Review and Gap Analyses of Technical Assumptions in PV Electricity Cost

Report on Current Practices in How Technical Assumptions Are Accounted in PV Investment Cost Calculation

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www.solarbankability.eu

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 approach 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 is a project funded by the European Commission under the Horizon 2020 Programme and runs for two years from 2015 to 2017.

The Solar Bankability consortium is pleased to present this report which as 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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Project Information

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Glossary & Abbreviations

ARIMA	auto-regressive integrated moving average
BOS	balance of systems (of PV plant)
CAPEX	capital expenditures
CDF	cumulative distribution function
CE	Conformité Européenne
CPN	cost priority number
CPP	cloud physical property
DE	Germany
DC/AC	direct current, alternative current

DLP	defect liability period
DOM-TOM	départements et territoires d'outre-mer (French Overseas Departments and Territories)
DSRA	Debt Service Reserve Account
EL	electroluminescence (imaging analysis)
EPC	engineering, procurement and constructions
EU	European Union
FiT	feed-in tariff
FMEA	Failure Modes and Effects Analysis
FR	France
GHI	global horizontal irradiation
GPR	guaranteed performance ratio
IEC	International Electrotechnical Commission
IR	infrared (thermal imaging analysis)
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
IT	Italy
NL	the Netherlands
KNMI	Koninklijk Nederlands Meteorologisch Instituut (Royal Meteorological Institute of the Netherlands)
KPI	key performance indicator
LCOE	levelized cost of electricity
LTYA	long-term yield assessment
MCF	monthly correction factor
MCP	measure-correlate-predict
MSG-CPP	Meteosat Second Generation Cloud Physical Properties
MW	mega-watt (size of PV installation)
nMBE	normalized mean bias error
nRMSE	normalized root mean square error
O&M	operations and maintenance

OPEX	operational expenditures
PID	potential induced degradation (PV panel failure)
POA	plane of array (irradiation, irradiance)
PR	performance ratio (of a PV plant)
PV	photovoltaic
PVPMC	PV Performance Modeling Collaborative (Sandia National Laboratories)
RV	residual value (used in LCOE formula)
RMSE	root mean square error
SDE	standard deviation of error
STC	standard test conditions
UAV	unmanned aerial vehicle
UK	the United Kingdom
WEEE	(European) Waste Electronics and Electrical Equipment

Executive Summary

Increasing Trust by Reducing Risk

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 photovoltaic (PV) projects. In this report we look at the concrete practices of PV cost and energy yield modeling and the corresponding risk assessment at present days. We inventory how technical assumptions are accounted in the various PV cost elements and identify the gaps of present day models. This enables the stakeholders to identify hidden technical risks and their potential impacts and, hence, to evaluate and possibly improve the quality of a proposed financial model. The Solar Bankability consortium will build further on these findings when establishing best practices on PV cost modeling and financial model evaluation.

The cost of electricity generation by photovoltaics can be modeled as the so-called levelized cost of electricity (LCOE). The LCOE depends on capital expenditures (CAPEX), operating expenditures (OPEX), and PV plant energy yield. For the calculation of these elements, the LCOE models use various technical assumptions. There is no commonly accepted practice for translating the technical parameters of plant components, performance and reliability into financial terms. Energy yield calculation today typically assumes a long-term average, most probable energy yield (so-called P50 yield) and an associated lower bound of confidence (commonly referred to as P90, i.e., yield that can be exceeded with 90% confidence). If the actual energy yield does not meet the initial estimates, the entire investment can be compromised as less revenues from energy sales will directly impact the servicing of the debt or the investment return. When assessing the investment-worthiness of a photovoltaic (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.

An investment risk may be defined as the probability that the actual Return on Investment will be lower than expected (financial loss) multiplied by the magnitude of this loss. In practice, risk depends on legal, financial, tax and technical risks. The PV investment technical risks start as early as from the project development phase and continue throughout the operational years, and end when the PV plant reaches the end-of-life stage. Technical risks in PV project development are associated to the components of a PV system, the planning and the development of a PV project. The main technical risks of PV plant operation are safety issues, the uncertainty of system performance and energy yield. Reducing the risk associated with investments in PV projects by increasing the trust of investors, financers and insurance companies is of utmost importance.

Establishing Common Practices for Professional PV Risk Assessment

The principal objective of the Work Package 3 of the Solar Bankability project is to develop guidelines on how the technical risks over the PV project life cycle should be taken into account in the different cost elements and when evaluating the PV investment cost. The project consortium has reviewed the current industry practices to obtain a view on how technical risk assumptions in PV investment cost calculation are commonly accounted. With this information in hands, the consortium then performed gap analyses between the present practice and the state-of-the-art methodology.

Eventually a guideline is created based on the knowledge gathered in the review and gap analyses. The current practice overview and gap analyses are presented in this report, while the recommendation guidelines will be part of the next report due in Q4'2016.

The Solar Bankability Project

The Solar Bankability is a project funded by the European Commission under the Horizon 2020 Programme and runs for two years from 2015 to 2017. The main goal of the Solar Bankability project is to establish a common practice for professional risk assessment which will serve to reduce the risks associated with investments in PV projects. Market data from historical due diligences, operation and maintenance records, and damage and claim reports are used to compile risks assessment and mitigation guidelines.

Conclusions and Takeaways

We have compared the current practices to the state-of-the-art scientific data and to the top 20 technical risks identified earlier in this Solar Bankability project. For the latter we refer to the cost-based FMEA CPN ranking method developed in Work Package 2 of the Solar Bankability project (see project results at *www.solarbankability.eu*). Our objective was to obtain a snapshot of the current practices and identify gaps in the technical inputs which will introduce risks into the evaluation of the CAPEX, OPEX and energy yield. This information will serve as the basis for the Solar Bankability consortium to carry out the next task in the context of PV LCOE, i.e. to develop a best-practice guideline in how to account for the technical risks in PV investment cost.

The essential takeaways are summarized in the tables below. These takeaways are divided in two subsections according to the structure of this report.

Technical Assumptions in Present-Day PV Financial Models

On the cost side, we have conducted a survey over the different cost elements of CAPEX and OPEX for the financial models of 18 ground-mounted PV plants in France, UK, Germany, and Italy developed between 2011 and 2015. The survey was then extended to a set of EPC and O&M contracts from eight ground-mounted and rooftop PV projects in France, UK, the Netherlands and Italy realized between 2014 and 2016. The review included the technical aspects found in the EPC and O&M frameworks. Results show that CAPEX is dominated by the EPC costs while OPEX is dominated by the O&M costs. Depending on the scope of service for EPC and O&M, different risks can be mitigated during planning and installation or during operation.

On the energy yield side, we have reviewed current practices for lifetime energy yield calculations by screening long-term yield assessment reports from seven different market actors. The review included, among others, sources of solar resource data, models and assumptions for resource assessment, PV modeling software, assumptions on long-term variability and risk assessment. Our review shows that the overall uncertainty on estimated lifetime energy yield is typically assumed to be ±5% to ±10% in terms of standard deviation. These estimates are usually dominated by the solar resource variability over the years.

The most important findings of the review exercise are summarized in Table 1 below.

Table 1: Technical assumptions in present-day PV financial models – review summary

Summary of technical assumptions in present-day financial models for PV
1. For PV LCOE, the CAPEX contributes to a significantly larger portion (~75 - 90%) to the lifecycle costs than the OPEX.
2. There is neither a unified method nor a commonly accepted practice for translating the technical parameters of plant components, performance and reliability into lifecycle costs.
3. The EPC and O&M costs make up to a large portion of the CAPEX and OPEX (70-90% and 30-70%, respectively); the technical details in the EPC and O&M are decisive for managing the technical risks in PV project investment.
4. Risk mitigation measures should be selected with an objective to minimize the LCOE by optimizing the balance between the CAPEX and OPEX.
5. The overall uncertainty on estimated lifetime energy yield is typically assumed to be between ±5% and ±10%.
6. The solar resource variability is one main technical source of uncertainty impacting mainly the risk assessment associated with the cash flow during a single year.
7. PV systems are often not built according to the design used for the initial yield assessment study overthrowing the initial project risk assessment.
8. The use of in-house developed PV modeling tools may lead to flaws in lifetime energy yield calculations.
9. The degradation rate is commonly assumed constant over time although this may not be the case and thus can lead to unexpected deviation in cash flow over the years.
10. Exceedance probabilities (e.g. P90) are typically calculated by assuming a normal probability distribution of e.g. annual irradiation around the expected value; the use of a cumulative distribution function based on long-term resource measurements may be more appropriate in this case.
11. Not all technical risks should be mitigated through technical measures. Financial or legal mitigations should be considered as alternatives.

Gaps in the Present-Day Technical Inputs for PV Financial Models

We analyzed the current industry practices on the PV LCOE technical inputs collected from our review exercise. We then compared these practices to the state-of-the-art scientific data and the top 20 technical risks identified earlier in this Solar Bankability project. The analyses were performed systematically according to the phases in PV project lifecyle and whether the root causes are likely to occur before or during the PV operation, i.e. *year-0 risks* vs *risks during operation*.

The results of this exercise show that technical gaps generally exist across all PV project phases. They occur in all elements of the PV LCOE, namely in the CAPEX, OPEX and energy yield estimation. There are two types of technical risks: those which influence the PV system performance and energy yield but not necessarily create a partial or overall outage of the plant, and those which cause failures such as the top 20 affecting the plant availability and also the performance. The root causes of both types of risk could be introduced either during project development (procurement, planning and construction) or during PV operation (O&M). The list of important gaps identified in the analyses are presented in Table 2 below.

Table 2: Important technical gaps in the present day technical inputs for PV financial models – gap analysis summary

Risk	Phase/field	Identified critical technical gaps
Year-0	Procurement/ product selection and testing	1. Insufficient EPC technical specifications to ensure that selected components are suitable for use in the specific PV plant environment of application. 2. Inadequate component testing to check for product manufacturing deviations. 3. Absence of adequate independent product delivery acceptance test and criteria.
	Planning/ lifetime energy yield estimation	4. The effect of long-term trends in the solar resource is not fully accounted for. 5. Exceedance probabilities (e.g. P90) are often calculated for risk assessment assuming a normal distribution for all elements contributing to the overall uncertainty. 6. Incorrect degradation rate and behavior over time assumed in the yield estimation. 7. Incorrect availability assumption to calculate the initial yield for project investment financial model (vs O&M plant availability guarantee).
	Transportation	8. Absence of standardized transportation and handling protocol.
	Installation/ construction	9. Inadequate quality procedures in component un-packaging and handling during construction by workers. 10. Missing intermediate construction monitoring.
	Installation/ provisional and final acceptance	11. Inadequate protocol or equipment for plant acceptance visual inspection. 12. Missing short-term performance (e.g. PR) check at provisional acceptance test, including proper correction for temperature and other losses. 13. Missing final performance check and guaranteed performance. 14. Incorrect or missing specification for collecting data for PR or availability evaluations: incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation.
Risks during operation	Operation	15. Selected monitoring system is not capable of advanced fault detection and identification. 16. Inadequate or absence of devices for visual inspection to catch invisible defects/faults. 17. Missing guaranteed key performance indicators (PR, availability or energy yield). 18. Incorrect or missing specification for collecting data for PR or availability evaluations: incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation.
	Maintenance	19. Missing or inadequate maintenance of the monitoring system. 20. Module cleaning missing or frequency too low.

1 Introduction

1.1 Photovoltaic Cost Definition

The levelized cost of electricity (LCOE) is a method which has been established to allow for a direct comparison of electricity generation cost among different technologies. The LCOE estimates the price of electricity [e.g. cents/kWh] over the lifetime of a system, taking into account the initial investment and all the costs related with the operation of the system. The LCOE facilitates deciding on the price the generated electricity should be sold at in order to break-even the cost of building and operating the generating plant.

In this project a review of five publications [1]–[5] published in recent years showed that there are different formulas that could be used at present day to calculate the LCOE value (see *Annex A LCOE Literature Review* for the summary of the publication review). However, the principle behind the calculation approaches remains the same, i.e. the electricity cost is obtained by dividing the total lifecycle cost of a system (from building the plant to operating to decommissioning) by the total energy yield of the system over the lifetime (equation (1)). The variations in the LCOE formula are driven by what other additional financial variables (discount rate, inflation, tax) are taken into account.

$$LCOE = \frac{Lifecycle\ cost}{Lifetime\ energy\ yield} \tag{1}$$

For the purpose of the works in the Solar Bankability project, the consortium together with the project industry advisory board have agreed to disregard the inflation rate and tax as these values are country and investor specific.

The lifecycle cost is the sum of initial capital expenditures $CAPEX$ and total annual operation costs $OPEX$ (including fuel and maintenance) discounted over the number of years the system is in operation N. The operational costs include any residual value of the system RV and the annual discount rate r. The lifecycle cost can then be expressed as follows.

$$Lifecycle\ cost = CAPEX + \sum_{n=1}^{N} \frac{OPEX - RV}{(1+r)^n} \tag{2}$$

The lifetime energy yield is the sum of the yearly energy produced over the number of years the system is in operation (equation (3)) taking into account the annual system degradation D and Y_0 represents the initial system yield/production. The lifetime energy yield is then calculated using the following formula.

$$Lifetime\ energy\ yield = \sum_{n=1}^{N} \frac{Y_o\,.(1-D)^n}{(1+r)^n} \tag{3}$$

Combining equations (2) and (3), the final LCOE calculation used in the Solar Bankability project is therefore:

$$LCOE = \frac{CAPEX + \sum_{n=1}^{N} \frac{OPEX - RV}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Y_o \,.\, (1-D)^n}{(1+r)^n}} \qquad (4)$$

where

N = PV system life [years]

$CAPEX$ = total initial investment (CAPEX) [€/kWp]

$OPEX$ = annual operation and maintenance expenditures (OPEX) [€/kWp]

RV = residual value [€/kWp]

r = discount rate [%]

Y_0 = initial yield [kWh]

D = system degradation rate [%]

As the formula above indicates, there are different variables whose values need to be set to calculate the final LCOE number. These variables in general are project and country specific. The discount rate is straightforward and could be obtained from reliable sources such as that from a study carried out within the EU-funded project DiaCore published in Feb 2016 [6], or from a reference table published by the European Commission [7], or from the World Bank website. Other variables - the CAPEX, OPEX, yield and degradation, have expected values that are achieved within a given range of confidence. Risks are taken into account via assumptions for worst-case bounds of confidence and the assumptions are generally strongly simplified. Lack of understanding of risks therefore could lead to taking flawed assumptions which in turn give incorrect valuation of the LCOE.

When deciding whether to invest or not in a PV project, different financial stakeholders have the desire to use the most appropriate assumptions in the risk consideration and to decide if to address the mitigation measures through financial, technical or legal solutions. In a nutshell, it is therefore important to understand the risks and the associated assumptions in order to choose mitigation options which ultimately optimize PV LCOE and thus elevate the finance-ability of the PV investment.

1.2 Technical Risks and PV LCOE

The PV investment technical risks start as early as from the project development phase and continue throughout the operational years, and end when the PV plant reaches the end-of-life stage. As illustrated in Figure 1, in the Solar Bankability project, the PV project lifecycle is divided into five phases: product procurement and testing, PV plant planning, transportation and installation which are the three phases before operation, and operations and maintenance (O&M) and decommissioning. In PV LCOE context, the CAPEX will comprise of the costs incurred in the product testing, PV plant planning, transportation and installation, while the OPEX are costs associated with the operations, maintenance and decommissioning activities. For decommissioning, sometime reserves are set aside at the beginning of the project; in this case then it becomes a part of the CAPEX instead.

The pre-operation technical risks are defined as *year-0 risks*, while the risks during operation and end-of-life decommissioning are called *risks during operation*. The *year-0 risks* include, among others, uncertainties in the PV system yield estimation in the planning phase, and issues during transportation and installation phases. These risks are likely to manifest into risks during operation such as under-performance or PV plant downtimes which could impact the operational and maintenance cost as well as the energy yield and thus the overall project income.

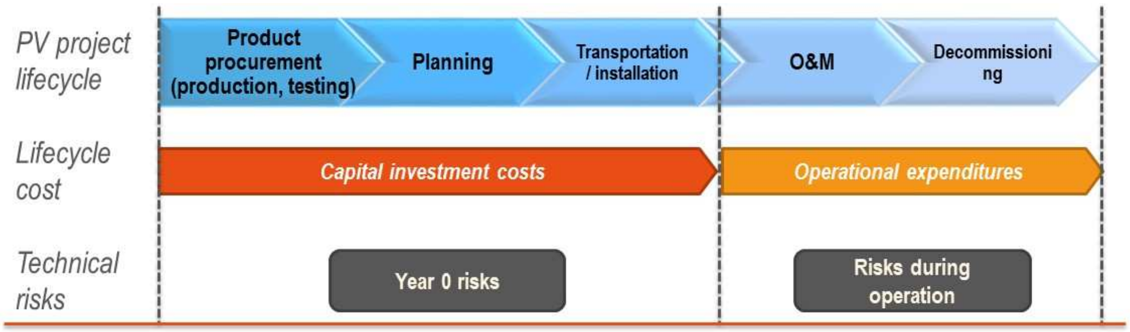


Figure 1: Lifecycle costs of PV projects and the link to different project phases

The principal objective of Work Package 3 of the Solar Bankability project is to develop guidelines on how technical risks over PV project life cycle should be taken into account in the different cost elements and when evaluating the PV investment cost. In this work package, the project consortium has carried out a review activity to obtain the snapshot of the current industry practices in how technical risk assumptions in PV investment cost calculation are accounted. With this information in hands, the consortium then performed gap analyses between the present practice and the state-of-the-art methodology. Eventually a guideline is created based on the knowledge gathered in the review and gap analysis. The current practice overview and gap analyses are presented in this report, while the recommendation guidelines will be part of the next report due in Q4'2016.

1.3 Guide to Readers

This report presents the results of the review exercise and gap analyses of the Solar Bankability project.

In Chapter 2, the current industry practices in PV investment cost calculation are reviewed. Moreover, we show how technical assumptions and associated risks are addressed in the CAPEX, OPEX, yield, and performance calculations. These are the results from various surveys on sample financial models, Engineering, Procurement and Construction (EPC) and O&M contracts, and engineering reports.

In Chapter 3, we analyze the gap between the current industry practices and the state-of-the-art methodologies. The state of the art as well as associated best practices for solar resource assessment, energy yield estimation and risk assessment are introduced and compared against the current industry practices as presented in Chapter 2. The main gaps and potential flaws with current practices are identified and discussed.

Finally, Chapter 4 presents the conclusions of the works described in this report with result highlights and recommendations for potential future works.

2 Current Practices of Technical Assumptions in PV Investment Costs

To develop guidelines on how technical assumptions and risks over the PV project life cycle should be taken into account in the different cost elements and when evaluating the PV investment cost, it is important to first understand the existing practice used in the PV investment sector at present days. This chapter of the report presents the review performed by the Solar Bankability project to obtain a snapshot of the current industry practices in PV investment cost calculation on how technical assumptions and associated risks are taken into account. We have focused our review on the three main LCOE variables mentioned in the Chapter 1, namely the CAPEX, OPEX, and yield as well as the technical performance of PV plants. The results of this review exercise are presented as a list of observed current practices at the end of this chapter.

2.1 Lifecycle Cost – CAPEX and OPEX

The lifecycle cost of a PV project consists of the capital and operational expenses (CAPEX/OPEX) incurred in building and operating the PV system. As introduced in the previous chapter, the PV levelized cost of electricity is an assessment on how the total lifecycle cost of a PV system compared to the electricity yield over the lifetime of the system. A relatively low PV LCOE means that the electricity is being produced at a low cost, thus likely giving high investment returns and make the PV competitive and attractive as an electricity generating source. Based on the equation (1) in §1.1, it is therefore desirable to have the lifecycle cost as low as possible. The optimization of the total lifecycle cost of PV systems must therefore include the two components (CAPEX and OPEX) and the most favorable combination of these two components which results in minimum lifecycle cost.

To obtain the picture of how technical assumptions and risks in CAPEX and OPEX are undertaken in present day industry practices, we started with compiling the various cost items/elements in the CAPEX and OPEX. We then went through this list and identified the costs which are associated with technical aspects for PV plants. In this context, we have performed a desktop review on 18 financial models of ground-mounted PV systems in France, UK, Germany, and Italy. The capacity of these plants are between 1 MW and 12 MW. The plants in FR and UK were developed in the period between 2013 and 2015, while the plants in DE and IT entered into operations in 2011. We have selected these plants primarily because they are readily available from within the Solar Bankability consortium partners. In addition, ground-mounted plant is one of the more common installation types in many countries in the EU. We expect the financial models from other market segments are built on similar principle but with different emphasis.

2.1.1 Lifecycle Cost

From the financial models of the 18 ground-mounted projects in FR, UK, DE and IT selected for our desktop review, we extracted the CAPEX and OPEX values. The lifecycle cost of each project was then calculated using equation (2). For the calculations, the system operational life was set to the typical time of 20 years and the residual values were set to zero. The discount rates used are the average values reported in the study carried out by an EU-funded project DiaCore in Feb 2016 [6];

they are 5.7%, 6.5%, 4% and 8% for FR, UK, DE and IT respectively[1]. The resulting absolute lifecycle cost values are not reported here due to confidentiality; however, for comparison purpose, the CAPEX and OPEX were normalized to the total lifecycle costs and the resulting cost ratio for the individual plants are presented in the following chart. From this analysis, it can be concluded that the capital expenditures contribute to a significantly larger portion (mid-70% to 90%) of the overall lifecycle cost than the operating expenses. Such observation is important to consider when evaluating technical risks in PV investment and choosing risk mitigation measures since the mitigation costs will either affect the CAPEX or OPEX number depending on where the mitigations are implemented in the pre-operational phases or after the PV system has been commissioned into operation.

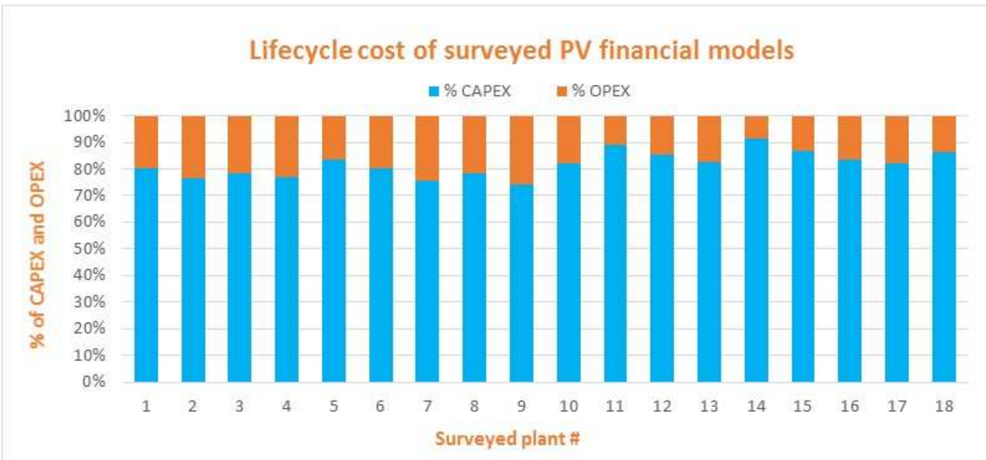


Figure 2: Lifecycle costs (CAPEX and OPEX) of 18 surveyed financial models of ground PV projects in FR, UK, DE and IT

2.1.2 CAPEX

The capital expenditures of a PV project encompass all the initial investments required to develop and build the PV plant. Such expenditures range from engineering to administrative to financing cost etc. From the desktop review exercise, the various cost elements found in the CAPEX of the surveyed financial models are shown in Figure 3 below.

[1] The DiaCore study refers to discount rates for wind on-shore projects and thus for PV, these values are somewhat conservative due to lower planning and operational risks.

Figure 3: List of cost items in capital expenditures found in surveyed financial models of ground PV projects in FR and UK

2.1.2.1 CAPEX Cost Items

The *Engineering, Procurement and Construction* (EPC) costs comprise of the costs to design the PV system, procure the necessary equipment and components, and construct the PV installation. The EPC costs cover the materials and labors for the EPC service and could possibly include the provision of spare parts. The supply of the equipment and construction of the infrastructure to connect the PV plants to the grid connection point is usually the EPC's responsibility as well.

For critical plant components such as inverters or solar trackers, *service agreements* are arranged to foresee defects or failures during the operation years and to avoid significant loss in production due to plant outage that will impact incomes. The costs of the service agreement are either paid upfront at the start of the project (thus included in CAPEX), or periodically during plant operation (thus appears under OPEX). Six of the surveyed projects have opted to pay the agreement fee upfront.

The European Waste Electronics and Electrical Equipment (WEEE) directive for the collection and treatment of photovoltaic module waste across Europe entered into force in August 2012 [8]. As a result, increasing number of PV investment financial models are including *decommissioning cost* in consideration. The decommissioning costs should include not only plant dismantling and component disposal and/or recycling, but also, if applicable, the expenses to restore the site (ground or rooftop) to its original condition.

There are many other expenditures related to the project development. Such costs include preliminary engineering, site selection including *environmental and site study*, application fee to obtain necessary *permits or licenses* to build the PV plant, and any *grid connection fee* payable to the grid operator.

Very important also is the cost to acquire or secure the site for the PV installation. For a ground-mounted PV system, the land could be purchased or leased while for a commercial or industrial rooftop installation, a rental agreement may be needed to use the roof space. Similar to service agreement fee, the *land purchase* or *land/site lease* could either be paid upfront (and included in CAPEX) or paid over the operational years (OPEX expenses).

Other possible CAPEX costs are expenses to set up *development contract*, public relation and community development costs, and site preparation cost (if not already included in the EPC scope of work). There are also fees to pay for the legal, financial or technical *due diligence* required by the lenders or investors in the pre-financial close. Project development costs in the past have been a large portion of CAPEX (having huge margins) but have decreased rapidly in the recent years.

The CAPEX also includes *financing costs* incurred in the lending process or to secure the financing for the PV project investment such bank fees or additional security fee for lenders (Debt Service Reserve Account, DSRA), and also interest during construction.

Last but not least, there are *insurance fees* and possibly payments to a *contingency fund*. They cover cost items which are not estimated in the CAPEX or errors in the energy yield or its inter-annual variability due to site-specific deviations. In the financial model, the contingency cost is usually a percentage of the total CAPEX. Not all financial models surveyed in the desktop review foresaw contingency fee.

Finally, we have observed among the surveyed financial models, two with rather uncommon expenses such as success fee and start-up/mobilization cost.

2.1.2.2 CAPEX Cost Structure

While reviewing the CAPEX cost items presented in the above paragraphs, the first observation gathered is that there appears to be no unified CAPEX cost structure in the PV industry. This means that all the costs in Figure 3 do not necessarily appear in all financial models. However, there are typical costs which are common in all financial models such as the EPC cost; this is expected as system material and installation costs are the major part of the capital investment of PV projects. The EPC price is determined based on the scope of work the contractor has agreed to perform. For PV projects where the contractor delivers a turnkey EPC service, the scope includes all aspects to deliver a PV plant including the infrastructure to connect the plant to the electricity distribution lines of the grid operators. However, deviation from this classical arrangement does occur. In fact, among the surveyed financial models, we found one case where the solar panels were supplied by the developer of the PV project; this developer was a part of a large holding group which has a solar panel manufacturing subsidiary and the objective of this project was to utilize panels made by the manufacturing subsidiary. This type of arrangement is not highly unusual especially when many PV panel manufacturers have decided to enter the PV market downstream to develop PV projects and populate these projects with their own PV panels. In this special case, the solar panel cost appeared as a separate entry in the CAPEX; when adding this cost to the EPC without panel cost, however, the result is in the range of the conventional EPC price range. Another example of deviation is grid connection infrastructure which is not necessarily included in the EPC cost as the construction was carried out by another party. In a couple of the surveyed financial models, this was the case.

The lack of uniform cost calculation in the CAPEX is further convoluted by inconsistencies in cost naming and in the definitions of what each cost should encompass. One good example of this is the development cost; we observed that there are wide variety of costs included in this group and there are overlaps with other cost entries. In one financial model the development cost is incurred to obtain permits and licenses to develop the project, while in several other financial models the permit and license fees are considered as administrative cost.

The variations in the CAPEX cost structure as found in the survey are understandable since each PV project is unique and the cost of investment to develop and realize the project is very much dependent on for example, how the roles of different parties (e.g. owners/developers, contractors) are organized and the scope of the EPC service provider is allocated. For e.g., PV projects which are delivered as turnkey EPC products will have less cost items as many costs (EPC and grid infrastructure, for e.g.) are lumped into a single EPC cost line item. The local legal and administrative laws will also require different permits and authorizations. Site location and condition are other aspects which will determine the CAPEX costs such as if there are existing nearby grid connection points which the project could be plugged into or if a new infrastructure for electricity evacuation need to be erected.

The lack of standardized cost structure observed is not necessarily a grave issue and certainly is a challenge which is not isolated in the PV sector. Nonetheless, from a practical point of view it does lead to complexity and ambiguities when discussing the topic of PV CAPEX cost and involved parties could find themselves having to line up the definition, a time effort which could be avoided if a standardized approach would exist. Albeit this lack of commonalities in the CAPEX cost structure, however, for the purpose of technical risk assessment and mitigation discussion, it is commonsense to differentiate costs which are directly linked to technical factors of a PV system (and therefore carry technical risks) distinctively from costs with financial or legal perspective.

2.1.2.3 CAPEX Pricings

From the surveyed financial models, we analyzed the distribution of the cost items described in the previous paragraphs within the CAPEX. The CAPEX costs fall in the range of 1.3 to 1.6 €/Wp for the projects developed in 2013 – 2015 and between 2.5 and 4 €/Wp for the projects developed in 2010 – 2011. Of the financial models studied, only the projects in FR and UK have EPC prices available and they are in the range of 1.0 to 1.1 €/Wp. For these projects, the EPC cost is the most significant portion of the CAPEX, contributing between 70% and close to 90% of the total capital investments. The other cost items are relatively low compared to the EPC costs (Table 3). The individual EPC-to-CAPEX price ratios are illustrated in Figure 4 below.

Table 3: CAPEX cost items of 9 surveyed ground PV projects in FR and UK

Cost categories	% of total CAPEX
EPC costs (incl. grid connection)	70 – 87 %
Service agreements	0 – ~7 %
Decommissioning costs	0 – ~8 %

Development costs, financing costs, due diligence fees, insurance and contingency and others	~15 %

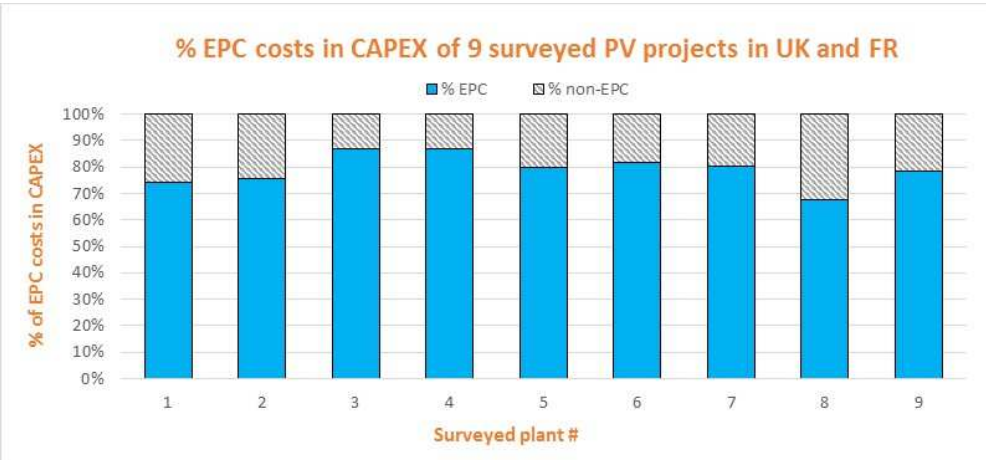


Figure 4: Percentage of EPC costs in the CAPEX of surveyed 9 financial models of ground PV projects in FR and UK

2.1.3 OPEX

The operational expenditures (OPEX) of a PV project encompass all expenses to operate and maintain the PV plant during the operational years. Unlike other power generation technologies, there are no fuel costs required for PV electricity generation. The cost items in OPEX obtained from the desktop review exercise is presented in the figure below.

Figure 5: List of cost items in the OPEX in 18 surveyed financial models of ground PV projects in FR, UK, DE and IT

2.1.3.1 OPEX Cost Items and Structure

The OPEX review exercise resulted in similar observations seen in the CAPEX structure: there is also no standardized approach in the cost structure, in the cost names and definitions of what each cost should encompass.

The *O&M* costs, as the name indicates, are costs required to operate and maintain operational PV plants. The O&M scope of works comprises of tasks such as real-time monitoring of the plant operation and electricity generation, periodic reporting, maintenance activities of the PV plant components including solar panel periodic cleaning, site maintenance, security and surveillance, etc. The O&M costs are usually split into fixed and variable O&M costs. The fixed O&M costs cover activities which are fixed during the O&M contracting phase. The variable costs cover activities which are expected to take place during the plant operation but the amount of expenses could not be pre-determined as it depends on the reason why the activities are carried out.

As previously mentioned in the CAPEX costs, for the *service agreements* or *land lease*, it is possible to allocate these expenses as operating costs over the PV plant operational years and pay them on recurring basis. Of the 18 surveyed PV projects, we have found three projects with the inverter maintenance services and warranty extension considered in the OPEX and the yearly costs are between 15% and 25% of the yearly OPEX (Table 4). The wide range of the service agreement cost is driven by the scope of the service.

Other OPEX costs are for *auxiliaries* to operate the PV installation: water, electricity (for lighting, surveillance, security office etc.), and telecommunication lines for plant monitoring. Operational expenses also include *management fees* such as those for general project management, asset management or administration (audit, accounting, legal etc.). Finally, there are *financing charges* during operation, bank fees or insurances and *taxes*.

2.1.3.2 Pricings

The distribution of the OPEX cost items from the surveyed financial models are given in Table 4 below. The results show that the overall O&M cost varies between around 12 to 15 €/kWp/year for the projects developed in 2013 – 2015 and between around 15 and close to 40 €/Wp for the projects developed in 2010 – 2011. Relative to the OPEX, the O&M cost range is very wide, spanning from as low as 30% to as high as 70% of the total OPEX (Figure 6). This spread is primarily due to the wide varieties of the O&M scope found in these surveyed contracts and also to some extent, the price of labor used to carry out the works. In the early days when PV investment was heavily populated with primary market, the O&M price was highly inflated with high margins. However, the price has come down significantly. Among the surveyed annual O&M per watt-peak prices, we have seen a general drop of slightly more than half from 2011 to 2014 – 2015 values. During the Solar Bankability project first public workshop held in May 2016, E.ON also reported a decrease of roughly 50% in the annual O&M price from 2008 to 2015 [9]. The O&M price drop is especially prominent in the secondary PV market where project refinancing drives very competitive O&M pricing.

Table 4: OPEX cost items of 18 surveyed ground PV projects in FR, UK, DE and IT

Cost categories	% of total OPEX
O&M	~30 – 70 %
Service agreements	~15 – 25 %
Other costs	~5 – 55 %

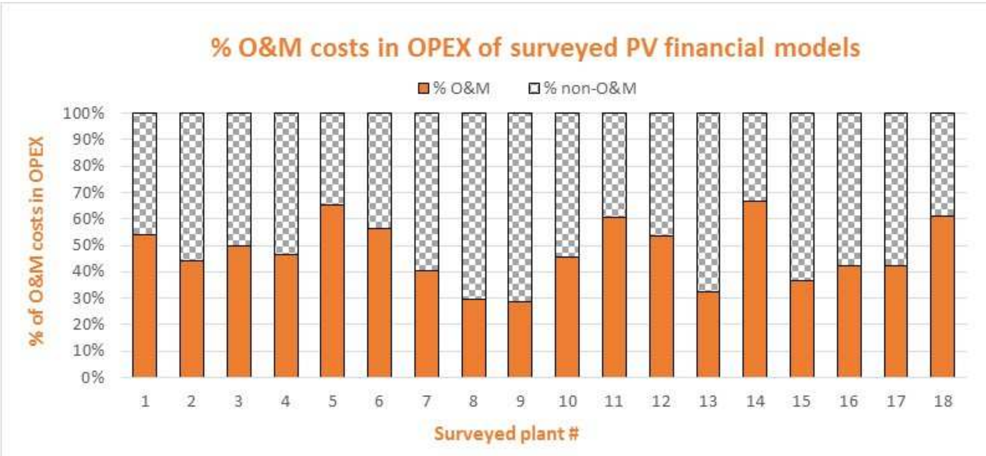


Figure 6: Percentage of O&M costs in the OPEX of 18 surveyed financial models of ground PV projects in FR, UK, DE and IT

The PV system lifecycle cost survey results so far point to EPC and O&M costs as the major contributors to overall CAPEX and OPEX respectively. We have therefore extended the review of current industry practices in PV investment cost calculation to how technical assumptions and associated risks are taken into account in the EPC and O&M frameworks, presented in the following two subsections §2.1.4 and §2.1.5.

2.1.4 EPC

In setting the EPC service, assumptions are taken and the scope of the EPC work must consider PV system technical risks and preferably account for important risks in the most effective, economical and profitable way. As the EPC work is generally defined in the EPC contracts, the Solar Bankability project has reviewed eight sample EPC contracts from PV projects (ground-mounted and rooftop) in France, UK, the Netherlands and Italy realized between 2014 and 2016[2]. The aim was to obtain a general overview of the technical aspects included in these EPC services, what assumptions are accounted and risks considered and addressed.

[2] Note these PV projects are not the same as the ones surveyed in the CAPEX and OPEX surveys in §2.1.2 and §2.1.3.

Among the surveyed EPC services, the technical aspects could generally be organized into the scope of works, the plant specifications, testing of plant and acceptance, and the performance and guarantees (Figure 7).

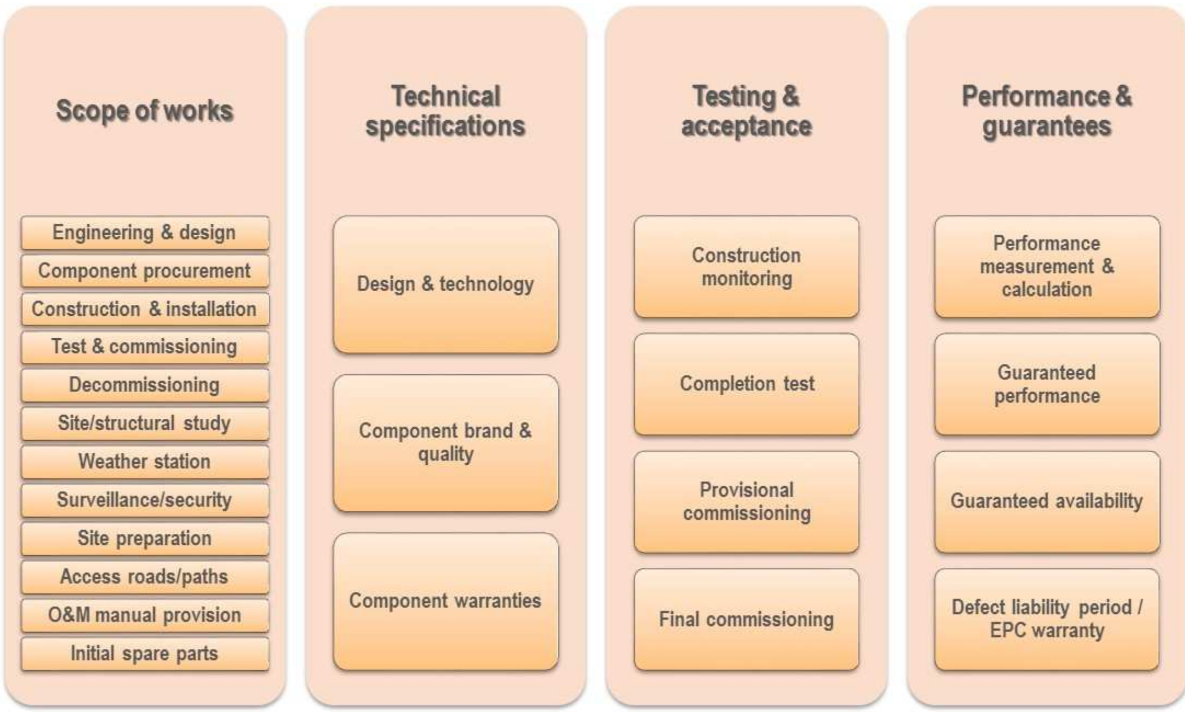


Figure 7: Technical aspects in EPC contracting from 8 surveyed EPC contracts of projects in FR, UK, NL and IT

Scope of Work

The scope of works of the EPC are defined in the main body of the EPC contract. The comparison of the eight surveyed EPC scope of works are shown in Table 5.

Table 5: Review of EPC scope of works from 8 EPC contracts of projects in FR, UK, NL and IT

Scope of work	A	B	C	D	E	F	G	H
Engineering & design	✓	✓	✓	✓	✓	✓	✓	✓
Component procurement	✓	✓	✓	✓*	✓	✓	✓	✓
Construction & installation	✓	✓	✓	✓	✓	✓	✓	✓
Test and commissioning	✓	✓	✓	✓	✓	✓	✓	✓
Decommissioning								
Site/structural study	✓	✓	✓	✓	✓		✓	✓
Weather station supply/installation	✓			✓	✓	✓	✓	✓
Surveillance and security system					✓		✓	✓
Site preparation	✓	✓	✓	✓	✓	✓	✓	✓

Access roads/paths					✓	✓	✓	✓
Documentation	✓	✓	✓	✓	✓	✓	✓	✓
O&M manual provision				✓	✓		✓	✓
Initial spare parts				✓	✓		✓	✓

Results show that there is more or less consensus on some core activities of the EPC service. These core activities are considered standard to EPC service and they include:

- Engineering and design of the PV system;
- Supply of plant components such as PV panels, inverters, the balance of systems (BOS) to realize the PV systems; this also includes the PV plant monitoring system and the equipment making up the low-to-mid voltage part of the PV system (transformer and delivery substations) up to grid connection point;
- Construction and installation of the components including the provision of all necessary equipment and tools for the works;
- Testing of the plant upon completion and commissioning the plant into operation as part of plant acceptance;
- Preparation of ground work or site necessary to erect the PV plant,
- Provision of all necessary plant-related documentation (mechanical and electrical schematics, data sheets, warranties, etc.) after completion and during plant hand-over.

The majority of the EPC costs lies in procuring the PV plant components. Among the surveyed nine financial models of ground PV projects in FR and UK in §2.1.2, the cost of modules makes up to roughly 50 to 55% of the total EPC cost. Within the procurement cost, the PV panels are the largest cost contributor; approximately half of the total procurement cost is due to the module purchase. Many publications and reports have been dedicated to addressing the topic of PV module, inverter and BOS price reduction to lower overall PV electricity cost and make investment in PV more competitive and attractive. The PV module price has decreased significantly by roughly 80% from 2008 to 2012 [1], driven by decrease in silicon price and improvement in production capability and efficiency. This trend has shift the PV system component focus to the price of the BOS. In their latest study [10], the International Renewable Energy Agency (IRENA) highlighted the continued need to focus on BOS cost reductions for solar PV power plants to become a key global electricity source.

While on the subject of PV system components, it is worth noting that in one of the surveyed EPC contracts (project *D*), the PV panels are not included as part of the EPC procurement service; the developer supplied the panels and the EPC was responsible to install these panels. As explained in §2.1.2, the developer of this project is a PV project investment subsidiary of a company who also has a panel manufacturing subsidiary and the latter provided the solar panels to the project developed by the former. This arrangement is part of a trend seen recently in the PV sector where upstream panel manufacturers are entering project development in order to gain more leverage and secure the utilization of the PV panels they produce. This could in reality be advantageous from EPC price viewpoint (and thus overall CAPEX) as it is likely the panel price will be lower than the market price as the panels are in a sense purchased internally. On the other hand, one challenge with such set up is it is unlikely the EPC contractor is willing to give guarantees on aspects related to the panels since they (i.e. contractor) may not have control over the quality of the products.

On top of the core activities above, there are optional works which could be included in the EPC service. The following list consolidates the optional activities found in the scope of work of the surveyed EPC services. In some contracts we found several of these items while in a few other contracts all these extras are considered; in the case of the latter, the EPC is considered a turnkey service.

- Carrying out site condition study (geotechnical, soil, rooftop stability) to assess the suitability of the site, soil and terrain for PV installation;
- Supply and installation of weather stations;
- Supply and installation of surveillance and security system;
- Access roads or paths.

Besides the technical scope of works, the EPC will normally provide supports to the plant owner or developer in the administrative aspects such as obtaining different permits (grid connection authorization, construction permit, external road for e.g.) to realize the plant. In most cases the EPC would also take an interface role between their client and the PV plant components and equipment suppliers before the ownership of the plant is handed over.

The EPC has the responsibility to deliver a PV system with ensured quality and the works are carried out in line with administrative and legal requirements.

Plant Technical Specifications

The technical specifications of a PV plant are usually included in an EPC contract. This is important because the EPC contractor is contractually bound to deliver the PV plant as it is stated in the contract. It is therefore necessary to have as much detail information as possible in the contract to avoid potential ambiguities which could lead to any potential technical disputes. The choice of site, plant capacity, technology and the complexity of the design and configuration will ultimately influence the investment capital and the energy yield used in the LCOE calculation of the said project. Moreover, these technical aspects will determine the extent of operational monitoring and maintenance coverage required to maintain the plant.

The comparison of the technical specifications included in the surveyed EPC services are shown in Table 6. In all eight services, the technical specifications are found in the annexes of the contract documents. The amount of information included in these annexes varies from one technical specification to another. In all of them, however, the followings are always found:

- General description of the project (location, site, capacity, and project name);
- High-level technology description (panel technology, inverter type and mounting structure, transmission equipment, monitoring system, meteorological station);
- Overview of the PV plant configuration;

- Quantity of the main PV system components; and
- Warranties of the plant main components.

Slightly over half of the technical specifications include more detail information such as the specific brand and model type of the PV system components. Moreover, only half of the surveyed technical specifications include the implantation schematic (drawing showing panel/inverter layout and features such as electrical cabinet, substations, and support facility for e.g., storage containers, security office, fencing etc.) and the electrical wiring diagram of the intended PV plant. In regards to certification requirements, five of the eight technical specifications call for IEC 61215/IEC 61646[3] and IEC 61730[4] certifications for the modules used in the projects while only two technical specifications require CE mark of conformity[5] for the inverters. None of the eight EPC services includes any level of module testing as part of acceptance test during delivery.

Table 6: Review of technical specifications from 8 EPC contracts of projects in FR, UK, NL and IT

Technical specifications	A	B	C	D	E	F	G	H
General project description	✓	✓	✓	✓	✓	✓	✓	✓
Technology	✓	✓	✓	✓	✓	✓	✓	✓
Plant configuration	✓	✓	✓	✓	✓	✓	✓	✓
Detail implantation schematic & wiring diagram				✓	✓		✓	✓
Component quantity	✓	✓	✓	✓	✓	✓	✓	✓
Component brand & model				✓	✓	✓	✓	✓
Component warranties	✓	✓	✓	✓	✓	✓	✓	✓
Module certifications	✓	✓	✓		✓			✓
Inverter certifications					✓			✓
Module testing								

Plant Testing and Acceptance

The vital task of the EPC service is to deliver a completely functioning PV system to their client by carrying out the contracted scope of works in the EPC contract. The testing of the plant upon completion and the commissioning the plant into operation are therefore very important. They serve as checks to verify if the PV system has been built according to the contractual requirements. If the built PV system initial performance falls short of the expected value estimated in the long-term yield

[3] IEC 61215 and IEC 61646 were compulsory design qualification and type approvals for crystalline silicon and thin film (respectively) terrestrial PV modules to be used in EU. These certifications have been combined and released into a single IEC 61215:2016 certification.

[4] IEC 61730 addresses the safety qualifications for PV modules to be used in EU. The latest version is expected for release in 2016.

[5] The CE marking is a mandatory conformance mark on products sold in the Europe and certifies that a product has met EU consumer safety, health or environmental requirements.

estimation in the project planning phase, this will affect the resulting LCOE value. Furthermore, if a PV system starts with lower-than expected initial performance, the long-term energy production is likely to not meet the initial estimates and thus the investment returns will be impacted.

A successful completion test and commissioning is followed by plant acceptance, usually marked by the owner/developer issuing a form of completion certificate which signals that the EPC contractor has fulfilled the contractual obligations. In general, the detailed plant testing and acceptance requirements are left to be decided between the negotiating parties, i.e. between the owner/developer and the contractor with the involvement of technical advisors or owner's engineers when deemed necessary.

The comparison of the plant testing and acceptance protocol in the surveyed EPC services are shown in Table 7. Results show that all plants required testing and the test protocols and plant acceptance criteria are included in the EPC contracts. *Mechanical completion* visual inspections aim to verify that all the PV plant components and facilities have been mechanically erected correctly and according to the technical specifications. The inspections are followed by *functional tests* to check the electrical functioning of the components of the installation. In the eight surveyed plants, the functioning of all inverters and electrical switchboards are verified and open circuit voltage is measured on between 5 and 10% of the PV module strings. Ground continuity and earthing check is always part of this test. Infrared (IR) inspection are only included in two of the eight plants: one plant requires hotspot inspection on 5% of the PV modules while the second plant requires hotspot checks on all modules and also all other plant components. It is interesting to note that only one out of the eight plants opted for construction monitoring during the construction phase of the PV system. There were four monitoring rounds carried out to check various stages of the constructions (ground/site preparation, module and inverter installation, electrical connections).

Table 7: Review of plant testing and acceptance from 8 EPC contracts of projects in FR, UK, NL and IT

Testing and acceptance	A	B	C	D	E	F	G	H
Are there test protocols?	✓	✓	✓	✓	✓	✓	✓	✓
Are there acceptance criteria?	✓	✓	✓	✓	✓	✓	✓	✓
Construction monitoring					✓			
Completion test - mechanical	✓	✓	✓	✓	✓	✓	✓	✓
Completion test - electrical / functional	✓	✓	✓	✓	✓	✓	✓	✓
Provisional commissioning/ performance test				✓	✓	✓	✓	✓
Provisional performance test period (*# consecutive days*)				*5*	*6*	*15*	*7*	*5*
Provisional acceptance	✓	✓	✓	✓	✓	✓	✓	✓
Final performance test	✓	✓	✓	✓	✓		✓	✓
Final performance test period (*# consecutive months*)	*12*	*12*	*12*	*24*	*24*		*24*	*24*
Final acceptance	✓	✓	✓	✓	✓		✓	✓

Once the mechanical and electrical functionality checks are completed, the PV system is commissioned, i.e. energized and proceeds to deliver electricity to the user/buyer of electricity or to the grid network. A *provisional performance test* is usually carried out to verify the functioning of the PV plant as an entity and the results are used for the decision to accept the plant preliminarily. The test procedure calls for letting the PV plant to operate for a limited period of time during which the energy yield and short-term performance ratio (PR) are evaluated. The test is considered passed when this initial PR is above an agreed value which is either minimum guaranteed PR or guaranteed PR. The minimum guaranteed or guaranteed PR are usually set based on the long-term yield estimation exercise during project planning. A second check of the plant performance is carried out usually after a reasonably extended period of time, usually one or two years of operation since provisional commissioning. The final performance ratio and yield are again checked against the initially estimated value with degradation taken into account.

Among the eight surveyed EPC services, six (projects *D* to *H*) have included both the provisional and final performance tests. The provisional performance test durations range from 5 to 15 consecutive days, and the final performance is checked 24 months (2 years) following the provisional commissioning. Two of these four plants also include interim performance check at one year after commissioning.

Three other EPC contracts (project *A*, *B* and *C*) have elected to not perform the initial performance test; the provisional acceptance of these plants are based on the successful completion of the mechanical inspection and electrical functionality tests. The performance check on these three systems are done 12 months after the commissioning, i.e. during the final performance test. One project (*F*) only has provisional performance acceptance check.

Performance and Guarantees

The survey results on performance and guarantees are summarized in Table 8 below.

Table 8: Review of performance and guarantees from 8 EPC contracts of projects in FR, UK, NL and IT

Performance guarantee	A	B	C	D	E	F	G	H
Guaranteed PR?	✓	✓	✓	✓	✓	✓	✓	✓
Guaranteed availability?					✓	✓	✓	
Is the measurement & calculation method included?	✓	✓	✓	✓	✓	✓	✓	✓
Irradiance threshold (min. W/m²)							100	35
Temperature correction				✓				
Monthly correction factor					✓			
Plant capacity definition	✓	✓	✓	✓	✓	✓	✓	✓
Availability level				99%	99%	98%	98%	100%
Measurement sampling rate and averaging				✓	✓		✓	✓
Monitoring system requirements	✓[1]			✓[2]	✓[2]	✓[3]	✓[4]	✓[1]

EPC warranty / defect liability period (# *years*)	1	1	1	2	2	1	2	2

[1] *pyranometers, module and ambient temperature sensors*

[2] *pyranometers, reference cells, module and ambient temperature sensors*

[3] *pyranometers*

[4] *pyranometers, module and ambient temperature sensors, wind speed and direction, rain and pressure gages, relative humidity sensor*

Key performance indicators (KPIs) are important to determine if the EPC service has been delivered accordingly and the erected PV plant is operating as expected. The EPC contractor designing and constructing a PV system is therefore normally required to guarantee a level of performance. Typical KPIs for EPC service are guaranteed performance ratio (GPR), guaranteed availability or guaranteed yield. Results of the comparison of the eight EPC services (Table 8) point to GPR as the most common KPI. Guaranteed availability is sometimes also used; in the survey we found only three projects have opted for this. The measurement and calculation approach for the short-term performance of the PV systems are included in the contracts if the KPI is used.

The short-term PR of each plant is calculated based on the operation data during the test period which ranges from several days to several weeks as shown in Table 7 above. To obtain the PR of PV system, the actual energy yield Y_f (Wh/Wp) as measured at the electricity meter point is divided by the reference yield Y_r (i.e. the yield of the plant when operating perfectly), as shown in equation (5). The detail formulas of the eight surveyed EPC contracts are summarized in the Table 9 below.

$$Performance\ Ratio\ PR = \frac{Final\ yield\ Y_f}{Reference\ yield\ Y_r} \qquad (5)$$

The reference yield to derive the PR is calculated based on the total irradiation in the plane of module array. There are various inputs to consider in the calculation of the short-term reference yield. These inputs are influenced by the test methodologies (time and irradiance threshold, measurement and data collection) and how the information collected (irradiance, temperature influence, plant capacity and availability) are used in the calculation. Six of the eight surveyed EPC contracts include information of the monitoring system and sensors for various measurements. All six contractors opted to use pyranometers (of good accuracies, i.e. ISO 9060 secondary standard) for the measurement of irradiance. In addition, five of these six contractors also installed module and ambient temperature sensors. These temperature data are needed if the seasonal temperature and other losses are to be included in the calculation of the short-term PR (projects *D* and *E*). Two of the surveyed EPC contracts define a minimum irradiance threshold below which the plant performance will not be considered in the PR calculation. In shorts, there are various ways to obtain the short-term PR among the surveyed projects.

In addition to the KPIs, the EPC contractor will also guarantee the overall EPC works. During this period of warranty, the EPC contractor has the responsibility to address and react to any EPC-related defects or failures in the PV system (thus EPC warranty period usually coincides with the defect liability period (DLP)). Our survey shows that EPC warranty usually lasts for either one or two years following provisional acceptance.

Table 9: Short-term PR calculation variations based on 8 surveyed EPC contracts

	A	B	C	D
PR formula	$\frac{E_{AC}}{H_I \times A \times \eta_{STC}}$ E_{AC} = *actual energy production* [Wh] H_I = *in-plane irradiation* [Wh/m2] A = *total module area* [m2] η_{STC} = *module efficiency after 1 year* [%]	$\frac{E_{AC}}{H_I \times A \times \eta_{STC}}$ E_{AC} = *actual energy production* [Wh] H_I = *in-plane irradiation* [Wh/m2] A = *total module area* [m2] η_{STC} = *module efficiency after 1 year* [%]	$\frac{E_{AC}}{H_I \times A \times \eta_{STC}}$ E_{AC} = *actual energy production* [Wh] H_I = *in-plane irradiation* [Wh/m2] A = *total module area* [m2] η_{STC} = *module efficiency after 1 year* [%]	$\frac{\frac{E_{AC}}{P_{DC}}}{\left(1-\frac{(25-T_c)\times\gamma}{100}\right)\times\frac{H_I}{G_{STC}}\times G_{AV}}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *nominal peak power at STC* [Wp] T_c = *cell temperature* [ºC] γ = *module power temperature coefficient* [/ºC] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2] G_{AV} = *guaranteed availability* [%]
	E	**F**	**G**	**H**
PR formula	$\frac{\frac{E_{AC}}{P_{DC}}}{\frac{H_I}{G_{STC}}\times G_{AV}\times MCF}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *nominal peak power at STC* [Wp] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2] G_{AV} = *guaranteed availability* [%] MCF = *monthly correction factor*	$\frac{\frac{E_{AC}}{P_{DC}}}{\frac{H_I}{G_{STC}}\times AV}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *rated plant capacity* [Wp] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2] AV = *plant availability* [%]	$\frac{\frac{E_{AC}}{P_{DC}}}{(1-D)\times\frac{H_I}{G_{STC}}}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *nominal peak power at STC* [Wp] D = *degradation* [%] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2]	$\frac{\frac{E_{AC}}{P_{DC}}}{\frac{H_I}{G_{STC}}}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *rated plant capacity* [Wp] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2]

2.1.5 O&M

An O&M service set for a PV system ideally should consider PV system technical risks and include activities which are geared to prevent or minimize the risks from occurring. If the risk occurrence is unavoidable, mitigation or rectification measures shall also be part of the O&M service. All these are to be done in manners to optimize the PV electricity cost.

To obtain an overview of current practices of technical aspects in the O&M services, we have analyzed the same group of sample projects as those used in the EPC contract survey in the previous section. The main technical aspects in the O&M service are the scope of work, and the performance guarantees (Figure 8).

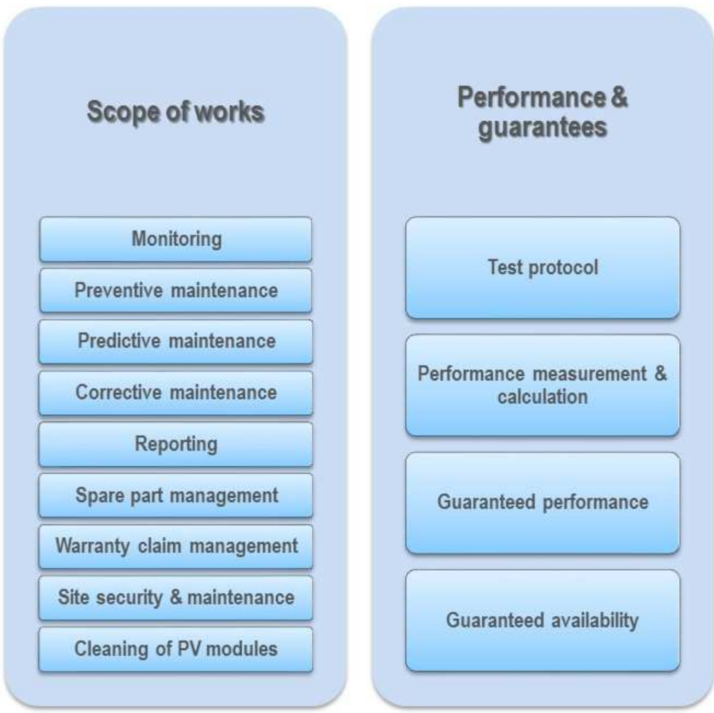


Figure 8: Technical aspects to consider in O&M contracting of projects in FR, UK, NL and IT

Scope of Work

The O&M scope of works are crucial during PV plant operational years since when performed well, the technical risks during operation are minimized which in turns means lesser overall operational expenditures.

The comparison of the O&M scope of works proposed by the eight surveyed contracts are shown in Table 5. Results show that there are core activities in the O&M scope and they include:

- Continuous monitoring of the plant operation;
- Preventive maintenance which are carried out on annual basis or with higher frequency;

- Predictive maintenance (e.g. exchange of inverter after 10 years);
- Corrective maintenance;
- Periodic reporting; and
- Warranty claim management.

The fixed O&M costs cover activities related to the above core activities in the O&M service. Although preventive maintenance is part of O&M fixed cost, the activities themselves could vary and usually include visual inspections and housekeeping of components (cleaning and dusting) and site (trimming of plants). Of the eight surveyed O&M services, we found only half of them include annual module cleaning; the other four O&M stated the cleaning could be done at extra cost (i.e. variable O&M cost thus increasing OPEX). Also, less than half of the contracts include infrared inspection (IR) on the modules and electrical cabinets and junction boxes; this latter is important when we discuss about gaps in mitigating technical failures during plant operational years.

As previously mentioned, there are costs such as inverter replacement which could either be planned ahead in CAPEX or included as part of O&M expenses. This predictive maintenance activity is not included in any of the surveyed O&M contracts.

Spare part management (storage and stockage) is usually included in the fixed O&M cost; however, in one of the projects surveyed, this is not included. The survey also found that not all of the reviewed projects include site security surveillance and site maintenance. This is not unusual if the PV plants are installed on rooftops where the site security and roof maintenance typically fall under the responsibility of the building owners.

There are O&M services which could not be immediately pre-defined. An example of these are the works carried out to repair plant or component failures which do not fall under regular preventive maintenance scope. This so-called corrective maintenance involves man hours to identify, analyze and fix the issues and the cost amount varies depending on the nature of the failure and rectification.

The wide varieties of the O&M scope are influenced by many factors such as plant size, complexity of design and technology, access to location and possibly local regulations. When the scope of the fixed O&M is comprehensive, it will consist of quasi-complete preventive maintenance activities including for instance, full inverter maintenance and replacement part supply and restocking. In this case, the variable O&M costs will likely be low as the required part of corrective maintenance is already addressed by the fixed O&M fee. This case is common for large plants at remote locations with large O&M operator. For small installations (few hundreds kWp or residential), it is likely the O&M fixed fee is minimized and thus the unanticipated variable O&M could be high. The final O&M cost is ultimately determined by the fixed and variable O&M cost portions.

Table 10: Review of O&M scope of works from 8 O&M contracts of projects in FR, UK, NL and IT

Scope of work	A	B	C	D	E	F	G	H
Monitoring	✓	✓	✓	✓	✓	✓	✓	✓
Preventive maintenance	✓	✓	✓	✓	✓	✓	✓	✓
Predictive maintenance								

Preventive maintenance frequency	annual	annual	annual	annual	annual	annual	annual	annual
Module cleaning				✓	✓	✓	✓	
IR inspection						✓[1]	✓[2]	✓[3]
Corrective maintenance	✓	✓	✓	✓	✓	✓	✓	✓
Reporting	✓	✓	✓	✓	✓	✓	✓	✓
Spare part management	✓	✓	✓	✓	✓	✓	✓	
Warranty claim management	✓	✓	✓	✓	✓	✓	✓	✓
Site security & maintenance					✓	✓	✓	✓

[1] *every 2 years on all plant components*

[2] *yearly on all PV modules*

[3] *yearly on all inverters, junction boxes, electrical cabinets and transformers, and on sample groups of modules*

Performance and Guarantees

Similar to the EPC service, key performance indicators are important to determine if the O&M service has been performed accordingly to allow the plant to operate as expected. Typical KPIs for O&M service are guaranteed performance ratio and guaranteed availability. Results of the comparison of the eight O&M services (Table 11) show that there is no general consensus of which of the two KPIs should be used. However, two of the eight services include both of the KPIs and three have elected to offer one of the KPIs. On other hand, three of the eight O&M operators have even not committed to any form of performance guarantee at all. Although not unusual, this practice has been seen in small installations where the O&M service is offered at very low annual price.

Table 11: Review of performance and guarantees from 8 EPC contracts of projects in FR, UK, NL and IT

Performance guarantee	A	B	C	D	E	F	G	H
Guaranteed PR?				✓	✓	✓	✓	
Guaranteed availability?					✓		✓	✓
Is the measurement & calculation method included?				✓	✓	✓	✓	✓
Irradiance threshold (min. W/m²)							100	35
Plant capacity definition				✓	✓	✓	✓	✓
Availability level				99%	99%	99%	99%	99%
Degradation per year				0.8%	0.7%	0.8%	0.3%	
Measurement sampling rate and averaging				✓	✓		✓	✓
Monitoring system requirements				✓[1]	✓[1]	✓[2]	✓[3]	✓[4]

[1] *pyranometers, reference cells, module and ambient temperature sensors*

[2] *pyranometers*

[3] *pyranometers, module and ambient temperature sensors, wind speed and direction, rain and pressure gages, relative humidity sensor*

[4] *pyranometers, module and ambient temperature sensors*

For the contracts with guaranteed performance ratio or guaranteed availability, the measurement and calculation approach are included in the contracts. The overview of these calculation methods are summarized in Table 12 below (projects *A*, *B* and *C* have no performance guarantee and thus not included in the table). The different exclusions found for the PR or availability calculations in the contracts are:

- Force majeure,
- Grid related failures and downtimes,
- Issues caused by owner or other parties, e.g. use of unauthorized spare parts by owner/employer, plant access issue due to owner not authorizing access,
- Unforeseen buildings and shading objects,
- When irradiation is below the set threshold,
- Protected plants causing shading,
- Access electricity beyond grid capacity,
- Failures or under-performance due to environmental temperatures outside plant equipment operation temperatures,
- Auxiliary losses,
- Vandalism/theft/damages by third party,
- Agreed allowance for schedule downtime and unavailability.

Comparing the four PR guarantees, it is clear that they use the same principle in calculating the performance ratio of the plants as expressed by equation (5). The variations in calculating the PR lie in whether additional factors such as plant availability (guaranteed or actual) and system degradation is taken into account in the calculation of the reference yield. The plant availability value used in the formulas is 99%, while a degradation of either 0.3%, 0.7% or 0.8% per year is assumed (all plants are using crystalline silicon module technology).

For availability guarantees, we have found from the survey that there are different ways to calculate the availability. This finding is in line with the results found by Sandia National Laboratories in a study reported in Nov 2015 [11]. The aim of the report is to provide best practice recommendations in availability guarantee in the O&M agreement. In their study, the authors have reviewed eight availability calculations and to what degree they included performance or equipment. The authors reported that four of them were found to be equipment focused, two were equipment and energy focused, and two were energy performance focused. In the Solar Bankability survey, of the four availability calculations, three have taken the time-based approach and one the energy production-based approach. Time-based availability represents the percentage of time during which the PV plant is producing power. It is expressed as the ratio between the duration of production activity and the recording period, both expressed in hours. Data at inverter measurement point are usually used to calculate this type of availability; sometimes an irradiance threshold (min W/m^2) or an hour range (from hh:mm in the morning to hh:mm in the afternoon or evening) is used to determine the period at which the PV plant is considered producing. Beyond this threshold, the measured data are excluded in the performance ratio or availability calculation. Two of the three contracts with the time-based availability calculation defined the PV plant to be producing when the irradiance is above 35 and 100 W/m^2 (projects *G* and *H* respectively).

While relatively easy to calculate, the drawback of the time-based indicator is that it does not allow for the calculation of the impact of unavailabilities on the overall system yield. Energy-based availability takes into account the reference yield, and therefore indicates the energy lost during times of unavailability. The energy-based availability is calculated as the ratio between the reference yield that has been converted to electricity and the total reference yield.

Table 12: PR and availability calculation variations based on 8 surveyed O&M contracts

	D	E	F	G	H
PR formula	$\dfrac{\frac{E_{AC}}{P_{DC}}}{\frac{H_I}{G_{STC}} \times G_{AV} \times (1-D)}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *nominal peak power* [Wp] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2] G_{AV} = *guaranteed availability* [%] D = *degradation* [%]	$\dfrac{\frac{E_{AC}}{P_{DC}}}{\frac{H_I}{G_{STC}} \times (1-D) \times G_{AV}}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *rated plant capacity* [Wp] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2] D = *degradation* [%] G_{AV} = *guaranteed availability* [%]	$\dfrac{\frac{E_{AC}}{P_{DC}}}{\frac{H_I}{G_{STC}} \times AV}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *rated plant capacity* [Wp] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2] AV = *plant availability* [%]	$\dfrac{\frac{E_{AC}}{P_{DC}}}{(1-D) \times \frac{H_I}{G_{STC}}}$ E_{AC} = *actual energy production* [Wh] P_{DC} = *nominal peak power at STC* [Wp] D = *degradation* [%] H_I = *in-plane irradiation* [Wh/m2] G_{STC} = *STC reference irradiance* [1000W/m2]	-
Availability calculation	-	Time-based	Energy-based	Time-based	Time-based
Availability formula	-	$\dfrac{Production\ activity}{Recording\ period}$ *Production activity* = total hours inverter in operation during daylight *Recording period* = total hours inverters turn on or in-plane irradiance exceeds threshold value	$\dfrac{Converted\ reference\ yield}{Reference\ yield}$ *Converted reference yield* is total energy produced during available hours *Reference yield* = total installed Wp x total hours plant is expecting to produce	$\dfrac{Production\ activity}{Recording\ period}$ *Production activity* = total hours inverter in operation during daylight *Recording period* = total hours inverters turn on or irradiance exceeds threshold value	$\dfrac{Production\ activity}{Recording\ period}$ *Production activity* = total hours inverter in operation during daylight *Recording period* = total hours inverters turn on

2.2 Lifetime Energy Yield

One of the main risks during the operational phase of a PV project arises from the uncertainty on the estimates of energy yield. If the actual energy yield does not meet the initial estimates, the entire investment can be compromised as less revenues from energy sales will directly impact the servicing of the debt or the investment return. This scenario can result from, among others, long-term solar resource effects, component failures, defects, forced outages, higher degradation rates than expected, etc.

A review of current industry practices in PV long-term yield assessments (LTYAs) to account for these technical risks was performed by the Solar Bankability project. The outcomes of this review are presented in §2.2.1, §2.2.2 and §2.2.3 below. These current practices are further discussed and analyzed against experimental data in Chapter 3.

As part of this exercise, several LTYA reports were analyzed in terms of, among others, solar irradiation data sources, algorithms, modeling software used, assumptions etc.

2.2.1 Solar Resource Assessment

The bankability of a PV project largely depends on the uncertainty of the solar irradiation data obtained during the solar source assessment phase [8], [12], [13]. The uncertainty of long-term average solar irradiation is therefore a dominating parameter in risk assessment of PV projects. This uncertainty depends in turn on several aspects such as the quantification of the solar resource, the models used, the long-term solar resource variability and trends, etc. Current practices of technical assumptions used for the assessment of the long-term solar resource are summarized below.

2.2.1.1 Survey: Long-Term Irradiation Data Sources

Various long-term solar irradiation data sources are available worldwide. Among others, the following are often used in the long-term photovoltaic simulations [14]:

- Average daily profiles based on long-term monthly averaged values (e.g. ESRA, PVGIS, RETScreen, NASA);
- Synthetic time series (e.g. Meteonorm, PVsyst);
- Typical Meteorological Year (e.g. PVWATTS, PVsyst, SAM, Meteonorm);
- Full multiyear series (e.g. SolarGIS, SoDa HC-3, CPP).

These databases use irradiation data obtained by different methods and, often, covering different periods. 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 [15], [12]. As introduced in the Solar Bankability report *Technical Risks in PV Project Development and PV Plant Operation* [8], significant differences can be observed when comparing the databases between each other or against reference meteorological observations. Consequently, the long-term irradiation uncertainty depends to a large extent on the source of the data and the reference period used.

Measurements of solar irradiation are among the most uncertain in any measurement discipline [16]. Moreover, models developed from measured solar irradiation data and satellite derived irradiation are always validated with measured data. Therefore, the resulting model uncertainty will impossibly be better than the uncertainty of the measured data. Some typical uncertainty values for different long-term irradiation data sources as found in literature are presented in Table 13.

Table 13: Typical uncertainty values for different irradiation data sources

Source	Uncertainty
Secondary standard pyranometer	˜ ±2%
First class pyranometer	˜ ±5%
Second class pyranometer	˜ ±10%
Silicon sensor	˜ ±5% - ±8%
Satellite derived data	˜ ±2.5% - ±5%

The results of the review exercise of irradiation data sources used by seven different market actors are shown in Table 14. Out of the seven consultants, three rely on one source of satellite-based irradiation only. The other four use data derived and interpolated from meteo stations as offered by the Meteonorm package as well as several different satellite data services. It seems that these four either combine the different data sources or select the most appropriate one for a given PV project.

Table 14: Review of irradiation data sources used by seven different market actors

Data source	A	B	C	D	E	F	G
SolarGIS	✓	✓		✓		✓	✓
SoDa HC-3			✓	✓	✓		✓
Meteonorm			✓	✓		✓	✓
PVGIS			✓	✓		✓	✓
NASA			✓	✓		✓	

2.2.1.2 Site Adaptation: Extrapolating Short-Term Measured Datasets

The uncertainty of satellite-derived irradiation data can be significantly reduced with the help of high quality on-site measured irradiation. The purpose of this 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 the measurement campaign (typically around one year [8], [13]), different methodologies can be applied between the measured data at the target site, spanning a relatively short period, and the satellite data, spanning a much longer period. The complete record of satellite data is then used in this relationship to predict the long-term solar resource 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.

Two main approaches for site adaptation of satellite-derived data were identified in literature ([13], [17], [18]): an adaptation to the input data of the model to better fit the local irradiation measurements and, empirical adjustments of the model output estimates by comparison with the on-site measurements. The study conducted by [13] concluded that each site would likely require a specific initial assessment to design the proper method for data adaptation. Moreover, the site-specific method may be a combination of the different approaches. Furthermore, it is highlighted in the study that the optimum duration of the overlapping period between ground observations and model estimates has not been widely studied so far. The Solar Bankability project compared different methods to provide more information on the optimal overlapping period. The first results of this study are presented in §3.1.

The result of the review exercise of site adaptation of satellite estimates provided by seven different market actors are shown in Table 15. The results show that most of the market actors do recommend to perform a site adaptation of the long-term satellite estimates. Moreover, there seems to be a consensus that a measurement period of at least six months is needed.

Table 15: Review of site adaptation techniques used by seven different market actors

Site adaptation	A	B	C	D	E	F	G
Site adaptation	✓	✓	Considered not needed	✓	✓	✓	✓
Minimum required measurement period (months)	6	12		6	6	6	NA

The use of site adaptation techniques potentially mitigates one of the highest risks related with the lifetime energy yield by minimizing the risk of an over-estimation of the solar resource in the initial assessment during project development. An over-estimation of energy yield will lead to under-estimation of the project LCOE and thus could mislead an investment decision. In addition, if the actual energy production does not meet the initial estimates the investment returns will be impacted.

2.2.1.3 Solar Resource Variability and Trends

As introduced in [8], the solar resource 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). However, there is currently no standard period to account for this variability of the resource in LTYAs. Very different results are obtained if, for example, a more recent period of 10 years is used instead of 20 years to calculate the variability. Results presented show that in average for 32 meteorological stations in the Netherlands, the annual variability (σ) of GHI considering the last 20 years is ±4.4%. In contrast, this value decreases up to ±2.3% when considering only the last 10 years.

As introduced in [8] the irradiation in several places across Europe showed a dimming period followed by a significant brightening trend starting from around 1990. Similar results were also reported by e.g. [15], [19], [20]. For example, in [15] a brightening trend of +3.3% per decade, starting from around 1984 in Germany is reported. The Solar Bankability project analyzed 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. A clear brightening trend starting around 1990 was observed with a slope of +2.63% per decade. Before 1990, not enough data was available and therefore no conclusions from a previous dimming trend can be derived from this data.

Figure 9 presents an overview of the variability (σ) of the GHI and the trend per decade for some representative weather stations located across Europe as extracted from Meteonorm v7 [21]. The covered period for most of the stations presented in Figure 9 is 20 years. However, for some stations, this period is much shorter as for e.g. for Cabau in the Netherlands, where a more recent and shorter period of only 8 years is used. Moreover, the reference period is not always the same; for most stations the reference period is 1991 – 2010. However, depending on data availability, different periods are used for other stations. For example, 1986 – 2005 is used for London whereas 1978 – 1996 is used for Paris.

Having different reference periods is unfortunately inevitable when using high quality long-term measured irradiation data from weather stations. Therefore, the use of long-term satellite derived data has gained popularity in the last years. However, satellite derived data has a higher inherent uncertainty and even if the models have been improved significantly in the last years, their resulting uncertainty will never be better than high quality measurement devices used in weather stations.

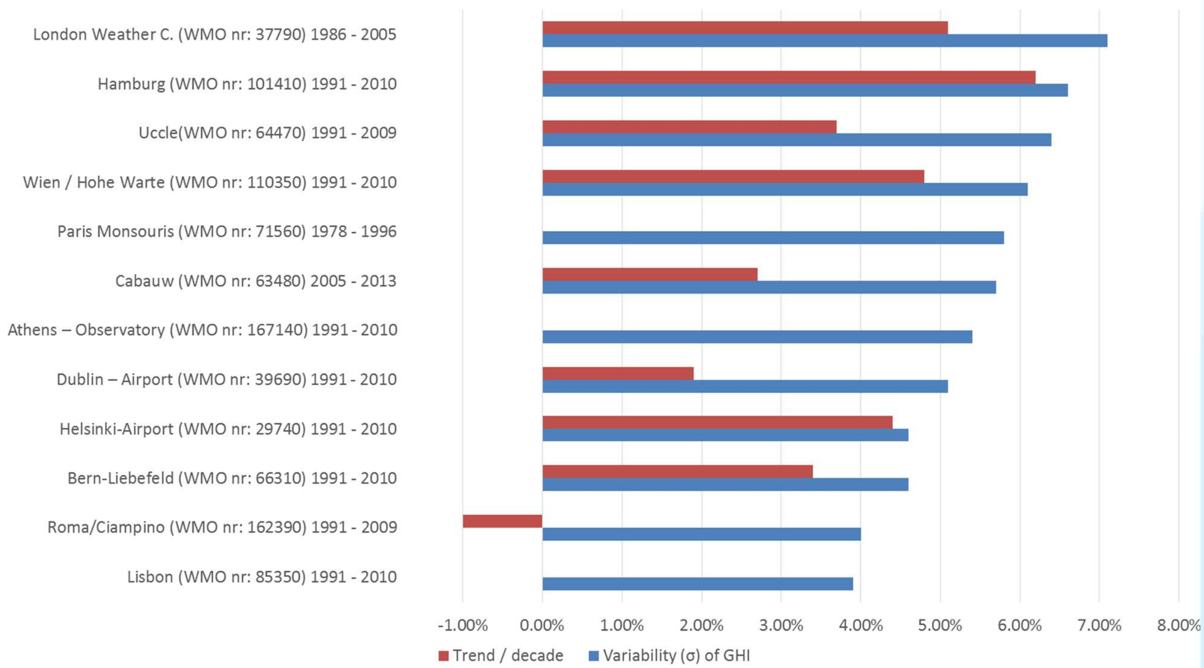


Figure 9: Variability and trends of the GHI for different sites in Europe

Unfortunately, there is no certainty on the future development of the observed long-term solar irradiation trends. 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 under-estimated.

Moreover, the annual variability that is calculated based on this long-term period may be overestimated impacting negatively the P90. Some studies have analyzed different scenarios to assess the impact of these trends on long-term solar resource assessments. For example, in [15] the results of analyzing 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 study concluded that when using the average GHI from the past to predict the average of the subsequent 20 years, the observed long-term trends create an additional uncertainty of about ±3%.

The recent projections of long-term changes in solar irradiation and near surface air temperature worldwide using state-of-the-art climate models were published by [22]. Reported clear sky irradiation trends are slightly negative or close to zero with projected smallest and largest trends of ca. -0.1 W/m^2/year and 0.05 W/m^2/year respectively in most regions of the world, except for parts of China and Europe. Trends in this quantity were found to be statistically significant almost globally. The median trends for all-sky irradiation show a similar pattern associated with clear sky irradiation in addition to the effects of cloud cover. The cloud cover tends to show a decrease of ca. -0.05%/year in the subtropical regions (i.e., South-East of North America, wide parts of Europe and China, the North of South America, South Africa and Australia). As a result, the all-sky irradiation is projected to increase by about 0.03 W/m^2/year in these regions with maximum values of ca. 0.4 W/m^2/year in the South-East of China. For the surface temperatures, globally robust and statistically significant positive trends are reported.

As highlighted in [8], the solar resource variability is one of the main technical source of uncertainty when analyzing the risk associated with the cash flow during a single year. 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. Finally, it is worth noting that the solar resource long-term climate variability is smaller than those seen for wind resource, a factor to be considered in investment in solar vs wind.

2.2.1.4 Conversion to the Plane of Array (POA)

The calculation to the plane of array (POA) for tilted and sun-tracking surfaces assumes the availability of diffuse and direct irradiance. However, not all data sources provide these components. Therefore, often algorithms to split the global horizontal irradiation (GHI) into its components are used. Different combinations of decomposition methods and algorithms for the horizontal to the POA conversion were evaluated by e.g. [12], [23]. The results from these studies show that the Perez and the Hay conversion models are the best performing algorithms. In [23] the Perez turns out to be the first in the ranking, closely followed by the Hay model. This ranking is inverted in [12]. The authors in [23] highlight that the Hay and the Perez models have a very similar behavior and that different results published in literature may be influenced by, among others, the reflected component. The Hay model is simpler than the Perez model and requires less input parameters. Therefore, it is often recommended in literature to use the Perez model only when high quality weather files are available as unreliable input data may potentially distort the output of the model. The newest version of the PVsyst software proposes to use the Perez conversion model as default. However, the users are informed that the Perez model usually gives yearly averages higher than the Hay model (up to 2% higher depending on the climate and the plane orientation). Such difference of up to 2% when using different conversion models has a direct impact on the solar resource estimation and thus on the predicted lifetime energy yield and affects the final LCOE number. For such cases where the results of both models may differ up to 2% (depending on climate and plane orientation), this over or under estimation of the lifetime energy yield will directly impact the LCOE of the project compromising potentially the entire investment.

The review exercise of current industry practices revealed that there is a tendency to use the Perez algorithm. Furthermore, the POA conversion algorithm is sometimes not mentioned in the final long-term yield prediction report as shown in Table 16.

Table 16: Review of POA conversion algorithms used by seven different market actors

POA conversion algorithm	A	B	C	D	E	F	G
Perez	✓		✓	NA	NA	NA	✓
Hay		✓					

2.2.2 Yield Estimation

The system energy production or *system yield* is a function of the system design and location, the solar resource and ambient conditions, the PV module technology, the power conversion system and the overall configuration. Figure 10 illustrates the energy flow in a grid-connected PV system describing the main energy conversion steps taking place within the system. Moreover, a limited but selected collection of measured and modeled parameters used to predict the system yield and to calculate the performance indicators such as the performance ratio are highlighted in Figure 10.

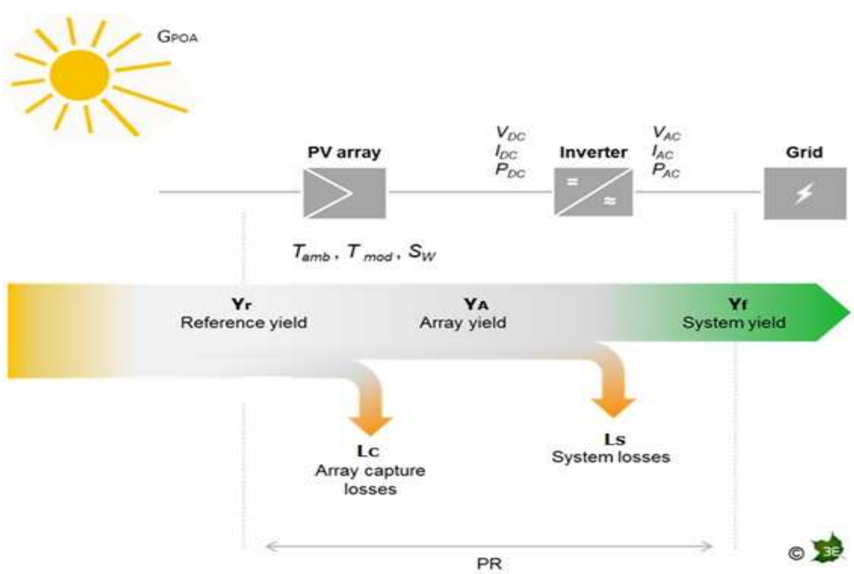


Figure 10: Energy flow in a grid-connected PV system

An overview of the current practices for PV yield modeling, emphasizing on the different aspects including models, input data, and user assumptions that are accounted for to calculate the final system yield is shown in Figure 11. The core of the PV yield modeling process is the PV yield modeling software. However, the output of any PV modeling software strongly depends on the underlying model algorithms used and on the various input parameters such as irradiance and weather related parameters, system design configuration, components technical characteristics, and several user inputs that are often estimates or assumptions based on user experience. Any PV yield modeling software requires the user to estimate some parameters such as soiling, mismatch, cabling and other losses or derating factors. Moreover, the users are requested to choose among data sources and, sometimes algorithms or sub-models to be used [24]. For example, as highlighted in the previous section, a PVsyst user may choose between two models (Perez and Hay) to convert the GHI into POA irradiation. As shown e.g. in [24], [25], these choices can lead to significantly different results even while using the same PV yield modeling software as shown in the next section as part of the review of PV yield modeling software.

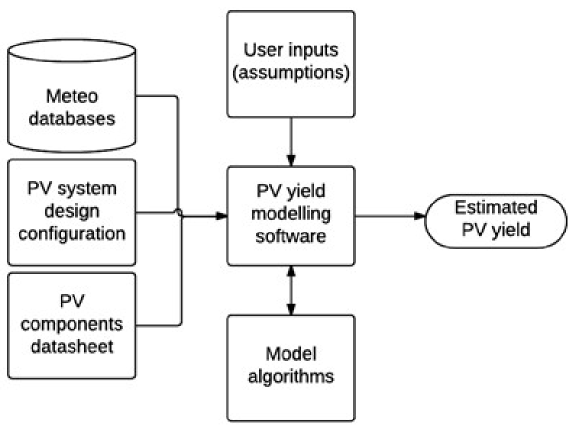


Figure 11: Overview of the PV yield modeling process

The three blocks on the left hand side in Figure 11 represent the three main input categories for the PV yield modeling process i.e., the meteorological data, the system design configuration, and the technical datasheets for the various components of the PV plant.

Meteorological parameters such as the long-term solar irradiation, the ambient temperature and the wind speed, typically come from databases and often involve some modeling steps as described in §2.2.1, e.g. POA irradiation conversion, site adaptation techniques, etc.

Furthermore, the main system configuration parameters such as location, tilt and azimuth, PV array configuration, row-to-row distance etc., are defined during the design phase of a PV plant. The more detailed the information provided, the better the accuracy of the PV yield simulation. However, often the systems are not built as expected during the yield assessment study. Design configuration is often re-adjusted in a later stage due to e.g. non-availability of components, incompatibility with site-specific characteristics, etc. These changes are often not reflected in the initial long-term PV yield predictions and could have a big negative effect on the project risk assessment impacting directly different cost elements of the LCOE as e.g. CAPEX and lifetime energy yield. This is discussed in Chapter 3 of this report.

Specific datasheets of the various components such as PV modules, inverter, measurement devices, etc. play a fundamental role in the PV yield modeling process and in the same way as for the design configuration parameters; the more detailed and specific the information of the PV components, the better the accuracy of the PV yield simulation. The review of current practices in PV modeling revealed among others, that there are significant differences in the sources of PV module data that are used among PV yield modeling software [24]. For example, PVsyst has its own database of the so-called PAN files. However, some manufacturers supply their customers with coefficients for PVsyst that they believe better represent the performance of their modules. Unfortunately, these coefficients are not always independently generated or verified by a third party. Furthermore, some users modify these parameters taking values directly from the PV module commercial datasheet potentially affecting other parameters that will no longer represent correctly the PV module in the modeling process. Other PV yield modeling software such as the Sandia PV array performance model uses performance coefficients from outdoor testing. Independent of which modeling tool is used, the PV module and inverter parameters used for PV yield modeling should be verified by independent laboratories.

The middle blocks in Figure 11 represent the core of the PV yield modeling process. The various inputs described above (i.e. the three blocks on the left hand side in Figure 11), are fed into a PV modeling yield software. This one in turn relies on several modeling algorithms and further user assumptions. The main modeling steps include a PV module model, a PV array model, and an inverter model. Furthermore, various field related derating factors involve several modeling steps with inputs from different sources and often user assumptions or estimates when no model and/or project specific data is available. These include among others, soiling losses, mismatch caused by row-to-row shading and/or due to module tolerances, degradation, reflection, DC and AC cabling losses, transformer losses, availability, auxiliaries consumption, etc.

2.2.2.1 Survey: PV Yield Modeling Software

PV yield modeling tools are used by developers and independent engineers during the project development phase to estimate the expected yield of the system. A variety of software are available in the market like, e.g. PVsyst, PVSol, SAM, PV-Planner, etc.; PVsyst being probably the most common PV yield modeling software used worldwide during the project development phase.

The review exercise revealed that in-house developed tools are also often used by independent engineers during the project development phase to estimate the long-term expected yield of the system (Table 17). The in-house tools seem to be mostly used in addition to the commercial PV yield modeling software such as PVsyst. However, in some cases it may be that only the in-house tools are used. This not only may result in the use of different models but also on several user assumptions and potential flaws.

Table 17: Review of PV modeling software used by seven different market actors

Software	A	B	C	D	E	F	G
PVSyst		✓	✓		✓	✓	✓
In-house tool	✓	✓	✓	✓		✓	✓

Different PV yield modeling software were assessed e.g. by [24]–[27]. In [25], for example, the authors assessed four different PV yield modeling tools by modeling six existing PV systems in Australia. The modeling tools assessed were PVsyst, HOMER, RETScreen, and SMA Sunny Design. The assessment revealed, among others, that the tools may tend to be conservative with an average bias of -3.25% and had an average standard deviation of circa 5%. Such tendency of conservative estimates of the PV modeling tools may be directly reflected in the LCOE, i.e. when the lifetime energy yield (denominator) decreases, the LCOE increases. Moreover, the assessment highlighted that the several estimates and assumptions that must be made as inputs into the modeling tools are critical to the accuracy of the model and are highly dependent on the user and their experience.

Another exercise to assess different PV yield modeling software was carried out during the PV Performance Modeling Workshop, hosted by Sandia National Laboratories in Albuquerque in 2010 [28]. The ca. 20 participants of this blind study included system integrators, independent engineers and consultants from the United States and Europe. Each participant was given three PV system designs and was asked to predict the annual yield from the systems using the software of their preference. The predictions from the participants were then compared with the actual measured annual energy from the three PV systems. The results of this blind study showed that most of the predictions overestimated the actual annual energy.

Moreover, the differences were significant even when same model was used. For example, the annual energy production estimates from two individuals from the same company using PVsyst differed by 15%. However, overall results show that predictions of annual output are within 5% of measured output across the analyzed range of systems and locations, with an average accuracy of 1.2% over predicted output. The overall conclusions were that models often do not agree, there are many user inputs, and often the uncertainty is ignored. Additionally, the different PV yield modeling software are quite different and are not always well documented. Therefore, one of the main lessons learned from this exercise was that greater consistency and transparency is needed.

A more recent study performed in 2014 [27] assessed five different PV yield modeling tools by modeling nine existing PV systems in the United States. The main modeling tools assessed were PVsyst, SAM and PV*SOL. As highlighted by the authors, while the analyzed tools implement many of the same internal sub-models, the inputs accepted and/or required for the tools differ slightly. Moreover, some site-dependent phenomena (e.g. soiling losses) are not explicitly modeled but rather an assumption is often made about its effect on the analyzed system. The results from the assessment show that the annual error of all analyzed tools were within ± 8%. However, the authors point out that the error includes measurement uncertainty of the irradiance data being entered into the models. A more detailed look revealed that all modeling tools present seasonal trend in their monthly error with higher error for winter months.

The overall conclusions from this exercise were that models are required to replace some of the assumptions on derating factors (losses) used today. Furthermore, better guidance on what values to use for certain losses should be provided to enable all models to make more informed decisions about system losses. This guidance should be provided by performing studies to determine more representative values specific to the characteristics of the PV system under consideration.

To address these issues, an initiative started by the Sandia National Laboratories in the US, is ongoing to facilitate a collaborative group of PV professionals (PV Performance Modeling Collaborative or PVPMC) [29]. One of the main goals of the PVPMC is to assemble and organize the most complete, transparent and accurate set of information about PV system performance modeling. This will increase the confidence in the accuracy of PV performance models to lead to lower financing costs and an increase in the number of PV projects that are built. This initiative that started originally in the US has now expanded into a worldwide audience and PV experts from all over the world are actively participating. The Solar Bankability project participated in the most recent version of this international PV performance and monitoring workshop held in Cologne, Germany last October 2015 [30].

2.2.2.2 Long-Term Behavior

PV module and balance-of-system (BOS) components of a PV system age, losing gradually some performance [31]. Most PV module manufacturers guarantee a certain value of nameplate power of typically around 80% after 20 or 25 years. The review of current practices revealed that a linear decline is often assumed with a yearly rate value of around 0.5 – 0.6%/year for crystalline silicon PV modules and 0.8 – 1.0%/year for thin film technologies. However, in some cases a stepped decline is assumed instead. As highlighted by e.g. [8], [31], the assumption of a degradation rate and its behavior over time has significant financial consequences. The assumption of a different degradation behavior over time (e.g. linear vs stepped) may have a significant impact in the cash flow of the project. Moreover, the probability distribution of this degradation will have an effect on the calculation of exceedance probabilities as discussed later in Chapter 3. The module degradation trend over time is also important from the perspective of trying to prove or implement module performance warranty.

Typical yearly degradation rates for different technologies as found in literature are presented in Table 18.

Table 18: Typical yearly degradation rates for different technologies

Technology	%/year
Crystalline-Si	0.5
CdTe	0.5
Amorphous-Si	1
CIS	1

2.2.3 Risk Assessment for Business Case

The exceedance probabilities such as P50 and P90 are commonly used in the technical and financial performance risk assessment of PV plants. In this context, the probability of achieving a given energy yield is represented by a percentile ("P" number). A P50 indicates that 50% of the annual production is expected to fall above the indicated value. A P90 denotes the level of annual production that is forecasted to be reached in 90% of the cases (90% exceedance probability or in other words, the risk of not reaching this value is 10%). The probabilities are obtained by considering all project specific uncertainties and can be calculated for different return periods of interest within the financial model. Different exceedance probabilities e.g. P50, P75, P90, P99, etc. are typically used in the technical and financial performance risk assessment of PV plant.

The results of the review exercise of the default reported exceedance probabilities from seven different market actors in the market are shown in Table 19. Results show that there is a consensus on the use of P50 and P90 values. However, it seems more common to report several different exceedance probabilities by default, including often an extreme P99 scenario for which, when using a Gaussian distribution as estimation to calculate this value, one should be careful when interpreting the results.

Table 19: Review of default reported exceedance probabilities from seven different market actors

Reported exceedance probability	A	B	C	D	E	F	G
P50	✓	✓	✓	✓	✓	✓	✓
P75		✓	✓		✓	✓	✓
P90	✓	✓	✓	✓	✓	✓	✓
P99		✓	✓		✓	✓	

Moreover, different return periods of interest are used by lenders or investors in their assessment of the value of a PV project. For example, a P90 yield for a 20-year period is a key factor to the value of the project and therefore, it might be used for e.g. to assess the project viability for debt financing (business plan). On the other hand, a much shorter return period of interest of 1 year is typically used for treasury purposes, i.e., to assess the risk associated with the cash flow during a single year.

The results of the review exercise of reference period used for the exceedance probability calculation as reported by seven different market actors in the market is shown in Table 20. Results show that different reference periods are used. The most common period used seems to be a long-term 25-year period. However, shorter periods of e.g. 10-year or 15-year are also observed. Moreover, the results point out that in many occasions a single-year period is not used which would not allow to assess the risk associated with the cash flow during single years.

Table 20: Review of reference period used for the exceedance probabilities calculation as reported by seven different market actors

	A	B	C	D	E	F	G
Reference period used	25-year	25-year	25-year	1-year 10-year	1-year 25-year	1-year 10-year 25-year	25-year

Figure 12 shows an example representation of typical evolution of the yearly expected specific yield (P50) together with its 90% (P90) and 10% (P10) exceedance probability for each year of the economic life of the project (i.e. cash flow analysis). In this example, the return period of the project is 20 years. Additionally, an exemplary solar resource variability is included in the figure to highlight the risk associated with this variable, impacting potentially the cash flow during single years.

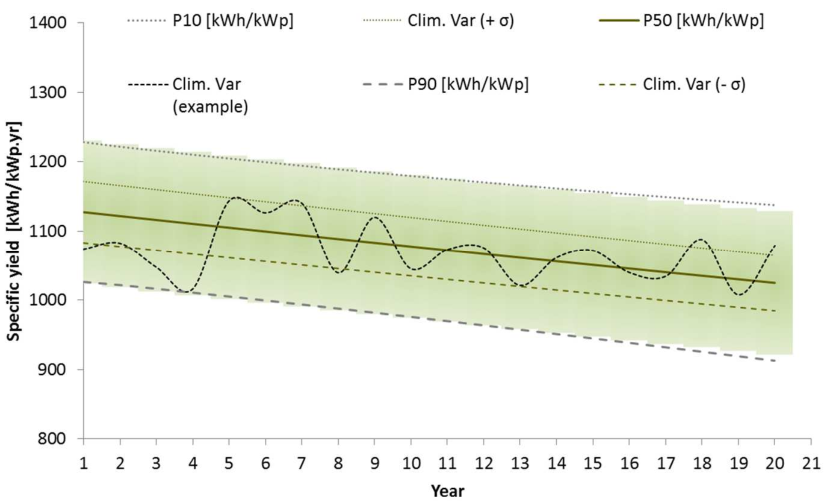


Figure 12: Yearly expected mean specific yield (P50) and its exceedance probabilities (P10 and P90) for each year of the economic life (return period) of the project i.e. cash flow analysis (Source: 3E)

The review of current industry practices revealed that these exceedance probabilities e.g. P50/P90 are typically calculated by fitting the dataset to a standard probability distribution (often assumed Gaussian) and calculating the exceedance probabilities from the distribution's cumulative distribution function (CDF) as defined in e.g. [32], [33]. For example, as stated in [32], the P50/P90 values provided in PVsyst are calculated assuming that over several years of operation, the distribution of the yearly energy yield will follow a Gaussian distribution. In this case, by definition the P50 is the mean value (μ) and the P90 is calculated from the CDF of the normal distribution using the standard deviation (σ) of the sample. The σ value is calculated from the various uncertainties in the simulation process. An overview of the energy flow in a grid-connected PV system with the uncertainties related to each conversion step is shown in Figure 13.

Another method as proposed by [33] is the so-called empirical method. In this case, no particular distribution is assumed to fit the data and rather an empirical CDF is used to calculate the exceedance probabilities. This empirical method is more appropriate when data is not normally distributed. However, this method relies on a sufficiently large dataset to establish a representative CDF from which to interpolate exceedance probabilities. These methods are analyzed further in § 3 of this report.

Figure 13 highlights the various uncertainties related to each conversion step in the energy flow in a grid-connected PV system. In general, the measured/expected energy production or system yield *Yf*, is reported together with the performance ratio (PR), which quantifies the overall efficiency of energy conversion of the PV system. The PR represents the ratio between the system yield *Yf* and the reference yield *Yr* and should be accompanied by an uncertainty, which in turn depends on the uncertainty in the final yield and reference yield quantification.

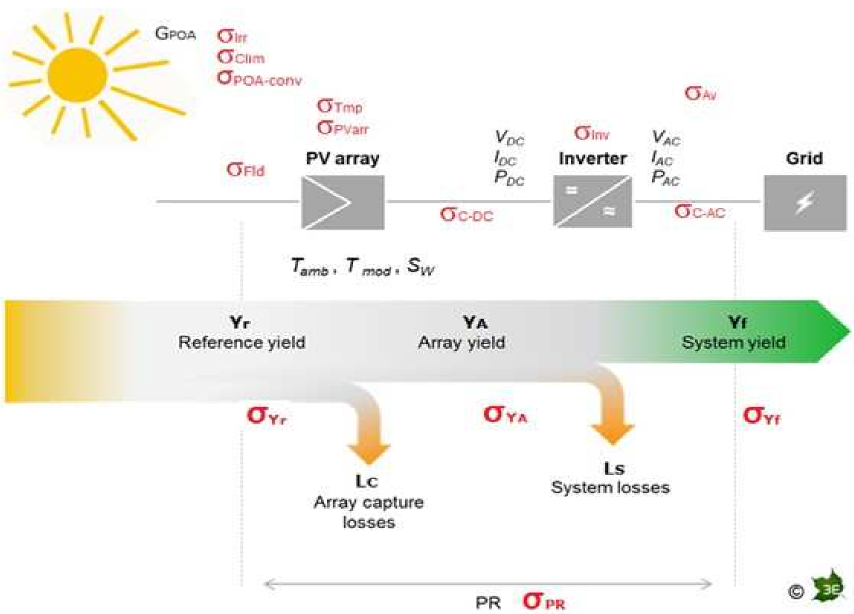


Figure 13: Energy flow in a grid-connected PV system (black= measured/calculated parameters; red= related uncertainties)

Table 21 summarizes the typical ranges of uncertainties found from the review exercise of current practices and complemented with values found in literature as presented in [8].

Table 21: Overview of uncertainties in the different conversion steps

	Uncertainty	Range
Solar resource	Climate variability Irradiation quantification Conversion to POA	±4% - ±7% ±2% - ±5% ±2% - ±5%
PV modeling	Temperature model PV array model PV inverter model	1°C - 2°C ±1% - ±3% ±0.2% - ±0.5%

Other	Soiling Mismatch Degradation Cabling Availability…	±5% - ±6%
Overall uncertainty on estimated yield		±5% - ±10%

Furthermore, as introduced in the previous section, the probability distribution assumption will have an effect on the calculation of P50/P90 parameters. As often the distribution type is unknown, a normal distribution is assumed for most of the uncertainties. However, as shown in the previous Solar Bankability report [8], skewed distributions will also have an impact on the resulting P90 value.

2.3 Chapter Summary

Chapter 2 describes the different factors that determine the business case of a PV investment in the financial model. From an LCOE point of view, these are CAPEX, OPEX and lifetime energy yield.

On the cost side, CAPEX is dominated by the EPC costs while OPEX is dominated by the O&M costs. Depending on the scope of service for EPC and O&M, different risks can be mitigated during planning and installation or during operation. We have conducted a survey over the different cost elements of CAPEX and OPEX for the financial models of 18 ground-mounted PV plants in France, UK, Germany, and Italy developed between 2011 and 2015. The survey was then extended to a set of EPC and O&M contracts from eight ground-mounted and rooftop PV projects in France, UK, the Netherlands and Italy realized between 2014 and 2016. The review included the technical aspects found in the EPC and O&M frameworks.

Moreover, we show how technical assumptions and associated risks are taken into account when calculating the LCOE. On the energy yield side, we have reviewed current practices for lifetime energy yield calculations by screening long-term yield assessment reports from seven different market actors. The review included, among others, sources of solar resource data, models and assumptions for resource assessment, PV modeling software, assumptions on long-term variability and risk assessment. Our review shows that the overall uncertainty on estimated lifetime energy yield is typically assumed to be ±5% to ±10% in terms of standard deviation. These estimates are usually dominated by the solar resource variability over the years.

The most important findings of the review exercise are summarized in Table 22 below.

Table 22: Technical assumptions in present-day PV financial models – review summary

Summary of technical assumptions in present-day financial models for PV
1. For PV LCOE, the CAPEX contributes to a significantly larger portion (~75 - 90%) to the lifecycle costs than the OPEX. 2. There is neither a unified method nor a commonly accepted practice for translating the technical parameters of plant components, performance and reliability into lifecycle costs.

3. The EPC and O&M costs make up to a large portion of the CAPEX and OPEX (70-90% and 30-70%, respectively); the technical details in the EPC and O&M are decisive for managing the technical risks in PV project investment.
4. Risk mitigation measures should be selected with an objective to minimize the LCOE by optimizing the balance between the CAPEX and OPEX.
5. The overall uncertainty on estimated lifetime energy yield is typically assumed to be between ±5% and ±10%.
6. The solar resource variability is one main technical source of uncertainty impacting mainly the risk assessment associated with the cash flow during a single year.
7. PV systems are often not built according to the design used for the initial yield assessment study overthrowing the initial project risk assessment.
8. The use of in-house developed PV modeling tools may lead to flaws in lifetime energy yield calculations.
9. The degradation rate is commonly assumed constant over time although this may not be the case and thus can lead to unexpected deviation in cash flow over the years.
10. Exceedance probabilities (e.g. P90) are typically calculated by assuming a normal probability distribution of e.g. annual irradiation around the expected value; the use of a cumulative distribution function based on long-term resource measurements may be more appropriate in this case.
11. Not all technical risks should be mitigated through technical measures. Financial or legal mitigations should be considered as alternatives.

3 Gap Analyses of PV Cost Technical Assumptions and Risks

This chapter presents the results from the gap analyses on the technical inputs used in the calculation of the PV levelized cost of electricity described in equation (1) in §1.1. In the gap analyses we compared the technical risks at year 0 and during operation in the current practice obtained in the works reported in the previous chapter and available state-of-the-art scientific data.

As introduced in §1.2, the technical risks associated with PV electricity cost fall into two general categories. The first are *year-0 risks* which emerge from actions or decisions taken in the pre-operational phases and could impact the plant performance and energy yield, e.g. incorrect performance and yield initial estimation, bad product procurement, poor transportation or faulty constructions leading to pre-mature plant component failures. The second risk group comprises of *risks during operation*, i.e. failures during operational years which are driven by the wear-and tear of the different PV plant components or associated to issues in the O&M of the plant.

For the gap analyses, we compared the current industry practices found in Chapter 2 to the state-of-the art data from scientific studies and the technical risk database established using a new risk ranking method developed in this Solar Bankability project (this latter is presented briefly in §3.2.1). We have included several *use cases* to give concrete examples of some specifically identified gaps.

At the end of this chapter, the outcomes of this work are summarized in a list of critical gaps of current industry practices.

3.1 Year-0 Risks from Lifetime Energy Yield Estimation during Planning Phase

One of the major risks in PV investment stems from incorrect performance and yield initial estimation in the project planning during the development phase.

From the current practice review reported in the previous chapter, it was found that some of the main technical risks in the lifetime energy yield calculations arise from the uncertainties related with the solar resource quantification and its long-term behavior, the several models and user assumptions involved in the PV modeling steps, and from the way exceedance probabilities such as P50 and P90 are calculated for the technical and financial performance risk assessment.

3.1.1 Solar Resource Assessment

3.1.1.1 Resource Quantification

As highlighted in the review of current practices, several market actors rely on satellite-based irradiation for their long-term yield assessments. The Solar Bankability project analyzed different satellite-based irradiation sources including several new or improved services that are available today in the market. The purpose of this analysis is to quantify the precision of the different models and services available for the practical use as reference yield. Additional information on the methodology and extended results of this analysis are described in [34]. The data from seven different satellite irradiance models have been evaluated and listed in Table 23.

Table 23: Evaluated satellite-based models

Model (abbreviation)	Available through	Ref.
MACC-RAD (maccrad)	CAMS Radiation service, through SoDa	[35], [36]
HelioClim-3 v3 (hc3_v3) HelioClim-3 v4 (hc3_v4) HelioClim-3 v5 (hc3_v5)	SoDa	[37]
MSG-CPP (cpp)	KNMI	[38]
GSIP (gsip)	NOAA (since 3/2014)	[39], [40]
EnMetSOL (enmetsol)	Uni. Oldenburg, turbidity model according to [41]	[42]

The satellite-based irradiation data have been compared to the pyranometer measurements from 203 meteorological stations maintained by the national public weather services of France, Belgium and the Netherlands. The available reference datasets are listed in Table 24 with the spatial distribution of the stations illustrated in Figure 14.

Table 24: Reference data from meteorological stations in FR, BE and NL

Provider	Sites	Aggregation	Coverage
MeteoFrance (FR)	160	Daily	2012 - 2013
RMI (BE)	12	Daily	2012 - 2013
KNMI (NL)	31	Hourly	2011 - 2015

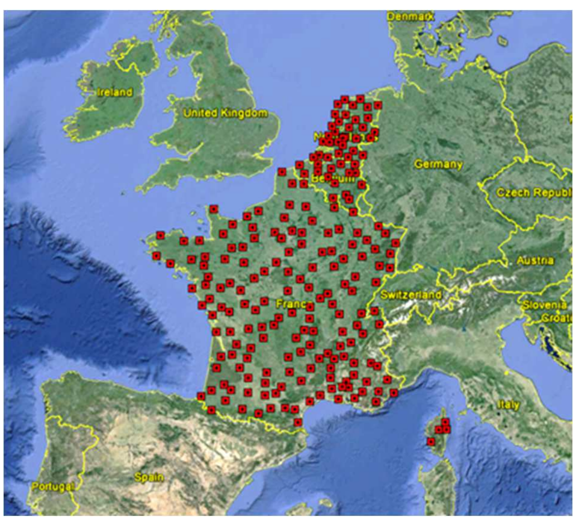


Figure 14: Meteo stations for the evaluation of the satellite-based models

The satellite irradiation data have been evaluated against the reference data by their root mean square error (RMSE), the standard deviation of error (SDE) and the bias with:

$$RMSE^2 = SDE^2 + bias^2 \tag{6}$$

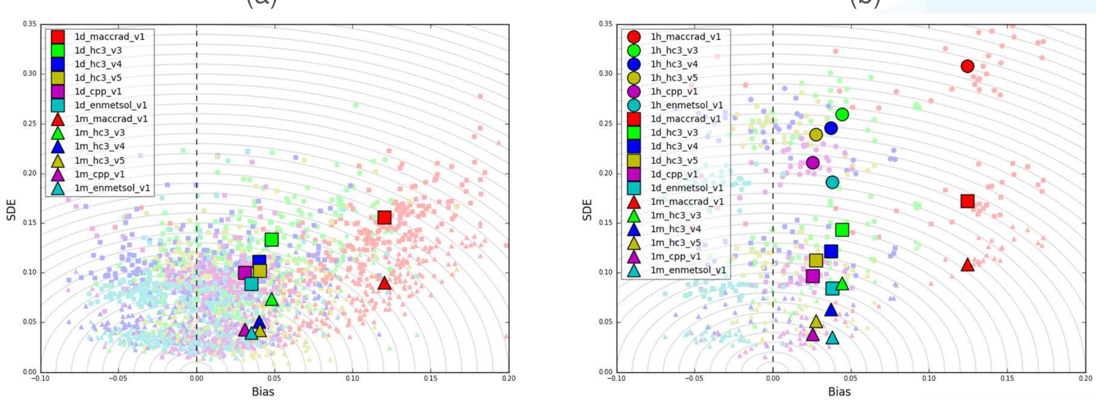
Equation (6) allows to split the RMSE into a random error (SDE) and a systematic error (bias). It describes a circle. When setting out the SDE against the bias in Cartesian coordinates, the RMSE is the distance from the origin. In practice, when computing irradiation by integrating irradiance over long times, random errors are averaged out while the bias will remain the same.

For each of the irradiance data services under test we have computed the three error measures separately for each station and per year. We have evaluated the three error measures for the monthly, daily, and in the Netherlands, also the hourly irradiation values. Finally, we have computed the expected error values $E(x)$ for each service, year and time aggregation from the geometric mean of error x over all stations. These values can be interpreted as the mean error values for each service over the region.

Further explanation on the validation methodology and extended results of this analysis are presented in [34]. The overall results show that the bias of most data services lies consistently between 3 and 5%. However, for individual sites, the bias rather ranges between -5 and 10% (Figure 15). The standard deviation of the error (SDE) can be as low as 2% for the monthly irradiation values for the MSG-CPP method. For the daily and hourly irradiation, the SDE, and hence, also the RMSE are much higher. The average SDE for the daily values lies above 10% for all services and for hourly values it lies even above 20%.

Accordingly, the RMSE values for the best performing models (EnMetSol, HelioClim-3 v5, MSG-CPP and GSIP) are of 3 to 6% for the monthly, and 9 to 11% for the daily irradiation. The RMSE for the hourly irradiation for the better performing models is much worse, in the range of 19 to 23%.

(a) (b)



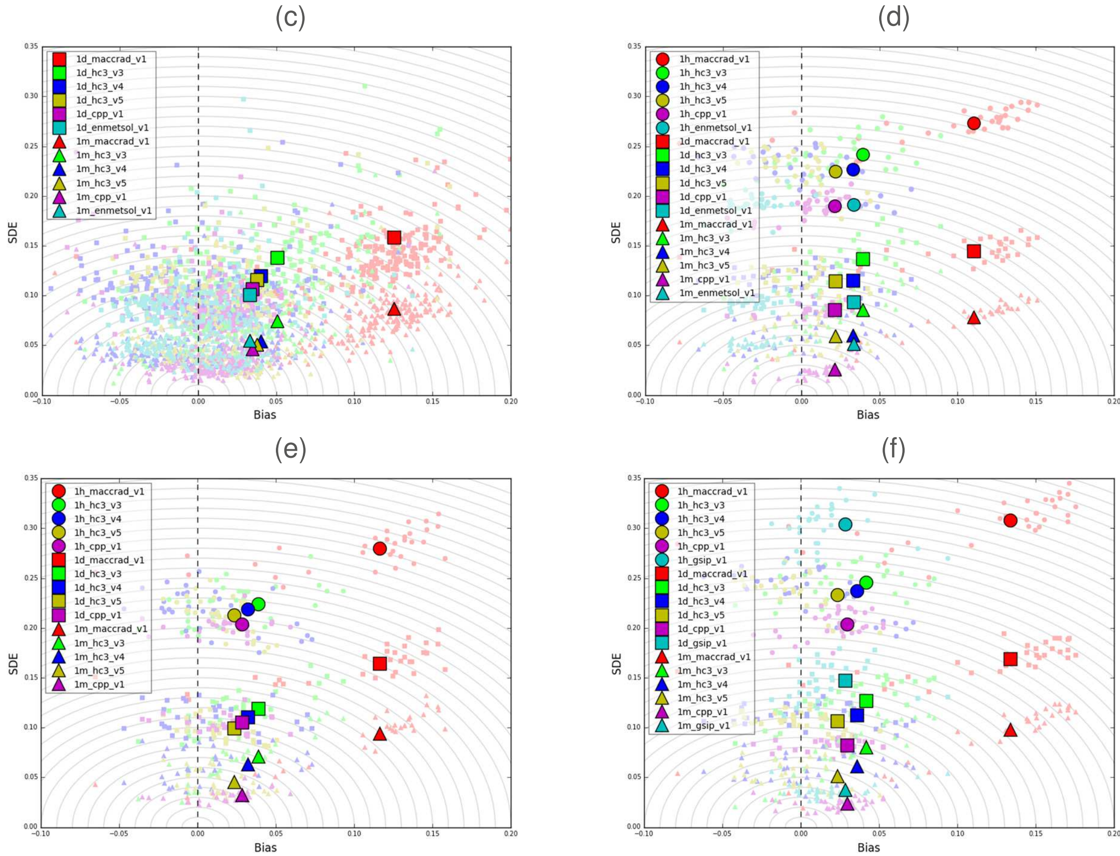


Figure 15: Error measures for the different models for hourly (circles), daily (squares) and monthly (triangles) irradiation in (a) 2012, (b) 2012 NL only, (c)2013, (d) 2013 NL only, (e) 2011 NL only, and (f) 11 months from Apr2014 to Feb2015 NL only

The average bias values of the different models are compared in Figure 16. For the MACC-RAD model, the bias is around 10% and much higher than for all other models. Notably, no default bias correction is applied to the results of the MACC-RAD model by Copernicus or SoDa. Being the direct outcome of an R&D project, the idea is that users of the model results would correct for the bias themselves and depending on their particular situation.

The results of the other models show much lower biases, around 2.5% for HelioClim-3 v3 and below 2% for the others.

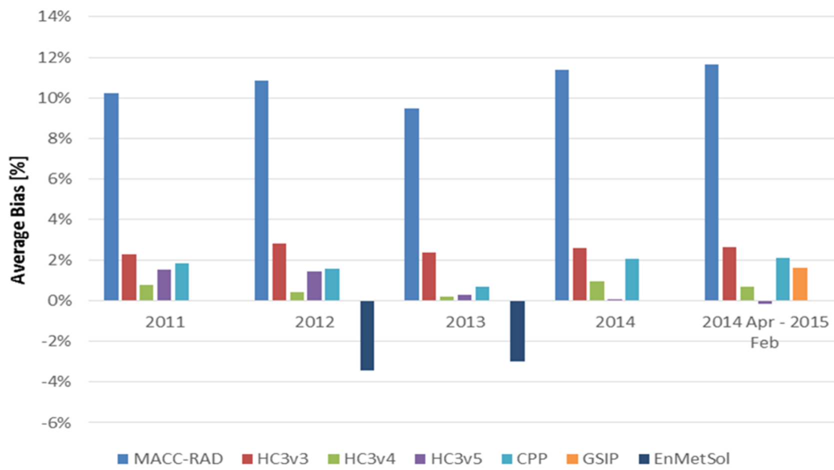


Figure 16: Arithmetic average bias over all stations in NL for the different models and years

Possibilities for further improvement

The resulting RMSE and bias for the best performing models are reasonably low. The bias may still be further reduced through so-called model output statistics. The data are then adjusted through a stochastic filter, taking into account time of the day, or other parameters. If available, the data may also be calibrated specifically for each site by means of measurements from nearby stations [43], [44].

Conversion to the Plane of Array (POA)

The error measures determined here apply to global horizontal irradiation. For irradiation in the plane of a PV array, the horizontal irradiation needs to be converted. The RMSE introduced by this conversion has been found to be between 4.5 and 5.4% [45]. When evaluating the satellite-based irradiation in the plane of array, this uncertainty has to be combined with the one of the horizontal global irradiation. This is done by adding the squared RMSE values for each step and computing the square root of this sum. Accordingly, the RMSE for the monthly plane-of-array irradiation for the best-performing models as listed above ranges between 5.4 and 8.1%.

Comparison to on-site sensors

When comparing the results to on-site measurements in the plane of array, it is clear that for the hourly and daily irradiation, on-site measurements with calibrated and well-maintained instruments will be much more precise than the satellite-based data. Also for the monthly irradiation, the precision of a well-maintained secondary standard pyranometer will be higher than the one from the satellite. However, for first and second class pyranometers as well as for silicon irradiance sensors as we often see them in small to medium size PV plants, the precision of the satellite service is generally comparable and sometimes even better than the one of the on-site measurement.

Generally speaking, the advantages of the on-site sensors are their precise localization of the measurement in time and space and the well-defined precision of the instrument. A disadvantage is the need for regular cleaning, maintenance and calibration, which are not always done correctly, especially for small to medium-size PV plants. The satellite-based irradiation is independent from local maintenance activities.

Furthermore, the combination of datasets can increase the accuracy of the predictions. For example, as stated by, e.g. [16], simple averaging may already be beneficial for models with similar accuracy, exploiting the fact that forecast errors of different models are usually not perfectly correlated. Moreover, the application of statistical methods by, e.g., additionally accounting for the strengths and weaknesses of the different datasets may reduce further the uncertainty as reported in [46].

Conclusions from this analysis

For global horizontal irradiation, the systematic error of most models ranges between 3 and 5%. For the monthly irradiation, the random errors can be as low as 2%. The overall RMSE for the best performing models are then situated between 3 and 6%. For the daily and hourly irradiations, the errors are still much higher.

For irradiation in the plane of the PV array, the overall RMSE also includes the uncertainty introduced by the receiver plane conversion. Accordingly, the RMSE for the monthly plane-of-array irradiation for the best-performing models ranges between 5.4 and 8.1%.

When comparing the precision to that one of ISO 9060 Secondary Standard thermopile pyranometers, we can formulate the following conclusions:

- Fault detection by O&M operator requires good data with hourly or daily resolution. On-site sensors are the first choice but require appropriate maintenance. Satellite data may be used as back-up when the sensors fail or appear to be badly maintained.
- For monthly to annual reporting on the overall plant performance by O&M operators and asset managers, satellite data are a valid and reliable reference. In case of doubt, the satellite should be evaluated with one or two years of data from a well-maintained meteo station in the neighborhood.
- For long-term yield estimates as computed by investors, installers and consultants, satellite data are a valid and reliable reference. In case of doubt, the satellite should be evaluated with one or two years of data from a well-maintained meteo station in the neighborhood.
- Finally, satellite data may also serve to validate the proper calibration and configuration of irradiance sensors in case of doubt. Particularly for large deviations, cleaning needs or shadowed sensors, the satellite may spare the operator a site visit and can already indicate what is wrong.

3.1.1.2 Extrapolating Short-Term Measured Datasets (MCP Methods)

As introduced in §2.2.1, the Solar Bankability project analyzed 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. The long-term measured irradiation data from these 32 KNMI stations in the Netherlands were used together with the satellite derived data from SoDa HC-3 for a concurrent period starting in 2004. Different common short-time periods starting from 1 month up to 2 complete years are used for the application of several measure-correlate-predict (MCP) methodologies described in literature.

A comparison between both datasets during a common one-year period is shown in Figure 17 where positive values (red) mean over-estimation from the satellite and negative values (blue) under-estimation. Figure 17 (left) represent a case where the satellite is consistently over-estimating the irradiation. Figure 17 (right) instead shows a different behavior with in some way less consistency throughout the year. The application of the MCP methodology will have different results for both scenarios as shown further.

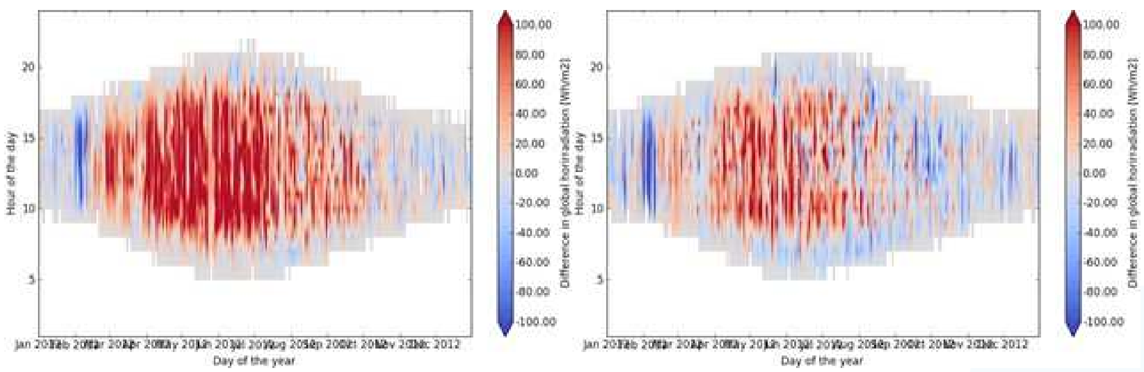


Figure 17: Difference between satellite estimations from SoDa HC-3 and ground measured data from KNMI for two stations in NL: Lauwersoog (left) and Gilze-Rijen (right)

Several MCP methods and their variations are compared with each other and evaluated against the real long-term measured data from these 32 sites in the Netherlands. Figure 18 shows a global overview of the root mean squared bias and root mean square error (RMSE) for each MCP method using different input resolutions (hourly, daily and monthly data) and different short-term reference periods from 1 up to 24 months (all possible combinations using a moving window starting in 2004). The complete analysis of the 32 sites shown in Figure 18 clearly shows that the MCP methodologies yield high accuracies with an uncertainty below 2% if the common period used is longer than 10 months.

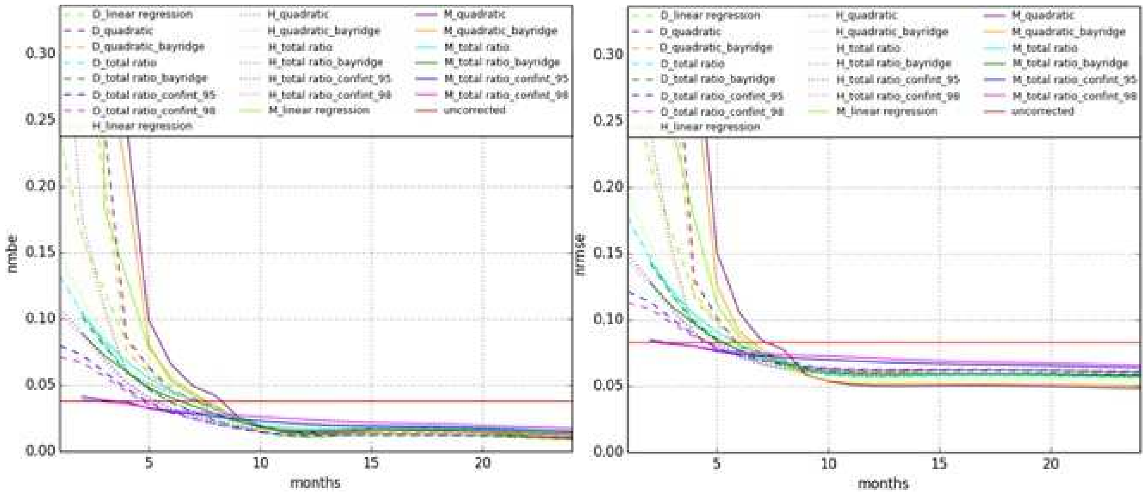


Figure 18: Root mean squared bias (left) and RMSE (right) of all possible reference short-term periods for different input granularities (H: hourly, D: daily, M: monthly data)

The best results from this example are shown in Figure 19, obtained using the total ratio method, merged towards zero by using the 98% confidence intervals during a common period of 12 months at the daily level. Figure 19 shows the normalized root mean square error (left) and bias (right) when both the satellite estimations without any correction (red) and after applying the MCP total ratio with 98% confidence interval methodology (blue) are compared against the long-term ground measurements of KNMI. The blue '+' marks represent each possible different 12-month period while the blue bar is the root mean squared value of all individual '+' points.

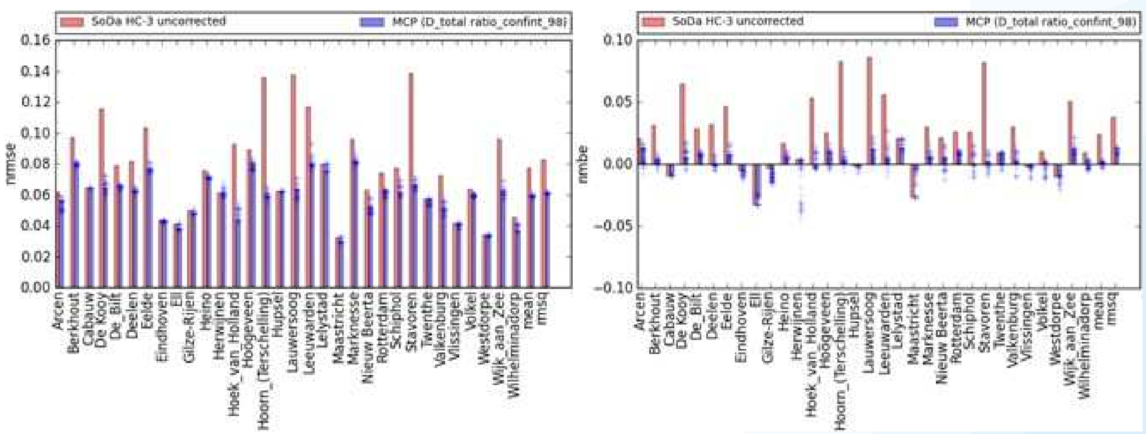


Figure 19: Comparison of monthly normalized root mean square error (left) and normalized mean bias error (right) using the total ratio method with 98% confidence interval and applied to daily values

The results presented in Figure 19 show that for those sites with a constant behavior of the satellite bias throughout the year (e.g. Lauwersoog), the improvement in terms of normalized root mean square error (nRMSE) and normalized mean bias error (nMBE) is bigger. On the contrary, there is not a clear improvement for the sites where the behavior is not constant during the complete reference period (e.g. Gilze-Rijen). This can be improved using more advanced MCP methods as proposed in e.g. [13].

The conclusions from this analysis are:

- Based on the analysis performed for 32 stations in the Netherlands, one can conclude that the MCP methodology yields very high accuracies with uncertainties below 2% (bias) if the common reference period used is longer than one year.
- If a short common reference period of less than 8 months is used, the different methods and its variations yield very different results. Thus, one needs to be careful on the selection of the method. For such short period (less than 8 months) the total ratio method tuned by using the confidence intervals as shown in the results above (Figure 18) yields the best results.
- A common reference period longer than one year will not necessarily improve the results having in fact a negative impact if, e.g., 18 months are used instead of 12 months. Nevertheless, if two complete years (24 months) are used, the uncertainty reduces again. Thus, based on the presented results, having 12 months of common reference period is enough to decrease the uncertainty to ca. 2% at yearly resolution for sites where the satellite bias is constant over the year.
- If the bias of the estimated values (satellite) is not constant over the year, the application of the MCP methodology based on periods shorter than one year can be strongly influenced and thus the accuracy of the results considerably lower. This can be improved using more advanced MCP methods as proposed in e.g. [13].

Recommendations:

- Other locations with different weather conditions and possible different behavior of the bias of the satellite should be analyzed to better assess the methodologies and its suitability to such different conditions.
- A detailed analysis of the bias of the satellite could be performed by e.g. analyzing the bias of the satellite as function of the sun elevation angle ($cos\theta$) and clearness index (kt). If patterns in the bias of the satellite are found, specific correction could be applied increasing the chances of improving the final results. Furthermore, more advanced methods as proposed in e.g. [13] should be included in the analysis.

3.1.1.3 Long-Term Variability and Trends

The long-term GHI measurement records from the 32 KNMI meteorological stations were used further to analyze the long-term variability and trends in this region (Figure 20). A clear brightening trend is observed in this region with a slope of +2.63% per decade starting since around 1990. Even though there is no certainty on the future development of these long-term solar irradiation trends, as discussed in §2.2.1, long-term yield estimates are based partly on the historical irradiation data from before 2000. As a result, the actual irradiation may be under-estimated (increasing the LCOE) and the annual variability may be over-estimated impacting negatively the P90 (overestimating the risk).

Therefore, an important gap on the current practices is highlighted as the effect of these long-term trends are not fully accounted for in any of the seven reviewed long-term yield assessment reports.

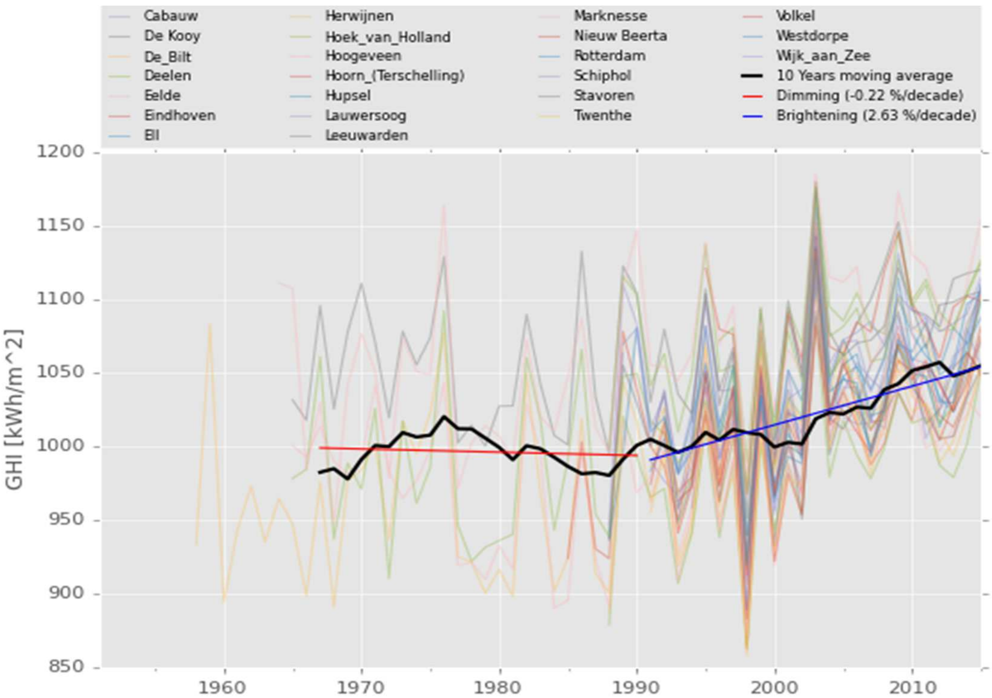


Figure 20: Annual GHI from 32 meteorological stations from KNMI in NL (black line= mean 10-yr moving average irradiation; red and blue lines= dimming and brightening trends respectively, calculated as the linear regression of the mean 10-yr moving average

The Solar Bankability project analyzed different options to account for these long-term solar resource effects into energy yield calculations. The outcome of taking different reference periods, i.e. 20-year and 10-year, to calculate the GHI forecast is shown in Figure 21 and Figure 22 respectively. Figure 21 represents the current practices where a long-term period of at least 20 years is often used. Figure 22 show the result of using a shorter 10-year reference period as recommended by some authors in literature. In both cases the trend is neglected and not accounted for in the GHI forecast.

The shorter reference 10-year period (Figure 22) results in higher mean value and lower yearly variability (σ) of the resource. The yearly variability is calculated using the student's T distribution with correction for unknown mean. One should note that the relatively small sample size (10-year period) may increase some uncertainties in the calculation. Using this approach (i.e. shorter reference period) may be correct for the determination of the expected mean value for the coming years due to the brightening trend effect. However, using this shorter period to calculate the yearly variability may mislead some effects as, at least for the example presented here, the yearly variability is clearly much lower in the past 10 most recent years than before. However, it is not clear whether this lower yearly variability is the new normal or just coincidence. One possible explanation is that also the high variability in the past was due to e.g. pollution (smog levels varying from year to year) which may not repeat with the same magnitude in the coming years.

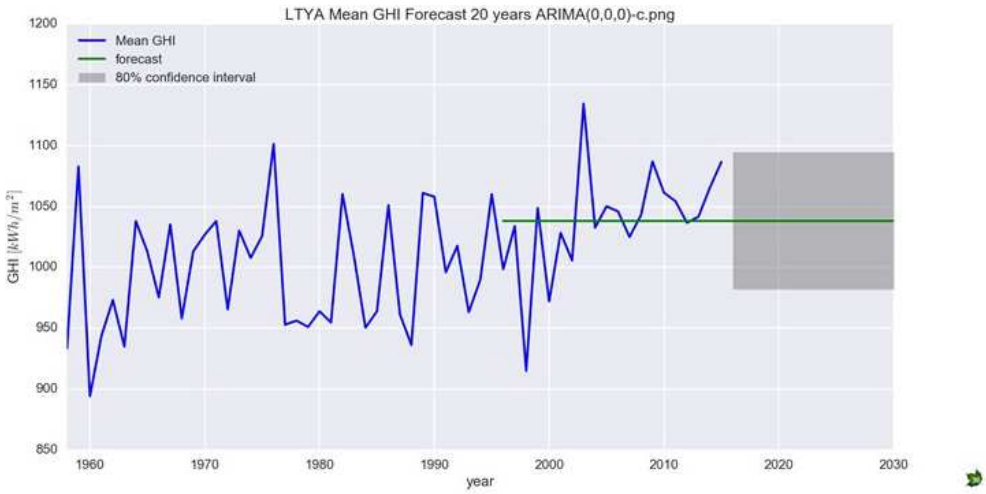


Figure 21: Solar resource trend and reference period (20 years) in NL

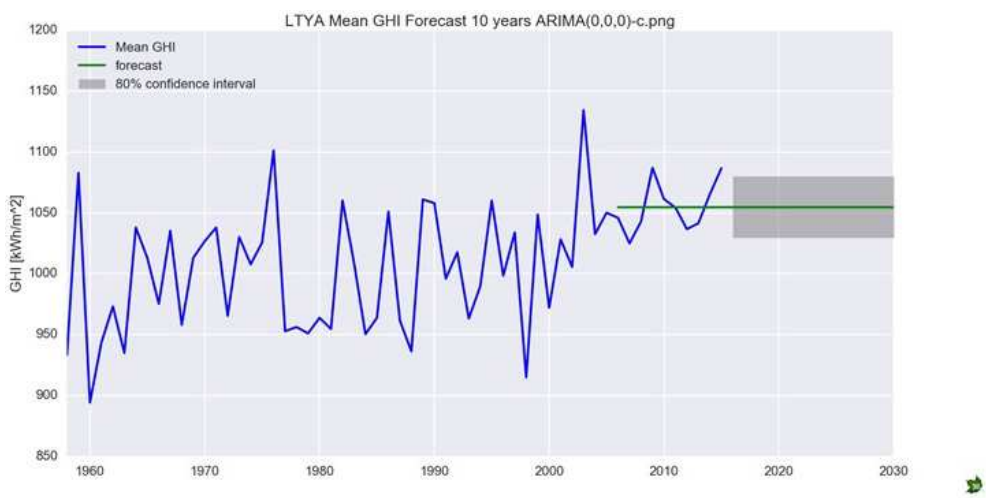


Figure 22: Solar resource trend and reference period (10 years as recommended in literature) in NL

Different alternatives were analyzed to overcome the weaknesses of simply taking a more recent and shorter reference period for the long-term solar resource forecast. Among others, an auto-regressive integrated moving average (ARIMA) model with and without trend effect was analyzed. The application of an ARIMA model allows for using the entire long-term historical data (e.g. 50-year+ period for the case of the example) to forecast the behavior for the coming years. Moreover, the ARIMA model allows for slowly varying (unknown) external effects that may impact the average value over time (e.g. due to pollution).

The outcomes of the application of an ARIMA(0,1,1) model (i.e. simple exponential smoothing) with and without trend are presented in Figure 23 and Figure 24 respectively. The use of these methods allows, among others, accounting for possible future evolutions (trends). One can, for example, assume a persistence of the trend (Figure 23) to forecast the irradiation for the coming years. Nevertheless, as this may be unrealistically extreme as discussed in §2.2.1, one can account for such trends as part of the uncertainty instead (Figure 24). In this case, the uncertainty increases the further one goes in the future. This method is recommended instead of including the trend or simply taking a shorter reference period of, e.g., 10 years as proposed in literature. For cash flow analysis (uncertainty of single years) this approach is clear and therefore, of-the-shelf algorithms can be used. However, for valuation analysis (uncertainty of multiple year sums), the approach to account for such uncertainty is not trivial and therefore, a clear methodology needs to be derived.

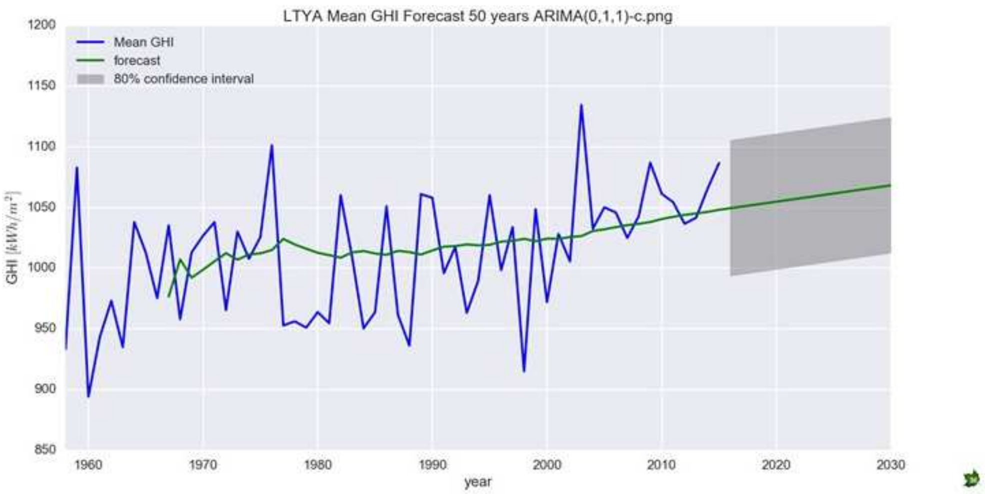


Figure 23: Forecast of future long-term irradiation using ARIMA(0,1,1) model with trend

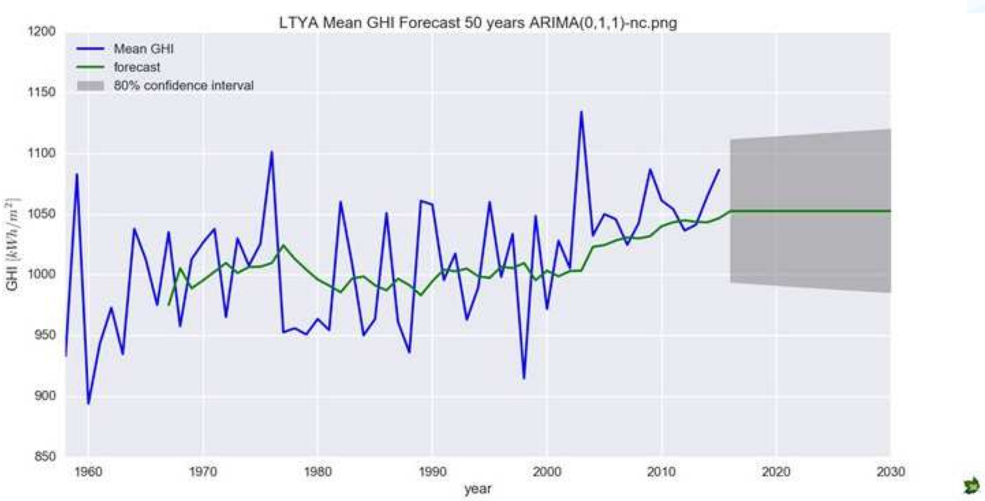


Figure 24: Forecast of future long-term irradiation using ARIMA(0,1,1) model without trend

The application of these methodologies can yield more accurate results. Nevertheless, the increase in complexity compared with the current practices (i.e. simple average of last 20 or 10 years) may be a potential source of errors which is an important drawback. More errors are usually made with complex models. Therefore, the procedure needs to be very well defined so that errors are minimized and results are comparable. The Solar Bankability project recommends further investigating these methods with the aim of defining a clear methodology that can be applied in all long-term yield assessment studies.

3.1.2 Risk Assessment for Business Case

As introduced in §2.2.3, a common way to quantify the risks associated with the different technical elements of the long-term energy yield estimation such as the variability of the solar resource, is to calculate the exceedance probabilities as, e.g., P50/P90. The review of the current industry practices revealed that in most cases a normal distribution is assumed for all elements. However, as proposed by some authors, e.g. [33], the use of an empirical method would be more appropriate, i.e. no particular distribution is assumed to fit the data and rather an empirical cumulative distribution function (CDF) is used to calculate the exceedance probabilities. This empirical method is more appropriate when the data is not normally distributed. However, this method relies on a sufficiently large dataset to establish a representative CDF from which to interpolate exceedance probabilities.

Unfortunately, there is not always a sufficiently large dataset available to establish the CDF from which to interpolate exceedance probabilities. Nevertheless, for some elements involved in the calculation of the long-term expected yield as, e.g. the solar resource, this method could be applied.

3.1.2.1 Cumulative Distribution Function (CDF) of Annual GHI

The Solar Bankability project compared the empirical CDF of the GHI with the normal CDF calculated from the mean (μ) and standard deviation (σ) of the dataset as proposed by [33]. The empirical CDF (blue) of the average GHI for the 32 KNMI meteo stations in the Netherlands together with the normal distribution CDF (red) calculated from μ and σ are shown in Figure 25.

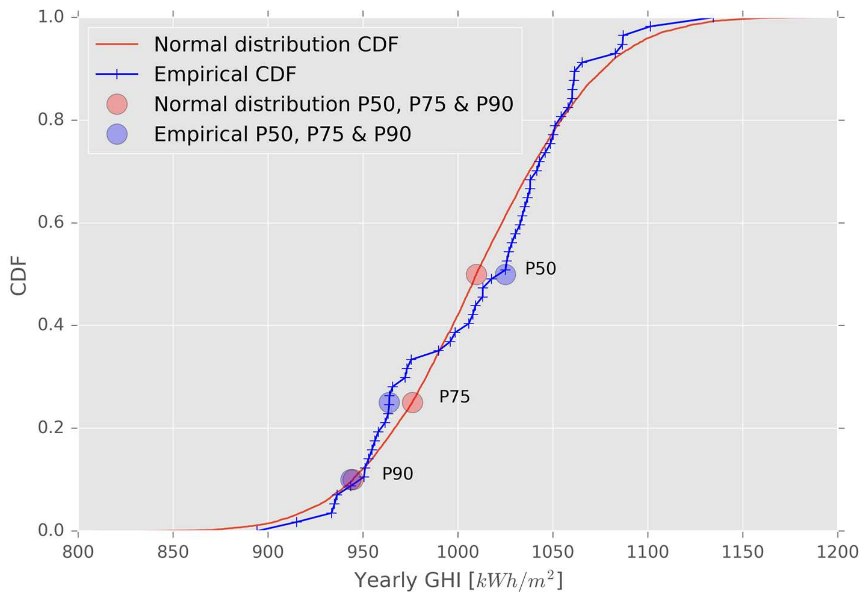


Figure 25: Cumulative distribution function for the long-term (58 years) GHI in NL

Figure 25 shows that even though the CDF calculated using the empirical method (blue line) may approximate a normal distribution (red line), there are some important deviations. For example, the P50 point, extracted from both scenarios and represented with the red and blue circles, are not the same. For this example, the P50 calculated assuming a normal distribution (red circle) is -1.5% lower than the empirical P50 calculated by interpolating exceedance probabilities directly from the empirical CDF. It is by coincidence that the P90 values for both empirical and normal distributions are nearly the same in this example (difference of only +0.12%). For a P75 scenario however, using the normal distribution approximation (current practice) would result in an over-estimation of 1.3% compared with the empirical value.

The percentage differences in the calculated exceedance probabilities for the P50, P75 and P90 scenarios for all individual 32 KNMI meteo stations are shown in Figure 26. The difference is defined as the exceedance probability (i.e. P50, P75 and P90) calculated assuming a normal distribution minus the empirical one. A positive value means an over-estimation by the normal distribution assumption compared with the empirical method. Differences of up to 3% are observed in some cases. As shown in Figure 26, calculating high exceedance probabilities assuming a normal distribution for the long-term GHI often results in higher deviations. Therefore, calculating extreme exceedance probabilities as observed in the review of the current practices (e.g. P99 scenarios) may result in misleading conclusions.

In conclusion, an important gap on the current practices is highlighted as exceedance probabilities for long-term irradiation are often calculated assuming a normal distribution. Furthermore, extreme scenarios (e.g. P99) are sometimes calculated using this approach which can yield in unrealistic results.

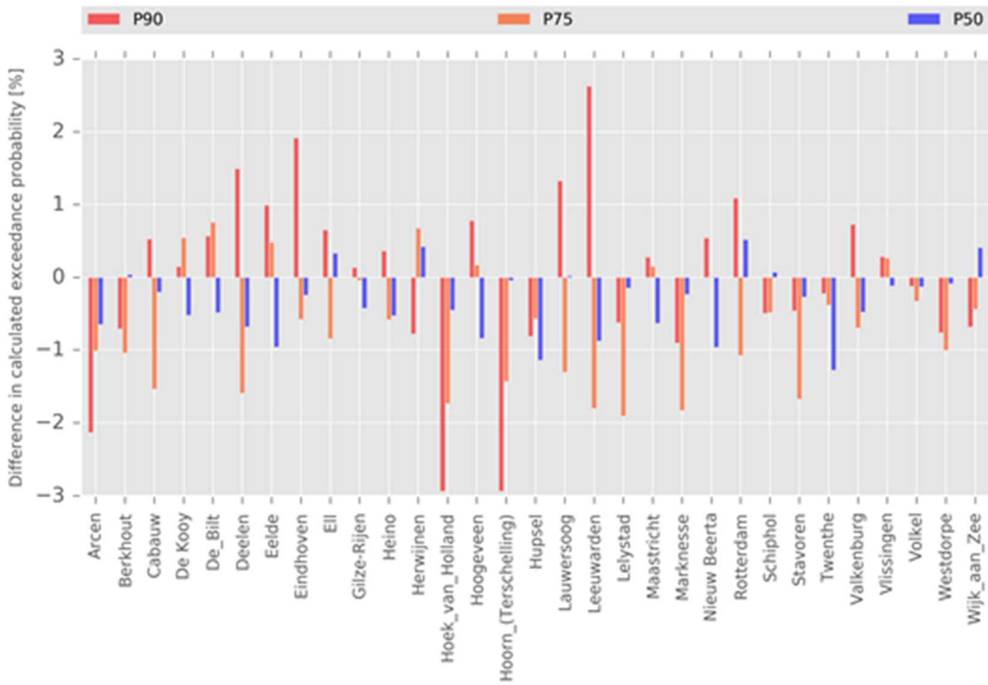


Figure 26: Difference in calculated exceedance probabilities (P50, P75 & P90) using the normal distribution and the empirical method (positive values mean overestimation by the normal distribution assumption compared with the empirical method)

In this section, we have given an example on how assuming a normal distribution for the solar resource uncertainties may not be the most correct approach. Different approach using a Monte Carlo technique to analyze the different uncertainties in energy yield modeling is discussed in the Solar Bankability report *Minimizing Technical Risks in Photovoltaic Projects - Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation* [47].

3.1.3 Availability for Financial Model vs O&M Guarantee

PV plant availability is one of the key performance indicators (KPIs) important to determine if a plant operator is operating and maintaining the PV installation properly. A guaranteed plant availability is therefore often included in the O&M contract as a legal binding of the O&M operator. Moreover, there are usually penalties or liquidated damages in the O&M contract in the case the O&M operator fails to meet the guaranteed availability. From the O&M contract survey in §2.1.5, we found that the guaranteed availability commonly committed is 99%.

It is important to recognize that the guaranteed availability in the O&M contract is different from the overall PV plant availability (productivity) from the perspective of income generation and PV LCOE. Logically, the O&M operator's guaranteed availability is always on the PV plant level and only covers all the aspects which are under their responsibilities. Therefore, the O&M operator is not liable for any causes of loss in the PV plant availability beyond the operator's fault (e.g. force majeure, grid outage due grid operator's issue, etc.). The common O&M exclusions in the guaranteed plant availability calculation assumed in the current industry practice are listed in §2.1.5.

For the purpose of calculating the LCOE and final income from electricity production, the availability assumption in the PV financial model should reflect the overall plant availability. This means an assumption of unavailability beyond the O&M service needs to be considered and added onto the plant unavailability. For example, in the case of the surveyed O&M contracts above, by considering the other sources of unavailability, the overall plant availability could be 98%.

In the following use case, we present a concrete example of the importance of evaluating the overall availability using the actual historical data, and adapting the initial overall availability assumption in the financial model to an actual value so that the financial model reflects better the actual production income.

Use Case 1: Adapting the availability assumption in the financial model with actual availability of operational PV plant

The gap between the initial long-term yield estimates and the actual yield of a portfolio of PV plants under operation was analyzed using monitored data from energy meters. The portfolio contains a total of 41 PV plants at sites in mainland France, French oversea departments and territories (DOM-TOM) and Italy. Rooftop and ground mounted systems, covering a wide range of installed capacity from 10 kWp up to 12 MWp were analyzed. Moreover, as shown in Figure 27, at least one year of operational data and up to 4 years for some plants were used in the analysis.

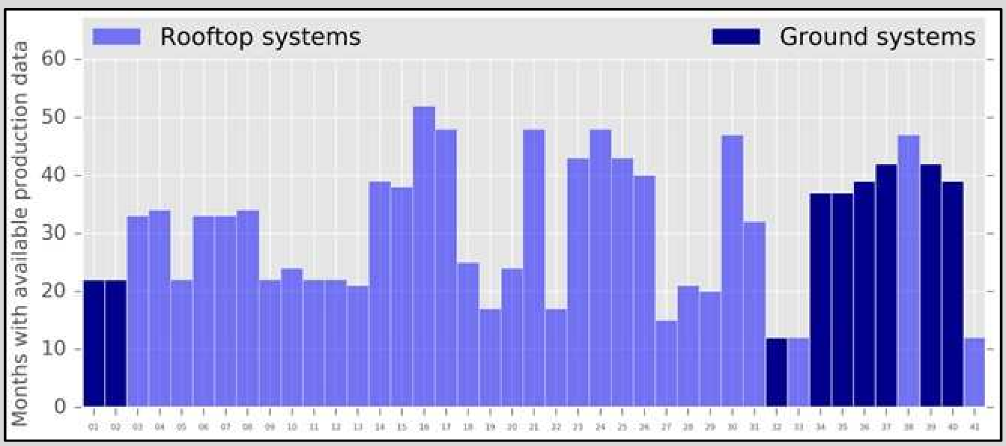


Figure 27: Overview of number of months with available production data of the 41 PV plants

The initial long-term yield estimates were compared against the actual yields of the PV plants across the portfolio. The results of a first exercise without any correction for the actual unavailability are presented in Figure 28. The initial long-term yield estimate for the first year of operation (P50) is represented as the zero line. The red and green background colors represent the P90 and P10 estimates respectively, being typically between ±7 and ±9% away from the P50. The difference with the actual production during the first year of operation is represented with the blue bars. In this case, a negative blue bar means that the actual production was lower than the initial estimate (i.e. over-estimation in the initial long-term yield assessment study). Ideally all bars should lie within the red (P90) and green (P10) regions.

The main purpose of this exercise is not to analyze each individual case but rather to understand the level of agreement, not only with the initial estimated yield (P50 values), but also with the related uncertainties leading to e.g. the P90 values. Figure 28 shows that for most of the analyzed PV plants, the actual production during the first year of operation (blue bars) lies within the expected uncertainty margins ($\pm\sigma$) calculated during the initial long-term yield assessment study. However, there are some PV plants within the analyzed portfolio of which the actual production is below the expected worst case scenario (i.e. P90). These deviations for some plants are further analyzed to understand the gaps.

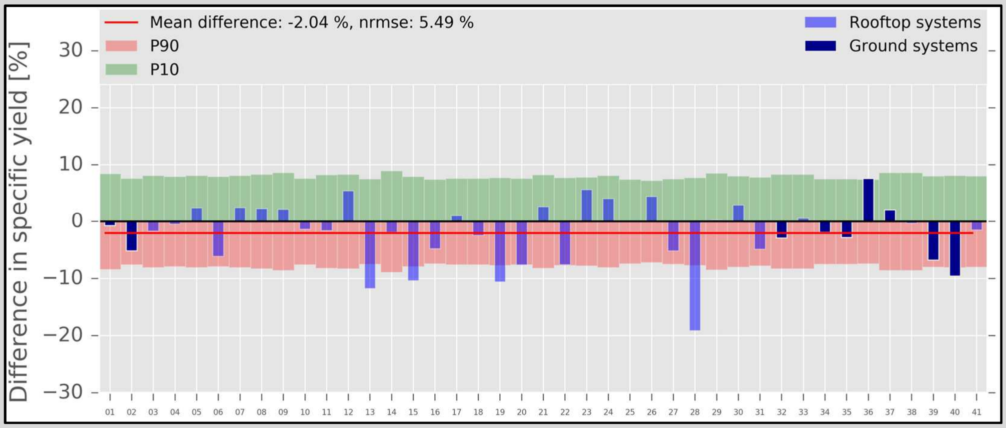


Figure 28: Difference in specific yield between initial estimated values and actual production data from 41 PV plants in FR, DOM-TOM region and IT

To understand better such deviations observed on some PV plants (Figure 28), the availability of each individual plant has been analyzed. Figure 29 shows the actual percentage unavailability (downtime) for most of the analyzed PV plants. For most cases, the unavailability data comes directly from the detailed O&M reports. Moreover, when possible, the unavailability was calculated from the high resolution data (15-minute data). However, unfortunately it was not possible to determine the unavailability for all 41 PV plants since the detailed O&M report is not available for some plants and often only monthly data is available.

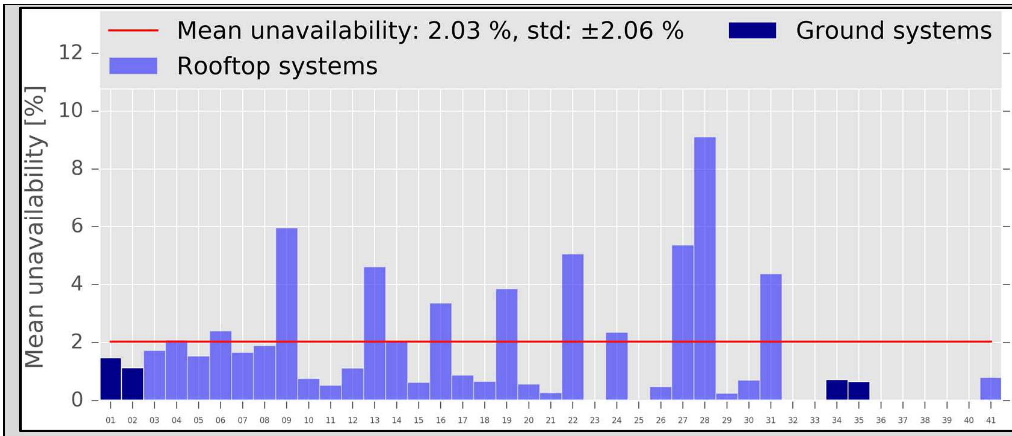


Figure 29: Actual unavailability data from most of the PV plants

Figure 29 highlights that for some PV plants in the portfolio, the actual unavailability is very high compared with the initial expectations (e.g. PV plant number 28). Moreover, the mean yearly unavailability of the analyzed portfolio is around 2%. As observed in the review of current industry practices in Chapter 2, a typical assumption of unavailability taken in initial LTYA studies and O&M contracts is around 1%. However, as previously mentioned, the unavailability values in the LTYA studies and in the O&M contracts are not necessarily the same as the O&M operators are only liable for plant outages caused by their negligence. Therefore, the unavailability used in the LTYA studies, which in turn will be used to assess the energy production income, are usually higher and should be adapted with the actual availability once representative operational data become available.

For this use case, the updated results of the comparison between the initial estimates and actual production taking into account the actual unavailability are presented in Figure 30. The effect of the actual unavailability correction is highlighted for some example cases with the orange arrows in Figure 30. Results show clearly that the gap is significantly reduced. Moreover, the deviations below the confidence margin (P90) disappear after the corrections as highlighted by the orange arrows in Figure 30 for some examples (e.g. PV plants numbers 13, 19 and 28).

The overall results taking into account actual unavailability show that in general there is a good agreement between the initial estimates and the actual production. The overall mean difference after correction is -1.15%. This means that over the analyzed portfolio the actual yield is, on average, slightly lower than the initial estimates done during the PV plant planning (design) phase. Furthermore, as shown in Figure 30, the dispersion (nRMSE) is around 4.4% for the analyzed portfolio. These variations lie within the normal expected ranges and are similar than the values reported in e.g. [48]. As shown in Chapter 2, such variations are typically expected mainly due to the variability of the solar resource and other on-site specific losses that are not precisely modeled during the design phase.

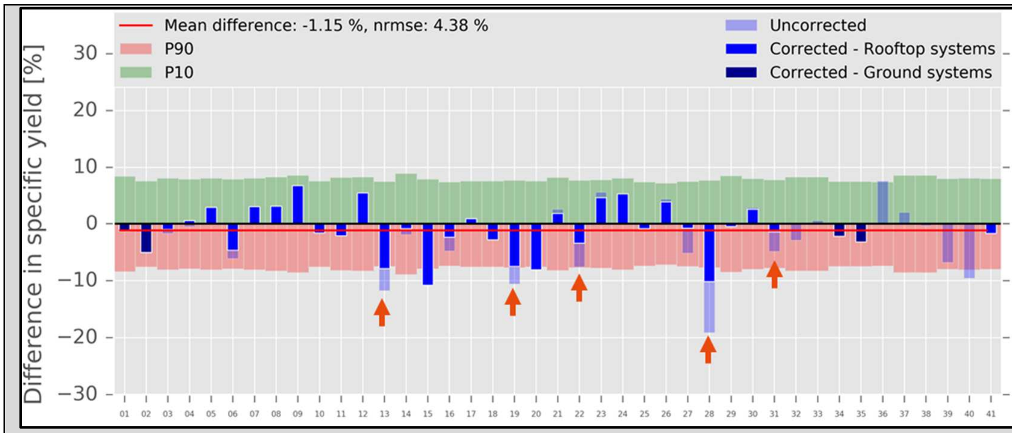


Figure 30: Difference in specific yield corrected for actual unavailability (orange arrows highlight the effect of the unavailability correction for some examples)

Figure 31 shows the same data presented in Figure 30 but in different formats. On the left the data is presented as a scatterplot, showing the specific yield absolute values. In the same way, the orange arrows highlight the effect of the unavailability correction for some examples. Furthermore, the difference and its distribution are shown on the right of Figure 31. Such difference is represented using a "violin plot" which is a combination of a box plot and a kernel density plot. This kind of plot gives not only the valuable information of a box plot but also shows the probability distribution (density) of the data at different values.

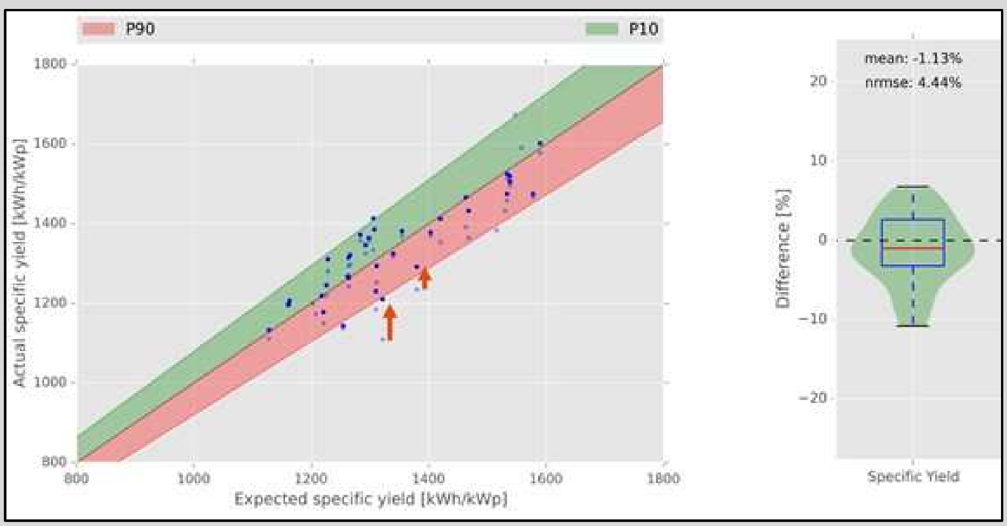


Figure 31: Scatterplot (left) and violin plot (right) of the difference in specific yield between initial expected yield and actual yield for the analyzed portfolio of 41 PV plants

Finally, the difference between the initial estimates from the LTYA study done during the design phase and the actual values during the first year of operation for POA irradiation and PR are shown next to the final specific yield in Figure 32. As it can be seen, the largest gap comes from the performance ratio estimates. As highlighted in the review of the current industry practices in the previous chapter, the initial estimates of system losses depend on several factors. In addition to the PV software modeling accuracy, several user estimates and assumptions affect the yield estimates. One should note that the results for the POA irradiation shown in Figure 32 are the outcome of comparing the initial estimate done during the LTYA against the satellite-derived irradiation from CPP for the first year of operation. Unfortunately, not all 41 PV plants in the portfolio had good quality on-site sensor measurements. Therefore, the satellite-derived irradiation data has been used to allow the analysis across the entire portfolio and for consistency purposes.

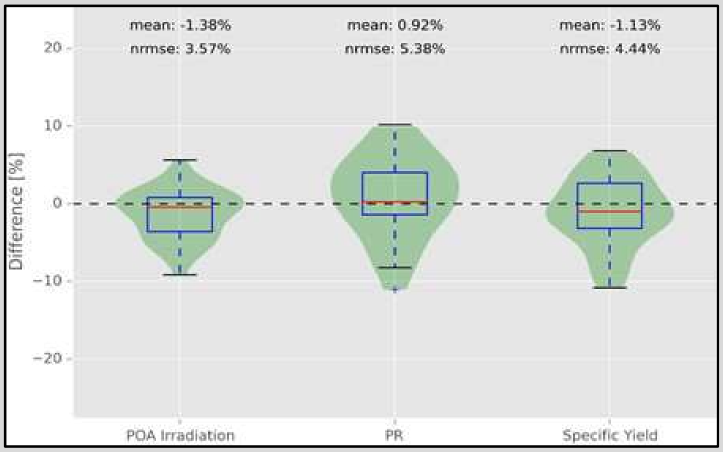


Figure 32: Violin plots for the difference in POA irradiation, PR and resulting specific yield between initial expected yield and actual yield for the analyzed portfolio of 41 PV plants

The results of this exercise show that overall, when taking into account the actual unavailability (downtime) of the systems, the initial energy yield estimates are in agreement with the actual production over the first years. The main gap in the long-term energy yield estimates seems to come from the estimation of the system performance. The dispersion (nRMSE) across the portfolio is around 4.4% which lies within the expected uncertainty ranges. As shown in the review of the current industry practices, the initial uncertainty in the yield estimates for a single site are around ±5% to ±10%. The results of this PV portfolio use case show that this range could decrease for a large portfolio of several PV systems.

Investing in a big portfolio of PV plants may be a risk mitigation strategy for investors through diversification of risks. As observed in this example, the overall risk of not achieving the expected energy yield decreases when comparing a portfolio of PV systems with a single site. This is valid for a portfolio that consists of a reasonable large number of systems which are spread over a large region. Similar results were presented e.g. by [48]. Several variables such as the number of systems, their geographical distribution, PV module technologies, the type of installations, system configuration, etc. will influence the resulting overall uncertainty.

3.1.4 Long-Term Behavior (Degradation)

The review of the current industry practices revealed that a linear decline is often assumed for the PV module performance during the design phase with a yearly rate value of around 0.5 – 0.6%/year for crystalline silicon PV modules and 0.8 – 1.0%/year for thin film technologies. These values are in agreement with literature studies as e.g. [31], [49]. Furthermore, the review of the eight O&M contracts found a similar range of yearly degradation assumptions, being between 0.3 and 0.8% for crystalline silicon technology (§2.1.5). However, very limited information on the differentiation between the first year and the lifetime degradation was found in the seven reviewed LTYA reports from different market actors and in the eight surveyed O&M contracts. This does not mean that these effects are not taken into account but rather that it seems there is no consensus yet, mainly on the long-term degradation behavior, i.e. linear decline versus a stepped decline.

As highlighted in Chapter 2, the assumption of a degradation rate and its behavior over time may have significant financial consequences. This may become a potential gap as the assumption of a different degradation behavior over time (e.g. linear vs stepped) may have a significant impact on the cash flow of the project. Moreover, the probability distribution of this degradation will also affect the calculation of exceedance probabilities (e.g. P90) impacting the risk assessment. The review of current practices showed that often a normal distribution for the degradation is assumed. This has been challenged by some recent studies but, to our best knowledge, there are currently no solid publications on this regard. Therefore, more efforts are still needed to better understand the long-term behavior of module degradation and its financial consequences.

One alternative approach in the assumption for module degradation is to use the guaranteed values offered by the module manufacturers. These values are usually stated in the module warranty document or sales agreement. This approach has been observed recently in some O&M contracts to derive the yearly values for performance ratio.

3.2 Year-0 Risks Leading to Operational Failures

In a global sense, the engineering, procurement and construction (EPC) contractor is required to deliver a completely functioning PV system to their client (owner/employer/developer etc.) by an agreed date, in return for a pre-determined EPC price. The EPC contractor's primary role is to design the PV system and configuration, select and procure the components of the system to the site, and construct the plant. In the year-0 of the PV project (i.e. the development phase), these works are to be carried out in such a way that the delivered PV plant will have an optimized lifecycle cost and lifetime energy yield, and minimized risks to make the investment of the said PV system attractive. It is therefore important for the EPC scope to address the technical risks at year-0 so that the likelihood as well as the impact of technical failures during PV plant operation are minimized.

3.2.1 Top 20 Technical Failures during Operation from Cost-Based FMEA

A cost-based Failure Modes and Effects Analysis has been developed in the Solar Bankability project with an aim to provide a tool to assess the technical risks during the PV project operational years not only from a technical viewpoint but also from the economic impact perspective. The detailed works and results could be found in the report *Technical Risks in PV Project Development and PV Plant Operation* [8]. In the cost-based FMEA methodology, a *cost priority number* (CPN) is assigned to each technical risk linked to PV plant failures; the CPNs give an indication of economic losses from planning failures, system downtime, and substitution/repair of components.

The CPN method was applied to a database (created within Solar Bankability) of over one million documented failure cases during installation and operational phase of utility scale PV plants and insurance claims. In this analysis, it was assumed that no specific mitigation measures were implemented to address the failures. The top 20 technical failures causing PV plant downtime obtained from this analysis are plotted in the following Figure 33.

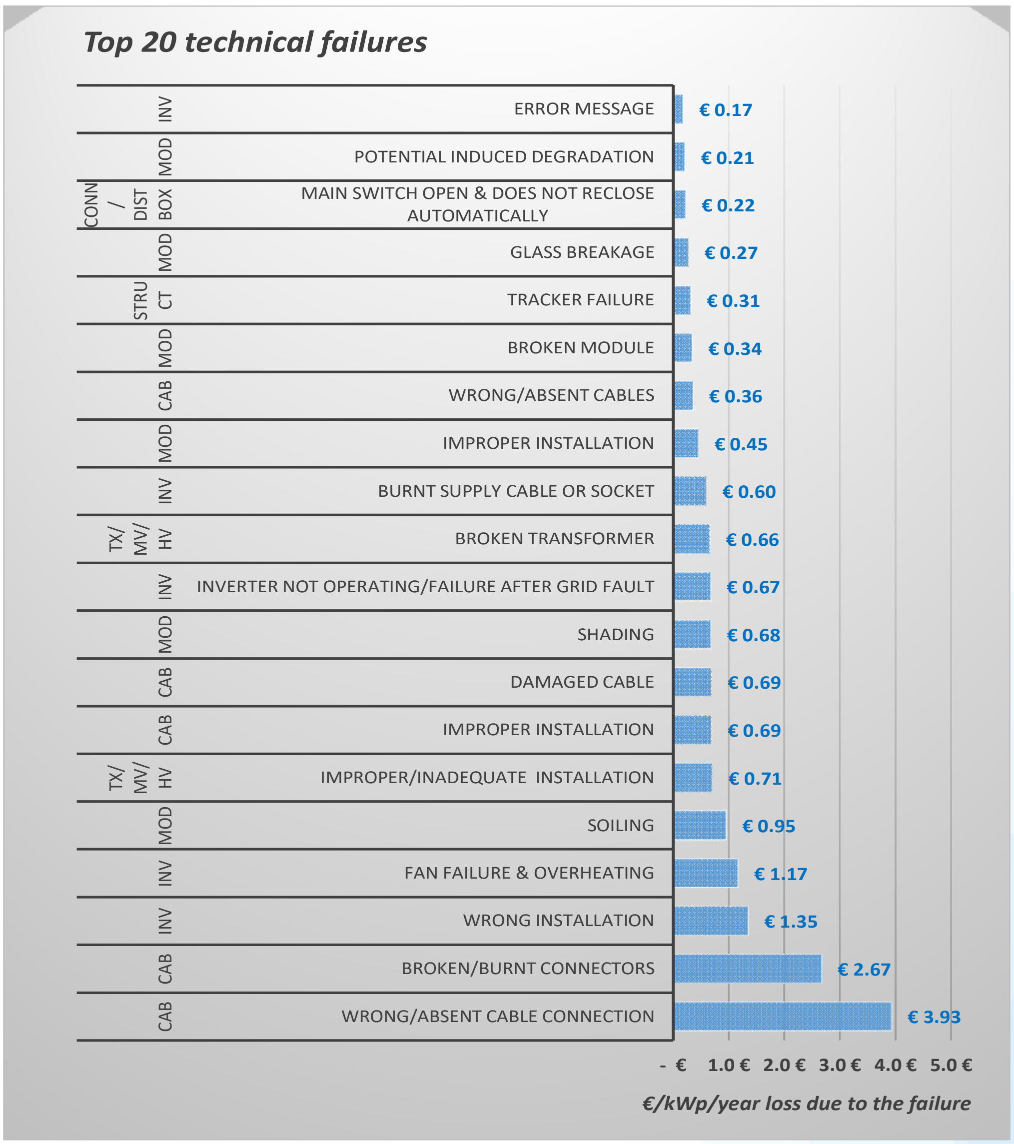


Figure 33: Top 20 PV plant failures by component type for all installation size obtained using the cost-based FMEA CPN ranking developed in Solar Bankability (CAB=cabling, INV=inverter, MOD=module, TX=transformer, STRUCT=structure)

From this figure it can be seen that the failures are spread quite uniformity over all different components of a PV system. Although these failures are detected during the operational phase, it is clear that many failures are due to issues introduced in the pre-operational phases, i.e. during component procurement and testing, plant planning, component transportation and installation. In reality, many of these failures could be due to multiple issues, as depicted in Table 25. For example, potential induced degradation (PID) of PV modules could be due to one or a combination of improper module type selection, incorrect system configuration (ungrounded array negative pole), or incorrect installation (missing ground connection). Another example is inverter fan failure and overheating which could be due to inherently bad fans in the inverter, poor ventilation from misplanning, bad construction, or poor O&M practice in fan vent cleaning.

Table 25: PV project phases vs source of the top 20 PV plant failures in Figure 33

	Component	Failure	%	Component procurement & testing	Planning	Transport / installation	O&M
1.	Cabling	Wrong/absent cable connection	23%			✓	
2.	Cabling	Broken/burnt connectors	16%				✓
3.	Inverter	Wrong installation	8%			✓	
4.	Inverter	Fan failure & overheating	7%	✓	✓	✓	✓
5.	Module	Soiling	6%		✓		✓
6.	Transformer/ MV/LV	Improper/inadequate installation	4%			✓	
7.	Cabling	Improper installation	4%			✓	
8.	Cabling	Damaged cable	4%			✓	✓
9.	Module	Shading	4%		✓		✓
10.	Inverter	Inverter not operating/failure after grid fault	4%				✓
11.	Transformer/ MV/LV	Broken transformer	4%			✓	✓
12.	Inverter	Burnt supply cable or socket	3%				✓
13.	Module	Improper installation	3%			✓	
14.	Cabling	Wrong/absent cables	2%		✓	✓	✓
15.	Module	Broken module	2%			✓	
16.	Mounting structure	Tracker failure	2%				✓
17.	Module	Glass breakage	2%	✓		✓	
18.	Connection/distribution box	Main switch open & does not reclose automatically	1				✓
19.	Module	Potential Induced Degradation	1%	✓	✓	✓	
20.	Inverter	Error message	1%				✓
		(Total)	(100%)				

From the PV cost perspective, the failures during operation are linked to the cost of periodic and corrective maintenance. For operational failures induced during pre-operational phases, it is worth exploring implementing mitigation measures during component procurement and testing, planning, transportation and installation and see if the decrease in the O&M cost (and thus OPEX) outweighs the increase in CAPEX, resulting in overall optimized lifecycle costs.

3.2.2 Risks during Product/Component Procurement

Having high quality PV system components is one crucial aspect of a well-performing and profitable PV plant. This includes not only the selection of component technologies most suitable for the specific project site and application, but also choosing reliable suppliers which are capable to deliver high quality products and preferably financially strong to still exist throughout the plant operational years from a warranty and guarantee perspective.

In the above top 20 technical failure chart (Table 25), there are three failures of which the root causes could originate as early as during the component procurement phase in the PV project development cycle. These failures are inverter fan failure and overheating (7%), module glass breakage (2%), and module potential induced degradation (1%). Examples of possible causes of these failures from the product procurement phase are listed in the following table.

Table 26: Possible root causes of failures during procurement

Failure	Possible root causes (examples, non-exhaustive lists)
• Inverter fan failure and overheating	• Bad batch of fan production from the fan supplier • Inverter type selected not suitable for the environment of application (e.g. desert or dusty location)
• Module glass breakage	• Incorrect glass type (not strengthened) selected to make modules • Bad batch of glass production used in module
• Module PID	• Selected modules are made with materials which are PID-prone • Module type not tested or certified for PID resistance

As the EPC service is the responsible party in the PV project value chain to procure system components, the technical specifications in the EPC contract should contain requirements that ensure high quality components will end up in the PV installation. This means the technical specifications should include mitigation measures which will address the technical failures during component procurement phase (product testing). As reported in the §2.1.4, of the eight surveyed EPC contracts, the technical specification annexes in the contracts contain high-level technology description of the components and only slightly over half of the technical specifications include more detailed information such as the specific brand and model type of the components. However, there are no concrete requirements in these EPC current practices which evidently address the possible root causes listed in Table 26.

The IEC 61215 and IEC 61730 certification requirements of PV modules found in five of the eight EPC technical specifications surveyed do, to a certain extent, ensure that the modules selected for the projects have materials (e.g. glass) which are suited for the specific module types and designs. However, they do not verify the PV module design to resistance to PID which is addressed by the IEC 62804 standard. Moreover, even if the modules selected meet the three IEC certification standards, there is no assurance that the quality of the sampled and IEC-tested modules could consistently be replicated in a large-scale production. None of the eight surveyed EPC technical specifications includes any specification of product testing to check for any manufacturing deviations which could address failures such as the module breakage or PID. For inverters, similar arguments could be applied. For example, having CE mark of conformity (as in two of the surveyed technical specifications) is not a guarantee to avoid inverter fan failure and overheating.

In summary, the gap in the current industry practices in specifying the requirements of main PV system components in the EPC technical specifications is highlighted. The current practices based on the EPC contract survey are simply not adequate to address the main technical failure risks identified by the CPN methodology in the product procurement phase.

In the following use case, we present an example of another technical risk where the gap could be closed by adding a product testing as an extra activity in the component procurement phase. The technical risk here is associated with modules delivered to a PV project where the actual output power is below the contracted power in the EPC contract. This is not a failure during PV plant operation and therefore does not appear in Table 25. However, this risk has an impact on the lifetime energy yield and investment perspectives.

Use Case 2: Additional product testing for power rating verification

In this use case, an EPC contractor was required to construct a 12 MWp plant with crystalline silicon PV modules with a 0 to +5 W power tolerance. The modules were manufactured over 20 consecutive production days. In the EPC contract, the technical specifications of the modules called for the typical IEC certifications, product CE compliance, and factory flash-test data to be provided to the project. As part of the financing terms the lender has requested an additional technical due diligence to verify the output power of the modules used for the project and the developer agreed to implement the required tests.

A sample of around 80 modules (0.2%) upon delivery were taken from different shipping containers representative of the production period. These modules were sent to an independent certified test laboratory and the module power at standard test conditions (STC) was measured in accordance to the industry standards on these modules. The test results showed that 45% of the tested modules have STC power values outside the contracted tolerance of 0 to +5 W (measurement uncertainties included) (Figure 34). Comparison of the individual STC power values measured by the laboratory to the values measured by the module producer on their factory IV flash-testers showed that the factory flash-test values are roughly 2.5% higher (Figure 34). Subsequent investigations were carried out and it was found that approximately 1.2% of the delivered modules were below the contracted power, and this translates to a decrease in plant performance ratio of roughly 1%.

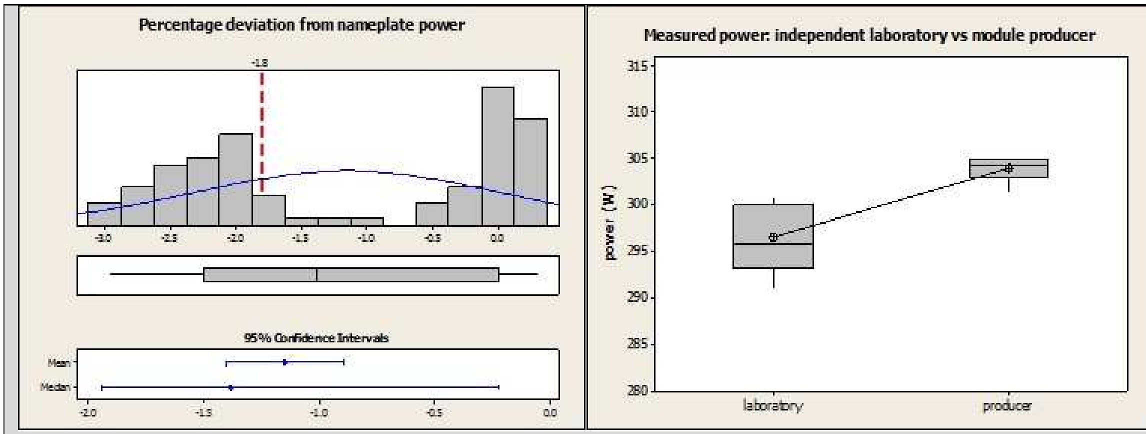


Figure 34: Independently measured module Pmpp deviation from nameplate power (left) and comparison of independently measured Pmpp vs the values from the producer flash-test (Source: 3E)

From LCOE perspective, the impact of including module testing was analyzed. Typical laboratory STC power measurement at present days costs less than 100 €/module (crystalline silicon technology). Therefore, the testing of 0.2% of sample modules for the project in this use case would cost no more than 10k €. For a 12 MWp project with a CAPEX of around 1.4 €/Wp, the total project CAPEX is roughly 16.8million €. The additional module testing would therefore increase the overall CAPEX by only 0.06%. On the other hand, the results of the module testing translate to 1% lower plant initial performance ratio and yield; the lower initial yield will have a noticeable impact on the production income over the PV plant operation years. Following these findings, the involved parties (the lender, the developer and the EPC provider) agreed to proceed with the project but the initial yield estimate was adjusted in the business plan. The module manufacturer also agreed to reimburse an agreed amount of the module payment.

The above use case illustrates an issue with module producer over-estimating power measurement which was not caught by the technical specifications in the EPC service. The gap was closed by including module testing upon delivery to project site. As the LCOE analysis shows, the benefits in adding a third party validation of the module output power clearly outweigh the additional cost in this use case.

3.2.3 Transportation and Construction Risks

As shown in the top 20 technical failure chart (Table 25), there appear to be many (12) PV system operational failure risks which could be attributed to issues in the transportation or installation phase of project development. The following table lists the possible root causes of these 12 failures. The root causes linked to transportation includes damage from vehicle movement, mishandling before and after transportation, and poor packaging quality. Construction issues could be due to poor workmanship, bad handlings or inadequate storage.

Table 27: Possible root causes of failures during transportation or installation

Failure	Possible root causes (examples, non-exhaustive lists)
• Inverter fan failure & overheating • Damaged cable • Broken transformer • Broken module • Glass breakage	• Transportation damage • Handling issue • Poor packaging quality
• Wrong/absent cable connection • Wrong inverter installation • Transformer/MV/LV improper installation • Improper cabling installation • Damaged cable • Broken transformer • Improper module installation • Wrong/absent cables • Broken module • Module glass breakage	• Poor construction workmanship • Bad handlings due to inadequate equipment and toolings during construction • Poor storage during construction
• Inverter fan failure & overheating • Module PID	• Construction not following design, e.g. spaces around inverter vents not respected, not following recommendation of array grounding for modules which are susceptible to PID.

3.2.3.1 Transportation Risks

Transportation risks are a big issue for PV projects since both repetitive or one-time excessive mechanical loads can damage PV system components, delaying project construction completion or affecting the long-term PV plant performance. Transportation risks are exacerbated if the product packaging is not up to the quality adequate to protect the contents. Dropping or tipping of the shipping pallet or containers could, e.g., loosen or break the electrical or mechanical connections in inverters, mechanically damage transformer parts, or break the solar cells or glass of PV modules.

PV modules, albeit supposedly being quite robust, still consist of parts such as solar cells, glass sheets or polymer back-sheets which could easily be damaged if not handled correctly and with care. Thin film modules built with glass-glass structure and without frames are susceptible to glass breakage which comes from impact to the edges of the modules [50]. For the crystalline silicon wafer-based modules, various studies have confirmed that the mechanical loads from transportation could cause micro-cracks in solar cells [51]–[53] which could then manifest into snail tracks/trails which in turn could affect the long-term module performance [50].

In any case, it is therefore important to have measures to ensure that the PV components shipped out from the manufacturers arrive in good conditions at the project sites. Initiatives and focuses are being placed more and more in regards to module transportation. For examples, DB Schenker in collaboration with TÜV Rheinland have developed a monitoring and control system for transporting

PV modules [54], while TÜV Rheinland has published a study on the development of a standardized test to assess the transportation quality [55].

Albeit the concerns of transportation risks and the availability of some inspection methodology, the responsibility of transportation in general still lies in the hands of the component manufacturer or logistics/shipping firms hired to do the job. Here the risks are generally addressed through transportation insurances. Although it is known that some EPC contractors do perform inspection upon product delivery, e.g., at the shipping ports or warehouses, the inspections are usually basic (visual inspection by naked eyes) and only apply to a small group of samples because of the tediousness of sampling large representative samples. In addition, such requirements are usually not found in the EPC service contracts. This is confirmed by our surveys of the eight EPC contracts in §2.1.4 where none of the surveyed EPC scope of works and technical specifications call for product delivery pre-acceptance inspections and criteria. This is clearly a gap in the transportation of PV system component.

3.2.3.2 Construction Risks

Many technical failures taking place during PV system operation phase (Table 25 and Table 27) are attributed to construction issues such as poor workmanship, bad handlings or inadequate storage. During the Solar Bankability project first public workshop held in May 2016, TÜV Rheinland reported that 55% of the defects in the plants are due to installation errors based on their internal study of PV plant data from the year 2014 and Q1 of 2015 [56]. Although the responsibility of the EPC contractor to deliver a completely functioning PV system is usually included in the EPC contract, installation errors could happen. The lender, investor or owner of the PV system therefore would require some form of testing of the plant upon construction completion and checking the preliminary plant performance before accepting the plant from the EPC contractor. Industry current practice is to include the testing requirement and procedures in the EPC contracts.

Provisional Plant Acceptance Inspection Test

Comprehensive plant testing and acceptance protocol should check for the quality of the construction as well as the initial performance once the PV system is commissioned to convert electricity. As reported from our survey of current industry practice, all eight reviewed EPC contracts include completion testing and the test protocols and plant acceptance criteria are included in the contracts. All EPC contractors committed to carry out visual inspection and functional tests of the PV system main components. However, in recent years the PV industry is seeing more and more development of advanced tools (beyond using plain naked-eyes) for PV system inspections. Infrared (IR) sensitive camera imaging has gained favors as a way to locate spots or areas of elevated temperature (“hot spots”) in the electrical cabinets, inverters and also the PV modules themselves. In fact, IR inspection on PV modules has experienced further growth following the surge of commercial unmanned aerial vehicles (UAVs or drones) which allow for high throughput IR inspections of large-scale PV installations [57], [58]. Electroluminescence (EL) imaging has also gained some ground for checking defects in the PV modules, e.g., for micro-cracks in solar cell [53]. In the past this approach saw rather restricted application since the test module needs to be tested in a controlled setup (dark room and energization of module) such as at test laboratories. Several alternative solutions are now available in the market to address this limitation and make the EL analysis accessible directly at the site of PV plants. Vendors are now offering module mobile testers equipped with EL (and also IR) camera which can be brought on site to the PV plant for module testing. This method has eliminated the time and effort needed to transport the test modules to the laboratories but still has the drawback of needing the removal of modules from the installation. Module analysis with a hand-held EL camera is another solution with more flexibility since no module dismantling is required. In both solutions, however, module energization is still a part of the test procedure which means disconnection of test modules from the PV array is still required.

Despite the increasing availability of such advanced PV system inspection tools, they are still not widely accepted as standardized plant acceptance inspection criteria. Of the eight surveyed EPC contracts, only two have included IR imaging as part of the plant inspection upon construction completion: one EPC will perform hotspot inspection on 5% of the PV modules while the second EPC will check for hotspots on all modules and also all other plant components. The employment of EL imagery was not found in any of these surveyed contracts. This is a gap worth noting as PID failures or solar cell micro-cracks (snail tracks) have been listed among the top ten module failures during operational years in Table 25.

Provisional Performance Test Methodology

The provisional performance test serves to check if the PV system has been constructed correctly and functioning without any major failures or defects. The methodology used for the performance test is therefore important and the aspects to consider are the test time duration, irradiance threshold, measurement sampling rate and averaging, and monitoring system used.

The performance test during PV system provisional acceptance is usually carried out over a short period, i.e. in a matter of days to a couple of weeks. Indeed, our EPC contract surveys found this duration to range between 5 and 15 consecutive days. The short period is preferred by the EPC contractors as the provisional performance test results are often used as an EPC payment milestone. The drawback of having such short time is that the results are not a good representative of the long-term PV system performance. In fact, the actual PV system performance verification should be carried out over a longer representative time duration such as one year. This approach was selected by three EPC contractors we have surveyed. These contactors have opted to not use a provisional performance check as a part of plant acceptance criteria. For the other five projects, provisional performance test is a requirement for plant acceptance and the several gaps are described in the next few paragraphs.

Irradiance threshold is sometimes defined in the EPC contract to determine the period at which the PV plant is not considered producing. Beyond the production hours, the measured yield and other plant parameters are excluded in the PV system performance ratio calculation. A higher irradiation threshold means lesser production hours are taken into account in the PR calculation. Ideally the irradiation threshold should match the level at which the inverters start producing (i.e. converting the solar energy). Therefore, the irradiation threshold should be set according to the inverter specifications and, if possible, by analyzing the historical site irradiation profile. Among the eight surveyed EPC contracts, two EPC contractors have decided to use an irradiance threshold of 35 and 100 W/m^2; these values were validated to be reasonable for the projects under consideration.

The remaining six EPC contractors do not specify any irradiance threshold which means all recorded values when the PV plants are producing will be used in the PR calculations.

Proper set up of the monitoring system hardware and sensors, and the data collection of PV plant performance parameters are important to provide good quality and reliable data for plant performance check. The IEC 61724 *Photovoltaic system performance monitoring - Guidelines for measurement, data exchange and analysis* and [12] provides best practice guidelines in terms of the requirement to collect and use the data for PV plant performance evaluation. Of the eight surveyed EPC contracts, six included, at the minimum, a requirement for irradiance measurement with pyranometers which are in line with the IEC 61724 and [12] guidelines. Five of these six contracts also include measurements of module and ambient temperatures. These temperature data are needed for the short-term PR correction described in the next subsection. Two of the eight EPC contractors have not included any measurement sensors in the PV plants they were building. They have decided to rely on satellite-derived irradiance data for any performance check. As these two PV plants are located at sites where the satellite irradiance data are available and of good quality, this is not an issue, as explained in §3.1.1. However, this method could potentially be an issue if the PV plants are not located at sites where the satellite-derived irradiance data is reliable.

Short-Term Performance Ratio Calculation at Provisional Acceptance

PV module efficiencies are temperature dependent and are known to decrease as temperature increases. The module temperature in turn depends on the incident irradiation on the module plane and the ambient temperature. In calculating the PV plant performance ratio over a short period of time such as that find during the provisional acceptance, the seasonal effect of the temperature or irradiance characteristics should be considered in the PR calculation [59]. The most commonly used PR correction is based on the temperature compensation method where the adjusted PR is calculated using the difference to the STC temperature (25ºC) multiplied with the temperature performance coefficient of module power. A more recent method for PR correction developed by Haeberlin and Beutler [60] considers not only the temperature effect but also introduces a *generator correction factor* for the PR which accounts for miscellaneous losses such as wiring, string diodes, low irradiance, partial shadowing, dirt accumulation, etc. In a separate study [61], two PR correction methodologies, one with only temperature correction and one with correction of combined temperature and other losses (called the *monthly correction factor / MCF* method), were applied to two PV plants at two different climates, one with high annual irradiation and another with relatively low annual irradiation. The authors confirmed that the more complete method (MCF) was found to be more reliable, particularly for the high-irradiation climate case, to obtain the actual plant short-term PR since it considers all the different loss factors. For the low-irradiation climate case, the large variability of the irradiation tends to make the MCF results less accurate.

Of the five EPC contracts we have surveyed where a provisional PR check is a requirement (Table 9), only two have taken the short-term temperature or irradiance effect into account. The first uses the temperature correction method while the second uses the MCF method. For the other surveyed PV systems, there is a potential that the provisional performance ratio may not reflect the actual PR since no correction method was applied to the calculated PR.

In summary, an accurate PR evaluation is important to verify that the commissioned PV system performs according to the initial PR estimation. Due to the short period of performance test during provisional acceptance, the short-term PR may need to be corrected to account for the seasonal influence on temperature and other system losses. Without this, an over-estimation of PR may give an impression that the PV system is performing better than actual. Although the PR over-estimation does not directly impact the PV investment financial model. Contractually, this could mean an avoidance by the EPC contractor in paying any penalties or liquidated damages for not meeting the guaranteed provisional acceptance PR.

Construction Monitoring

In addition to having a good plant acceptance and provisional performance ratio testing protocols, it is worthwhile to include construction monitoring during the project installation phase. Construction monitoring is useful to check the progress of the work, to verify if the installation is erected according to the technical specifications in the EPC contract, and to randomly audit the construction work. Among the surveyed eight EPC contracts, construction monitoring is only found in one of them. This gap is worth pointing out since with a proper construction monitoring protocol, any installation errors found could be rectified as soon as possible, potentially preventing any costs which could be incurred at later stage. Construction monitoring also serves as an EPC payment milestone validation, and thus intermediate retentions could be held back to compel the EPC contractor to solve any issue as soon as possible.

Use Case 3: Construction monitoring to identify module mishandling during construction

This use case exemplifies the benefit of performing construction monitoring during PV project installation phase. The project is a ground-mounted utility scale project of which the construction period spanned several months in 2013 and 2014. The owner of the project has included a construction monitoring due diligence consisting of several site visits to be carried out by an independent technical advisor.

During one of the visits, incidents of careless handling of the PV modules were observed during the unpackaging process and when the modules were hand-carried from the unpackaging points to the mounting structure where they were going to be installed. Some of the installed modules were visually inspected by the technical advisor on the subsequent site visit and it was found that many modules exhibited snail track defects with the pattern that is typically associated with cell micro-cracks caused by mishandlings. The EPC contractor was requested to perform a random visual inspection on a 2% of all installed modules and the outcomes were about 0.5% were showing snail track defects due to mishandlings. A group of 20 modules with snail tracks were dismantled and sent to a certified test laboratory for STC power measurement and EL imaging analysis. The resulting EL images were compared to the ones obtained by the module producer at the end for the production lines. The results clearly showed that the micro-cracks did not originate from the factory. In addition, the results show that almost half of the tested 20 modules with snail trails showed STC power values between 3 and 9% below the contracted power (tolerance and measurement uncertainties included). Based on these findings, the EPC contractor agreed, at its own cost, to replace all the affected modules and also to increase the module spare part stock in anticipation to future similar defects.

From the LCOE viewpoint, the extra cost of the technical advisor's construction monitoring site visits and the extra laboratory module testing amounted to less than 0.02% of the EPC cost. The benefit of identifying the construction module mishandling issue and getting a rectification prior to plant acceptance (and thus minimizing future issue due to this defect) clearly outweighs the said incurred extra costs.

3.3 Risks During Operation

3.3.1 O&M and Risks During Operation

3.3.1.1 Problematic O&M

Although many technical failures during PV system operation are attributed to root causes introduced in the pre-operation phase, issues related to the O&M activities could also contribute to the PV plant failures or outages during operation. There are 12 PV plant technical failures among the top 20 identified by our CPN ranking method (Table 25) which could be initiated by problematic O&M aspects such as that shown in Table 28.

Table 28: Possible root causes of failures due to problematic O&M aspects

Failure	Possible root causes (examples, non-exhaustive lists)
• Cable broken/burnt connectors • Inverter fan failure & overheating • Module soiling • Damaged cable • Module shading • Inverter not operating/failure after grid fault • Broken transformer • Burnt supply cable or socket • Wrong/absent cables • Tracker failure • Main switch of connection/distribution box open & does not reclose automatically • Inverter error message	• Operational monitoring issues, e.g. monitoring system outage resulting in unnoticed or escape failures • Maintenance issues, e.g. insufficient maintenance frequency, maintenance does not follow manufacturer's guidelines • Defect detection issues, e.g. monitoring system inadequate capability to analyze and identify defects, defects undetectable through visual inspection

One possible O&M problem is an outage in the PV plant operation monitoring system itself due to, e.g., communication network issue, or loose or disconnection of the wirings in the data logger. The monitoring system or part of it consequently stops functioning and collecting data. Any plant failures during this downtime are not recorded and alarms are not sent out either. The monitoring system plays such a key role in the PV plant operation that its maintenance should therefore be a part of the overall plant O&M service scope. Moreover, the maintenance should check for both the functionality of the data acquisition devices as well as the measurement sensors. Of the eight surveyed O&M contracts in §2.1.5, three do not include any check of the monitoring system in their O&M preventive maintenance activities. In fact, this gap has resulted in an issue for one of the projects where a set of measured data from one irradiation sensor was missing because the communication router was not functioning for a period of time.

Another O&M issue is related directly to improper maintenance protocols, either in terms of the frequency of the maintenance or the manner the maintenance activities are carried out. In general PV component manufacturer guidelines should be respected by the O&M service provider when performing the maintenance works. A failure to do so is likely to result in a voidance of the manufacturer warranties (this condition is usually explicitly stated in the warranty documents). All eight surveyed O&M contracts state that the maintenance activities should be carried out according to the manufacturer guidelines. As for the maintenance frequency, it can vary from quarterly to biennially (every two years), with the annual frequency being the most commonly practiced. This is seen across the eight surveyed O&M contracts. However, only four of the eight contracts include an annual module cleaning in their O&M scopes. Module soiling could cause a decrease in the module performance [62]; specifically, concentrated soiling could cause localized high temperature zones which result in module hotspot failure. Module soiling failure is among the top technical risks during operation according to Table 25; therefore, periodic module cleaning is not trivial and the cleaning frequency (which will affect the O&M scope and price and ultimately the PV LCOE) should be optimized by considering the rate of soiling and any cleaning effect from the natural rainfalls.

It is important within the problematic O&M context to understand that the technical risks during PV plant operation could come from the lack of good defect detection capability. This encompasses of two different aspects. One has been discussed earlier in §3.2.3.2 regarding advance visual inspection tools such as IR and EL imaging cameras to check for module defects not visible with the naked-eyes during the provisional plant acceptance test. The IR thermal inspection has recently become a more common practice in the O&M service scope. It is useful not only for module fault detection but also to check for high temperature spots which could lead to failures such as burnt cable connectors or sockets, or inverter overheating as shown in Table 28.

Looking at the results of the O&M contract survey summarized in Table 10, we see that the O&M contractors for three of the eight surveyed PV projects have included IR inspection in their preventive maintenance activities. The frequency and coverage of the inspection differ among these three inspections, however. Two have decided to perform the IR check every year but one checks all PV plant components while the other one does IR scan on only the modules in the installation. The third contractor chooses to perform the IR inspection on all plant components but only every other year. The second advance PV plant inspection tool, an EL camera, is less common than the IR imaging (for the reasons previously explained in §3.2.3.2) and has so far found its use only for module inspection. In addition to detecting micro-cracks in crystalline silicon solar cells, EL imaging could also detect modules with PID or by-pass diode failure as reported by [63].

The second aspect of defect detection capability problem lies on the monitoring system capability. The classical monitoring systems at present day feature basic functions which include collecting the PV plant data and reporting them on recurring set times. The classical monitoring systems use the collected data to calculate (and report) the plant performance ratio. In general alarms are sent out for events related to faults. Because of these limitations, the classical monitoring systems are also limited in terms of their capability to identify the exact defect type and the root cause(s) the defect stems from. This limitation could mean that the classical monitoring system could identify a failure such as plant outage due to grid fault in Table 28, but will likely miss any under-performance due to, e.g., module soiling or shading.

PV Plant Smart Monitoring

Smart monitoring systems have higher intelligence than the classical PV monitoring systems in terms of how the collected PV plant data are processed for more in-depth plant performance diagnosis. This in-depth analysis could be done manually for classical monitoring but a person has to take the data, prepare them in certain formats before analyzing then. The process is tedious and lengthy. In the smart monitoring case, the data processing and diagnoses are performed automatically by a machine through an algorithm.

The objective of a smart monitoring is to be able to detect and remediate faults early. Early detection of performance issues requires an accurate model of the expected behavior of the well-performing PV plant. The model needs to be created by the smart monitoring software and this requires accurate input parameters and thus accurate sources and sensors for monitoring. Using the model created, the monitoring algorithm makes comparisons of the plant parameters over time and try to assess the degradation and the distribution of different types of losses affecting the performance. In addition, a smart monitoring system would look at the characteristics and changes in the PV plant parameters and try to diagnose any issues and identify the associated root causes.

Having a smart monitoring means being able to proactively monitor the condition of the PV plant during operation and detect faults in real time. Through smart monitoring, fault remediation could be taken promptly to minimize the fault impacts on the system performance. Moreover, the faults could be prevented from propagating further, affecting other components in the installation, and eventually causing an outage on the entire PV system, impacting the plant availability. A study reported in [64] analyzed the added value of having a smart monitoring system on, among others, the performance ratio and availability of a hypothetical 100 MWp PV project at low and high irradiation conditions. Two scenarios were considered – one with all plants in the portfolio having an average performance (P50 case) and the other with 25% of the plants below the average performance (P25 case). The authors concluded that by shifting from a standard monitoring system to a smart one, the early detection of under-performance lead to a PR gain of 0.45% and 2.2% for the P50 and P25 scenarios respectively. In addition, the early detection of fault root causes results in an availability gain of 0.16% and 0.92% for the P50 and P25 scenarios respectively.

A PV Health Scan methodology has been developed in the Performance Plus project as a feature to enhance a smart monitoring to characterize the PV array through physical parameters estimated from operational data and to provide insight in the root causes of performance losses [65]. The diagnosis starts from closed-form relationships between regression parameters and underlying physical parameters of a PV plant. The methodology allows the systematic analysis of operational data in an efficient way, identifying how design choices and O&M practices lead to inferior or, on the contrary, superior performance in the field. The methodology has been demonstrated on several PV plant performance analyses, one of the examples is presented in the use case below.

From the PV plant financial model perspective, the smart monitoring could lead to a reduction of the O&M costs. Efficient and reliable fault detections could facilitate a more effective communication between the plant operator and intervention teams, reducing notification and response times. In addition, by monitoring the occurrence and behavior of the faults closely, the remediation could be planned in advance, thus avoiding unplanned site visits which are often costly since the maintenance labor rates usually vary depending on the day and time the work is carried out. By knowing faults in advance, the maintenance work could be scheduled to take place at the most economical labor rate time. Ultimately, the PV LCOE could be optimized by balancing between the additional cost of including a smart monitoring and the reduction in the O&M costs through a more efficient and realistic maintenance coverage.

Use Case 4: Smart monitoring diagnosis of operational PV plant hinting to potential PID issue

Using the PV Health Scan methodology described above, a performance diagnosis was carried out on a 4-year old operational ground-mounted PV plant in France. It is a utility scale installation conceived with crystalline silicon PV modules and 10 central inverters. The installation is configured into 10 arrays (corresponding to the 10 inverters) and there are two types (models) of modules among these arrays. The objective of the Health Scan analysis was to identify and quantify any energy losses and performance irregularities during the years the plant has been operating. The data used in the Health Scan was supplied by the owner and operator of the PV installation. The analysis was performed on the level at which data are available (inverter or array string level).

On a system level, from a standard performance ratio and availability analysis, the results indicate a reasonably well-performing installation. The performance ratio of the most recent 12-month period (87%) is within the guaranteed value. Moreover, the plant availability at the inverter level is high (99.8%). The analysis reveals several faults of which the root causes were identified, e.g. disconnected strings and arrays, bypass diode issues.

The current- and voltage-based losses over the four-year period were further analyzed at the array level to evaluate the performance degradation. The analysis took into account any temperature effect on the current and voltage performances. Figure 35 shows the degradation rates based on the current- and voltage-based losses for each of the 10 arrays in the installation. As it can be seen in the left chart, the yearly current-based degradation rates among the arrays vary significantly and also demonstrate wide large confidence margins. On the contrary, the array voltage degradation rates, as shown in the right chart, are consistent across the different arrays. The confidence margins are also very narrow. Moreover, the two types of PV modules exhibit different levels of voltage-based degradation. The module type installed in the arrays *C* and *D* appear to have lower annual degradation rates (0.2 – 0.3%) than the module type installed in the other arrays (*A* to *B*, and *F* to *J*) (0.5 – 0.8%). Overall, analysis results suggest an overall system degradation of around 0.6% per year.

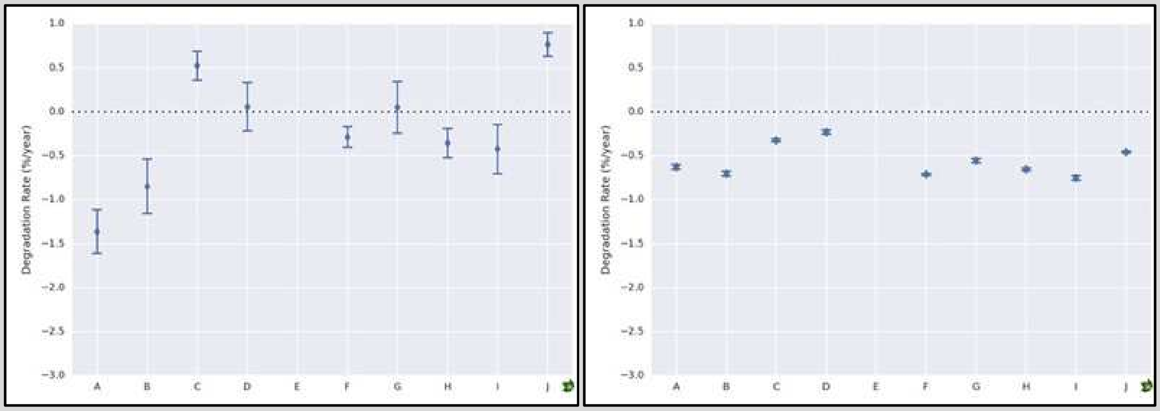


Figure 35: Long-term yearly degradation rates for current-based losses (left chart) and voltage-based losses after temperature correction (right chart) per array, with 95% confidence bounds (note array E data is not available to be included in the analysis)

Although the analyzed degradation rates are not excessive considering the typical module manufacturer's power warranties at present day, the difference seen on the two groups of modules is clear and gives hints to a systematic power deterioration in the modules in these arrays. Based on PV module degradation publications (e.g. [50]), the degradation mechanism that could lead to a gradual reduction in string voltage consistently throughout the entire array such as that observed in this project is potential-induced degradation or a general and creeping increase in solar module series resistance. This information was subsequently fed back to the owner/operator of the PV plant together with a set of recommendation actions for further investigation.

The above use case illustrates the advantage of having a smart monitoring system with advanced data processing and analysis feature such as the PV Health Scan which allow for detail analysis of PV plant performance. When using a classical monitoring, at first glance, the PV plant in the use case will appear to have performed fine, with performance ratio meeting the guaranteed value and very high inverter availability. However, the smart monitoring analysis is able to highlight the different degradation rate behavior between the current-based vs the voltage-based losses, and reveal that the two types of PV modules behaved differently in terms of the voltage degradation. This early fault identification and diagnosis allows for remediating the potential fault (e.g. PID) before the plant performance and availability are severely affected. The advantage of minimizing energy yield loss in turns will be favorable from the PV LCOE perspective, even taking into account that having smart monitoring system is likely to add some additional operational cost (1 to 3 €/kWp/year).

3.3.1.2 Plant Performance and Availability

The performance of a PV plant over its lifetime affects directly the income in the project financial model. Having an accurate indicator to the plant performance is therefore important to tell how well the PV investment is performing. Key performance indicators commonly used to gage the plant performance are performance ratio, availability or energy yield/output of the PV system. An initial estimation of the performance ratio and energy output are performed during the plant development phase and the calculations are based on an assumption of a certain level of the system availability. The estimated values are then used by the O&M operators as performance guarantees in the O&M contracts.

Likewise to the short-term performance ratio of the provisional acceptance of PV plant (§3.2.3.2), the long-term PR assessment should be based on reliable data and using the right formula. The requirements for irradiance threshold, measurement sampling rate and averaging, and monitoring system used remain the same as already discussed in §3.2.3.2. However, since the long-term PR is usually checked on yearly basis, the seasonal effect of the temperature or irradiance characteristics becomes less significant and averages out over the 12-month period. As such, PR correction using the temperature or other losses method previously needed for the calculation for the short-term provisional PR is thus no longer used in the long-term PR calculation. Instead, the PR should consider the annual rate of system degradation and the availability.

For the annual degradation input in the long-term PR calculation, in reality the value should reflect the degradation at the PV system level. However, in the project development phase this number is normally unknown and thus the module-level degradation is used in the assumption. Once the plant has been operational for reasonable number of years, the actual system degradation could be assessed and used for adaptation.

As previously discussed in §3.1.3, the availability assumption used in the PV investment financial model or business plan is not necessarily the same as the availability guaranteed by the O&M operator since there are factors affecting the plant uptime beyond the liability of the operator. When evaluating if the O&M service has been carried out in accordance to the O&M contract, the outages due to events outside the operator's responsibilities are therefore excluded. It is therefore important to know which availability assumption is to be taken when checking the annual performance of a PV plant. For the purpose of assessing the O&M service, the plant-level availability should be used while for assessing the plant production income and investment returns, the overall availability should be taken. Moreover, the importance of adapting the availability value to the actual availability following several years of operation is discussed in the Use Case in §3.1.3 above.

From availability perspective, it is also essential to understand that some root causes of the operational failures listed in Table 28 are not automatically due to the O&M operator. An example of this is the defect detection capability of the monitoring system. In most cases the choice of monitoring system is made in the project development phase and the plant operator is usually not involved in the decision making process. Such gap could be addressed by having an early engagement of the O&M operator in the development phase for their inputs in the discussion of aspects of the PV system which will affect the operation of the plant and the O&M works.

Of the eight surveyed O&M contracts in §2.1.5, three have no performance guarantees. The fact that there are still O&M contracts with no form of guarantees is a gap in the current industry practice. Without any contractual guarantees, there is no assurance that the three plants are going to be operated and maintained properly to ensure a performance that will meet the project investment objectives. Of the five O&M contracts with guaranteed performances, two include both guaranteed

PR and plant availability. Two others choose to only guarantee PR while one has opted to guarantee availability. All five have set 99% as the plant availability level in their contracts; this value is typical in the O&M practice at present day. The events for plant availability calculation exclusion proposed in the O&M contract are acceptable. The overall availability value for investment calculation is usually not found in the O&M contract and thus the investor setting up the financial model has to find a reliable source to determine a realistic value in this assumption. Taking up an insurance could be a potential mitigation measure to address the uncertainties associated with this assumption. The module degradation used in the surveyed O&M contract is in line with the present day scientific data [31], [49]. The considerations to be taken for a better assumption of the degradation rate is discussed in §3.1.4 above.

3.4 Chapter Summary

In this chapter, we analyzed the current industry practices on the PV LCOE technical inputs collected from our review in Chapter 2. We then compared these practices to the state-of-the-art scientific data and the top 20 technical risks identified earlier in this Solar Bankability project. The analyses were performed systematically according to the phases in PV project lifecyle and whether the root causes are likely to occur before or during the PV operation, i.e. *year-0 risks* vs *risks during operation*.

The results of this exercise show that technical gaps generally exist across all PV project phases. They occur in all elements of the PV LCOE, namely in the CAPEX, OPEX and energy yield estimation. There are two types of technical risks: those which influence the PV system performance and energy yield but not necessarily create a partial or overall outage of the plant, and those which cause failures such as the top 20 affecting the plant availability and also the performance. The root causes of both types of risk could be introduced either during project development (procurement, planning and construction) or during PV operation (O&M). The list of important gaps identified in the analyses are presented in the following table.

Table 29: Important technical gaps in the present day technical inputs for PV financial models – gap analysis summary

Risk	Phase/field	Identified critical technical gaps
Year-0	Procurement/ product selection and testing	1. Insufficient EPC technical specifications to ensure that selected components are suitable for use in the specific PV plant environment of application. 2. Inadequate component testing to check for product manufacturing deviations. 3. Absence of adequate independent product delivery acceptance test and criteria.
	Planning/ lifetime energy yield estimation	4. The effect of long-term trends in the solar resource is not fully accounted for. 5. Exceedance probabilities (e.g. P90) are often calculated for risk assessment assuming a normal distribution for all elements contributing to the overall uncertainty. 6. Incorrect degradation rate and behavior over time assumed in the yield estimation. 7. Incorrect availability assumption to calculate the initial yield for project investment financial model (vs O&M plant availability guarantee).

	Transportation	8.	Absence of standardized transportation and handling protocol.
	Installation/ construction	9.	Inadequate quality procedures in component un-packaging and handling during construction by workers.
		10.	Missing intermediate construction monitoring.
	Installation/ provisional and final acceptance	11.	Inadequate protocol or equipment for plant acceptance visual inspection.
		12.	Missing short-term performance (e.g. PR) check at provisional acceptance test, including proper correction for temperature and other losses.
		13.	Missing final performance check and guaranteed performance.
		14.	Incorrect or missing specification for collecting data for PR or availability evaluations: incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation.
Risks during operation	Operation	15.	Selected monitoring system is not capable of advanced fault detection and identification.
		16.	Inadequate or absence of devices for visual inspection to catch invisible defects/faults.
		17.	Missing guaranteed key performance indicators (PR, availability or energy yield).
		18.	Incorrect or missing specification for collecting data for PR or availability evaluations: incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation.
	Maintenance	19.	Missing or inadequate maintenance of the monitoring system.
		20.	Module cleaning missing or frequency too low.

4 Closing Remark & Next Step

In this report, we have presented the results of the review exercise conducted within the European Commission-funded Solar Bankability project on the current industry practices in terms of the technical assumptions in the PV investment cost calculation. We have compared these current practices to the state-of-the-art scientific data and to the top 20 technical risks identified earlier in this Solar Bankability project. For the latter we refer to the cost-based FMEA CPN ranking method developed in Work Package 2 of the Solar Bankability project (see *Technical Risks in PV Project Development and PV Plant Operation* [8]). Our objective was to obtain a snapshot of the current practices and identify gaps in the technical inputs which will introduce risks into the evaluation of the CAPEX, OPEX and energy yield. This information will serve as the basis for the Solar Bankability consortium to carry out the next task in the context of PV LCOE, i.e. to develop a best-practice guideline in how to account for the technical risks in PV investment cost.

using the cost-based FMEA CPN ranking method developed in this Solar Bankability project). The objective of these works is to obtain a snapshot of the current practices and identify gaps in the technical inputs which will introduce risks in the different cost elements of PV levelized cost of electricity value, namely the CAPEX, OPEX and energy yield. This information will serve as the basis for the Solar Bankability consortium to carry out the next task in the context of PV LCOE, i.e. to develop a best-practice guideline in how to account for the technical risks in PV investment cost.

The best-practice guideline to be developed will include a list of all technical parameters to be used in the PV investment cost calculation, and where and how to account for the technical risks within the CAPEX, OPEX, and energy yield. In addition, we aim to include several case studies where different scenarios of LCOE will be evaluated. The case studies will utilize the costs associated with different mitigation measures presented in the Solar Bankability report *Minimizing Technical Risks in Photovoltaic Projects: Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation* [47]. This upcoming report will be available in the last quarter of 2016 (please check the project website www.solarbankability.eu for updates).

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Annex A LCOE Literature Review

In the review of the current industry practices in PV investment cost calculation on how technical parameters and associated risks are taken into account, the consortium has taken the first step to define the Levelized Cost of Electricity formula to use for the purpose of this project. A review of five publications [1]–[5] issued in 2013 to 2015 was carried out and the different versions of LCOE formula are summarized in this appendix. From these different versions, the Solar Bankability consortium has selected the calculation version considered to be most suitable for use in this project.

EU PV Platform

In Jun 2015, the European Photovoltaic Technology Platform (www.eupvplatform.org) PV LCOE Working Group published a report [1] presenting an overview of the PV LCOE across Europe for 2014, and the outlook for 2020, 2025 and 2030. The LCOE of PV electricity generation was calculated for six locations (London, Stockholm, Munich, Toulouse, Rome and Malaga) and four market segments (residential (5kWp) and commercial (50kWp) rooftop, and 1MWp and 50MWp ground-mounted systems). The study includes sensitivity analysis on the CAPEX, OPEX, location, WACC, lifetime and module degradation. The following LCOE formula used in the study.

$$LCOE = \frac{CAPEX + \sum_{t=1}^{n} \frac{OPEX(t)}{(1 + WACC_{Nom})^t}}{\sum_{t=1}^{n} \frac{Utilization_0 \, . \, (1 - Degradation)^t}{(1 + WACC_{Real})^t}} \quad (7)$$

where

t = time [years]

n = economic lifetime of the system [years]

$CAPEX$ = total investment expenditure of the system made at t=0 [€/kWp]

$OPEX(t)$ = operation and maintenance expenditure in year t [€/kWp]

$WACC_{Nom}$ = nominal weighted average cost of capital [per annum]

$WACC_{Real}$ = real weighted average cost of capital (per annum) = (1 + $WACC_{Nom}$) / (1 + Inflation) - 1

$Utilization_0$ = initial annual utilization of the nominal power of the system [per annum]

$Degradation$ = annual degradation of the nominal power of the system [per annum]

CREARA

In May 2015, Creara Energy Experts (CREARA), a consultancy and management service company in Spain, has published an updated issue of Grid Parity Monitor report [2] containing analyses of the electricity prices for commercial consumers (30 kW PV systems) in seven countries (Brazil, Chile, France, Germany, Italy, Mexico and Spain). The study took into account local regulation for self-consumption sensitivity and used the following LCOE formula.

$$LCOE = \frac{I + \sum_{t=1}^{T} \frac{C_t \,.\, (1 - TR)}{(1+r)^t} - \sum_{t=1}^{T} \frac{DEP_t \,.\, TR}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}} \tag{8}$$

where

T	= average PV system lifespan [years]
t	= year t
I	= initial investment [€/kWh]
C_t	= O&M costs and other operating costs (incl. replacement of inverter) (€/kWh)
E_t	= PV electricity generated on year t [kWh]
r	= nominal discount rate (WACC) [%]
TR	= corporate tax rate per country [%]
DEP	= depreciation for tax purpose [€/kWh]

IRENA

In Jan 2015, the International Renewable Energy Agency (IRENA) published a report [3] on the generation costs of different renewable technologies for countries around the globe. The study focused on the LCOE and the influencing factors such as policy support and deployment, technology types (biomass, geothermal, hydro, PV, solar thermal, and wind) as well as the cost metrics. The following LCOE formula was used for the calculation of the generation costs for different technologies.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{9}$$

where

n	= life of the system

I_t = investment expenditures in the year y

M_t = operations and maintenance expenditures in the year t

F_t = fuel expenditures in the year t

E_t = electricity generation in the year t

r = discount rate

ECOFYS

In Jul 2014, ECOFYS issued a report on the basic principles and requirements of the LCOE calculations [4] in the renewable electricity incentive tariff level setting process. Four case studies where LCOE calculations were used to set the tariff in the Netherlands, UK, Germany and Spain were included for example. The following LCOE formula was used in the studies.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + OM_t + F_t}{(1+DR)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \qquad (10)$$

where

n = economic lifetime of the power plant

I_t = investment expenditures in the year t

OM_t = operations and maintenance expenditures in the year t

F_t = fuel expenditures in the year t

E_t = electricity generation in the year t

DR = discount rate

Fraunhofer ISE

Fraunhofer Institute for Solar Energy Systems (ISE) carried out a study analyzing the LCOE of different renewable energy technologies [5] in late 2013. The main focus on the study was on the LCOE for PV, wind and biomass sources in Germany. The following LCOE formula was used in the study.

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{t,el}}{(1+i)^t}} \qquad (11)$$

where

n	= economic operational lifetime [years]
t	= year of lifetime
I_0	= investment expenditures [€]
A_t	= annual total costs in year t [€]
$M_{t,el}$	= produced quantity of electricity in respective year [kWh]
i	= real interest rate [%]

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