRMSE) of 4.8% for hourly resolution was obtained for the best combination of available algorithms (using the Skartveit decomposition algorithm in combination with the Hay and Davis conversion algorithm). Similar values are reported for e.g. in (Cameron et al., 2008) where 4.5% for the Perez model is reported and 5.4% for the Hay model.

The uncertainty of the POA irradiance is higher than for the GHI when translational algorithms are used. Irradiance should therefore be preferably measured on the POA whenever possible.

Effective irradiance estimation

The effective irradiance is the POA irradiance after taking into account the optical losses in the PV module due to reflection on the front surface of the module and due to spectral variations. Spectral variations have a minor effect on the annual energy production from a crystalline silicon PV module. For crystalline silicon PV module, the variations in module performance that occur during each day and over the seasons effectively average out on an annual basis. However, the reflection losses can have a more important impact on the annual energy production. The reflection effects relate primarily to the direct normal component of the irradiance. For a horizontal plane, the optical loss is directly associated with the reflectance loss from the glass front surface (King et al., 2002). The reflectance of the glass surface increases as the angle-of-incidence (AOI) increases with a significant increase for the AOI greater than 60 degrees. The reflection losses can have a significant seasonal effect depending on the location and orientation (tilt and azimuth) of the PV modules. However, the influence of this optical loss on annual energy production for optimally designed systems is relatively small, i.e. ca. 1% (King et al., 2002).

Cell temperature estimation

Different models are available for estimating the cell temperature of a PV module. From simple models that neglect both thermal dynamics and wind speed, up to advanced models that take into account both dynamics and wind speed effects are available (Figure 9, (Maturi et al., 2014)). Validation results of different temperature models reported in (Richter et al., 2015) show that the uncertainty in the cell temperature estimation using an advanced model that takes dynamics and wind speed into account can be as low as 1°C, though most traditional models show uncertainties of 2°C and higher. Typical RMSE of the *k* factor relating ΔT and irradiance G is around 2%.

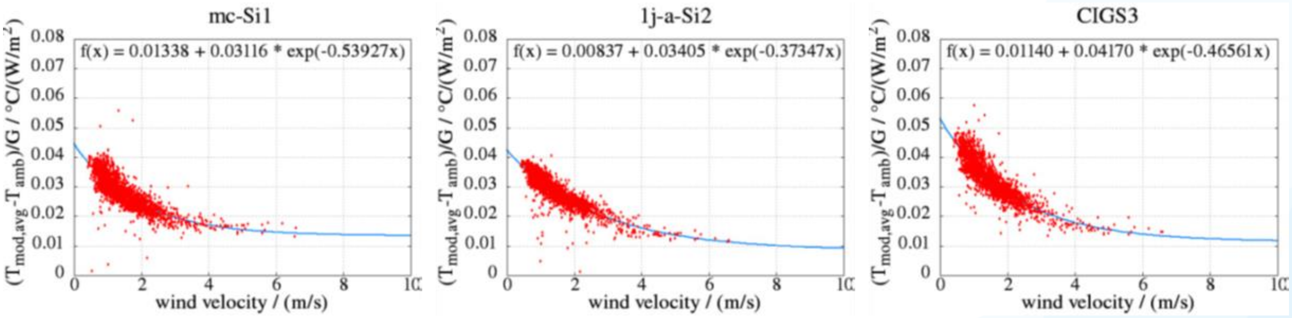


Figure 9: Wind cooling effect for various technologies installed in free field at the PV plant ABD in Bolzano, north of Italy.

Temperature dependencies

The operating temperature of a PV module affects the performance ratio (PR) through the MPP power temperature coefficient. An increase of the operating temperature causes mainly a decrease in voltage. As reported in (King et al., 2002), where a sensitivity of annual energy production to temperature coefficients was investigated for different PV module technologies, the effect of the operating temperature on annual energy production was found to be dependent on both module technology and site environmental conditions, with an influence on the annual energy production of -2% to -10%.

ESTIMATION OF ARRAY DC LOSSES

Mismatch - Power tolerance of modules

The nameplate power of a PV module frequently differs from the measured power. Manufacturers have typically a nameplate band of 5 Wp which results in approximately 2.5% variation from the best to the worst module, i.e., ±1.25% uncertainty. In addition, the flash tests that are carried out by independent test facilities typically guarantee the measured values to ±2% (Ransome, 2007). Other authors, as for e.g. (Thevenard and Pelland, 2011), consider a ±3% uncertainty based on the typical tolerances usually given by module manufacturers.

Furthermore, the differences of cell temperature, direct and/or diffuse irradiance and degradation behaviour of PV modules within the array cause mismatch losses. These mismatch losses moreover increase over time. The impact is rather difficult to estimate as it depends on many site-specific conditions.

Soiling

PV module soiling is caused, amongst others, by pollution, bird droppings, accumulation of dust and/or pollen and its impact is strongly site dependent (Laukamp et al., 2002). As a result, the effect of dirt and soiling on the PV energy yield is difficult to model or extrapolate from case studies and therefore a standard deviation of ±2% is often assumed (Thevenard and Pelland, 2011). In temperate regions with year-round rain, the soiling losses are typically between 0% to 4%, whereas in arid regions with seasonal dry periods and dust, extreme soiling losses up to 25% have been reported (Andreas Beneking, 2011; Ransome, 2007). This suggests that losses due to soiling could be estimated by considering the rainfall information of the site, the module cleaning schedule and the inclination angle of the PV modules.

Shading

Shading losses can arrive from different factors, such as horizon shading, inter-array or row-to-row shading, and shading caused by nearby objects e.g. trees, buildings, etc. Simulation programs allow simulating the occurrence of shading with very little uncertainty compared to other modelling

Figure 10: Example of shading due to nearby objects. Left :(tree). This type of shading is seasonal depending on foliage. Right : shading due to bad planning

steps. However, the effect of partial shading on the overall PV array performance is more difficult to model as this depends, for example, on the configuration of the PV modules within the array and on the number and configuration of bypass diodes in the PV modules.

PV INVERTER MODEL (AC POWER CALCULATION)

The uncertainty of the inverter measured efficiency is given by the combined uncertainty of the DC and AC power measurements. The load dependency of the efficiency can be estimated with good accuracy from the European efficiency, the maximum efficiency and the power at which maximum efficiency is obtained. However, the voltage dependency is generally neglected. According to (Baumgartner et al., 2007), the dependency of the efficiency with the DC voltage is less than 1% for most inverters with a maximum efficiency of 97% or higher. On the other hand, inverters with maximum efficiency values lower than 95% exhibit a significantly higher voltage dependency of around 2.5%.

Compared with the other models in the PV modelling chain, the inverter model is subject to smaller uncertainties. Typical uncertainty values are in the order of ±0.2% to ±0.5% (Richter et al., 2015).

5.1.4) Factory Inspections

Many PV module testing institutes require the performance of periodical factory inspections as the prerequisite for the issuance and maintenance of module certificates. The purpose of these periodical inspections is to ensure that the quality level of the certified products continuously remains the same and that no production step has any negative impact on the quality of the final product.

The factory inspection usually consists of three main parts:

1) Verification of all raw materials used for the certified products

2) Inspection of the complete production process

3) Review of general quality-related issues.

Within the first part, the utilization of all materials used for the final tested and certified PV module types is verified through the submission of appropriate documents such as invoices or delivery notes. A serial number of a PV module produced recently may in addition be chosen randomly during the inspection in order to check for consistent material usage.

The second part comprises a comprehensive inspection of the PV module production line during an on-going production of certified products. The manufacturer should be able to demonstrate all quality assurance tests performed in-line and off-line during this production tour.

In the third main part of the inspection, general quality-related issues are reviewed. For this purpose, corresponding documents such as ISO certificates, the Quality Manual etc. may be reviewed. It should also be possible to demonstrate procedures that ensure process traceability, how faulty products are handled, etc.

TÜV Rheinland has globally elaborated a list of possible weaknesses which may typically be detected and defined during PV module factory inspections. Within this list, it is clearly differentiated between *deviations* and *recommendations*, where the deviations have to be resolved by the manufacturers within a given timeline in order to receive or maintain the certification of their product. The list comprises weaknesses found during all of the three inspection parts listed above.

For the PV module factory inspections performed by inspectors from TÜV Rheinland, all deviations defined by the auditors have been systematically categorized and statistically evaluated over several years. The plot below (**Fehler! Verweisquelle konnte nicht gefunden werden.**) shows the distribution of deviations of all factory inspections during the years 2012 – 2015.

The chart is based on 311 deviations in total which were identified from 208 factory inspections resulting in an average of 1.5 deviations per inspection.

At first the chart shows that a big variety of possible weaknesses is found. There are a large number of categories including high findings under the “Other” category which summarises rare or rather peculiar non–conformities (each having a contribution of 1.5% or less to all deviations). Among those issues, used materials or process parameters not matching those of the certified product appear to be significant (~15%); these issues could lead to serious quality problems.

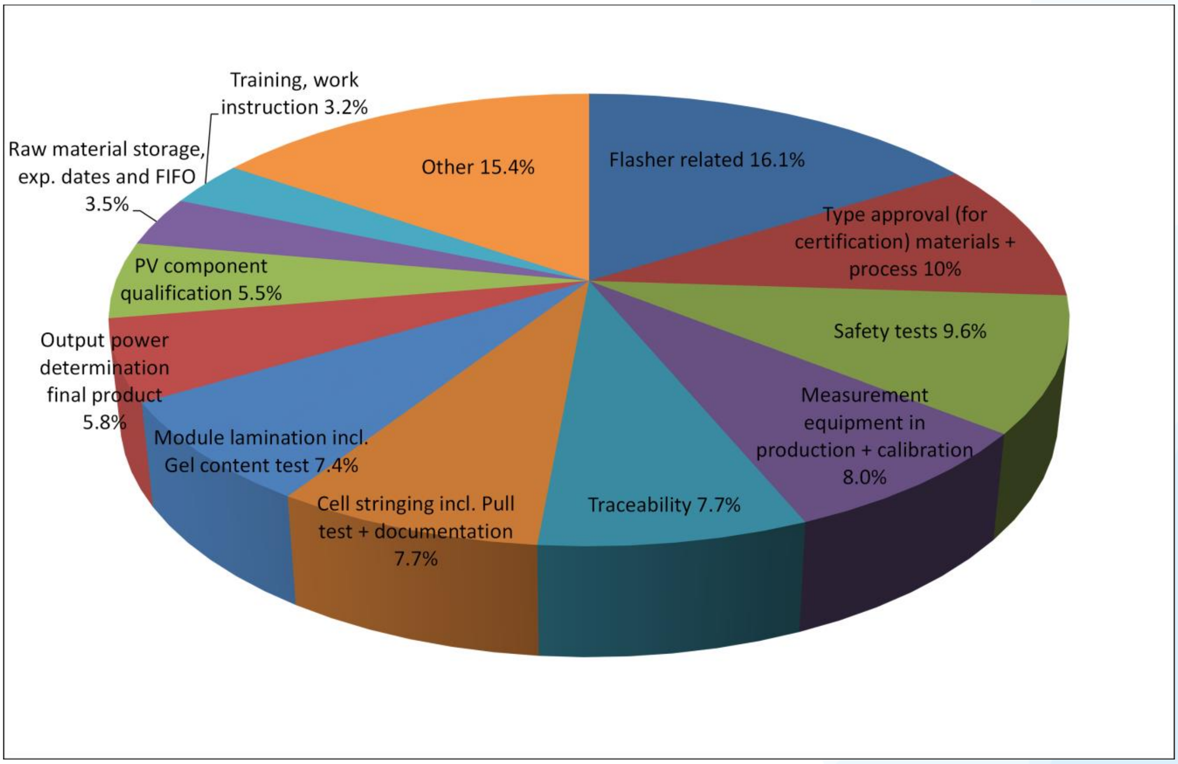


Figure 11: Distribution of deviations of all factory inspections during 2012-2015

Flasher related deficiencies refer to the applied methods to determine the output power of the PV module: adjustment and applied correction procedures to STC in terms of irradiance (6.1%) or temperature (1.6%), calibration of equipment used for the power measurement and general maintenance of the flasher (6.4%), and flasher classification (2.0%). These deviations sum up to 16.1% flasher related deficiencies in total.

Typically, manufacturers indicate a production tolerance of ±5% for the measured output power at STC. It is assumed by manufacturers that this tolerance fully covers the measurement uncertainty for $P_{mpp,STC}$, which is however not determined or even estimated by them. On the other hand, gaps of up to ~10% in $P_{mpp,STC}$ have been found by TÜV Rheinland by comparing laboratory measurements with the manufacturer's label values. Assuming a laboratory measurement uncertainty of ±2%, this would, even in the best case for the manufacturer, mean an overestimation of output power by 3.4%. An overestimation of output power - as a technical risk generated during the product testing phase - has a direct impact on a business model as it leads to an overestimation of the energy produced.

Insufficient performance in safety tests in production (e.g., missing or irregular high potential test or ground continuity test, insufficient test conditions etc.) are the most critical points (9.6%). This may impose safety risks for installers and operators due to insufficient insulation of current-carrying parts.

Many of the deviations are related to the equipment used for the measurements in the production line and its regular calibration (8%).

Production traceability (7.7% in total for traceability of raw materials, process, and serial number) is partly insufficient, leading to problems in meeting the warranty and proving certificate conformity.

Further weaknesses are defined for the core process steps for crystalline silicon module production (stringing, lamination) and related standard quality tests (7.7% and 7.4%, respectively).

Furthermore, the output power is in many cases are not determined for the entire final product (5.8%); instead, the power is measured e.g. by directly measuring at the electrical contacts within the junction box, neglecting the junction box, cables, etc. and thus the output power could be overestimated. Consequently, the labelled output power (which essentially defines the module price) is imprecisely determined in those cases.

5.1.5) Overall Impact on the Energy Yield

Table 10 summarises the uncertainty contribution of each identified effect. The overall uncertainty is based on values available in the literature. (Muller et al., 2015) reported an analysis based on 26 systems located in Germany and Spain where the measured energy yield was 4% higher than initially estimated. This was mainly due to an overestimation of the annual insolation for the selected location with a +4.9% and an underestimation of the PR of -0.9%. This is of particular importance for systems where a guaranteed yield is requested together with a PR. (Reich et al., 2015) give an overall uncertainty on the energy yield due to various effects in the range of ±5-11%. (Richter, M et al., 2015) give a value of ±6-8% for the energy yield and ±2-6% in PR.

Table 10: Summary of contribution of the overall uncertainty of the energy yield

Effect	Overall uncertainty range (1 STD)
Insolation variability POA transposition model	± 4-7% (see 5.1.1) ± 2-5% (see 5.1.1)
Temperature coefficients and temperature effects	± 0.02%/°C (5% relative error for crystalline silicon-based modules) (lab measurements)
Temperature deviation due to environmental conditions	1-2 °C (± 0.5-1%) (see 5.1.3) Up to ±2% if environmental conditions are not included
PV array and inverter model	±0.2% to ±0.5% (see 5.1.3) for the inverter model ±1% to ±3% for the PV array model
Degradation	± 0.25-2% (see 5.1.2)
Shading	Site dependent
Soiling	± 2% (see 5.1.3) (Also site dependent)
Spectral mismatch (modelled)	± 0.01% - 9.45% (depending on PV technologies)[9] ± 1% to ±1.5% for c-Si
Nominal power	±1-2%
Overall uncertainty	± 5-10%

[9] G. Belluardo, G. Barchi, D. Baumgartner, M. Rennhofer, P. Weihs, D. Moser. Uncertainty analysis of a radiative transfer model using Monte Carlo method: impact on PV device calibration parameters. Proc. 31st OTTI Symposium Photovoltaische Solarenergie. Bad Staffelstein, 9-11 March 2016

We have already shown in Figure 3 the impact of the energy yield uncertainty on the exceedance probability with a difference of around 60 kWh/kWp at P90 assuming a P50 value of 1000 kWh/kWp (>5% difference at P90). The curve was created based on a normal distribution of the energy yield where the median is equal to the mean value. Positively or negatively skewed distribution (due for e.g. to not normally distributed irradiance or PLRs) will also have an impact on the exceedance probability. Figure 12 shows the effect of a negatively skewed distribution (not

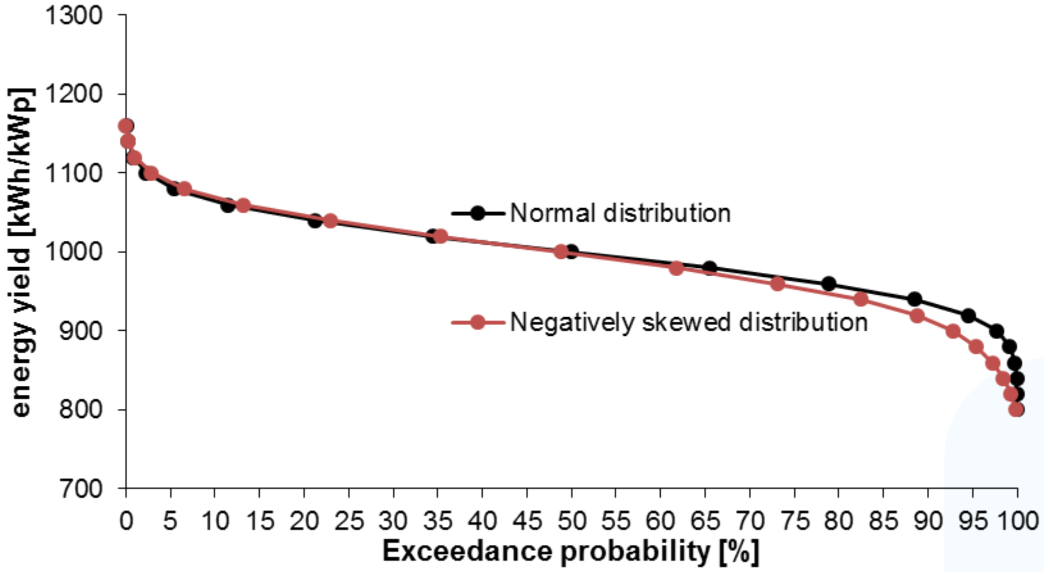


Figure 12: Impact on the exceedance probability of a negatively skewed energy yield distribution

based on real data). The tail of the PLR distribution towards more negative values could lead to this result for example.

5.2) Description of CPN Method Developed in the Project

For the calculation of the economic impact of the PV plant technical risks, which are likely to occur during the implementation phase, namely during the plant operation and maintenance, the Occurrence and Severity were calculated in a dedicated table. The table was designed to allow for generalization and flexibility in order to maximise the use of the methodology and to not constrain the results to the analysis carried out in the project. The following parameters were thus considered:

- PV market segment (in kWp)
- PV plant type (ground or roof-mounted)
- Specific yield (to account for latitude/geographic dependent analysis)
- Costs due to downtime (loss of feed-in tariffs, loss of electricity valorisation, cost of reduced energy savings)
- Costs due to fixing the failure (cost of detection, cost of repair or substitution, cost of transport, labour cost)

The statistical parameters used for the evaluation were defined as:

- number of tickets: number of reports of failures
- number of plant cases: number of plants affected by a specific failure
- number of components in affected plants
- number of component cases: number of components affected by a specific failure.

This distinction allows the method to provide a broader picture from a statistical point of view, to define outlier and to account for possible bias.

The economic impact of a specific failure can be split into two categories:

a) Economic impact due to downtime and/or power loss (kWh to Euros)

- Failures might cause downtime or % in power loss

-Time from failure to repair/substitution and should include: time to detection, response time, and repair/substitution time

- Failures at component level which might affect other components (e.g. module failure might bring down the whole string.

b) Economic impact due to repair/substitution costs (Euros)

- Cost of detection to account for various techniques (IR for hotspots, EL for crack cells, visual inspection, monitoring systems, etc)

- Cost of transportation of component

- Cost of labour (linked to downtime)

- Cost of repair/substitution

Specifically, the downtime costs are calculated considering the lead time to detection, t_{td}, the lead time to repair/substitution (i.e. the time between the detection and the intervention, highly dependent on the availability of spare parts), t_{tr} or t_{ts}, and the time to fix the problem, t_{fix} (e.g. the time it takes to substitute a PV module or repair an inverter). The steps that lead to the downtime costs are the following:

- Calculation of downtime caused by a specific failure of a specific component [hours]

$$t_{down,fail} = (t_{td} + t_{tr,ts}) \cdot PL \cdot M + t_{fix} \cdot M$$

where *PL* is the performance loss (or power loss), expressed in fraction (or %), therefore *PL*=1 for failures causing total downtime. For example, hotspot in modules are associated to a *PL*=0.02 (2%), while theft of module causes a *PL=1* (100%) using the values defined in Table 18. *PL* is thus a derating factor of the performance caused by a specific failure on 1 component.

M is a multiplier to consider failures that cause problems at higher component level (e.g. 1 module takes down the whole array caused by theft of module). To avoid an overestimation of downtime, *M* was considered equal 1 in the analysis reported in Chapter 6.

- calculation of total downtime for the n_{fail} number of components affected by a specific failure over 1 year (e.g. number of modules affected by hotspots) [hours/year]

$$t_{down} = t_{down,fail} \cdot n_{fail,1\,year}$$

- calculation of total downtime normalised by the total number of components (e.g. number of modules of all the PV plants present in the database, affected and unaffected) [hours/year]. $t_{down,comp}$ is the downtime due to a specific failure over all components (not only the affected ones).

$$t_{down,comp} = t_{down}/n_{comp}$$

- calculation of occurrence over a time t_{ref} [fraction and can be expressed in % as performance reduction due to a specific failure over the whole portfolio over 1 year]

$$O_{CPN} = t_{down,comp}/t_{ref}$$

t_{ref}, given in [hours/year], could be either the equivalent hours per year (specific yield), the total number of hours per year or the number of sun hours per year. Maximum impact is achieved when we consider that the downtime due to failure happens when the plant is working at the nominal power. If the total number of hours per year is used, this means that the downtime due to failure is equally distributed over day and night. The occurrence, O_{CPN}, is thus an indication of the % in reduction of performance averaged over the whole portfolio over 1 year.

- calculation of production losses, *L*, due to downtime [kWh]

$$L = O_{CPN} \times S_{CPN}$$

The severity, S_{CPN}, is defined as the total production of one PV plant or all the PV plants within the database over one year in absence of failures. The occurrence, O_{CPN}, is calculated based on the downtime of a specific failure normalised over the number of components and the total hours, and the calculation of downtime costs as missing production / savings:

- calculation of downtime costs as missing production/savings

$$C_{down} = L \times (FIT + PPA + RCE)$$

For the calculation of the costs due to downtime, it is important to consider the missing income of feed-in tariffs (FIT), the missing income from power purchasing agreements (PPA), and/or the missing savings generated by PV plants installed on roofs/facades defined as retail cost of electricity (RCE).

- The costs related to fixing the failure results from the sum of the costs of repair/substitution, the costs of detection, the costs of staff, the costs of transport, and the cost of labour. Costs can be given in €/components and normalized over the total nominal power in the database or only the nominal power of the affected plants.

$$C_{fix} = (C_{det} + C_{rep/sub} + C_{transp}) \cdot n_{fail} + C_{lab} \cdot t_{fix} \cdot n_{fail}$$

The sum of C_{fix} for various components is then equal to the cost of monitoring/detection and corrective maintenance. Preventive maintenance is not included in this cost as it is carried out periodically.

The calculation of the Cost Priority Number is then given by

$$CPN = C_{down} + C_{fix}$$

The division into the various categories allows the calculation of CPNs for very generic cases or to plant specific figures depending on the type of input data available. As input data specific plant related figures or statistical analysis of failures can be used. For the analysis presented in this paper, we have used as input data the number of failures, number of components, number of components of affected plants and the nominal power of the PV plant. Time and cost parameters have been set based on defined scenarios. The database readily contains information on the PV technology type, the time to repair, the geographical position of the PV plant, the type of inverter (centralised vs string), and the number of modules per string. With the increase of the size of the database, input data for the analysis can thus be deduced directly from the database instead of being imposed based on defined scenarios.The parameters used for the calculation of the CPN can also be given as country dependent by applying country-based coefficients to take into account different FITs schemes, retail cost of electricity, annual insolation, cost of labour, etc.

This methodology can only be applied to the failures with a direct economic impact to the business plan either in terms of the reduced income due to downtime or the costs for repair or substitution. The technical risks included in the risk matrix which cannot be described with an exceedance probability or with a CPN are very important and have to be considered as they might have an impact on the CPN value of other component failures. For example, the technical risks related to monitoring system, spare parts, normative and documentation, insurance reaction time, operation and maintenance contract, video surveillance, detailed field inspection (IR, EL, etc.), just to name a few, can reduce or increase the time to detection or the time to repair/substitution and might have an impact on the detection costs. A thorough analysis was carried out in relation to the mitigation measures and is covered by the project Deliverable "Recommendations for minimizing technical risks in PV project development and technical risks of PV plant operation".

5.3) Critical Aspect of the Proposed CPN Approach

The proposed CPN approach allows for statistical estimation of the economic impact of various failures that causes the downtime and costs associated with repair and substitution. Some critical aspects are connected to the methodology proposed and will be critically discussed in this section.

5.3.1) Failures that Cause Problems at Higher Level

Some failures have an impact at higher level and if the effect is only computed for the single component it might lead to an underestimation. Examples:

- Broken module having an impact at string level
- Power losses having an impact at string level
- Cables failure having an impact at module/string/inverter/plant level

IMPLEMENTED SOLUTION: A multiplier factor M was included in the methodology to account for this issue.

5.3.2) Time Distribution of Failures

For some components it would be desirable to have a statistical probability distribution of when the failure is more likely to occur. This is particularly valid for inverters, which affect directly the business case. As this information is not readily available, the acquired failure database and methodology is based on an equal annual probability of failure for all components. Moreover, the operational time of the plants is limited to a maximum of 5 year with weighted average time to failure (from year 0 to year of failure) of 2.7 year.

IMPLEMENTED SOLUTION: The methodology already allows for an analysis of the failures related to plants with the same installation year to derive probability distribution of failures. This is only possible when the number of failures is statistically relevant when this higher granularity is required.

5.3.3) Geographical bias

Some of the data contained in the database (around 10% in nominal power) used for the analysis come from the alpine area and therefore failures due to snow could be overrepresented.

IMPLEMENTED SOLUTION: The statistical parameter "number of affected plants" is inserted to check if the analysed failure is related only to a limited number of plants.

5.3.4) Technology Bias

The cost of the technology is based on multi-crystalline silicon modules, which represent a large share of the market.

IMPLEMENTED SOLUTION: The type of technology is included for each ticket to allow for technology-based assessment.

5.3.5) Calculation of Components

Not in all the cases it is possible to know the detailed figures for each components (nominal power of modules, number of modules, number of structures, length of cables, etc). Some of the values need to be estimated and this will lead to statistical error.

IMPLEMENTED SOLUTION: The following assumptions were considered in the calculation of number of components in the CPN table:

- 20 modules per string
- 2 string cables per string
- 2/3/4 strings per mounting structure (depending on installation)
- 10/6/3 combiner boxed per inverter (depending on inverter size)
- 1 transformer per 800 kVA

These values have been validated using plants in the database for which detailed information was readily available.

5.3.6) Extrapolation of Tickets

During on-site plant inspections, it is a common practice that not each single detected failure is counted individually. Especially in larger PV plants, the quantity of failures is in some cases only counted for a defined sampled area, e.g. 10%, and the detected failures are extrapolated for the whole PV plant. This approach leads to uncertainties in calculating the real quantity of the failures.

IMPLEMENTED SOLUTION: In order to estimate this uncertainty the differences between the extrapolated and the counted number will be evaluated in our analysis for PV plants containing both information.

6) Analysis and Results

In this section the described CPN method is applied to the collected failure data. The aim is to prioritise the risks by means of the CPN ranking and the associated economic impact. The failure data are based on owner-provided failures tickets and detected failures during on-site inspections. The two databases of EURAC and TÜV Rheinland of collected failures are provided in an aggregated form and merged into one.

The data was analysed in total and divided into the four market segments as stated below and as defined in the SolarPower Europe Global Outlook report and used in the Solar Bankability report, ”Snapshot of Existing and New Photovoltaic Business Models” (Deliverable 4.1).

- Total: systems with a capacity of Pn > 0kWp
- Residential: systems with a capacity of Pn <= 10kWp
- Commercial: systems with a capacity of 10kWp < Pn <= 250kWp
- Industrial: systems with a capacity of 250kWp < Pn <= 1000kWp
- Utility scale: systems with a capacity of Pn > 1000kWp

An overview of the total amount of analysed plants, components and detected failures is given in Table 11. In total 1,094,742 failure cases were included in the analysis of 772 PV plants including 2,386,742 components. The failure mode database contains data of around 442 MW_p of PV plants nominal power corresponding to around 0.5% of the installed peak power in Europe.

Table 11: Summary of main figures of the failure data collection

	Total number of plants	Total Power [kWp]	Average number of years
TOTAL	772	441676	2.7
Components	**No. tickets**	**No. Cases**	**No. Components**
Modules	473	678801	2058721
Inverters	501	2583	11967
Mounting structures	420	16147	43916
Connection & Distribution boxes	256	12387	25305
Cabling	682	384600	246084
Transformer station & MV/HV	57	224	759
Total	2379	1094742	2386742

6.1) Definition of Costs

In order to apply the CPN methodology, as described in Chapter 5.2, the values for two groups of parameters have been defined. The first group relates to the missing production costs (C_{down}) based on an average electricity price, down time and specific power loss. The second group relates to the costs of fixing a specific failure for a specific component (C_{fix}) where the costs for labour, repair, cleaning and transportation are considered. These values (shown for “modules” in Table 12 and for all components in Appendix 4) were derived from standard market costs and serve for the base scenario as input. If a certain project with known cost figures shall be analysed, these values can be adjusted accordingly. For the **base scenario** the following conditions are taken into consideration:

1. No monitoring system installed
2. No O&M contract or on-site inspection
3. No surveillance
4. No spare parts stored

The comparison of the outcome including the impact of different combinations of mitigation measures is not part of this report, but is presented in the project deliverable “Recommendations for Minimizing Technical Risks in PV Project Development & Recommendations for Minimizing Technical Risks of PV Plant Operation” (Deliverables D1.2 and D2.2). To assess the impact of failures for various O&M strategies we define two extreme types of scenarios. In the first scenario we assume that failures are never detected. This scenario is called "never detected", in the second scenario we assume that the failure is fixed after detection using a lead-time to repair/substitution of 1 month.

Table 12: Values used in the analysis and determination of CPN values for failures related to PV modules

	Failures	C_{det} [€/component]	C_{sub} [€/component]	C_{rep} [€/component]	C_{transp} [€/component]
Modules	Hotspot	0 €	108 €	0 €	10 €
	Delamination	0 €	108 €	0 €	10 €
	Glass breakage	0 €	108 €	0 €	10 €
	Soiling	0 €	0 €	0 €	10 €
	Shading	0 €	0 €	0 €	10 €
	Snail track	0 €	108 €	0 €	10 €
	Defective backsheet	0 €	108 €	0 €	10 €
	PID = Potential Induced degradation	0 €	108 €	0 €	10 €
	Failure bypass diode and junction box	0 €	108 €	0 €	10 €
	Corrosion in the junction box	0 €	108 €	0 €	10 €
	EVA discoloration	0 €	0 €	0 €	0 €
	Theft of modules	0 €	108 €	0 €	10 €
	Broken module	0 €	108 €	0 €	10 €
	Corrosion of cell connectors	0 €	108 €	0 €	10 €
	Improperly installed	0 €	0 €	0 €	0 €
	Module damaged due to fire	0 €	108 €	0 €	10 €
	Missing modules	0 €	108 €	0 €	10 €

	Failures	t_{td} [h]	$t_{tr,ts}$ [h]	t_{fix} [h]	PL [%]	M
Modules	Hotspot	8760	744	2	2%	1
	Delamination	8760	744	2	1%	1
	Glass breakage	8760	744	2	10%	1
	Soiling	8760	744	0.01	10%	1
	Shading	8760	744	0.01	10%	1
	Snail track	8760	744	2	1%	1
	Defective backsheet	8760	744	2	1%	1
	PID = Potential Induced degradation	8760	744	2	10%	1
	Failure bypass diode and junction box	8760	744	2	33%	1
	Corrosion in the junction box	8760	744	2	1%	1
	EVA discoloration	8760	744	0	0%	1
	Theft of modules	8760	744	0.5	100%	1
	Broken module	8760	744	2	100%	1
	Corrosion of cell connectors	8760	744	2	1%	1
	Improperly installed	8760	744	2	5%	1
	Module damaged due to fire	8760	744	0.5	100%	1
	Missing modules	8760	744	2	100%	1

For the calculation of the CPN, for the first scenario, a value of 8760 hours was chosen for the parameter "time to detect" (t_{td}) corresponding to an entire year (it is the maximum number of hours per year). This scenario is defined as the "**never detected" scenario** and the corresponding CPN is thus equal to C_{down} as the economic impact of the failure is only related to the downtime (i.e. performance loss/missing production) caused by it.

$$CPN_{never\_detected} = \frac{(t_{td} \cdot PL \cdot M) \cdot n_{fail}}{n_{comp} \cdot t_{ref}} \cdot S_{CPN} \cdot (FIT + PPA + RCE)$$

For the analysis of the base scenario, to give also an indication of the overall costs of repair or substitution, we have also included the values needed for the calculation of C_{fix}. The corresponding CPN for the **"failure fix"** scenario is equal to C_{fix} (cost of fixing the failures) with in addition a small downtime term C_{down} (downtime after detection) due to the time to repair (t_{tr}) and repair time (t_{fix}), 744 hours (1 month) and up to 2 hours for PV modules, respectively. The value of 1 month was selected assuming that no spare parts are available.

Overall cost of repair / substitution:

$$CPN_{failure\_fix} = \frac{(t_{tr/ts} \cdot PL \cdot M + t_{fix} \cdot M) \cdot n_{fail}}{n_{comp} \cdot t_{ref}} \cdot S_{CPN} \cdot (FIT + PPA + RCE) +$$

$$(C_{\mathrm{det}} + C_{\mathrm{rep/sub}} + C_{\mathrm{transp}}) \cdot n_{fail} + C_{\mathrm{lab}} \cdot t_{fix} \cdot n_{fail}$$

This allows the comparison of the two scenarios "never detected" and "failure fix" using the parameters C_{down} and C_{fix} for different failures belonging to the same component. All parameters used for the calculation of the CPN value are summarised in Appendix 4.

6.2) Analysis of Downtime and Occurrence

As presented in Chapter 5, the occurrence, O_{CPN}, is an indication of the % in reduction of performance averaged over the whole portfolio over 1 year. This value is important as it gives an indication of the overall impact of failures and failures per component. Table 11 summarises the overall impact on terms of performance reduction per component typology. Values for the occurrence, O_{CPN}, for the whole portfolio in the database are in the order of 1% and 2.7% for PV modules and inverters, respectively. When just the plants affected by a failures are considered, the impact is much more evident. The differentiation into the impact over the whole portfolio and over affected plants will be used for the analysis in section 6.4. The values presented in Table 11 have been used as a reference scenario for the analysis of the impact of downtime on the utilisation factor included in the definition of the LCOE as presented in (Caroline Tjengdrawira and Mauricio Richter, 2016).

Table 13: Values of the occurrence O_{CPN} defined as the % of reduction in performance over 1 year for the whole portfolio and for just the plants affected by a specific failure

	O_{CPN}	
Component	**whole portfolio**	**only affected plants**
modules	1.01%	14.96%
inverters	2.69%	22.05%
Mounting structure	0.21%	10.82%
Connection & Distribution boxes	0.14%	15.17%
Cabling	2.76%	6.85%
Transformer station & MV/HV	0.45%	0.39%

6.3) Analysis and Results for Various Market Segments (Residential, Commercial, Utility Scale)

The analysis was based on the described CPN method in Chapter 5.2, the collected failure data and the defined downtime costs and fixing costs for each failure in Chapter 6.1.

Therefore, all developed results are strongly depending on the database and the defined conditions (see Table 12 and Appendix 4). Furthermore, the critical aspects described in Chapter 5.3 must be taken into account when evaluating the data and assessing the results.

6.3.1) PV Modules

The first look is into the total quantity of PV module failures (see Table 14 and Figure 13). The ranking of the risks is based on the CPN, which describes the frequency and the economic impact of the specific failure. The economic impact in the "never detected" scenario is entirely due to downtime in terms of production loss (red bars in Figure 13) and it appears to be minimal for the module dominant failures. The dominant factor in the "failure fix" scenario (blue bars in Figure 13) is the cost of substitution, since repairing of a defective module is only possible in particular cases, e.g. cleaning of the surface or changing of defective bypass diodes. The second reason is that repairing a defective module might actually violate the module manufacturer's warranty restriction (i.e. unauthorised modification or tempering of module) resulting in warranty claim exclusion and thus substitution of the defective module is the preferred procedure.

Table 14: Results of analysis for relevant failures in PV modules

Failures	No. Tickets	No. Cases	No. Componentsin whole portfolio	no. Components in affected plants	Overall cost of repair / substitution per year [€/kWp/Year]	Overall cost of repair / substitution per year for affected plants [€/kWp/year]	Missing production per year [€/kWp/Year]	Missing production per year for affected plants [€/kWp/Year]	CPN per year [€/kWp/Year]	CPN ratio [-]
Improperly installed	40	145,990	2,058,721	528,802	12.4	50.4	0.4	1.7	12.8	4.1
Glass breakage	62	43,851	2,058,721	1,093,711	8.1	15.8	0.3	0.5	8.3	2.0
PID = Potential Induced degradation	4	33,619	2,058,721	92,743	6.2	111.2	0.2	4.4	6.4	18.0
Snail track	11	28,975	2,058,721	300,189	5.3	36.9	0.0	0.1	5.3	6.9
Defective backsheet	33	19,835	2,058,721	1,028,642	3.6	7.1	0.0	0.0	3.6	2.0
Delamination	16	16,045	2,058,721	283,794	2.9	35.5	0.0	0.1	3.0	12.1
Hotspot	26	13,311	2,058,721	599,382	2.4	9.0	0.0	0.0	2.5	3.7
Soiling	37	158,578	2,058,721	712,325	1.5	4.2	0.9	2.7	2.5	2.7
Overheating junction box	2	6,714	2,058,721	86,343	1.2	26.7	0.0	0.1	1.2	21.6
Failure bypass diode and junction box	19	6,533	2,058,721	437,699	1.2	5.9	0.1	0.6	1.3	4.9
Shading	59	113,982	2,058,721	1,095,628	1.1	1.9	0.7	1.3	1.7	1.8
Broken module	91	5,555	2,058,721	793,463	1.0	2.7	0.3	0.9	1.4	2.6
Corrosion of cell connectors	5	4,924	2,058,721	106,525	0.9	20.1	0.0	0.1	0.9	22.2
Cell cracks	8	921	2,058,721	242,203	0.2	1.4	0.0	0.0	0.2	8.2
Corrosion in the junction box	4	354	2,058,721	44,826	0.1	3.1	0.0	0.0	0.1	47.1
Theft of modules	4	431	2,058,721	4,362	0.1	23.1	0.0	12.0	0.1	431.1
Missing modules	8	39	2,058,721	149,961	0.0	0.1	0.0	0.0	0.0	12.4
Module damaged due to fire	2	31	2,058,721	42,902	0.0	0.2	0.0	0.1	0.0	58.8
EVA discoloration	23	78,952	2,058,721	583,378	0.0	0.0	0.0	0.0	0.0	3.7

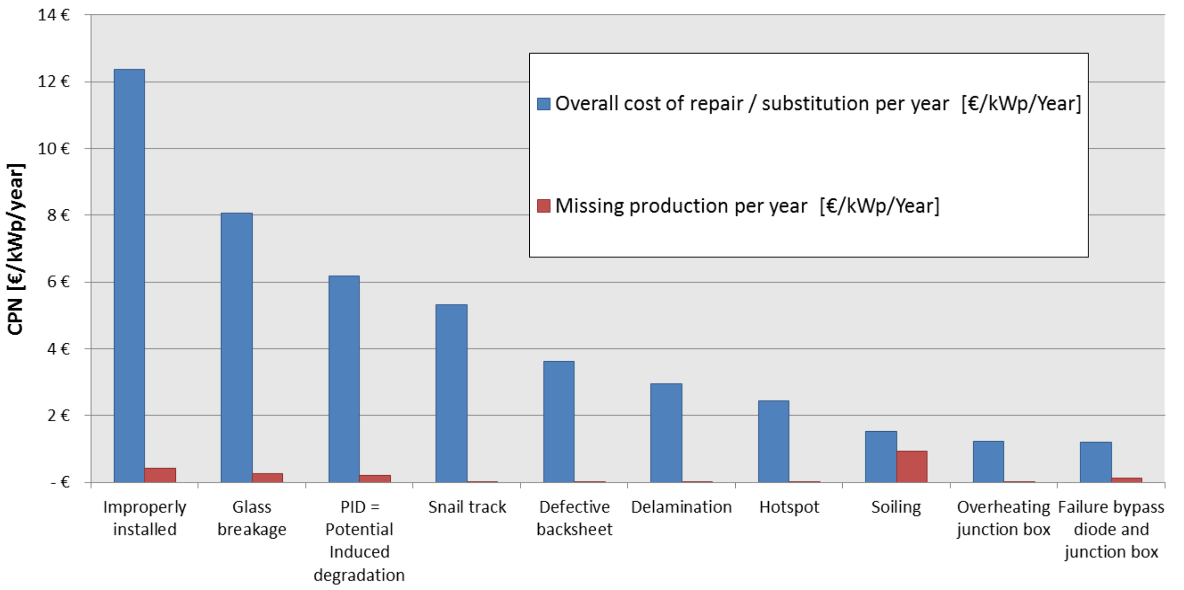


Figure 13: Top 10 risks for PV modules of all systems; blue bars correspond to $CPN_{failure\_fix}$, the red bars to $CPN_{never\_detected}$. The overall CPN is the sum of the two parameters and is given in €/kWp/year.

In Figure 13 the CPN figures are shown for PV modules of all system configurations (from residential to utility scale). The two parameters given in Figure 13 correspond to the “never detected” scenario (red bars) and the “fix” scenario (blue bars) as previously defined. The sum of the impact of the two scenarios gives an overall CPN value for each failure. When the failure is considered over the lifetime of a PV project, mitigation measures will have different impacts on the two parameters and various mitigation strategies can be compared.

As it can be seen in Figure 13, the 10 dominant risks for all PV systems range from installation issues to material/processing defects to maintenance practice. The dominant risks with high economic impact (high CPN) such as bad installation quality, glass breakage and PID can be distinguished from low order risks with small impact (low CPN) such as soiling and shading. The improperly installed module failures comprise of various failure modes such as module mishandling during installation, damaged frame, clamping system etc. (see Appendix 2). Overall the common failures such as glass breakage, improper installation or PID bear a higher level of economic risk.

It is important to highlight that a lower CPN value for the “never detected” scenario does not mean that this strategy is more cost-effective than fixing the problem. Power losses will increase over the years and the existing or impending failure could also pose safety risks! The worst case scenario presented in Chapter 6.3 will show how the impact of the “never detected” scenario can vary depending on the chosen *Performance Loss* parameter (PL).

For a better overview of the available data, the analysis and comparison of each segment were separately conducted and the overall results are described in the following paragraphs.

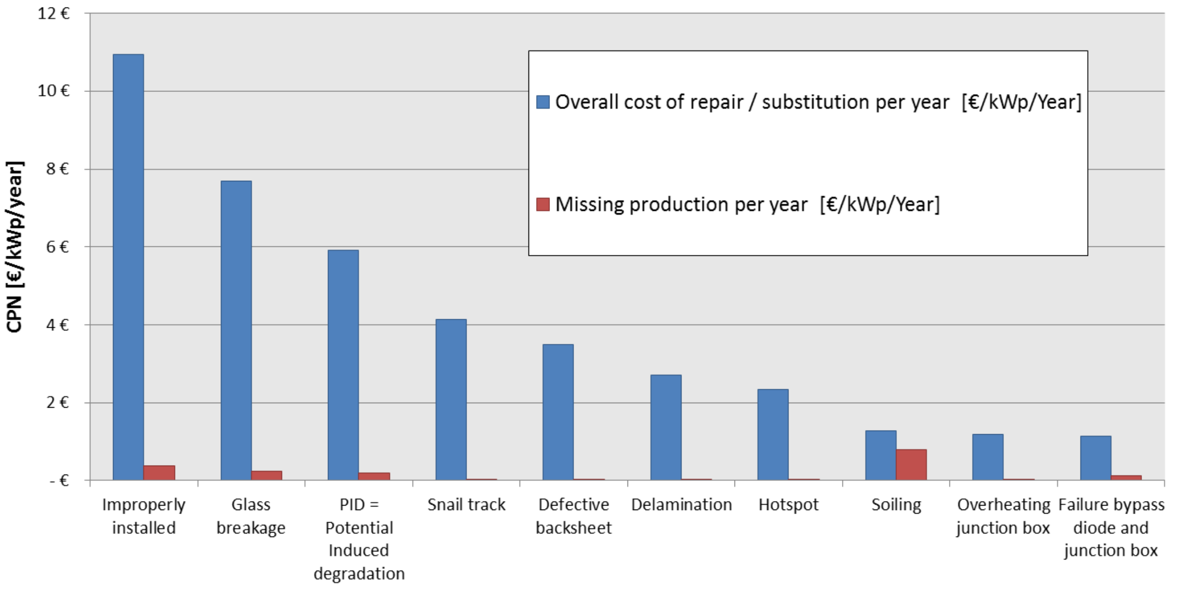


Figure 14: Top 10 risks for PV modules in the utility segment; blue bars correspond to $CPN_{failure\_fix}$, the red bars to $CPN_{never\_detected}$. The overall CPN is the sum of the two parameters and is given in €/kWp/year

If we focus the analysis on large-scale systems >1 MW (Figure 14) we found the dominant risks are in very good agreement with the module risks of all systems shown previously in Figure 13. Additionally in Figure 14, a variety of failures detected by different techniques is demonstrated, e.g. improperly installed PV modules that can be detected by visual inspection as well as PID or hotspots where more sophisticated detection techniques are required.

On the other hand, for residential sector (see Figure 15), it appears that the failures which could be detected by visual inspection are the ones which stand out the most. This does not mean that PV modules in small-size plants do not generate failures such as hotspots, delamination, etc. On the contrary it is likely that the other types of failures could not be detected by simple visual inspection and require more advanced inspection methods (EL, IR) which are not usually applied in small residential installations e.g. due to cost reason.

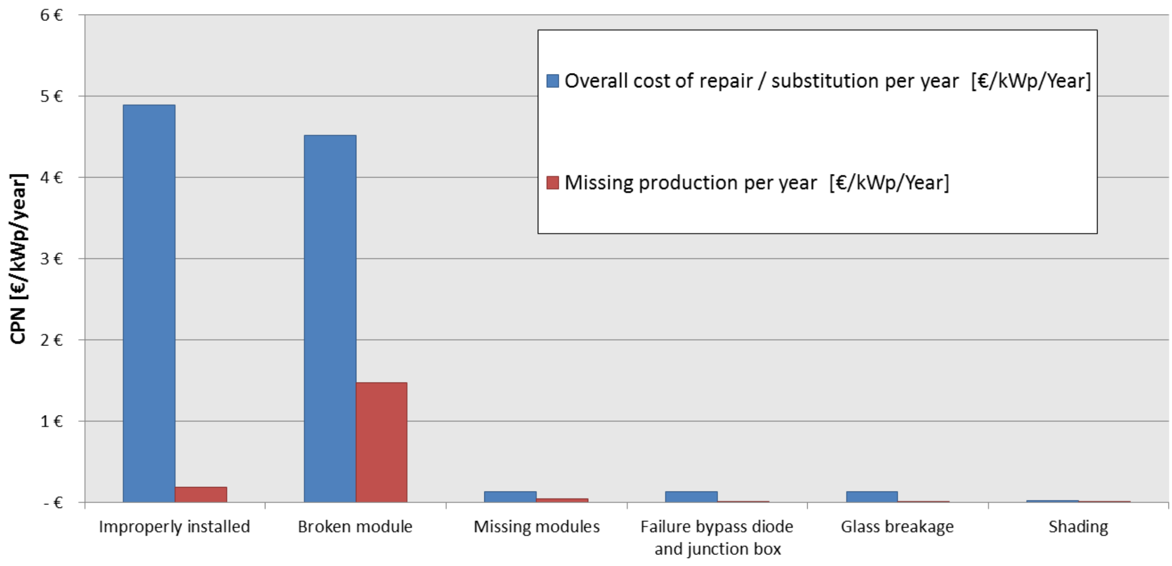


Figure 15: Top 6 risks for PV modules in the residential segment; blue bars correspond to $CPN_{failure\_fix}$, the red bars to $CPN_{never\_detected}$. The overall CPN is the sum of the two parameters and is given in €/kWp/year

6.3.2) Inverters

The most important risks of inverters sorted by the CPN parameter are shown in the Table 15. The significant number of tickets and cases of bad installation errors conceivably shows the lack of expertise in parts of the PV sector. Thus, it is highly recommended to carry out a third-party verification of the planning and development phase as well as the installation phase of the project in order to detect inverter failures as listed below at a very early stage. This third party inspection and qualification will help to reduce CAPEX and OPEX-related failure costs. However, this consideration applies not only for the inverters, but for all components.

Table 15: Results of analysis for typical failures for inverters

Failures	No. Tickets	No. Cases	No. Componentsin whole portfolio	no. Components in affected plants	Overall cost of repair / substitution per year [€/kWp/Year]	Overall cost of repair / substitution per year for affected plants [€/kWp/year]	Missing production per year [€/kWp/Year]	Missing production per year for affected plants [€/kWp/Year]	CPN per year [€/kWp/Year]	CPN ratio [-]
Inverter not operating	155	252	11967	95968	0.32	1.20	2.56	0.32	2.88	3.69
Error message	104	160	11967	60994	0.21	4.82	1.62	0.32	1.83	23.40
Fan failure and overheating	25	540	11967	20432	0.35	2.30	1.10	0.64	1.45	6.54
Wrong installation	9	928	11967	1136	0.53	7.59	0.95	9.96	1.48	14.27
Burned supply cable and/or socket	2	55	11967	378	0.07	17.04	0.56	17.68	0.63	240.61
DC entry fuse failure	4	14	11967	249	0.02	0.16	0.14	6.83	0.16	8.68
Fault due to grounding issues	18	121	11967	3534	0.03	0.08	0.12	0.42	0.15	2.72
Switch failure/damage	3	12	11967	85	0.02	3.44	0.12	17.15	0.14	222.72
Polluted air filter - derating	8	45	11967	115	0.03	0.33	0.09	9.52	0.12	11.31
Wrong connection (positioning and numbering)	26	163	11967	2491	0.09	1.32	0.08	0.40	0.17	15.23
Inverter theft or vandalism	2	7	11967	1482	0.03	37.44	0.07	0.57	0.10	1269.73
Inverter damage due to lightning strike	2	3	11967	168	0.00	0.00	0.03	2.00	0.03	11448.31
Inverter wrongly sized	8	9	11967	310	0.01	30.32	0.01	0.35	0.01	5881.17

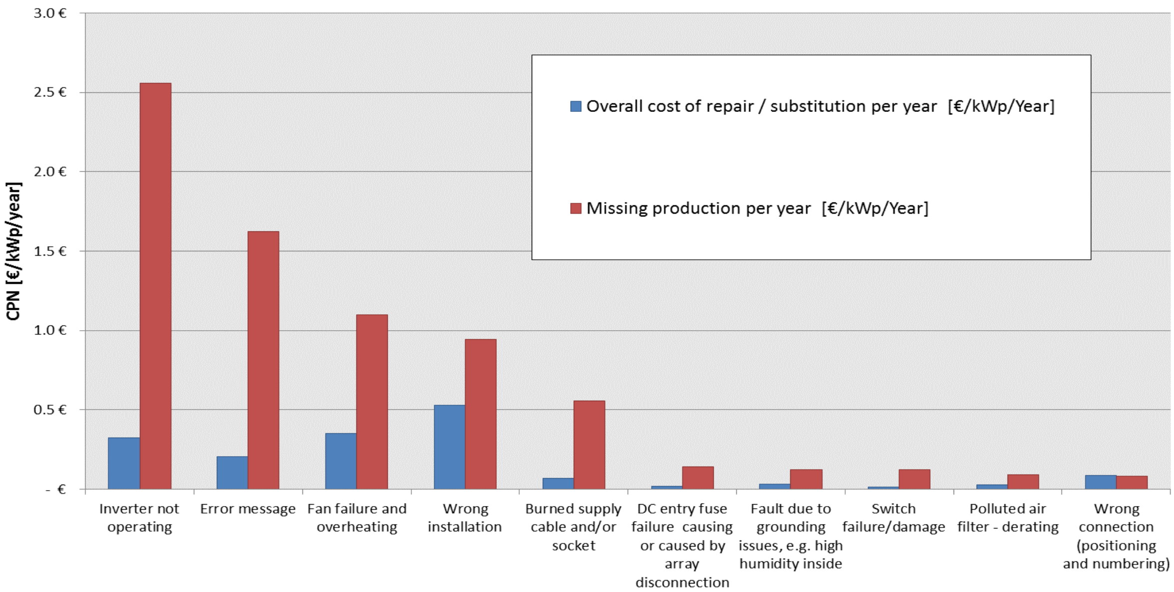


Figure 16: Top 10 risks of inverters; blue bars correspond to $CPN_{failure\_fix}$, the red bars to $CPN_{never\_detected}$. The overall CPN is the sum of the two parameters and is given in €/kWp/year

Unlike the PV module risks, the inverter related-risks appear to have a significant impact on the production (red bars in Figure 16). The production losses caused by the missing production are higher than the overall repair costs (blue bars). In this case, it is clear that repair or substitution of the component should be addressed as early as possible once detected. The same conclusions apply for almost all the market segments separately since the risks are following the same pattern as shown in Figure 16.

6.3.3) Cabling

For cabling-related failures, the most prominent risks are improper installation and the use of different types of connectors in the same PV string/plant (Figure 17). Furthermore, broken cable ties, most likely, due to poor quality choice during the planning phase, are among the most common failures in the cabling categories. In Table 16 and Figure 17 the results of the specific risks on the economic impact are shown. The first two prominent risks with high CPN (issues of cable connections and connectors), which are in the same order of magnitude as the top PV module risks, differ from the rest of the cabling risks with lower CPN in a sense that they have significant production loss impacts.

Table 16: Results for typical failures for cabling

Failures	No. Tickets	No. Cases	No. Components in whole portfolio	no. Components in affected plants	Overall cost of repair / substitution per year [€/kWp/Year]	Overall cost of repair / substitution per year for affected plants [€/kWp/year]	Missing production per year [€/kWp/Year]	Missing production per year for affected plants [€/kWp/Year]	CPN per year [€/kWp/Year]	CPN ratio [-]
improper installation	243	133895	246084	521567	11.37	5.58	0.67	0.32	12.04	0.49
Wrong/Absent cables connection	155	154472	246084	422300	0.62	0.36	3.81	2.22	4.44	0.57
Broken/Burned connectors	56	5333	246084	75392	0.33	1.08	2.63	8.59	2.96	3.27
Wrong/absent cables	31	13975	246084	40534	1.92	12.45	0.35	2.10	2.26	6.49
Damaged cable	40	9006	246084	29426	0.89	8.08	0.67	5.58	1.56	9.08
Broken cable ties	17	17550	246084	53622	0.91	4.67	0.00	0.01	0.91	5.16
Conduit failure	5	5748	246084	9544	0.66	16.65	0.00	0.09	0.66	25.37
Wrong connection, isolation and/or setting of stri	84	25287	246084	75226	0.53	3.17	0.00	0.01	0.54	5.93
UV Aging	3	2967	246084	4022	0.40	28.69	0.01	0.91	0.42	71.27
Cables undersized	6	121	246084	11036	0.25	21.81	0.00	0.02	0.25	86.63
Wrong wiring	3	63	238546	404	0.06	7.97	0.00	0.05	0.07	122.76
Theft cables	2	3	246084	964	0.00	0.64	0.00	0.00	0.00	193.99

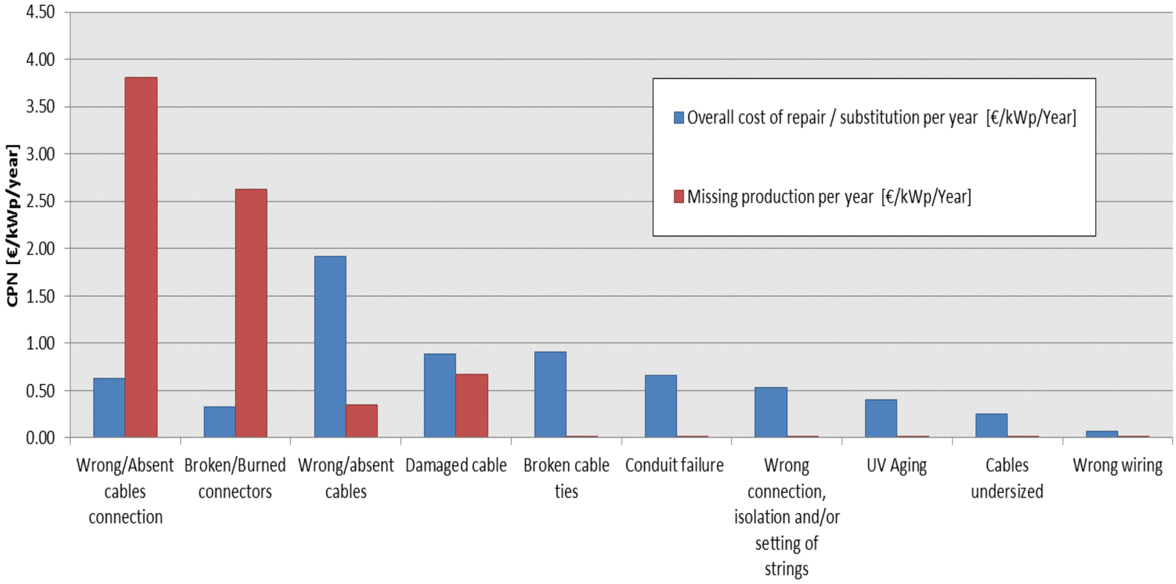


Figure 17: Top 10 risks of cabling; blue bars correspond to $CPN_{failure\_fix}$, the red bars to $CPN_{never\_detected}$. The overall CPN is the sum of the two parameters and is given in €/kWp/year

6.3.4) Other Components

Mounting structures and transformers of the PV plants have been evaluated in this report as well. However, the insignificant number of detected failures and the lack of measured losses mean limited outcomes due to the uncertainty of the parameters needed for the risk CPN assessment.

In Figure 18 the risks of the component “combiner boxes” are shown. These risks can be summarised in two different groups. The first group consists of the failures that have almost no influence on the production but increases the risk of the PV plant. The second group is composed of failures that have a large influence on the productivity of the plant and must immediately be repaired, e.g. an open or broken switch.

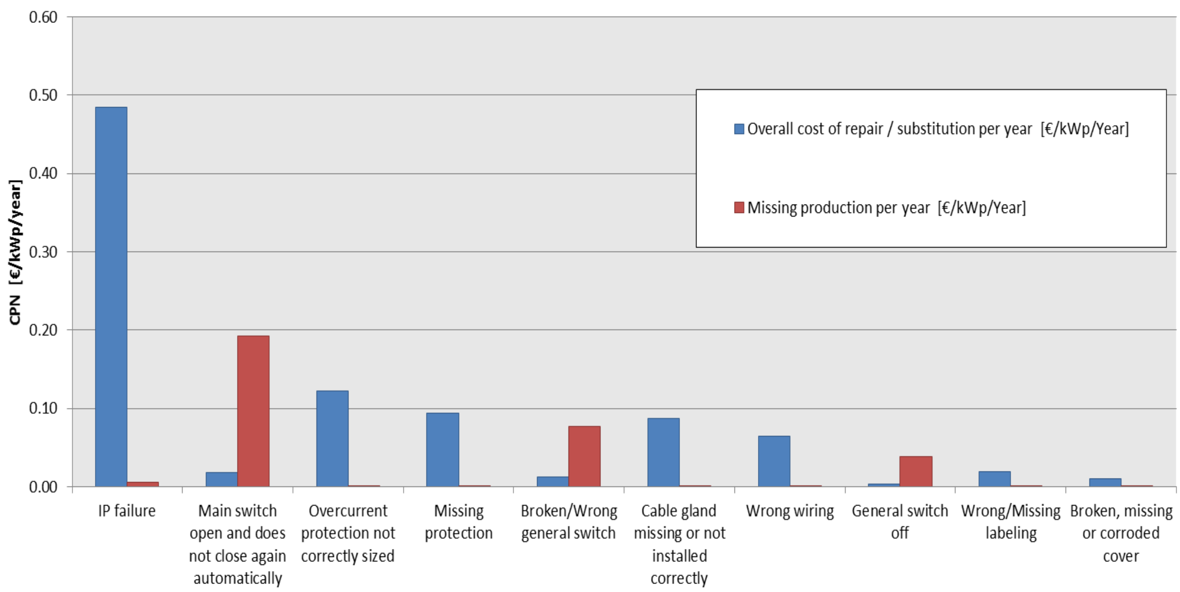


Figure 18: Top 10 risks of combiner boxes; blue bars correspond to $CPN_{failure\_fix}$, the red bars to $CPN_{never\_detected}$. The overall CPN is the sum of the two parameters and is given in €/kWp/year

6.3.5) All Components

The analysis can be expanded for all components to have a broader overview for the whole PV Project during the operation and maintenance phase. Figure 19 shows the top 15 technical risks when all components are considered for the “never detected” scenario. Technical risks related to cabling and inverters are dominant over risks related to PV modules. For the “failure fix” scenario shown in Figure 20 the situation is characterised by the improper installation of various components and by technical risks related mainly to PV modules. It is clear how preventive mitigation measures such as “design review” can readily avoid the technical risks with the highest impact in the “failure fix” scenario. The sum of the annual value for the CPN varies from 17 €/kWp/year for the “never detected” scenario up to 100 €/kWp/year for the “failure fix” scenario (see for the top 15 technical risks). A real case scenario will include a combination of the detection of a failure and the fixing of the failure. The impact of mitigation measures can then be assessed to evaluate the decrease of the annual overall CPN value thanks to an effective implementation and the results are available in the report (Jahn et al., 2016) where the best combinations of mitigation measures can reduce the overall CPN as low as 20 €/kWp/year.

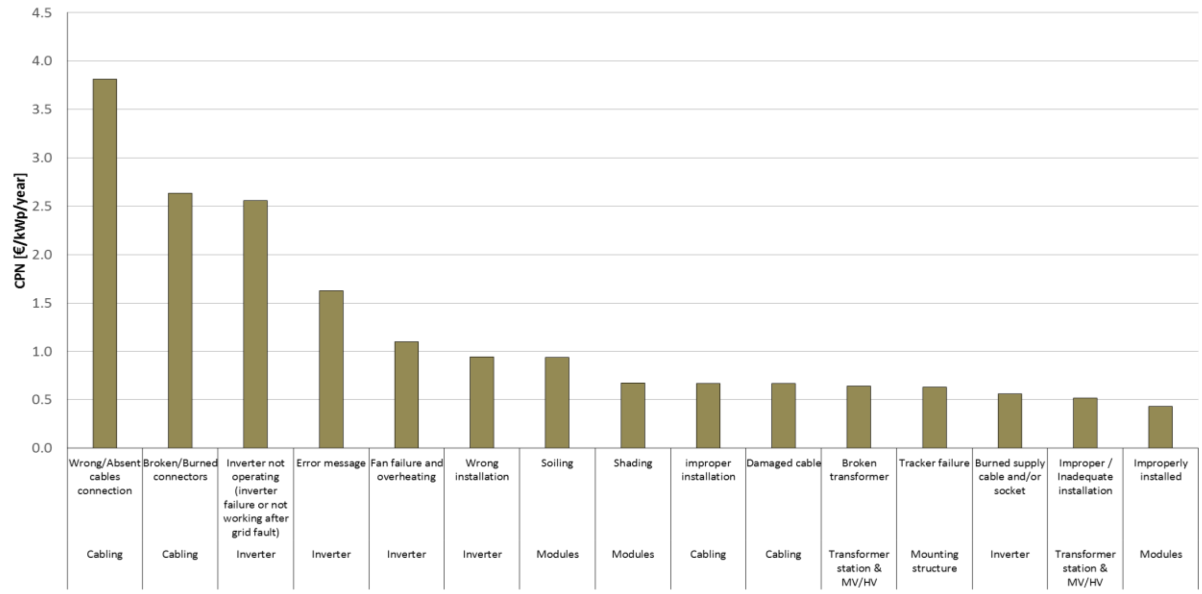


Figure 19: CPN for the "never detected" scenario for 15 technical risks considering all components for the whole portfolio

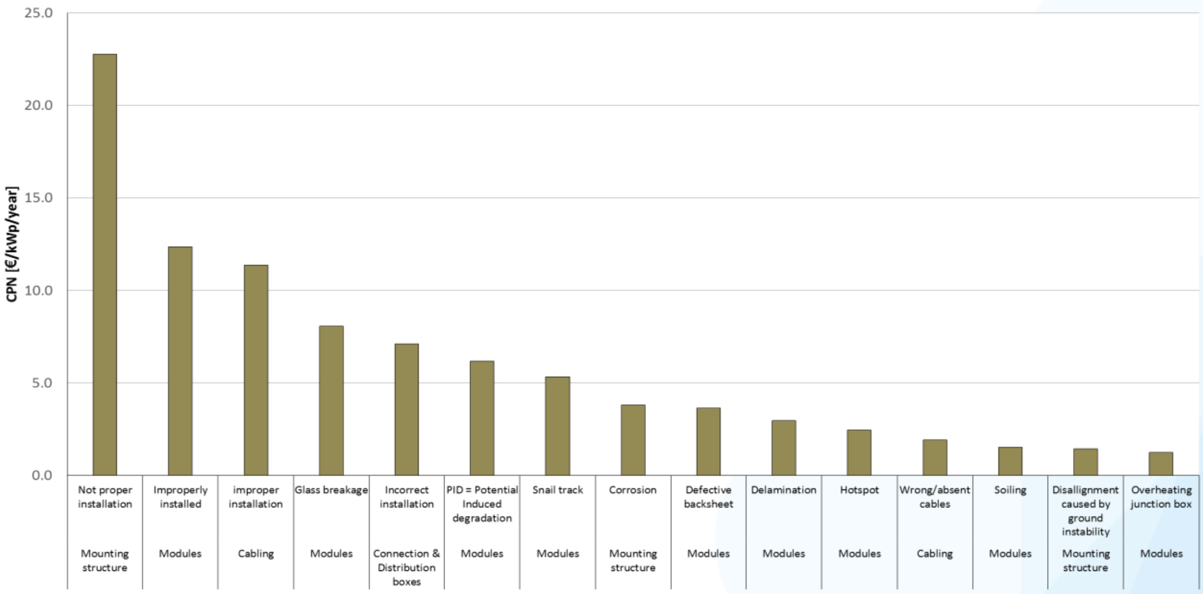


Figure 20: CPN for the "failure fix" scenario for 15 technical risks considering all components for the whole portfolio

6.4) Comparative Studies

This report section describes the impact of varying values of the base scenario and shows the impact of the CPN methodology of the technical risks. The advantages and benefits of the CPN method will be highlighted.

6.4.1) Failure Rate vs CPN

In order to demonstrate the influence of the failure rate on the proposed CPN, the top 10 ranked PV module failures - analysed purely by their failure rates and by the CPN methodology - are compared and presented in Table 17. It can be seen that the PV module failures requiring a substitution of the module (marked yellow), appear in the same order for both approaches at a different level. As described in Chapter 6.1, the CPNs for PV modules are dominated by the costs of substitution and therefore are strongly dependent on the failure rate. On the contrary, PV module failures, which can be resolved without substitution, e.g. soiling or shading, have lower CPNs and thus a reduced rank in terms of risks (although the impact of the related power loss is much higher). The analysis of the other components also shows this dependency on the failure rate for components which predominately have to be substituted.

Table 17: Failure rate vs CPN demonstrated for the component PV module

Rank	Failure rate	CPN
1	Soiling	Improperly installed
2	Improperly installed	Glass breakage
3	Shading	PID = Potential Induced degradation
4	EVA discoloration	Snail track
5	Glass breakage	Defective back sheet
6	PID = Potential Induced degradation	Delamination
7	Snail track	Hotspot
8	Defective back sheet	Soiling
9	Delamination	Overheating junction box
10	Hotspot	Failure bypass diode

6.4.2) Worst Case vs Base Scenario

Since the impact of each failure on the productivity of the PV modules in terms of power loss is not always the same, a **worst case scenario** has been considered for the modules. The results are important taking into account that if no mitigation measures are applied, it is very likely that the worst case is likely to happen after a certain time. The definition of worst case production losses for each PV module failure can be found in Table 18.

Table 18: Losses related to PV module failures for the base and worst case scenario

Failures	PL [%]	Max PL [%]
Hotspot	2%	20%
Delamination	1%	30%
Glass breakage	10%	50%
Soiling	10%	30%
Shading	10%	40%
Snail track	1%	8%
Cell cracks	1%	15%
Defective backsheet	1%	20%
Overheating junction box	1%	33%
PID = Potential Induced degradation	10%	70%
Failure bypass diode and junction box	33%	33%
Corrosion in the junction box	1%	33%
EVA discoloration	0%	10%
Theft of modules	100%	100%
Broken module	100%	100%
Damage by snow	100%	100%
Corrosion of cell connectors	1%	15%
Unsufficient theft protection	0%	100%
Improperly installed	5%	20%
Module damaged due to fire	100%	100%
Missing modules	100%	100%

The difference in missing production (“never detected” scenario) for the top 10 most relevant PV module failures between worst and base scenario is shown in Figure 21.

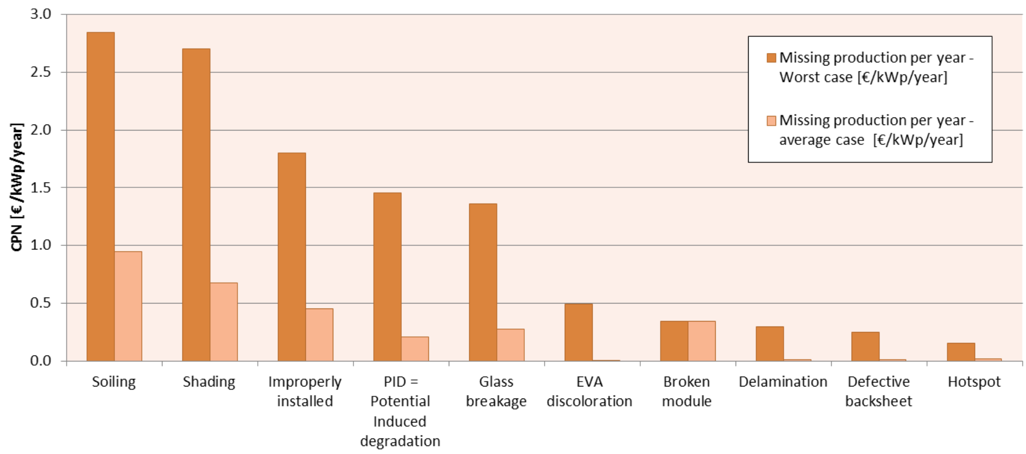


Figure 21: Difference between base and worst-case scenarios in €/kWp/year for the "never detected" scenario

Figure 21 demonstrates the relevance of varying the severity for each failure in terms of associated power loss. The economic impact due to missing production (failure never detected) for the worst case scenario is now of the same order of the economic impact of repairing the failure ("fix" scenario). This impact is even higher if calculated over the lifetime of the PV plant. All these considerations strongly affect the selection-strategy for suitable mitigation measures.

6.4.3) Affected PV Plants vs Total Number of PV Plants

The results presented so far were normalised over the total number of PV plants and thus the total number of components. The database allows us to analyse also how a specific failure is distributed, e.g. if it is present in most of the PV plants or if it had an impact on just a few PV plants. For this analysis we have calculated the ratio between the CPN calculated for the affected plants with the CPN calculated for the total number of plants. Looking at the CPN ratio, it can be stated that for high CPN ratio, if one of the failures is detected for a specific plant, the risk to detect the same failure type for other components increases by a significant multiplier. This can be observed for product failures, e.g. potential induced degradation, delamination and failures of the junction box, or external hazards on the overall PV plant, e.g. destruction by fire or theft of modules as shown in Figure 22.

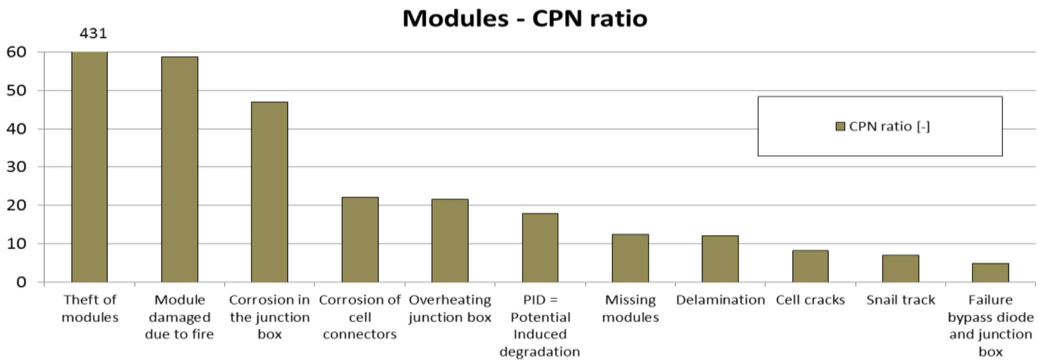


Figure 22: CPN ratio between affected plants and total number of PV plants

6.5) O&M Costs and Link with CPN Method

The overall O&M costs include the costs for, among others, monitoring, preventive maintenance, corrective maintenance, and for security (see Figure 23).

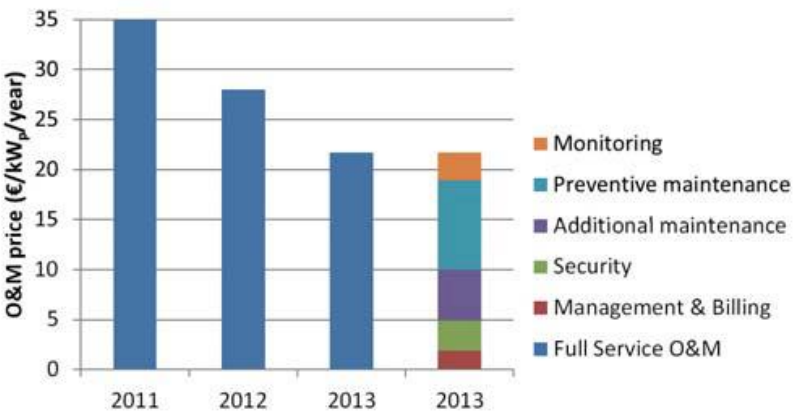


Figure 23: Typical O&M costs (Development of "Full Service" O&M contract price in Italy (Bloomberg New Energy Finance, 2013))

Figure 23 gives typical values of O&M costs, which do not take into account the cost of financing, insurance costs, land costs, local tax costs. The values are in line with what has been reported in the US by the Federal Energy Management Program (FEMP) with cost figures of around $21 +/- $20 /kW/year for systems < 10kW to $19 +/- $10 /kW/year for large systems >1 MW[10]. In 2010, EPRI reported costs of $6/kW/year to $27/kW/year for systems less than 1 MW and costs of $47 to $60/kW/year for larger utility-scale systems depending on PV type and fixed or tracking mounts.

[10] http://www.nrel.gov/analysis/tech_cost_om_dg.html (accessed 19.2.2016)

Other sources indicate $40/kW/year, about half is amortised by inverter replacements (Wiser et al., 2009).

Figures provided by other PV plants operators for overall OPEX costs are around 65/75 €/MWh/year (depending on the specific yield this can be translated into 60/80 €/kWp/year). Insurance costs are in the order of 4-6 €/kWp/year depending on PV plant size.

The need for O&M measures depends on the investor's willingness to carry risks, e.g., how much preventive maintenance is required. It must be analysed on a case to case basis whether the added O&M costs add value. The CPN method can be applied to determine the reduced cost priority number for specific failures after selected O&M measures are applied.

7) Estimating Risk from Monitoring Data

7.1) Approach

Most of the commercial PV systems have monitoring equipment installed to continuously measure and store different plant operation parameters throughout the lifetime of the PV system. The data collected encompass, among others powers, voltages and currents measured at different stages of the system. Often, other parameters such as solar irradiance, ambient temperature, wind speed, module temperature, inverter events, and insulation resistance are also monitored. These data are typically logged with a time resolution of 15 min or higher and should be stored for the rest of the project lifetime.

3E has been operating the commercial monitoring platform SynaptiQ since 2009. Currently, SynaptiQ is monitoring more than 2,000 commercial PV plants. In this section, we statistically evaluate the inverter lifetime based on these monitoring data; we have used the record starting from 2010. This should allow to conclude on the failure rates as a function of lifetime and, thus, derive the probability of pre-mature failure.

Beyond the failure rates, the following failure parameters were studied in the course of the Solar Bankability project:

- how frequently and at what operational lifetime are inverters replaced,
- how often and how long the inverter was unavailable over its lifetime,
- the degradation of the PV plant performance over time, and
- the type of degradation loss:
    - balance-of-system (inverter, cabling, etc.),
    - current type (e.g. due to soiling),
    - voltage type (e.g. due to bypass diode short-circuit failure).

By aggregating these parameter data over many systems, the average values and especially the frequency distribution of these values can be calculated. Some results from this analysis are still being processed and will be published in later versions of this document. The technical parameters derived from this analysis – such as the degradation over time, the number of inverter failures occurring, the mean time to repair (MTTR), the number of inverters being replaced, … – can be used into the CPN calculation and the financial analysis as implemented in the Solar Bankability project.

7.2) Operational lifetime of PV inverters until replacement

An inverter failure results in the permanent shutdown of the inverter, until an intervention is performed, either repairing or replacing the inverter or part of the inverter. Large (+100 kW) inverters are in most cases investigated and repaired on-site, whereas for small or medium-sized inverters it is often more cost-effective to simply replace the full inverter whenever a permanent failure occurs. The latter is usually preferred to ensure fast resumption of the plant production without further delay needed to investigate the failure on site. The defective inverter is sent back to the factory for investigation, reparation and testing; in some cases, refurbished inverters are reused as a replacement inverter for other failed inverters. However, if the inverter design allows for fast and reliable replacement of modular parts and if the failure location is known in advance, the most cost-effective solution is to replace only that modular part of the inverter that has the faulty component.

In our analysis, the replacement of inverters as logged by SynaptiQ is investigated. The population consists of all inverters that are installed since 2010 and that are smaller than 100 kW. Figure 24 shows the cumulative share of inverters that have achieved a certain age so far (blue curve) and the cumulative share of inverters that have been replaced at a certain operational lifetime since installation (green curve).

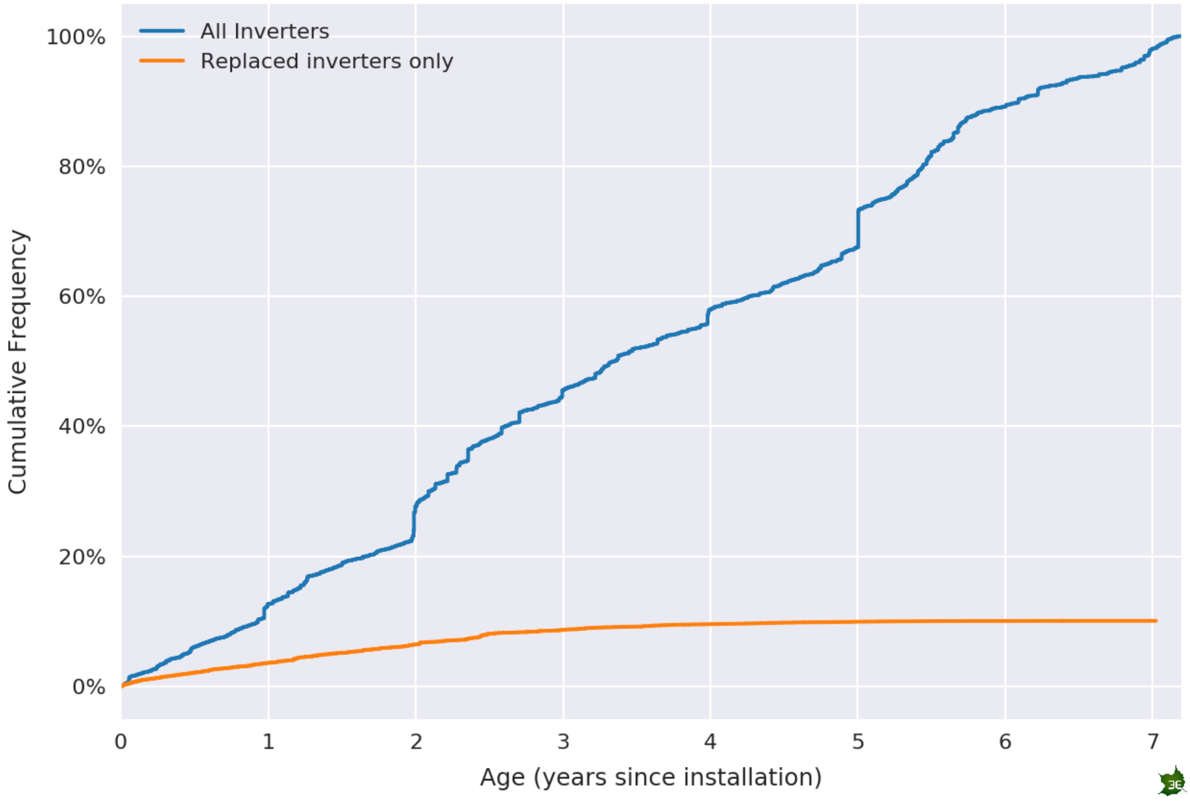


Figure 24: Cumulative distribution function of inverter operational lifetime (total population: 40955 inverters; source: 3E SynaptiQ monitoring system)

It can be seen from the blue curve that all inverter ages up to 7 years are well represented in the total population, with the median inverter having an age of about 3.5 years. From the green curve, it can be observed that ~10% of the inverters have already been replaced, the vast majority of them before 3 years. Starting from the fourth year, the replacements seem to level off. Nevertheless, such a conclusion may be a bit pre-mature given the mix of installation years in the database.

In Figure 25, the yearly inverter replacement rates are shown as a function of installation dates. As the figure illustrates, there appears to be large variations in the inverter replacements depending on the installation dates. Especially, 2011 turned out to be a bad year – already more than 20% of inverters installed during that year have been replaced by now.

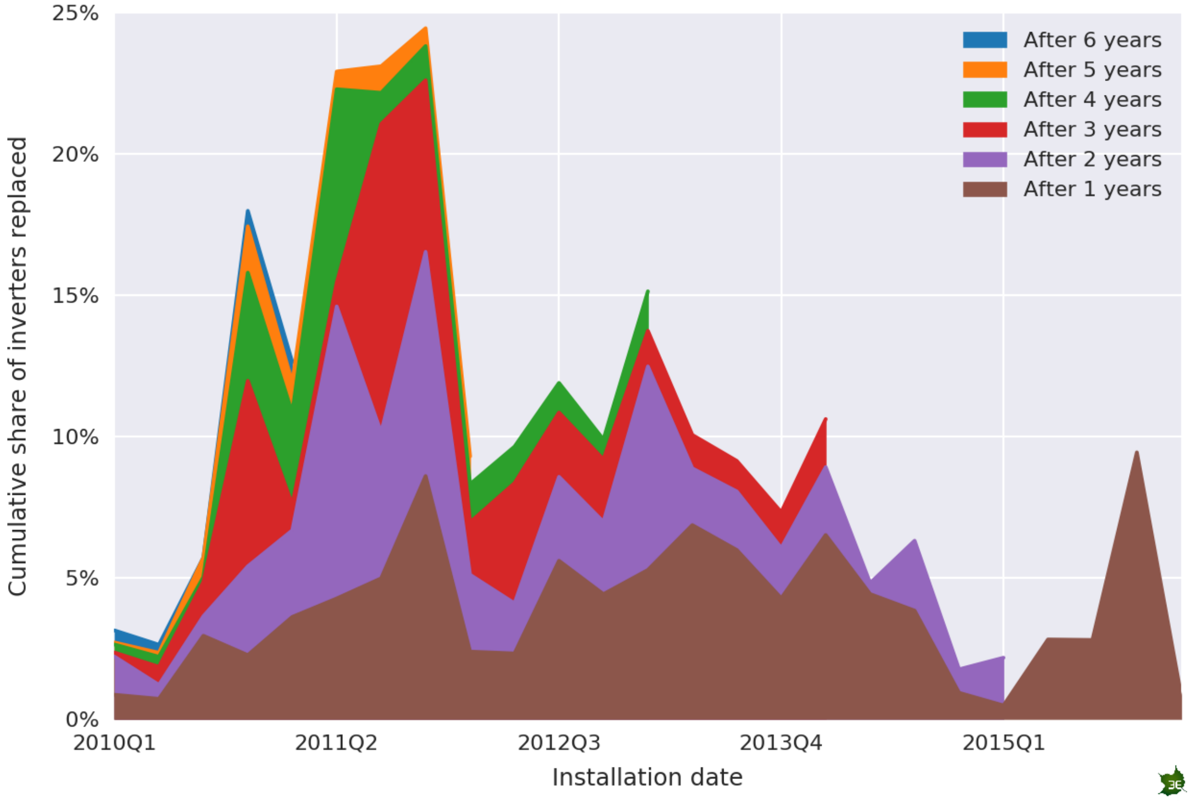


Figure 25: Cumulative share of inverters replaced as a function of installation date and age (total population: 40955 inverters)

The failure trend over the lifetime is of interest in product reliability. In reliability engineering, a 'bathtub curve' mapping the failures in the initial, middle and final (near end-of-life) phases of product operation is widely used. A bathtub curve provides not only the failure trend but also information such as the rates of the failures and the timings of the transitions between the phases. In general, a bathtub curve is made up of three phases:

- The first phase with decreasing failure rates, known as early (infantile) failures;
- The second phase with a constant failure rate;
- The third phase with increasing failure rates, known as wear-out failures.

We have used the inverter replacement records to generate (part of) a bathtub curve for our analysis. Figure 26 shows the average inverter replacement rate as a function of operational lifetime for the inverters logged in SynaptiQ. The first phase of the bathtub curve is clearly visible with the replacement rate decreasing from more than 3.5% during the first three years to less than 1% in the fifth year. Thus, it seems that most replacements are due to early failures. Though data of older inverters are missing, there are indications that the onset of the second phase occurs approximately in the fifth year and that the constant replacement rate during the second phase is around 0.5%. Finally, the onset of the third phase could not yet be derived from the data, but in any case, it does not occur in the first seven years of operation.

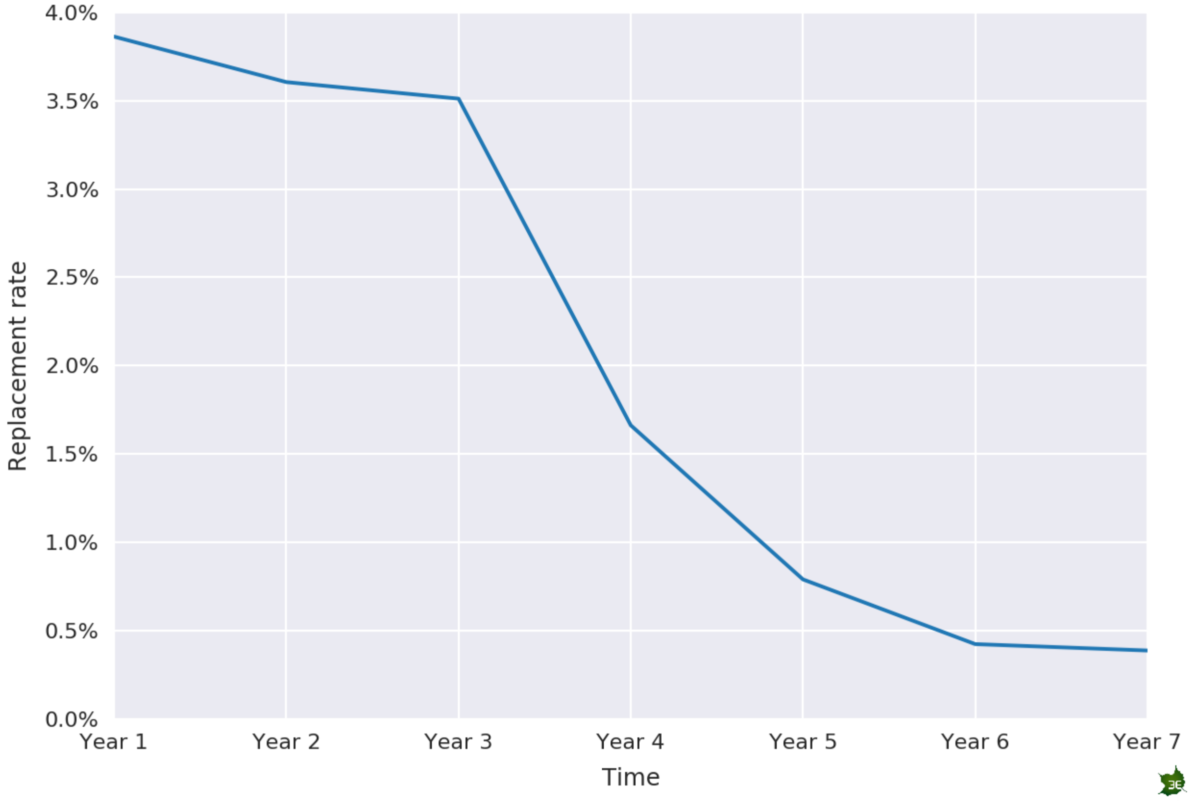


Figure 26 : Inverter replacement rate as a function of operational lifetime, showing the initial phase of the so-called 'bathtub curve'.

In addition to the investigation of the failure trends with respect to the inverter age, we have also analysed the influence of inverter brand and model on the inverter replacement. More than 30 brands were studied and there are multiple models in one brand. Due to the confidential nature of the data we will not show the results in this report. However, the following observation are gathered:

- Despite the differences in service policy between different manufacturers, the number of replaced inverters as derived from the SynaptiQ monitoring database gives a first indication of the reliability of the inverters in the field.
- New inverter models typically suffer the most from early failures.
- Inverter failure rates are rarely disclosed by inverter manufacturers, and if they do, the claimed failure rates are typically much lower than the actual replacement rates found in our analysis. This discrepancy may be due to early failures which are typically not accounted for in claims made by manufacturers. Nevertheless, the observations of this analysis are more or less in line with the limited independent literature where inverter failure rates have been found to vary greatly from 0% to 15% per inverter year for inverters installed between 1990-2001 (Laukamp et al., 2002; Maish et al., 1997) It is however remarkable that failure rates appear to not have improved significantly since.

7.3) Performance Losses

In order to better understand the root causes of variabilities and uncertainties in the performance ratios of commercial plants, a statistical analysis was performed on the monitoring data of 600 plants for the year 2016.

Based on the monitoring data, for each plant the performance ratio was calculated and the performance loss was split up according to the energy conversion step at which the loss occurs:

- Availability loss: due to unavailability of grid, inverter or dc input (power equal to zero while there is light)
- Array (current) loss: due to deviations of the measured DC current from proportionality with irradiance through STC, for times when the plant is available
- Array (voltage) loss: due to deviations of measured DC voltage from 'STC voltage'
- Inverter loss: due to deviations between measured AC and DC power

The split-up of the performance loss according to these stages is illustrated in Figure 27 for one exemplary plant. The performance ratio of this plant during 2016 was 79%, being the sum of the different loss components. It can be observed for this example that Array (voltage) and Inverter losses correspond with the provided model, whereas the observed Array (current) loss is larger than modelled. The final loss stage 'AC installation' in Figure 27, representing (mostly) the AC cable losses, was disregarded for the analysis in this section due to technicalities and the knowledge that it does not substantially contributes to variances and uncertainties in the performance ratio.

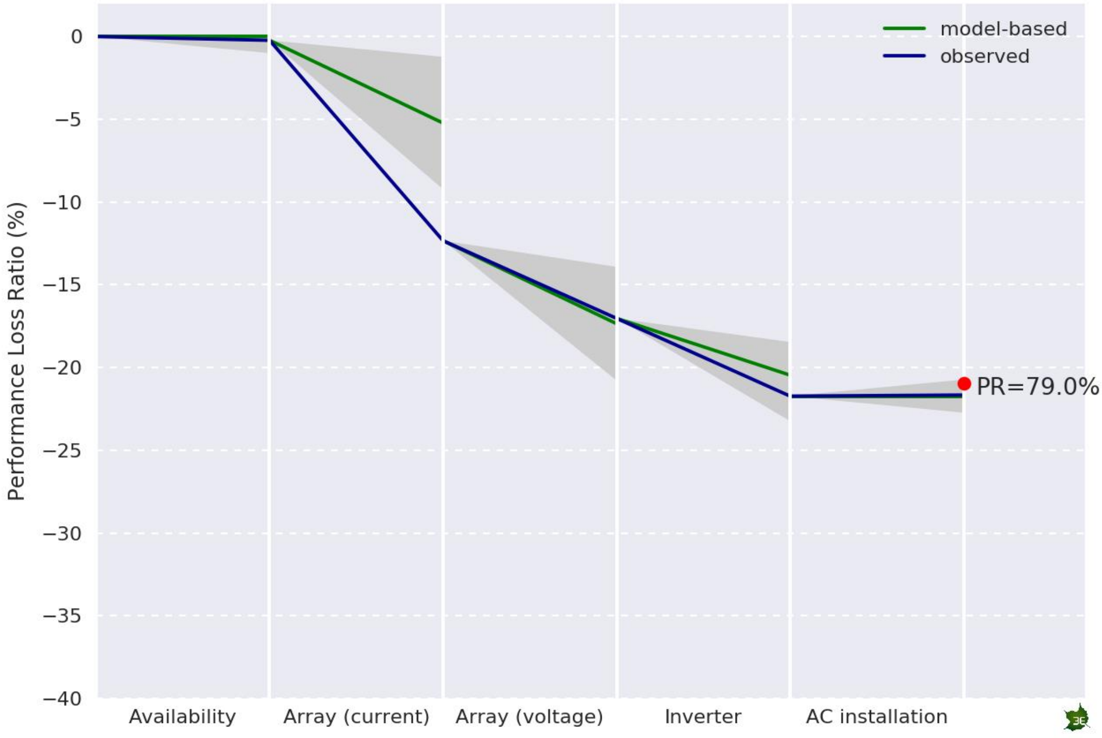


Figure 27: Waterfall diagram of Performance Loss split over the energy conversion chain (example)

For the statistical analysis, 600 plants were selected based on a number of criteria:

- Data is available for each of the required monitoring stages for all inverters of the plant.
- At least 90% of concurrent data availability during the year 2016 for all (relevant) data at all components and monitoring stages of the plant. In other words, data is assumed available for a given time stamp and plant only if all required datasets (at any stage and component) are present.
- A feasibility check confirms that the provided inverter and array configuration of the plant is complete and feasible and does not contradict with the measured data.

The 600 plants encompass exclusively commercial plants with a diversity of plant sizes, ages and configurations (distributed and central inverters, different array configurations, different inverter capacity ratings, rooftop and field installations, different azimuth and inclination of PV panels). The inverters and PV modules originate from various manufacturers. The plants are installed, owned, operated and maintained by various installers, owners and O&M providers. The plants are mainly located in Belgium, France, Italy, Greece and UK. The vast majority of plants contained crystalline PV modules.

For each of the plants, the performance loss components at each stage is calculated. Satellite irradiance data from 3E's commercial Data Services[11] was used as an independent and consistent reference for the irradiation. Figure 28 shows the cumulative probability density curve for each of these performance losses as observed for the 600 plants. Also shown is the total performance loss, corresponding to the sum of the loss stages and equal to 100% minus the performance ratio (disregarding ac cable losses).

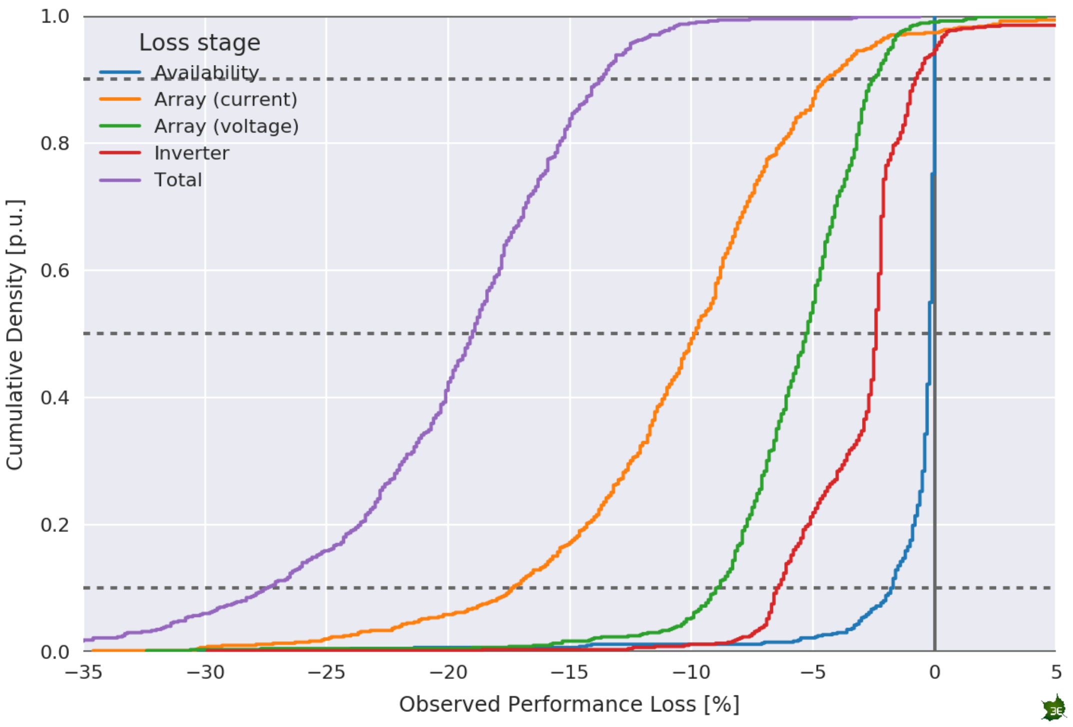


Figure 28: Cumulative probability density curve of the performance loss observed at each stage

The horizontal dashed lines correspond with the 90% (P90), 50% (P50) and 10% (P10) percentiles. The values corresponding with these levels are summarized in Table 1.

Table 19: Observed P90, P50 and P10 performance loss ratios for each stage

	P90	P50	P10
Availability	-1.7%	-0.2%	0.0%
Array (current)	-17.3%	-9.9%	-4.5%
Array (voltage)	-8.9%	-5.3%	-2.5%
Inverter	-6.4%	-2.4%	-0.8%
Total	-27.4%	-19.0%	-13.7%

Thus, the median (P50) observed performance ratio was 81%, with the P10 at 86.3% and P90 at 72.6%. It should be noted that these values are based on measurements performed by the inverters and are thus affected by measurement errors. Especially, the P10 value of -0.8% for the inverter loss is too optimistic and merely a result of (relative) error magnification when subtracting

[11] 3E Data Services – Solar Resource Data, https://solardata.3e.eu, 28/02/2017.

two nearly equal values. Also, the P90 and P50 availability loss values are too optimistic as timestamps where (part of) data was lacking (which are often, but not always accompanied by plant unavailability) where disregarded.

The Array (current) loss is responsible for half of the total performance loss, followed by the Array (voltage), Inverter and finally the Availability loss. The spread between P90 and P10 is determined by the different loss stages in the same order of importance, but with Array (current) loss playing an even more dominant role. And this already dominant role of Array (current) loss becomes even more prevalent when evaluating the uncertainty (or risk) by comparing the observed loss with the expected loss as shown below.

Based on the data provided in the monitoring platform, reasonable models could be made for expected inverter and array (voltage) loss based on datasheet specifications. The accuracy of these models is limited by the information provided in these datasheets, especially with regard to the dependency on environmental and electrical conditions. The observed versus expected performance loss of array (voltage) and inverter for all analysed plants are shown in Figure 29 and Figure 30, respectively. Whereas not perfect, a clear correlation between observed and expected values can be observed, with the trendline over all plants approaching the perfect model (dashed line). Deviations for the inverter performance loss are partly attributable to measurement errors (remark e.g. the positive observed values) and partly due the dependency of the inverter efficiency on DC input voltage, which was not considered in the model. Deviations for the Array (voltage) loss are due to non-perfect modelling, under- or overestimation of PV module temperature, PV module tolerances and deviations from datasheet specifications, degradation, mismatch losses, operation outside Maximum Power Point and various failures (e.g. bypass diode short-circuit failures).

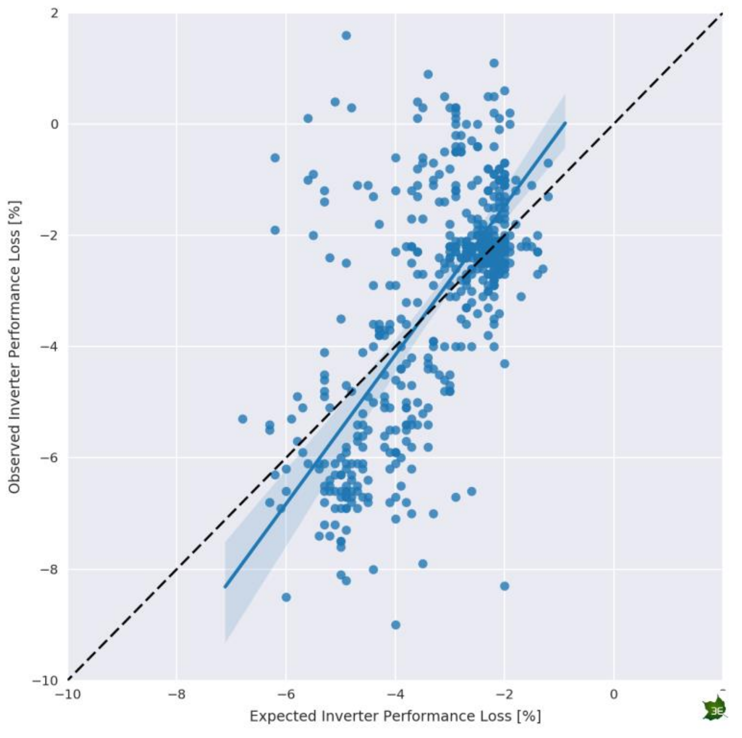


Figure 29: Observed versus expected inverter performance loss

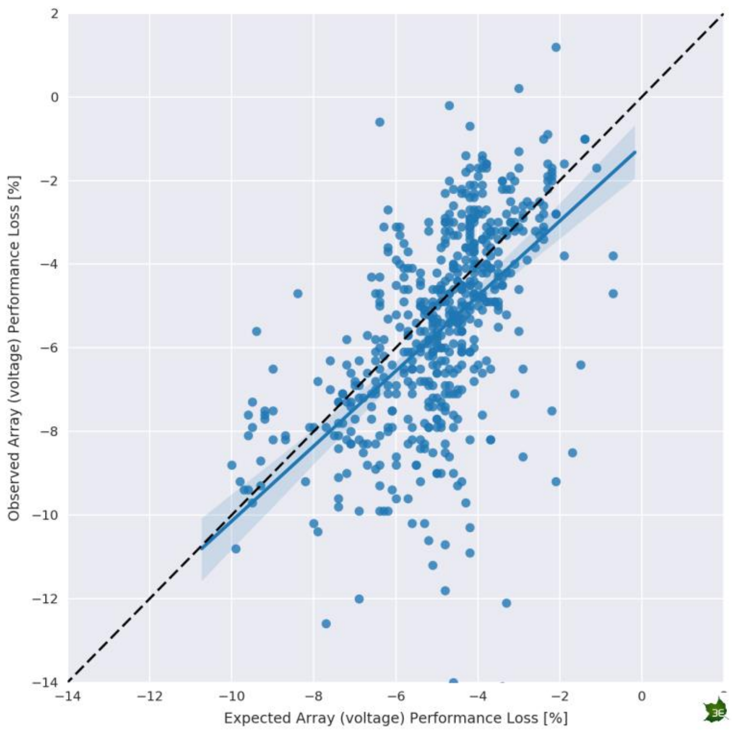


Figure 30: Observed versus expected Array (voltage) performance loss

The Array (current) loss is mainly a result from various optical losses, such as shading, soiling and reflection losses. Other factors that play a role are string faults, degradation, PV module mismatching, losses due to operation outside the Maximum Power Point and errors in the assessment of irradiation (from satellite) and/or DC current. Accurate models for these losses are rarely available. Even when models for these losses exist in literature (e.g. inter-array shading), they often require detailed site-specific information which was not available for this analysis. Similarly, availability losses could not be modelled. Therefore, due to the lack of good models, the uncertainty of Array (current) and availability losses is basically determined by their spread in Figure 28.

Correlations between Array (current) loss and various parameters such as location, orientation, plant age and array configurations were investigated but the results were non-conclusive.

The Array (current) loss shows a relatively large variability not only when comparing distinct plants, but even (though to lesser extent) when comparing the individual strings or inverters of a single large PV plants, as shown in Figure 31 for one exemplary plant with uniform configuration but with slight differences in (inter-array) shading conditions. This further underlines the difficulty in reducing the uncertainty associated with the Array (current) loss.

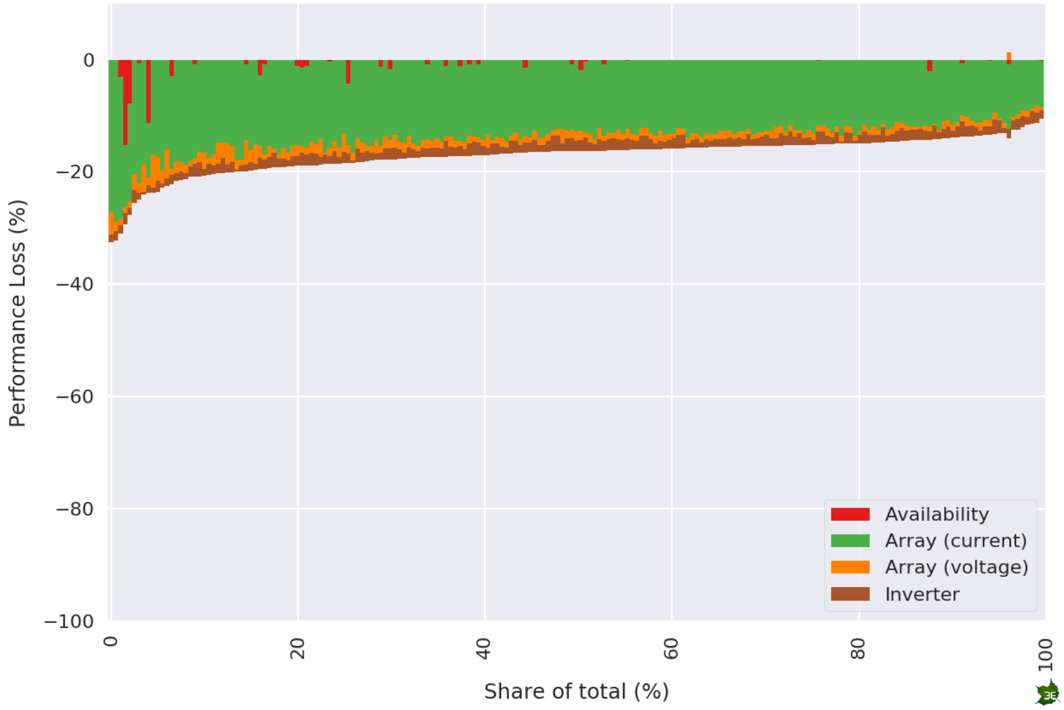


Figure 31: Stacked loss diagram of individual inverters at a large PV plant

7.4) Conclusions from Monitoring Data

The analysis of the inverter replacements logged by the SynaptiQ monitoring system on inverters (<100 kW) from more than 2,000 commercial operating plants since 2010 shows relatively high replacement rates in the first few years after the inverters entered into operation. The replacement rate rapidly decreases from more than 4% in the first year to less than 1% in the fifth year of operation, indicating that most replacements are linked with early failures. The replacement rate is highly variable, depending on the installation year, inverter brand and model. Comparing inverter replacements between different manufacturers reveals big differences in service strategies. Some manufacturers show very low replacement rates close to zero; this is a result of service practice replacing components of the inverter instead of replacing the full inverter. Also for most large inverters (>100 kW) this is common practice; however, it is also the service practice for small and medium-size inverters from some specific manufacturers. Unfortunately, component replacements are not captured by the above analysis as these are not logged by the monitoring system.

The analysis of monitoring data from 600 plants shows that roughly half of the total performance loss is attributed to the DC current, with the remaining to be found in the DC voltage, inverter and availability. The DC current is also responsible for the largest spread in performance loss between different plants. Whereas fairly accurate models exist for DC voltage and inverter losses, accurately modelling the DC current of the plant in operation remains a challenge. It would require detailed information on plant-specific parameters, e.g., (inter-array) shading, the STC current per module, the STC current's dependency on the angle of incidence.

7.5) Link to Financial Figures

Historically, O&M has often been considered an added cost by plant owners and investors. To achieve higher levels of reliability and reduce deviations from the cash flow model, sound O&M strategies need to be incorporated into PV system planning, design, and asset management activities. More systematic adoption of O&M best practices into evolutionary phases of PV plant development has the potential to better recognize the cause and effect relationships of the failures that can, in turn, help to increase the product quality and long-term reliability, while reducing the O&M costs over the lifetime of a PV plant. As PV assets change hands over the course of their lifetimes, well-documented O&M activities will furthermore be required to ensure that the best financial outcomes are consistently realized for both asset and buyers.

8) Lesson Learnt from Failure Collection

In this report a methodology for the calculation of the economic impact of technical risks is reported. The quality of the analysis is strictly limited to the amount of data available in the database, for various market segments, geographical spread, year of installation, etc. The granularity of the statistical analysis strongly depends on the quality and quantity of the collected data. In principle the methodology would allow for the analysis of failures for different PV module technologies or PV inverter manufacturers. However, this is not part of the objectives within the Solar Bankability project. In addition, the probability distribution function of a specific failure could be derived.

The collection of meaningful data for good analysis is a difficult task as it is not common practice in the industry to implement a detailed recording of the failures along the PV project lifetime at this moment. Thus, the quality of the data collected and the level of details vary from source to source. Ideally, during the process of failure detection and correction, an automatic ticketing system should be in place. This is not always the common practice and the collection of a high number of failure data for statistical analysis should also consider existing failure reports, which might come in paper form and may not include all the necessary information.

Most of the available data of collected failures in the field comes in fact in paper form where the need for digitalisation was highlighted. An electronic database would allow to better document the status of each plant and understand if the plant is prone to failures or if a particular failure is dominant over others for a specific component. The complete configuration plan of the plant should also be ready for consultation so that the number of components can easily be included in the failure report. In Appendix 3 we have provided a form which could serve as a template for failure collection to be used by experts who carry out maintenance work in PV plants. This template linked to the risks as listed in Appendix 2 represents a first step towards a common approach in harmonized failure collection.

9) Conclusions

In this report the most important technical risks related to PV projects were identified and included in a risk matrix organised by components and divided into 5 categories to cover the whole PV value chain: product testing / development, PV plants planning / development, transportation / installation, PV plant operation and maintenance, decommissioning. The allocation of the risks to a risk matrix is considered a fundamental step to enable the possibility to share failure data based on an agreed nomenclature and definition by different stakeholders. The prioritisation of the risks was not estimated by following a classical FMEA approach by assigning a RPN value, but by developing a methodology that was never previously applied to PV systems, a ***Cost-based FMEA with Cost Priority Numbers***. CPNs are given in €/kWp or in €/kWp/year and can thus directly give an estimation of the economic impact of a technical risk.

The CPN methodology was defined in order to assess two main economic impacts of a specific failure: ***impact due to downtime*** and ***impact due to repair / substitution cost***. For the calculation of C_{down}, parameters such as time to detection, time to repair, repair time were considered, while for C_{fix}, cost for detection, labour cost, cost of repair / substitution, cost of transportation were included. As a result, the overall CPN value for various components and failures would correspond to the cost of O&M for various scenarios. The methodology also considers the year of installation, the year of failure and the nominal power in order to be able to run analysis for different market segments and to evaluate the distribution of failure probability once the available data in the database reaches statistical relevance to this type of granularity. The methodology also considers other statistical parameters such as the number of affected plants and the number of components in affected plants; in this way it is possible to understand if a specific failure is PV plant dependent or if it is equally present over the whole PV plant portfolio.

The CPN methodology can only be applied to failures with a direct economic impact to the business plan either in terms of reduced income due to downtime or costs for repair or substitution. However, the technical risks included in the risk matrix which cannot be described with a CPN are also very important and have to be considered as they might have an impact on the CPN value of other component failures. For example, technical risks related to monitoring system, spare parts, normative and documentation, insurance reaction time, operation and maintenance contract, video surveillance, detailed field inspection (IR, EL, etc.), can reduce or increase the time to detection or the time to repair/substitution and might have an impact on the detection costs. A thorough analysis was carried out in relation to mitigation measures and is covered by the other deliverables of this project, available since August 2016.

Other risks can have an impact on the overall uncertainty during the initial energy yield calculation and assessment. A reduced uncertainty can in fact correspond to a higher level of energy yield for a given exceedance probability value (given as Px) and thus directly impact the business model. In this report, the typical uncertainties related to the main parameters affecting the energy yield were given together with an analysis on how the distribution function of a specific parameter might influence the exceedance probability. Works in literature have shown the importance of providing the industry operating in the field with a common framework that can assess the impact of technical risks on the economic performance of a PV project.

In the next years, as the availability of measured data will exponentially increase, it will be important to build large databases with potentially a uniform method to increase the confidence level of the statistical analysis and thus reduce the perceived risks for investors. With the availability of these large databases the necessary information (minimum requirements) can be filtered out to perform tailored analysis and evaluation in a uniform way i.e. same granularity, same data, same formulas. Our CPN methodology attempts to provide such a benchmark.

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APPENDICES

APPENDIX 1 - EXERCISE OF OCCURRENCE

A challenge in the FMEA lies on how to define the evaluation parameters – cost, severity, occurrence, detectability, time to repair, etc. We have found from the preliminary exercises that these indicators are opened to a very wide range of interpretations. In assigning the occurrence number for example, it is important to understand in which context the failure occurrence is expressed against. The percentage of failures will change depending on whether the failure occurrence is calculated over a certain period of time, or based on the number of components in a plant, or with respect to the nominal power of the plant. To address this matter, the consortium has therefore started a “round robin” exercise using the failure list we have created. In this exercise we will analyse the failure occurrence calculated based on two different datasets:

1. One failure event (ticket) per plant for many plants,
2. Many failure events (tickets) for the same plant.

Figure 26 shows the results of the occurrence normalised over the number of tickets. The incidence of failures for the component “Module” and “Inverter” is similar with around 30-35% of occurrence. Figure 32 shows the comparison of the normalisation over the number of tickets with the normalisation over the number of related components. Two different messages can be extrapolated from this specific exercise. When there is a failure, the likelihood to be related to the component “Inverter” or “Module” is similar. At the same time, the incidence of failures over the total number of the related component is much higher for inverters than for modules and it gives indication on the reliability of a specific component.

The results of this exercise helped in achieving a common definition of occurrence. Similar effort was also needed for the definition of severity and detectability.

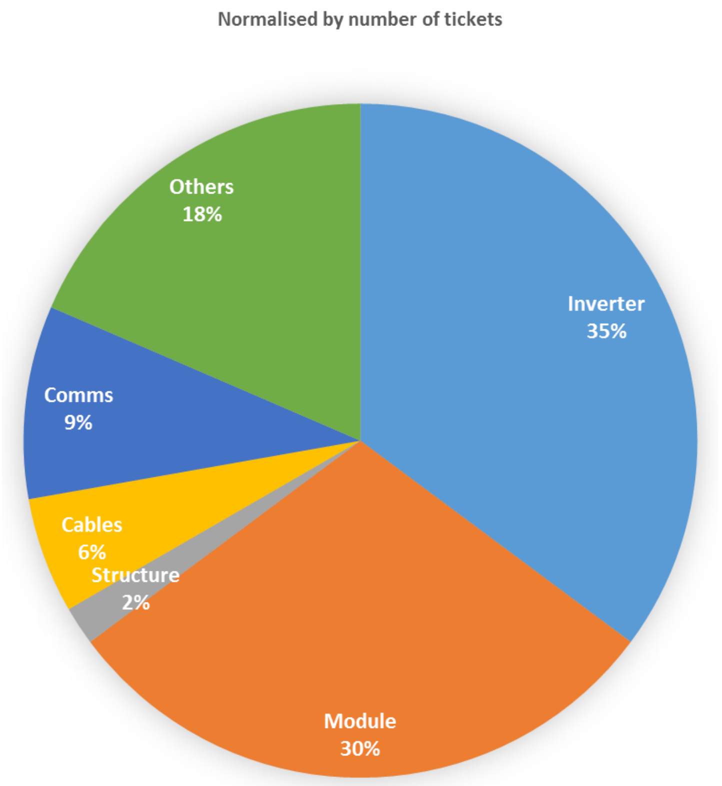

Figure 32: Results of occurrence normalised over number of tickets

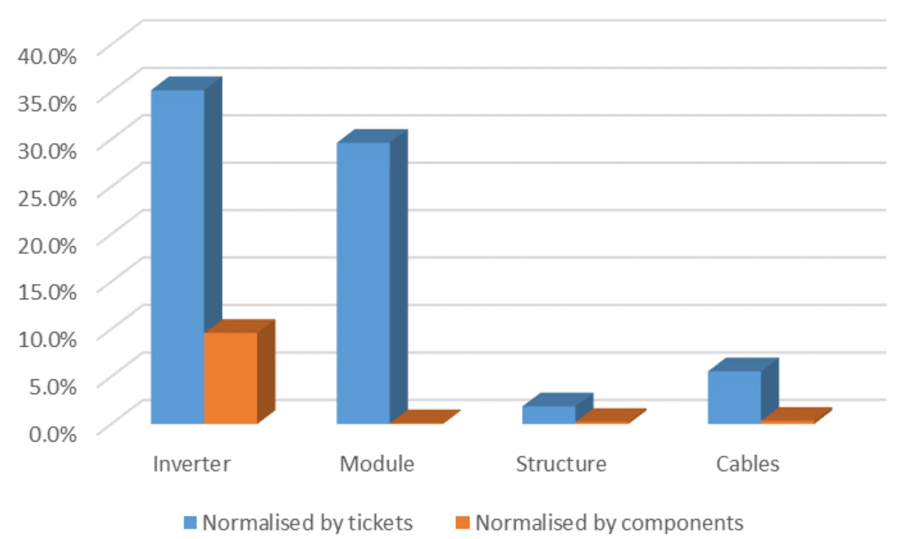

Figure 33: comparison between normalisation by components or by tickets

APPENDIX 2 - RISK MATRIX (VERSION 1.0)

In this appendix, the failures included in the final version of the risk matrix as presented in Chapter 3 are listed with a short description. The aim is to provide a step towards standardisation of the nomenclature used for failure description.

A. MODULES
Product testing / development
1. Failed insulation test - modules with failed or skipped insulation test can cause dispersive and dangerous currents, leading to safety risks.
2. Incorrect cell soldering – imperfections in cell soldering can lead, amongst others, to corrosion, undesired electrical resistances and bad current transmission.
3. Undersized bypass diode - increases chances of hotspots (overheating of cells) or the damage of the bypass diode itself.
4. Junction box adhesion - incorrect adhesion of the junction box can cause, amongst others, blocked connections interrupting module current, humidity ingress with subsequent corrosion leading to performance losses and increasing risk of electrical arcing and subsequent initiation of fire.
5. Delamination at the edges - water can ingress causing humidity, oxidation, corrosion leading to performance losses and increasing risk of electrical arcing and subsequent initiation of fire.
6. Arcing in a PV module - caused by damaged cell, can cause fire during the operation of the module.
7. Visually detectable hotspots - cells are overheating, which has a negative impact on the energy production of the module (module degradation).
8. Incorrect power rating (flash test issue) - sorting of the modules by performance will not be possible, PV modules mismatch losses undefined. High uncertainty of the nominal power of the PV plant and thus uncertainties of specific yield and performance ratio (PR).
9. Uncertified components or production line - life cycle, reliability and quality of PV modules can be significantly reduced.

10. Failure on mechanical load – modules with failed mechanical loading test are more prone to breakage due to wind, snow, and human mishandling.
11. Cell mismatch - interconnection of solar cells without identical electrical properties, within a module.
12. Cell overlap – can cause solar cell breakages due to the unequal thermal and mechanical expansion.
13. Bubbles – bubbles within the encapsulant material are generated by the release of organic compounds by polymers during the lamination phase. They can cause delamination.
14. Snail trails – snail trails are the result of chemical processes occurring at the silver-polymer interface, and depend by the quality of the encapsulant and the backsheet foil. They can become evident at or close to solar cells' micro-cracks.
15. Defective label of solar module – defective labels can detach or ink can bleach or vanish under outdoor conditions, leading to a lack of information for the operator. This might lead to safety risks.
16. Module label not explicit – labels without sufficient information for the operator can lead to safety risks.
17. Junction box broken - breakage of the junction box can cause, amongst others, blocked connections interrupting module current, humidity ingress with subsequent corrosion leading to performance losses and increasing risk of electrical arcing and subsequent initiation of fire.
18. Solar cell broken – solar cell broken can cause a lack of electrical connection within the cell itself or between cells, and have a negative impact on the energy production of the module (module degradation).
19. Potential induced degradation – modules prone to PID tend to degrade dramatically on the field when wrongly grounded, due to stray-currents.
20. Manufacturer's insolvency – the impossibility of warranty claim and the appropriate substitution of defective modules cause loss of the energy production.
21. Lack of manufacturer´s experience in the field – can cause unexpected power degradation of solar modules, with loss of energy production.
22. Incorrect assessment of module degradation – can lead to too optimistic warranty conditions, and cause

an unexpected loss of energy production.
PV plant planning / development
1. Soiling losses - less energy production due to soiling caused, amongst others, by pollution, bird droppings, and accumulation of dust and/or pollen. Its impact is strongly site dependent.
2. Shadow diagram - needed to design the right layout of the PV plant. Shadowed modules can have negative impact on the production.
3. Modules' mismatch - caused by interconnection of solar cells or modules without identical electrical properties or conditions (due to soiling, shadow, etc.).
4. Modules not certified - no quality warranty, modules of unknown origin.
5. Flash test report not available or incorrect - sorting of the PV modules not possible, mismatch losses undefined.
6. Special climatic conditions not considered (salt corrosion, ammonia, etc.) – can have a negative impact on the lifecycle of all components of the PV plant.
7. Incorrect assumptions of module degradation - Light induced degradation unclear may lead to high uncertainty of energy production.
8. Quality of module production unclear (lamination, soldering, etc.).
9. Simulation parameters (low irradiance, temperature, etc.) unclear - missing module or inverter files for simulation software (e.g. module PAN files or inverter OND files for PVSYST) - data should be reliable and certified.
10. Glass breakage – can be caused by the wrong design of clamp shape and dimensions, and clamps positioning. Glass breakage causes loss of performance due to cell and electrical circuit corrosion, leading also to safety issue.

11. Modules weight – when excessive modules weight is not considered, there is a risk of collapse of the underlying structure (roof) with consequent safety issue.
12. Mechanical resistance - modules with insufficient mechanical resistance can more easily break due to wind, snow, and human mishandling.
13. No protection against reverse current – reverse current can lead to excessive temperature within the module, with consequent loss of energy, risk of module breakage and risk of fire.
14. Different types of modules – connection of modules with different electric properties and performance degradation can lead to a mismatch and therefore to a loss of energy production.
15. Lack of experience in the field – unexperienced designers increase the risk of unappropriated design of PV systems, with consequent loss of energy production as well as increased safety risk.
Transportation / installation
1. Module mishandling (Glass breakage) - incorrect transportation – logistics may lead to damaged module components.
2. Module mishandling (Cell breakage) - incorrect transportation – logistics may lead to damaged module components.
3. Module mishandling (Defective backsheet) - incorrect transportation – logistics may lead to damaged module components.
4. Bad wiring without fasteners – mechanical tension that may lead to loose connections and even permanent disconnection of modules/strings causing subsequent performance loss and safety risks.
5. Soiling – installation in a dusty environment due to ongoing construction work can lead to energy losses.
6. Breakage during transport and installation – power degradation of the module with respect to the factory condition.

7. Modules fixing system - inadequate clamps positioning and excessively tightened screws can lead to glass breakage.
8. Module frame damage.
9. Module plug connectors substituted – substituting the original connector with a new one can cause power loss and electric arcs with consequent fire and safety risk.
10. Incorrect connection of modules – incorrect connection of module may cause damage to the bypass diodes, cable and junction box, with consequent fire and safety risk, and energy loss.
11. Short circuit or defect at modules - may cause damage to the bypass diodes, cable and junction box, with consequent fire and safety risk, and energy loss.
12. Scratches at front glass – scratches at front glass deteriorate glass transparency, and might be also associated with (micro)cracks at solar cell level, with consequent loss of energy.
13. Special climatic conditions not considered (salt corrosion, ammonia,...) – aggressive environment, not duly considered, can increase the module's power degradation.
Operation / maintenance
1. Hotspot - overheating of cells etc. can cause burn marks. Temperature difference between neighbour cells should not be over 30°C. Infrared cameras can be used for imaging the defects of the modules. Hotspots can also identified by visual inspection from the rear side of the module.
2. Delamination - separation of cells from tedlar, usually caused by insufficient lamination process e.g. too short lamination times. Humidity can be induced and cause oxidation, corrosion etc.
3. Glass breakage - during operation due to thermal shock, mishandling by the operator, etc.
4. Soiling losses – due to operational conditions: e.g. smog, sand particles, bird droppings, etc. Its impact is strongly site dependent.

5. Shading losses - during operation due to growing vegetation on the front side of the module, object recently installed.
6. Snail track - discoloration effect, mainly caused by micro cracks in solar cells. Can be only detected by visual inspection or electroluminescence (EL) of the PV modules.
7. Cell cracks - due to mechanical or thermal loads. It can be detected during EL image inspection of the module.
8. PID = Potential Induced degradation - when the charged atoms are driven, from voltage potential and leakage currents, between the semiconductor material and other components of the module e.g. frame, glass etc. Low fill factor measurement might indicate PID phenomenon.
9. Failure of bypass diode and junction box - may cause heating of the cells, or reduce the generated energy. The defective diode can be detected by opening the junction box or by measuring the open circuit voltage of the module.
10. Corrosion in the junction box - may cause defective bypass diodes leading to a significant reduction of the produced energy and increasing risk of electrical arcing and subsequent initiation of fire.
11. Theft or vandalism of modules - significant reduction in the energy production.
12. Module degradation – may lead to lower energy production than predicted.
13. Slow reaction time for warranty claims, vague or inappropriate definition of procedures for warranty claims.
14. Spare PV modules not available or module manufacturer no longer existing or producing - costly string reconfiguration may contribute to additional costs for repair.
15. Defective backsheet – defective backsheet can cause delamination and/or glass breakage, with consequent risk for safety and loss of energy.
16. Overheating junction box – overheating of junction box can cause fire, with consequent safety risk and energy loss.

17. EVA discoloration – EVA discoloration might contribute to the module power degradation.
18. Special climatic conditions not considered (salt corrosion, ammonia, hail, ...) - aggressive environment, not duly considered, can increase the module's power degradation.
19. Unfortunate sorting of module power.
20. Damage by snow – excessive snow load can cause module breakage.
21. Insufficient theft protection – theft of module can cause dramatic energy loss, and safety risk.
22. Broken modules due to atmospheric agents (wind, hail, snow, etc).
23. Wrong modules - Wrong installation – can cause an excessive stress to BoS components with consequent risk of energy loss, fire, and - more in general – safety risk.
24. Module damaged due to fire - can cause dramatic energy loss, and safety risk.
25. Missing modules - cause dramatic energy loss.
Decommissioning
1. No product recycling procedure defined or implemented.
2. Higher costs of different module technology.
3. Capacity to recycle module.

B. INVERTERS
Product testing / development
1. Inverter derating might start at approximately 40 °C working temperature - Temperature derating occurs when the inverter reduces its power in order to protect the sensitive semiconductor components from overheating. The power is reduced in steps and in extreme cases the inverter will shut down completely. This procedure is working properly if the temperature sensors and DC operating voltage are properly set up in the device software during the manufacturing process.
2. Maximum Power Point Tracker (MPPT) issues - During the manufacturing process and certification of the inverter the software architecture does not fulfil the technical requirement. As a consequence the inverter's software is not able to properly run the MPPT procedure. This leads to inaccuracy when following the Maximum Power Point, in case of variable weather conditions or different relative Maximum Power Points.
3. Overheating – when temperature derating fails to protect inverter components and it reaches the maximum admissible temperature, the inverter suffers severe damage with consequent energy loss.
4. Master/slave operation issues – master/slave operation allows the switching on of a required number of inverters as long as the incoming irradiance increases. This way, the overall efficiency improves because all inverters are operated at their optimum efficiency level.
5. Manufacturer´s insolvency - the impossibility of warranty claim and the appropriate substitution of defective inverters cause loss of the energy production.
6. Lack of manufacturer´s experience in the field - can cause unexpected degradation or faults of solar inverters, with loss of energy production.
7. Low production quality/serial defects - can cause unexpected degradation or faults of solar inverters, with loss of energy production.
8. Marking of inverters – solar inverters without sufficient marking can lead to safety risks.

PV plant planning / development
1. Inverter wrongly sized – Not properly considered during the planning of the electrical characteristics of the conversion group. The maximum voltage of the PV module string has to be calculated not only at nominal temperature of 25 °C, but also considering the temperatures at operating conditions. This is especially important for the early hours in the morning. Wrong dimensioning of the inverter may lead to dangerous over voltages and to the breakdown of the device or void of warranty.
2. No protection against overvoltage - Overvoltage protection serves to prevent damage to the inverters as a result of excessive voltages. It is intended to prevent damage to buildings and the photovoltaic system due to lightning strikes. Overvoltage protection is strictly required in case of photovoltaic plants installed on buildings and in any case, it is recommended to carry out a risk analysis for ground mounted PV plants.
3. IP number does not comply with installation conditions - The IP codification defines the operating conditions of electrical devices. As a component of a PV installation the inverter could be installed outside or inside the building, room, cabinet, etc. For the same device, mainly inverters, it could have both configurations indoor/outdoor, following the technical requirements of the inverter installation.
4. Inverter cabinet not sufficiently ventilated - Air is supplied through the fan grills inside the inverter to cool down its operating temperature. The exhaust air is emitted through the ventilators and must be ducted away from the device to avoid power derating and possible thermal damage which may lead to short circuits. Inverter manufacturers recommend a sufficient airflow around the device and, especially for central inverters, the installation of a ventilation system into the inverter cabinet. On-site measures must be taken to ensure that supply air and exhaust air are ducted separately and that there is always an adequate supply of fresh air.
5. Inverter wrongly sized - excessive derating. Low performance operating area - The optimal sizing ratio according to specific yield will vary from system to system, based on the designers' allowances for the various derating factors. It is common in industry to oversize the PV array by using a PV array/inverter sizing ratio of around 1.15. Oversizing the array ensures that the inverter is driven always to its maximum output, at least during the best sun hours of the day. Going above a limit value of 1.3 bring the inverter to the limit operating conditions with consequences of overheating and a power derating.
6. Inverter exposed to direct sunlight - Derating - To prevent overheating, power derating caused by exposure to direct sunlight must be avoided. Typical examples are: inverters installed in locations exposed to direct sunlight, locations without air circulation and inverters installed one above the other. These situations lead to a localised increase in operating temperature.

7. Non-availability of spare parts - Especially for large PV installations, the probability of one failure during 20 years' lifetime should be considered. Therefore, it is recommended to consider already in the planning phase the availability of a minimum number of spare parts or components. This will lead to a significant reduction of the plant downtime.
8. Special climatic conditions not considered (altitude, temperature, salt mist near the sea, etc.) - the installation manual of the inverter must be respected; void of warranty is possible.
9. Simulation parameters (low irradiance, temperature dependencies, etc.) unclear - this might lead e.g. to wrong sizing of the inverter and hence to reduced production.
10. PID Degradation is a potential induced performance degradation in crystalline PV modules. The cause of the harmful leakage currents, besides the structure of the solar cell, is the voltage of the individual PV modules to the ground. The installation of an inverter with transformer can be considered as mitigation measure for the PID phenomenon. On the other hand, the trade-off with the inverter efficiency and the cost of the inverter must be taken into account.
11. Overheating - when temperature derating fails to protect inverter components and it reaches the maximum admissible temperature, the inverter suffers severe damage with consequent energy loss.
12. Low performance operating area.
13. Maximum voltage limit exceeded by open circuit voltage of the PV array – the inverter might suffer severe damage with consequent energy loss.
14. Marking of inverters - solar inverters without sufficient marking can lead to safety risks.
15. Inverters distances - the installation manual of the inverter must be respected; void of warranty is possible.
16. Inverters orientation.
17. Missing water protection.
18. Manufacturer´s insolvency - the impossibility of warranty claim and the appropriate substitution of defective inverters cause loss of the energy production.

19. Lack of manufacturer´s experience in the field - can cause unexpected degradation or faults of solar inverters, with loss of energy production.
20. Safety class or enclosure IP rating not appropriate for site erection – inverters might be installed in a unsuitable environment with regards to water and dust penetration, with risk of energy loss and for safety.
21. Accessibility to inverter cabin by road.
Transportation / installation
1. Inverter configuration (e.g. parallel versus independent MPP tracker, global MPP tracking) - the configuration must be according to manufacturer and parallel MPP tracker must be avoided if it is possible.
2. Fuse is not adapted to the cross-section - this might cause the damage of the cable or the damage of the fuse
3. Missing contact protection - due to missing parts or forgotten to be installed. Dangerous situation for the personnel working at the PV plant.
4. Inverter does not include surge protection - damage of the electronic equipment of the inverter might occur. If there are no SPDs in the DC and AC side of the inverter, due to wrong PV planning development, great loss of production might occur
5. PID = Potential Induced Degradation. Can be prevented by grounding the positive or negative pole of galvanically isolated inverters.
6. Not appropriate installation (IP requirements not accomplished, overheating) - the inverter might suffer severe damage with consequent energy loss, and safety risk.
7. Overheating - when temperature derating fails to protect inverter components and they reach the maximum admissible temperature, the inverter suffers severe damage with consequent energy loss.
8. Unequal inclinations.

9. Missing dummy plug.
10. Missing inverter connector – the inverter cannot be connected, with consequent energy loss.
11. Unstable installation.
12. Low insulation value - can cause dispersive and dangerous currents, leading to safety risks.
13. Corrosion on retaining bolts.
14. Strain relief missing.
15. Safety class or enclosure IP rating not appropriate for site – can cause energy loss and safety risk.
16. Special climatic conditions not considered (altitude, temperature, ...) - the installation manual of the inverter must be respected; void of warranty is possible.
Operation / maintenance
1. Fan failure and overheating - may cause the temperature derating and reduce the production. Following the inverters' error message, appropriate measures must be taken immediately.
2. Switch failure/damage - due to many operations or defect from the manufacturer, etc. The disconnection of the inverter or the PV modules connected to it (for maintenance or troubleshooting purposes), requires more complex procedures leading to safety risks.
3. Inverter theft or vandalism - Theft or vandalism are frequent events concerning PV installations, especially in ground-mounted systems installed in remote areas. These criminal acts can force the plant to stop for several weeks and are extremely difficult to prevent. Beside the technical replacement of the stolen electrical components, there is a non-negligible work updating the plant documentation with new inverter datasheet or serial number.
4. Fault due to grounding issues, e.g. high humidity inside the inverter.

5. Inverter firmware issue - updating the firmware for technical reasons and to update the system to new standards/grid technical requirements.
6. DC entry fuse failure causing PV array disconnection - due to undersizing of the fuse or oversizing of the PV array.
7. Inverter not operating (inverter failure or inverter stops working after grid fault) - due to wrong configuration or malfunction of the inverter.
8. Inverter damage due to lightning strike - European standards require the protection of metallic structures and electronic devices against lightning strike. The anti-lighting system protection can protect the plant for being stopped for several weeks and substitution of expensive components.
9. Slow reaction time for warranty claims, vague or inappropriate definition of procedure for warranty claims -. The definition of clear procedures in case of theft, vandalism, component breakdown, is fundamental to act quickly and efficiently, replacing or repairing system components. Clear definition of subjects involved at different levels and their responsibility (ownership, system installer, O&M, component/service supplier) should help to elaborate and close the claim in a short time period.
10. Inverter Subunit failure.
11. Low performance operating area – due to wrong configuration of the inverter.
12. Auxiliaries power charger failure.
13. Polluted air filter – a polluted air filter might trigger inverter derating.
14. Inverter pollution.
15. Error message.
16. Inundation damage.
17. Vague or inappropriate definition of procedure for warranty claims.

18. Special climatic conditions not considered (altitude, temperature, ...).
19. Snow damage.
20. Lack of or inappropriate consideration of inverter repairs or substitution (s. 8 Phase II).
21. Data entry broken – measured parameters not available for analysis and alarm generation.
22. Display off (broken or moisture inside of it) – lack of status information for the operator can lead to safety risks.
23. Wrong connection (positioning and numbering) – can lead to a misinterpretation of measured data, leading to an inefficient intervention and to energy loss.
24. Burned supply cable and/or socket - the inverter might suffer severe damage with consequent energy loss, and safety risk.
25. Inverter wrongly sized - wrong dimensioning of the inverter may lead to dangerous over voltages and to the breakdown of the device or void of warranty.
Decommissioning
1. Inverter size and weight - The standard WEEE (*Waste of electric and electronic equipment***)**, defines the inverter as electrical device. The sustainable decommissioning has to be considered technically and economically. Parameters such as easy access to the device, device locations in the PV system, inverter size and weight, become relevant planning input

C. MOUNTING STRUCTURES
Product testing / development
1. Mounting structure corrosion - The material reacts with the chemicals in the environment and leads to deterioration over time. As a consequence, the characteristics of the material have changed and the static requirements are no longer fulfilled.
2. Galvanization (zinc-layer) too low - During the galvanization process a protective zinc coating is applied on the material. The coating protects the material against ambient influences. The coating itself disintegrates over time and must be dimensioned properly. Therefore the on-site conditions and the exposure time must be taken into account. The corrosion resistance of the material must correspond to the planned operating conditions.
3. No or incorrect structural expertise - Proof or documentation of the tested properties, durability, corrosion resistance, accuracy, manageability and resistance to weather and corrosion, must be available.
PV plant planning / development
1. Weak anchorage - might cause a great amount of energy loss especially in windy areas.
2. Roof and static analysis missing (roof mounted) - human life and installation are at risk. It is one of the important requirements from the insurance companies.
3. Incorrect dimensioning of cantilever - might cause delay of the project and add extra cost.
4. Ground and static analysis missing (free field) - important for the calculation of the piles and the mounting structure overall.
5. Sun shading angle - excessive inter-array losses - a compromise between the distance of the arrays and the inter-array losses should be aimed at.
6. No or incorrect structural expertise - may lead to an improper system installation which affect the static

properties of the mounting structure.
7. Overestimation of tracker accuracy - leads to discrepancy between the estimated and actual energy yield.
8. Manual change of tilt – requires seasonal intervention by the operator.
9. Short distance from roof edge – appropriate spacing must be assured in order for the operator to access modules at the lowest part of the roof under safe conditions.
10. Clamps on the short side – when clamps are used to install modules on the short sides, the load capacity is lower than the long sides, with risks of breakages.
11. Landscape/portrait installation – according to module technology and characteristics of near shading, module at landscape/portrait orientation can have different energy loss.
12. Insufficient foundation – subsurface terrain condition should be investigated adequately before planning the foundations. Inadequate foundations can lead to ground instability with risk of damages of components and collapse of the structure.
13. Low module clearance from ground – snow accumulation or flood can cause energy loss and/or severe damages and safety risks when involving components of a PV system under tension.
14. Safety measures on roofs – missing or incomplete safety measures can cause safety risks for the operators.
Transportation / installation
1. Small module distance – Mounting structures mounted too close to each other can lead to self-shading between modules
2. Mounting structure does not comply with static calculations – possible delay of the project and extra cost. If no measures are taken, the realization of the project overall is in question.

3. Screw not fixed – can cause decrease in load capacity with consequences on energy production and safety risks.
4. Damaged support pillar – can cause decrease in load capacity with consequences on energy production and safety risks.
5. Angular position of support pillar – can cause decrease in load capacity with consequences on energy production and safety risks.
6. Cover over the purlin is misaligned.
7. Low bearing surface – issues with load capacity with consequences on energy production and safety risks.
8. Frame parts not deburred – safety risks for operators.
9. Landscape installation.
10. Weighting is broken.
11. Bad numbering – can lead to errors in intervention by operators, with increase of costs.
12. Module clamp not fixed correctly - issues with load capacity with consequences on energy production and safety risks.
13. No or incorrect structural expertise - issues with load capacity with consequences on energy production and safety risks.
Operation / maintenance
1. Tracker failure - caused by mechanical problems, sensor, etc. Direct loss of energy and in case of big and high trackers, if they cannot go into safe position the construction is in danger due to high wind-force.

2. Damage due to excessive wind loads - cannot be avoided and must be considered in the insurance contract. Surveillance and monitoring are key factors for the claim.
3. Damage due to snow loads - the static study must consider the snow load and the amount of snow according to the location of the plant.
4. Tracker maintenance – inspection and maintenance of moving parts is important for the correct operation of trackers, to avoid loss of energy production. This should be done according to the manufacturer's specifications.
5. Earthquake damage.
6. Not appropriate installation - issues with load capacity with consequences on energy production and safety risks.
7. Damage during maintenance work (of the roof).
8. Misalignment caused by ground instability.
9. Corrosion - the characteristics of the material can change and the static requirements might no longer be fulfilled.
10. Oil leakage.
Decommissioning
1. Damage on the roof or land - restoration of the installation area should be considered.
2. Rotten structure difficult to recycle.

D. CONNECTION & DISTRIBUTION BOXES
Product testing / development
1. Cracking or rusted housing cover.
2. Material incompatibility.
3. Contact resistances at connecting points.
4. Diode selection / thermal stress.
5. Missing safety hint.
6. Protection class label is missing.
PV plant planning / development
1. Wrongly sized cable gland - If the cable gland is too large for the implemented DC main cable, the cable gland does not give any cable support, and the IP classification of the box is violated. All cable glands must fit to the diameter of the cables.
2. Wrong series fuses - The fuses protect the circuit against overcurrent by acting as a sacrificial device. The fuses must be designed for the maximum DC voltages and currents and must be appropriate in respect to the expected environmental conditions.
3. Climate valve is missing or incorrect installed.
4. Missing fault-current circuit breaker.
5. No weather protection.

6. Bad selection of DC fuse/poor quality.
Transportation / installation
1. Cable gland missing or not installed correctly - If the cable glands are not attached, the functions of the cable support and the IP classification are invalidated. All cable glands must be checked and fixed.
2. Missing and broken protection against electric shock - A touch protection against electric shock is required for live parts in connection and distribution boxes. Missing protection or broken protection must be replaced.
3. Incorrect or missing installation instructions and safety information.
4. Incorrect treatment of aluminium cables.
5. Lack of strain relief.
6. Missing locks.
7. GCB not in operation.
8. Missing certification Degree of protection (IP54).
9. Water in GAK.
10. Not used cable glands.
Operation / maintenance
1. IPS off.

2. Main switch open and does not reclose again automatically.
3. Cable gland missing or not installed correctly.
4. Missing protection.
5. Broken/Wrong general switch.
6. UPS off/broken.
7. Wrong wiring.
8. General switch off.
9. Wrong automatic recloser.
10. IPS not in compliance with laws.
Decommissioning
1. Rotten structure difficult to recycle.

E. CABLING
Product testing / development
1. Broken connector - should be checked and not delivered to the installation site. Otherwise this constitutes a high safety risk.

2. Corrosion in connector - should not be delivered to the installation site.
PV plant planning / development
1. Cable undersized - due to wrong calculations. Can reduce the produced energy especially when the current in the cable is higher than the nominal current of the cable. The cable might be damaged and cause losses of the energy production. In case of short circuit the cable might not withstand the I_{sc} and be destroyed, leading to safety risks.
2. UV protection cable - Polymers are prone to UV irradiation and after daily exposure they will crack and split over time. Therefore UV protection cables must be considered in case of outdoor installations while it is recommended in any case to have cables shielded from direct exposure to the UV radiation.
3. Different types of connectors – may lead to malfunctioning and reduced energy production.
4. Power line and data line are not separated.
5. Unprotected connector.
6. Cable in the ground.
7. Connection of PV modules (loops).
8. Deviation in cable cross-section.
9. Insufficient cable cross-section.
10. Different type of solar cables.
Transportation / installation

1. Different types of connectors - Different types (brands) of connectors are used often in practice. Besides the fact that they may not fit correctly, the durability of the connection is not certain. Thus, it is highly recommended that only connectors of the same type are installed.
2. Loose module or string cables - when the cables are hanging freely in the air then the connection points of the cables are likely to be damaged after a certain time leading to production losses and even safety risks.
3. Improper cabling - different failures during cabling installation which are not covered in this report and have only low negative influence on the plant.
4. Connector not properly mated - the continuity of the circuit is not guaranteed and may cause arcing leading to safety risks.
5. Open connector - the loop of the string is open resulting in a performance reduction.
6. Cables exposed to direct sunlight – especially in-between PV modules and arrays. The cables must be protected from direct sunlight. The insulation of the cable will be damaged after being exposed to UV radiation for a certain period.
7. Missing edge protection.
8. Cable extended.
9. Bending radius too small.
10. Inadequate labelling.
11. Improper insulation.
12. String cables laid under ground.
13. Cable protection conduit loose.
14. Cable conduit not closed.

15. Damaged cable.
16. Open cable ducts.
17. Wire mounting in vertical cable channel.
18. Cable conduit not laid in earth.
19. Green - Yellow tape for labelling.
20. Cable not protected against mechanical damage (DC underground cables).
21. Connecting of aluminium cable.
22. Loose cables with open ends.
23. Damaged cable insulation.
24. Missing cable lugs.
25. Strand cable damaged by roof tiles.
26. Connector gland not closed.
Operation / maintenance
1. UV aging - it happens when the cable is exposed to UV radiation. This phenomenon can be reduced by protecting the cables from direct exposure to sunlight.
2. Theft of cables - the surveillance of the PV plant and appropriate alarm concept may prevent it to some extent.

3. Broken cable ties - due to aging or improper installation. Spare parts at the installation should be considered during development phase. Broken cable ties must be replaced as they represent a safety risk.
4. Cables damaged by rodents - mostly underground when cables are installed without conduits or in the medium voltage (MV) or low voltage (LV) substation. The repair costs depend on the design of the plant. This may lead to a performance reduction and even a safety risk.
5. Wrong/absent cables.
6. Wrong connection, isolation and/or setting of strings.
7. Broken/Burned connectors.
8. Wrong/Absent cables connection.
9. Wrong wiring.
10. Cables undersized.
Decommissioning
1. Price of Copper.

F. POTENTIAL EQUALIZATION & GROUNDING, LPS
Product testing / development
PV plant planning / development

1. No grounding system installed - electrical or electronic equipment are in danger leading to a safety risk.
2. Inappropriate grounding system - when the design or the materials used for the grounding system are not appropriate.
3. Incorrect surge concept.
Transportation / installation
1. Missing or incorrect fixed potential equalization - due to lack of materials or improper supervision of the project. The installation should be potential equalized.
2. Corrosion at unprotected grounding connections - if the selection of the materials is not carefully done. The connection must be replaced and their continuity has to be checked.
3. Overvoltage arrester not connected to the ground - in case of overvoltage the installation is at risk since arresters cannot provide a path to earth, leading to a safety risk.
Operation / maintenance
1. Wrong setting of antielectrical and/or magthermic switches.
2. Broken fuses.
3. Broken magthermic switch.
4. Broken contactor.
5. Too high grounding value.

6. Broken antielectrical switch.
7. Grounding missing.
8. Connection missing/wrong.
9. Missing or incorrect fixed potential equalization.
10. Grounding, corrosion at unprotected grounding connections.
11. Overvoltage arrester not connected to the ground.
Decommissioning

G. WEATHER STATION & COMMUNICATION & MONITORING
Product testing / development
PV plant planning / development
1. No monitoring system installed - in order to reduce the costs of the installation. The remote monitoring of the plant will not be possible.
2. Shadow and soiling of irradiance sensors - should be avoided. The sensors should have similar properties as the modules have.
3. Inadequate or non-existent module temperature measurements or temperature assessment - these measurements are important since the efficiency of the modules is directly related with the module temperature. The evaluation of the quality and efficiency of the modules cannot be performed.

4. Inadequate or non-existent monitoring of DC voltage and current - Information will be missing, the monitoring and troubleshooting of the plant will not be performed based on analysis of sufficiently meaningful information.
5. Inadequate data logger - the data logger cannot handle all the provided information which leads to an incomplete overview of the performance of the plant.
6. Missing weather sensors, inadequate or non-existent irradiance, ambient/module temperature and wind speed sensors - alternative solution must be considered e.g. use of satellite data.
7. Different orientation between solar irradiation sensor and PV array – erroneous estimation of system performance.
8. Inadequate or non-existent ambient temperature measurement.
9. Disturbance on data communication – can lead to an incomplete overview of the performance of the plant.
10. Electrical outlets for measurements unprotected – can lead to safety risk for operators.
11. Junction box without UV protection – risk of damages in case of outdoor installations.
12. E-sensor not protected.
13. Sensors only partially suitable.
14. Module temperature sensor on non-representative PV module – the correct evaluation of the quality and efficiency of the modules cannot be performed.
15. Ambient temperature sensor not protected from direct sunlight – risk of damages.
Transportation / installation
1. Misalignment between the solar irradiation sensor and PV array - due to insufficient space or lack of

knowledge. The calculation of the PR as well as the evaluation of the produced energy will be incorrect. Irradiance sensors should have similar properties as the modules have.
2. Sensors not calibrated - should not be installed since their accuracy is undefined. This inaccuracy will have an impact on many performance indicators of the PV plant which may lead to erroneous conclusions.
3. Erroneous data and/or missing information implemented in the monitoring system - the quality of the data and the information implemented in the monitoring system should be validated.
4. Wrong information supplied to monitoring platform – the correctness and completeness of the information during the installation should be checked.
5. Soiling.
6. Inadequate module temperature measurement.
7. Inadequate ambient temperature measurement.
8. Disturbance on data communication.
9. Inadequate communication cables.
10. Not connected communication cables.
11. E-sensor fixed inadequately.
12. Pyranometer and Si-sensor connection cables not fixed appropriately.
13. Reference sensor must be adjusted.
14. Shadow ring is not adjusted – erroneous measurement of diffuse irradiance.
15. Communication cables not well shielded from EMI.

16. Inadequate attachment on PV module temperature sensor.
Operation / maintenance
1. Damaged sensor - must be detected and replaced. Spare parts or an alternative solution should be considered during the planning phase.
2. Monitoring system failure - possible defect on site will not be detected therefore troubleshooting is not possible.
3. Uncalibrated reference sensor - leads to incorrect assessments of the PV plant indicators. The sensors must be calibrated according to the manufacturer's specifications.
4. Reference sensor not in plane of array, orientation of irradiation sensor changed - incorrect information will be received. The sensors must have the same properties as the modules as far as possible.
5. Soiling over the solar reference sensor - usually from bird droppings. The error should be detected and the sensor should be cleaned. Regular monitoring of sensor operation is recommended if possible.
6. Data loss, monitoring system not available - can happen if the PV plant was offline for a long period of time or the memory of the data logger is not big enough. This fault can lead to wrong assessments of the annual energy yield and performance indicators.
7. Sensor shaded during part of the day - the properties of the sensor and of the modules must be identical as far as possible. Otherwise, the performance assessments will be incorrect. In this particular case, the PR value will be too high.
8. Erroneous module temperature measurement - the evaluation of the quality and efficiency of the modules cannot be performed.
9. Erroneous ambient temperature measurement - the evaluation of the quality and efficiency of the modules cannot be performed.
10. Data logger power charger failure – datalogging is interrupted, which leads to an incomplete overview of

the performance of the plant.
11. Data communication error or disturbance - incomplete overview of the performance of the plant.
12. Power monitoring is missing - incomplete overview of the performance of the plant.
13. Network Monitoring relays malfunction indicator light.
14. Sensor calibration time elapsed – erroneous measurements.
15. PV module temperature sensor detached – a temperature value close to the ambient one is measured in place of module temperature. This can bring to an erroneous evaluation of the quality and efficiency of the modules.
16. Monitoring concept does not allow detection of fault – an efficient and prompt detection of failure is not possible.
17. Broken or inappropriate counter kw.
18. Inappropriate installation.
19. Missing counter kw.
20. Data communication error.
Decommissioning

H. TRANSFORMER STATION & MV/HV

Product testing / development
PV plant planning / development
1. Insufficient clearance space around the transformer station - in order to save space for the modules or lack of expertise. Route should be sufficient enough for the transformer to be replaced.
2. Sizing of the Uninterruptible Power Supply (UPS) for the main protection device of the plant - if the UPS is undersized and the duration of a grid fault is long enough, the UPS will be empty, and consequently the PV plant will not be able to reconnect into the grid and produce energy.
3. Escape route is not sufficient for transformer station.
4. Access to transformer with standard key.
5. Cabin doors not grounded.
6. Missing socket outlet in the inverter station.
7. Accessibility to transformer cabin by road.
Transportation / installation
1. First aid sign not completed.
2. Labelling equipotential bonding.
3. Missing labelling.
4. Flammable materials in the transformer station.

Operation / maintenance
1. Broken transformer - can cause important energy losses (plant level). The plant might be offline for a long period of time until the transformer is repaired.
2. Lack of or inappropriate consideration of inverter repairs or substitution.
3. Wrong transformer configuration.
Decommissioning

I. INFRASTRUCTURE & ENVIRONMENTAL
Product testing / development
1. Inadequate protection from climbing over the fence.
PV plant planning / development
1. Technical approval not completed - this can delay or, under worst case scenario, stop the project.
2. Moving/transportation access difficult because of uneven ground - the access road to the plant for maintenance and troubleshooting should be taken into account in the design phase.
3. Non-standard lightning protection - standards and regulation must be considered according to the installation site. Ignoring this may lead to safety risks.
4. The conduit is laid over a fire protection wall - the installation is not according to the standards. In case

of a fire incident the area in not isolated and the fire wall does not function leading to a safety risk.
Transportation / installation
1. Lighting rod cross with solar cables.
2. Non-standard lightning protection.
3. Door system is defected or inefficient.
4. The conduit is laid over a firewall.
5. Missing protection mat.
6. The fences are bolted from the outside.
Operation / maintenance
1. Grid.
2. Fence damaged.
3. Bad weather conditions avoid control/maintenance operations.
4. Bad weather conditions cause plant stoppage.
Decommissioning

J. STORAGE SYSTEM
Product testing / development
1. Low quality storage system badly tested - the reliability of the installation is not ensured.
PV plant planning / development
1. Battery wrongly sized - due to lack of knowledge or cost savings - can reduce the life cycle of the battery or loss of produced energy because the batteries when battery are fully charged (PV modules in open circuit if not grid connected). Another issue might be that the batteries might not be able to cover the load.
2. Changes in load profile – The battery was sized for a specific load profile, which changes overtime. Load matching and/or share of self-consumed energy changes affecting the business model.
Transportation / installation
1. Storage system in not in ideal environmental conditions - The storage system is not allowed to be installed anywhere, the standards must be considered. Temperature is too high for the operative conditions of the battery system.
Operation / maintenance
1. Explosion of storage system - due to the nature of the material. Mitigation against explosion must be taken into account e.g. fire extinguishers.
2. Operational problem with PV inverters – The control logic or communication between the battery and the

PV inverter is not optimal or is not working.
Decommissioning
1. Hazardous material - to be transported to a recycling facility specialized for such materials.

K. MISCELLANEOUS
Product testing / development
PV plant planning / development
1. Irradiance over/underestimated - due to wrong measurements. Leads to incorrect performance indicators.
2. System documentation incomplete - as-built files should be made available on-site for future interventions.
3. Shading.
4. AC circuit diagram is missing.
5. Measurement protocols are not completed.
6. Failure of the Network Security Management.
7. Yield reports, AC lost.
8. Missing panic lock.

Transportation / installation
1. Disturbance on communication.
2. Disturbance on over communication.
3. PV warning sign is missing in the meter cabinet.
4. Waste on the plant area.
5. Unsecured hole.
6. Declaration as electrical operating area is missing.
7. Drainage without dirt pan.
8. Mounting residues.
9. Equipment damage.
Operation / maintenance
1. Surveillance system not installed - the security of the plant is not ensured. Possible intrusion of the property cannot be identified.
2. Inappropriate maintenance report, system documentation incomplete - if the maintenance report does not include all the necessary mitigation measures according to standards, the reliability of the plant is uncertain.
3. Fire - fire alarm, especially in the substation, must be considered.

4. Weather and natural disaster, force majeure events - these risk parameters can put the whole project in danger and should be taken into account in the insurance contract of the PV plant.
5. Normative.
6. Malfunction in UPS.
7. Power purchasing agreement final user bankruptcy.
8. Risk for cables by overgrowth plants.
9. Security camera is not in operation.
10. Failure of auxiliary power supply.
11. Equipment damage.
12. Lack of valid feed-in permit.
13. Inability of grid operator to accept the produced electricity.
14. Soil pH level, ground water – corrosion.
15. Plant stoppage for unspecific reasons.
16. Too high voltage in grid connection.
17. Recurring interruption for unspecific reasons.
18. No grid connection for missing components.
19. Wrong documentation.

20. Damage inside the building because of the wrong plant installation (water infiltration, holes, etc.).
21. Missing or wrong equipment for maintenance/substitution/installation operations.
22. Inappropriate roof for the installation.
23. Totally wrong installation of the PV plant.
24. Low production for unspecific reasons.
Decommissioning
1. Different norms in different countries.
2. Change in land destination.
3. Low end value of PV components.
4. Damage on roof.

APPENDIX 3 - TEMPLATE FOR FAILURE COLLECTION

The following Table is provided as a template to be used on the field by experts (EPC contractors, installers, O&M companies) in electronic or in paper form. It contains the minimum amount of required information towards a standardised failure collection.

Plant Information		
Power (Wp)		
Activation date		
N° inverters		
N° modules		
N° trackers		
Location		
Distance from the Intervention Centre		
On building		Ground mounted

Warning Information	
Date of warning	
Type of warning signal	

Intervention Priority	Low – Intervention within a week Medium – Intervention within 24 – 48 hours High – Immediate intervention
Loss of production	Yes No

Intervention Information		
Work Carried out during the intervention		
Used/Required Components		
<u>Description</u>	<u>Quantity</u>	<u>Cost per unit (Euro)</u>

Man Power		
N° technicians involved in maintenance work		
Cost per hour	………………………… Euro	
External company required	Yes No If yes, please write the cost ……………………………… Euro	
Intervention date	Hours for maintenance work	Hours for transportation
Notes:		

APPENDIX 4 – COST TABLE USED FOR THE CPN CALCULATION IN CHAPTER 6

	Failures	Time to detect [h]	Time to repair/substitution [h]	Repair/substitution time [h]	Power loss [%]	Multiplier
Modules	Hotspot	8760	744	2	2,00%	1
	Delamination	8760	744	2	1,00%	1
	Glass breakage	8760	744	2	10,00%	1
	Soiling	8760	744	0,01	10,00%	1
	Shading	8760	744	0,01	10,00%	1
	Snail track	8760	744	2	1,00%	1
	Cell cracks	8760	744	2	1,00%	1
	Defective backsheet	8760	744	2	1,00%	1
	Overheating junction box	8760	744	2	1,00%	1
	PID = Potential Induced degradation	8760	744	2	10,00%	1
	Failure bypass diode and junction box	8760	744	2	33,00%	1
	Corrosion in the junction box	8760	744	2	1,00%	1
	EVA discoloration	8760	744	0	0,00%	1
	Theft of modules	8760	744	0,5	100,00%	1
	Broken module	8760	744	2	100,00%	1
	Damage by snow	8760	744	2	100,00%	1
	Corrosion of cell connectors	8760	744	2	1,00%	1
	Improperly installed	8760	744	2	5,00%	1
	Missing modules	8760	744	2	100,00%	1
Inverter	Fan failure and overheating	8760	744	4	20,00%	1
	Switch failure/damage	8760	744	4	100,00%	1
	Inverter firmware issue	8760	744	4	0,00%	1
	Polluted air filter - derating	8760	744	4	20,00%	1
	Inverter pollution	8760	744	4	1,00%	1
	Data entry broken	8760	744	4	0,00%	1
	Display off (broken or moisture inside of it)	8760	744	4	0,00%	1
	Wrong connection (positioning and numbe	8760	744	4	5,00%	1
	Burned supply cable and/or socket	8760	744	4	100,00%	1
	Inverter wrongly sized	8760	744	4	10,00%	1
	Wrong installation	8760	744	4	10,00%	1
Mounting structure	Tracker failure	8760	744	5	50,00%	1
	Not proper installation	8760	744	48	0,00%	1
	Corrosion of module clamps	8760	744	0,5	0,00%	1
	Disallignment caused by ground instability	8760	744	48	1,00%	1
	Corrosion	8760	744	24	0,00%	1
	Oil leakage	8760	744	5	0,00%	1
Combiner Boxes	IP failure	8760	744	24	0,00%	1
	Main switch open and does not reclose aga	8760	744	1	100,00%	1
	Broken/Wrong general switch	8760	744	1	100,00%	1
	Wrong wiring	8760	744	24	0,01%	1
	General switch off	8760	744	1	100,00%	1
	Wrong/Missing labeling	8760	744	1	0,00%	1
	Incorrect installation	8760	744	24	0,00%	1
	Overcurrent protection not correctly sized	8760	744	4	0,00%	1
	Broken, missing or corroded cover	8760	744	1	0,00%	1
Cabling	UV Aging	8760	744	2	1,00%	1
	Theft cables	8760	744	24	100,00%	1
	Broken cable ties	8760	744	1	0,01%	1
	Wrong connection, isolation and/or setting	8760	744	0,5	0,01%	1
	Broken/Burned connectors	8760	744	0,5	100,00%	1
	Wrong/Absent cables connection	8760	744		5,00%	1
	Wrong wiring	8760	744	0,5	1,00%	1
	Cables undersized	8760	744	48	1,00%	1
	Damaged cable	8760	744	1	15,00%	1
	improper installation	8760	744	1	1,00%	1
	Conduit failure	8760	744	2	0,10%	1
	Broken transformer	8760	744	48	100,00%	1

	Failures	Rm (average cost of detection/component) [€]	Rsu (average substitution cost /component or unit) [€]	Rr (average repair cost/component) [€]	Rp (average transport costs per component) [€]
Modules	Hotspot	0,00 €	108,00 €	0,00 €	10,00 €
	Delamination	0,00 €	108,00 €	0,00 €	10,00 €
	Glass breakage	0,00 €	108,00 €	0,00 €	10,00 €
	Soiling	0,00 €	0,00 €	0,26 €	10,00 €
	Shading	0,00 €	0,00 €	0,08 €	10,00 €
	Snail track	0,00 €	108,00 €	0,00 €	10,00 €
	Cell cracks	0,00 €	108,00 €	0,00 €	10,00 €
	Defective backsheet	0,00 €	108,00 €	0,00 €	10,00 €
	Overheating junction box	0,00 €	108,00 €	0,00 €	10,00 €
	PID = Potential Induced degradation	0,00 €	108,00 €	0,00 €	10,00 €
	Failure bypass diode and junction box	0,00 €	108,00 €	0,00 €	10,00 €
	Corrosion in the junction box	0,00 €	108,00 €	0,00 €	10,00 €
	EVA discoloration	0,00 €	0,00 €	0,00 €	0,00 €
	Theft of modules	0,00 €	108,00 €	0,00 €	10,00 €
	Broken module	0,00 €	108,00 €	0,00 €	10,00 €
	Damage by snow	0,00 €	108,00 €	0,00 €	10,00 €
	Corrosion of cell connectors	0,00 €	108,00 €	0,00 €	10,00 €
	Improperly installed	0,00 €	108,00 €	0,00 €	10,00 €
	Missing modules	0,00 €	0,00 €	0,00 €	0,00 €
Inverter	Fan failure and overheating	0,00 €	0,00 €	0,00 €	0,00 €
	Switch failure/damage	0,00 €	108,00 €	0,00 €	10,00 €
	Inverter firmware issue	0,00 €	0,00 €	377,00 €	10,00 €
	Polluted air filter - derating	0,00 €	0,00 €	377,00 €	10,00 €
	Inverter pollution	0,00 €	0,00 €	377,00 €	10,00 €
	Data entry broken	0,00 €	0,00 €	377,00 €	10,00 €
	Display off (broken or moisture inside of	0,00 €	3.770,00 €	0,00 €	150,00 €
	Wrong connection (positioning and numl	0,00 €	3.770,00 €	0,00 €	150,00 €
	Burned supply cable and/or socket	0,00 €	0,00 €	377,00 €	10,00 €
	Inverter wrongly sized	0,00 €	0,00 €	377,00 €	10,00 €
	Wrong installation	0,00 €	0,00 €	377,00 €	10,00 €
Mounting structure	Tracker failure	0,00 €	0,00 €	377,00 €	10,00 €
	Not proper installation	0,00 €	0,00 €	100,00 €	0,00 €
	Corrosion of module clamps	0,00 €	300,00 €	100,00 €	50,00 €
	Disallignment caused by ground instabili	0,00 €	300,00 €	100,00 €	50,00 €
	Corrosion	0,00 €	300,00 €	100,00 €	50,00 €
	Oil leakage	0,00 €	0,00 €	0,00 €	0,00 €
Combiner Boxes	IP failure	0,00 €	0,00 €	2,00 €	0,50 €
	Main switch open and does not reclose a	0,00 €	20,00 €	30,00 €	10,00 €
	Broken/Wrong general switch	0,00 €	50,00 €	0,00 €	20,00 €
	Wrong wiring	0,00 €	2,00 €	0,00 €	0,50 €
	General switch off	0,00 €	10,00 €	0,00 €	2,00 €
	Wrong/Missing labeling	0,00 €	100,00 €	0,00 €	10,00 €
	Incorrect installation	0,00 €	0,00 €	5,00 €	1,00 €
	Overcurrent protection not correctly size	0,00 €	0,00 €	0,00 €	0,00 €
	Broken, missing or corroded cover	0,00 €	0,00 €	0,00 €	0,00 €
Cabling	UV Aging	0,00 €	0,00 €	10,00 €	2,00 €
	Theft cables	0,00 €	10,00 €	0,00 €	2,00 €
	Broken cable ties	0,00 €	50,00 €	0,00 €	20,00 €
	Wrong connection, isolation and/or setti	0,00 €	50,00 €	0,00 €	10,00 €
	Broken/Burned connectors	0,00 €	50,00 €	0,00 €	10,00 €
	Wrong/Absent cables connection	0,00 €	10,00 €	0,00 €	1,00 €
	Wrong wiring	0,00 €	50,00 €	0,00 €	10,00 €
	Cables undersized	0,00 €	0,00 €	0,00 €	0,00 €
	Damaged cable	0,00 €	1,50 €	0,00 €	1,00 €
	improper installation	0,00 €	1,50 €	0,00 €	1,00 €
	Conduit failure	0,00 €	0,00 €	0,00 €	0,00 €
	Broken transformer	0,00 €	50,00 €	0,00 €	10,00 €

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Funded by the Horizon 2020 Framework Programme of the European Union

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 649997. The content of this report reflects only the author's view and the Commission is not responsible for any use that may be made of the information it contains.