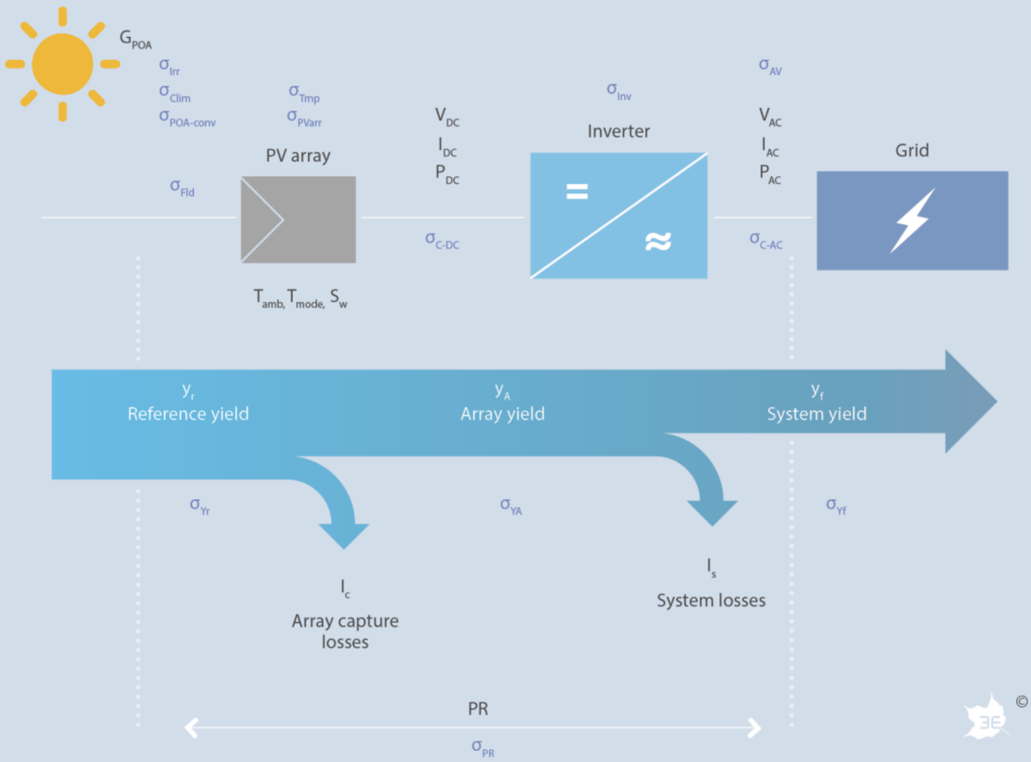
IEA INTERNATIONAL ENERGY AGENCY

Technical Assumptions Used in PV Financial Models

Review of Current Practices and Recommendations



PVPS

PHOTOVOLTAIC
POWER SYSTEMS
PROGRAMME

Report IEA-PVPS T13-08:2017

INTERNATIONAL ENERGY AGENCY
PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

Technical Assumptions Used in PV Financial Models

Review of Current Practices and Recommendations

IEA PVPS Task 13, Subtask 1
Report IEA-PVPS T13-08:2017
May 2017

ISBN 978-3-906042-46-6

Primary authors:

Mauricio Richter, Caroline Tjengdrawira
3E s.a., Belgium

Jan Vedde
SiCon, Denmark

Mike Green
M.G. Lightning Electrical Engineering, Israel

Lyndon Frearson, Bert Herteleer
CAT Projects, Australia

Ulrike Jahn, Magnus Herz
TÜV Rheinland Energy GmbH, Germany

Marc Köntges
Institute for Solar Energy Research Hamelin, Germany

Contributing authors:

Bengt Stridh
ABB AB, Corporate Research, Sweden

Karl Berger
Austrian Institute of Technology GmbH, Energy Department, Austria

Eckhard Janknecht
TÜV Rheinland Energy GmbH, Germany

David Moser, Giorgio Belluardo
EURAC research, Italy

Nils Reich
Fraunhofer ISE, Germany

This report is supported by:

German Federal Ministry for Economic Affairs and Energy (BMWi)

Israel Ministry of National Infrastructures, Energy and Water Resources

Danish Energy Agency, Energy Technology Development and Demonstration Program (EUDP)

Table of Contents

Foreword

The International Energy Agency (IEA), founded in November 1974, is an autonomous body within the framework of the Organization for Economic Co-operation and Development (OECD) which carries out a comprehensive programme of energy co-operation among its member countries. The European Union also participates in the work of the IEA. Collaboration in research, development and demonstration of new technologies has been an important part of the Agency's Programme.

The IEA Photovoltaic Power Systems Programme (PVPS) is one of the collaborative R&D Agreements established within the IEA. Since 1993, the PVPS participants have been conducting a variety of joint projects in the application of photovoltaic conversion of solar energy into electricity.

The mission of the IEA PVPS Technology Collaboration Programme is: To enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems. The underlying assumption is that the market for PV systems is rapidly expanding to significant penetrations in grid-connected markets in an increasing number of countries, connected to both the distribution network and the central transmission network.

This strong market expansion requires the availability of and access to reliable information on the performance and sustainability of PV systems, technical and design guidelines, planning methods, financing, etc., to be shared with the various actors. In particular, the high penetration of PV into main grids requires the development of new grid and PV inverter management strategies, greater focus on solar forecasting and storage, as well as investigations of the economic and technological impact on the whole energy system. New PV business models need to be developed, as the decentralized character of photovoltaics shifts the responsibility for energy generation more into the hands of private owners, municipalities, cities and regions.

IEA PVPS Task 13 engages in focusing the international collaboration in improving the reliability of photovoltaic systems and subsystems by collecting, analyzing and disseminating information on their technical performance and failures, providing a basis for their technical assessment, and developing practical recommendations for improving their electrical and economic output.

The current members of the IEA PVPS Task 13 include:

Australia, Austria, Belgium, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, Malaysia, Netherlands, Norway, SolarPower Europe, Spain, Sweden, Switzerland, Thailand and the United States of America.

This report focusses on the economics of PV system performance and reliability. The report presents an overview of current practices in PV financial models, a review and an analysis of the technical assumptions used by project developers, banks and asset managers to evaluate the profitability of a PV project. The analysis provides understanding of the existing gaps between the present practice and state-of-the-art methods and available scientific data. Finally, this report provides guidelines and recommendations for mitigating and hedging financial risks in a PV investment.

The editors of the document are Mauricio Richter, 3E, Belgium, Jan Vedde, SiCon, Denmark, Mike Green, M.G. Lightning Electrical Engineering, Israel and Ulrike Jahn, TÜV Rheinland, Germany.

The report expresses, as nearly as possible, the international consensus of opinion of the Task 13 experts on the subject dealt with. Further information on the activities and results of the Task can be found at: http://www.iea-pvps.org.

Acknowledgements

This report received valuable contributions from several IEA-PVPS Task 13 members and other international experts, all of whom are listed as primary and contributing authors. In addition, we thank the following individuals for their careful reviews and suggestions:

- Achim Woyte 3E s.a., Brussels, Belgium
- César Hidalgo López DNV GL, Barcelona, Spain

Abbreviations and Definitions

List of Abbreviations

AM	Air mass
AOI	Angle of incidence
ARIMA	Auto-regressive integrated moving average
BOS	Balance of systems
CAPEX	Capital expenditures
DC/AC	Direct current, alternating current
CE	Conformité Européenne
CPP	Cloud physical property
CSD	Classical seasonal decomposition
DOM-TOM	Départements et Territoires d'Outre-Mer
DWD	Deutscher Wetterdienst (German Meteorological Office)
EL	Electroluminescence
EPC	Engineering, procurement and construction
FIT	Feed-in tariff
GHI	Global horizontal irradiation
GCR	Ground coverage ratio
IAM	Incidence angle modifier
IEC	International electro-technical commission
IR	Infrared
IRR	Internal rate of return
ISO	International organization for standardization
KPI	Key performance indicator
LID	Light-induced degradation
LOWESS	Locally weighted scatterplot smoothing
MCP	Measure-correlate-predict
NREL	National Renewable Energy Laboratory
NRMSE	Normalized root mean square error
O&M	Operation and maintenance

OPEX	Operational expenditures
PID	Potential induced degradation
PLR	Performance loss rate
POA	Plane of array
PR	Performance ratio
PPA	Power purchase agreement
PV	Photovoltaic
QC	Quality control
ROI	Return on investment
SPV	Special purpose vehicle
STC	Standard test conditions
TA	Technical advisor
Ta	Technical availability
TDD	Technical due diligence

Definitions

Definition	Abbreviation	Explanation
Long-term yield assessment	*LTYA*	Assessment of the expected PV system yield including risk evaluation for bankability purposes.
Historical period	T_{Hist}	Historical period used to calculate the available solar energy.
Prediction period	T_{Pred}	Assumed lifetime from the economic perspective. In other words, the prediction period is the same as the financial lifetime (see definition below).
Financial lifetime	$T_{L\text{-}financ}$	Expected financial lifetime (i.e. according to financial specifications), used for example, for the calculation of the levelized cost of electricity (LCOE).
Technical lifetime	$T_{L\text{-}tech}$	Expected technical lifetime (i.e. according to technical specifications). For example, for a PV module with 25-year warranty, the technical lifetime is $T_{L\text{-}tech}$ = 25 years.
Probability of exceedance	*PXX*	The probability of achieving a given energy yield is represented by a percentile, e.g. P90 denotes the level of annual production that is expected to be reached in 90% of the cases (90% exceedance probability or in other words, the probability of not reaching this value is 10%). The probabilities are calculated by considering all project specific uncertainties and can be computed for different return periods of interest within the financial model (see "financial lifetime" definition above). The choice of exceedance probabilities e.g. P75 or P90 depends typically on the risk appetite of the lenders/investors.
Time based availability	A_T	Percentage of time during which the PV plant was producing. It is expressed as the ratio between the duration of production activity and the recording period (both expressed in hours). This time-based indicator does not allow for the calculation of the impact of un-availabilities on the overall system yield.
Energy based availability	A_E	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.
PV module power at standard test conditions	$P_{mpp,STC}$	Nominal PV module power, measured at Standard Test Conditions (STC i.e. irradiance of 1000 W/m^2, air mass (AM) of 1.5 and module temperature of 25 °C)

Executive Summary

PV financial models are used by project developers, banks and asset managers to evaluate the profitability of a PV project. The objective of this work is to present an overview of current practices for financial modelling of PV investments and to review them in view of technical and financial risks during the different phases of a PV project. This report focuses on establishing common practices for translating the technical parameters of performance and reliability into financial terms. The full report delivers a comprehensive set of practical guidelines and recommendations for mitigating and hedging financial risks in a PV investment.

How do PV Financial Models Currently Deal with Technical Assumptions and Risks?

In order to obtain an overview of current practices on the use of technical parameters in PV financial models, 84 PV projects covering nine countries, several technologies and different business concepts have been screened and evaluated. A questionnaire was developed and distributed among members of the Task 13 Subtask 1 contributors. The information collected from the questionnaire is complemented with the findings from the Solar Bankability[1] project reported in [1].

The solar irradiation data used for the long-term energy yield estimates are in general collected, analyzed, and assessed with a great deal of professionalism. However, different historical periods (T_{Hist}) are used depending on the irradiation data source. Moreover, no considerations on possible effects of long-term trends in the solar resource and how to account for these in the LTYA is typically provided. The overall impression on energy yield estimates is that they are calculated by engineers for the specific project and are “topped off” with an uncertainty margin that is selected from “experience or installer judgement”, which most likely refers to a common praxis/convention within the long-term yield assessment (LTYA) sector.

For the cost elements, depending on the complexity of the project, the capital expenditure (CAPEX) depends strongly on the construction cost. In a few cases, the considered technical assumptions are clear before the final CAPEX value is determined. Furthermore, financial models normally only make use of a single number for the CAPEX value and it is not a common practice to account for the inherent uncertainties of the CAPEX value in the financial model. Technical assumptions are also important when determining the operational expenditure (OPEX). However, these technical assumptions are often not explicitly presented in the project presentations. Operating expenditures should reflect the expected wear-out profile of the individual components. Such expenditures should be calculated using technical parameters that describe the technical lifetime ($T_{\mathrm{L\text{-}tech}}$) profile of the equipment instead of the financial lifetime ($T_{\mathrm{L\text{-}financ}}$) of the project as these can often differ significantly. Regarding the monitoring of the plant, this typically focuses on the performance ratio (PR) and technical availability as these key performance indicators are of high importance in ensuring the overall profitability of the project.

Finally, there are different business models used in PV investments, e.g. guaranteed feed-in tariffs, green certificates, tax credit, self-consumption (in whole or in part), private or, public sales to a third party according to a power purchase agreement (PPA). Unfortunately, the questionnaire responses do not provide more detailed information in this regard.

[1] The Solar Bankability project is funded by the European Union’s Horizon 2020 research and innovation programme under the grant agreement No 649997.

What are the Main Weaknesses when Dealing with Technical Assumptions and Risks in PV Financial Models Today?

Project phase	Weakness
PV plant design	• The effect of long-term trends in the solar resource are often not fully accounted for • Exceedance probabilities (e.g. P90) are often calculated for risk assessment assuming a normal distribution for all elements contributing to the overall uncertainty • Incorrect degradation rate and inaccurate rendering of the system behavior over time is assumed in the yield estimation • Incorrect availability assumptions are used to calculate the initial yield for the project investment financial model as opposed to the O&M plant availability guarantee
Procurement process	• The technical specification of the PV plant components usually consists only of a high-level description; in most cases, only the brand, model, and quantity of the components are listed • Requirements for PV modules and inverters extend only to stating that they have to carry valid IEC certifications or CE mark of compliance. Project specific requirements such as salt-mist, ammonia or resistance to potential-induced-degradation, with the relevant IEC certification testing, are not always specified • There is a lack of specifications requiring factory inspection or product testing that serve to prevent inadequate manufacturing process or material deviations which could lead to batch specific product defect or failure
Plant construction	• Disregard of published transportation and handling protocol • Inadequate quality control in component unloading and handling during construction • Inadequate storage of components on site • Lack of construction supervision • Lack of industry accepted methods for plant acceptance after completion of the construction process
Plant acceptance procedure	• Inadequate protocol for visual inspection • Lack of relevant equipment for visual inspection (e.g. infrared and electroluminescence equipped cameras) • No short-term performance test at provisional acceptance • Missing final performance test of guaranteed performance • Incorrect or missing protocol for collecting data for PR or availability evaluations • Missing final check of monitoring system availability and functionalities • Incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation
Operation & Maintenance	• The corrective maintenance costs are often not properly included in the financial model • The monitoring system is not of defined quality to enable effective trouble shooting during project life • Data acquisition is incompatible with attaining good results in the defined reporting requirement • System data is effectively unavailable for troubleshooting problems • Data is not vetted for viability • The subset of data parameters collected is too small to enable the use of advanced statistical tools • Missing or inadequate maintenance of the monitoring system • Module cleaning missing or frequency too low • Inadequate or absent devices for visual inspection to find invisible defects and faults • Missing guaranteed key performance indicators (PR, availability or energy yield) • 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 and availability calculations

How to Mitigate and Hedge Financial Risks in a PV Project

In general, the task of mitigating and hedging financial risks in a PV project could be addressed at the following levels:

1. **Strategy**: A prerequisite for any successful risk mitigation strategy is to ensure that the overall process is recognized by the top-level decision makers and that this management level takes responsibility for defining an appropriate strategy and assignment of the necessary resources to undertake this process.
2. **Classify**: Set a team that includes a wide variety of skills and experiences; brainstorm and use checklists to make sure all potential risks are identified; assess and classify the risk factors according to expected occurrence frequency, severity in terms of financial impact and overall risk ranking.
3. **Understand**: Analyze the root cause(s) of the various risk factors including possible interrelations between different factors. Identify the specific most important influencer that may challenge the financial performance of the project.
4. **Manage**: Introduce and follow-up on actions to mitigate the identified risk items.

One of the keys to mitigate and hedge financial risks is to ensure that the financial model prepared during the feasibility and early development stages of a project will continue to reflect the financial activity of the plant over the 20-30 years of operation. The necessity for ensuring that the design and construction of the plant will enable the assumptions to be realized is extremely important.

The guidelines and assumptions necessary to fulfil this task must also include suggestions regarding the project pre-feasibility, plant design, procurement and construction, acceptance, and operation of the plant. The following guidelines and recommendations as per these project stages are suggested:

1) Project pre-feasibility
Changing design concepts and equipment characteristics in the early stages of plant design is a common practice that leads to the PV plant's optimization. It is important that a financial model be undertaken at the end of the design process, since in all likelihood, many key parameters may have changed.

2) Plant design
Quality control during the design process is critical for enabling the realization of the financial plan. A well designed and specified plant that is modelled correctly in the financial model as described in this report should enable realization of the financial plan. Finding and correcting errors at the design stage are inexpensive, at most embodying the cost of quality control methodology that may not have been calculated in the design costs. However, as per the "Anderson Rule" described in Section 4.3.1, errors not found during this stage will cost ten times more during the next stage, procurement or construction.

3) Procurement and construction
This stage, including the procurement aspect of the project, has little to do with the core discussion of this report – technical assumptions used in PV financial models, yet every-

thing to do with ensuring that the plant will adhere to the financial model. Since correcting mistakes during procurement cost 10 times more than during the design process and 100 times more during the construction process it is advisable to apply quality control measures during the project's early phases. The essence of success in any project can be defined as quality control, for the hardware, the workmanship and software.

4) Acceptance
Plant acceptance is the period during which the plant is examined for compliance to design, quality of work and deemed as functioning as per the specification written to meet the business plan. Acceptance is the most important milestone of the project, and substantial capital is dependent upon successful achievement of this milestone. Neither the contractor nor the developer wish to wait a full production cycle of one year before the quality of the plant becomes legally apparent. Two options exist for overcoming this problem: by performing an acceptance test that enables determination of the yield capability of the plant irrespective of the season, or including a conditional acceptance that does not determine the final yield capability at time of the acceptance testing, but makes acceptance conditional on the first year's operation.

5) Operation and maintenance
The key to the successful operation of a PV plant is the monitoring system. The system's initial cost is covered in the CAPEX, but the value is only evident to those working on the OPEX. Without accurate monitoring with suitable time resolution that enables downloading any available parameters from any collection of plant elements across any time span, there is little possibility for optimizing operational activities. With a quality monitoring system, it is possible to optimize maintenance tasks such as module washing frequency and ascertain if string fuses have blown before preventative maintenance activities take place.

The key to ensuring that the financial model remains correct throughout the project lies not only in accurate assumptions for the future behavior of the plant at the outset of the design process, but also in ensuring that these assumptions are enabled during the design, building, commissioning, operating and maintaining the plant. This requirement points to a necessity for a high level of quality control throughout the life of the plant. Therefore, suggestions made in this report are not only on the assumptions to be made but also how to ensure that these assumptions will hold true to realize the business plan.

In this report we discuss methods for increasing the accuracy of our assumptions and of mitigating risks to these assumptions. This is achieved with lists of the shortcomings found in our discussion on the current practices accompanied by methods to mitigate these shortcomings in the technical management of the project during the design, construction and operational stages of the project. Special attention must be paid to mitigating the uncertainty parameters calculated or assumed for the inputs into the business model. We present a method of calculating final business model values for produced energy, revenue and IRR using statistical tools such as Monte Carlo calculations on the input values, and then again on the output values. This method demonstrates how a P50 and P90 model can be generated. Further statistical graphic tools, such as the Tornado and Spider plots are introduced as tools to visualize the relative effect of each of the input parameters on the final calculated output number.

Finally, this report provides guidelines and recommendations for undertaking the design, construction and operation of a PV plant in a manner that will enable fulfilling the calculated financial plan.

1 Introduction

1.1 Objective

Financial models for commercial PV investments take into account various technical and technically related assumptions in the derivation of various aspects such as income from the PV plant production, capital expenditures (CAPEX) and operating expenditures (OPEX). PV financial models are used by project developers, banks and asset managers to evaluate the profitability of a PV project. The task is to predict the discounted cash flow as accurately as possible, to assess if the project represents an attractive investment opportunity. The most important key performance indicator (KPI) is the internal rate of return (IRR) or return on investment (ROI) of the invested capital, but as investors seldom like surprises, the level of uncertainty related to the IRR is of interest. One method to present this perspective to the investors is by stating the most probable energy yield (the so-called P50 yield) and an associated lower bound of confidence commonly referred to as the P90 yield, the yield with 90% exceedance probability. This yield calculation uncertainty demonstrates a willingness to address the risk profile of the project. However, this approach simply deals with the risk in the eyes of the investor by adding a blanket uncertainty to the yield report but does not offer transparency as to the impact of sources of uncertainty that affect the projects' achievable IRR.

Previous and ongoing works within the IEA PVPS Task 13 and by others have identified and quantified reliability and failures of PV plant components (mainly PV modules) that could impact the plant performance. Studies have proven the importance of quality assurance throughout the life cycle of a PV investment, from component manufacturing, system design, installation and then on to commissioning and operation. Performance and reliability and, consequently, energy yield and return on investment strongly depend on these practices of quality assurance. To the best knowledge of the authors, there is no commonly accepted practice yet for translating the technical parameters of performance and reliability into financial terms. The objective of this work is to present an overview of current practices for financial modelling of PV investments and to review them in view of technical risk during the different phases of a PV project. The main outcome of this work is presented as guidelines and recommendations for mitigating and hedging financial risks in a PV investment.

1.2 Guide to Readers

This report presents a review of current practices used in PV financial models and provides guidelines and recommendations for mitigating and hedging financial risks in a PV investment. General definitions, terminology, and technical naming conventions used in PV financial calculations are introduced in the "Abbreviations and Definitions" section. Section 2 presents an overview of current practices used in PV financial models. The overview is based on a screening of 84 PV projects covering 9 countries, several technologies and different business concepts. The information was collected through a questionnaire and is complemented with the findings from the Solar Bankability[2] project reported in [1]. In Section 3, we review the current practices by comparing the technical assumptions against scientific data, state-of-the-art methods and recommended industry best practices for solar resource assessment (§3.1), energy yield estimates (§3.2), capital expenditures (§3.3), and operating expenditures (§3.4). Reliability and failures of PV system components are reviewed and summarized in §3.5 based on inputs from other sub-tasks from the IEA PVPS Task 13 work. Section 4 summarizes the findings from the review of current practices and identifies the opportunities for mitigating and hedging financial risks in PV investments. These findings

[2] The Solar Bankability project is funded by the European Union's Horizon 2020 research and innovation programme under the grant agreement No 649997.

are translated into guidelines and recommendations for mitigating and hedging financial risk in PV investments (Section 5). Finally, Section 6 presents the conclusions of the works described in this report.

2 Overview of Current Practices

2.1 Financial Models for PV Investment

PV financial models are used by project developers, banks and asset managers to evaluate the profitability of a PV project. The task is to predict the discounted cash flow as accurately as possible, to assess if the project represents an attractive investment opportunity.

A typical PV financial model addresses the following topics:

1. Irradiance resource estimation
2. System losses and energy yield estimate including system degradation
3. Energy sales price and yearly revenue
4. Operating expenditures including O&M and land lease
5. Financing cost and taxation

When project specific information is collected on these topics, it is possible to calculate the cash-flow of the project. The most popular key KPI used to assess the financial performance of the PV project will be the IRR and the ROI on the invested capital. Since investors seldom like surprises, the level of uncertainty related to the IRR/ROI is also of interest.

2.2 Technical Assumptions Used in PV Financial Models

In order to obtain an overview of current practices in the use of technical parameters in PV financial models a questionnaire was developed and distributed among members of the Task 13 Subtask 1 contributors. From the 6 respondents, a total of 84 projects covering 9 countries, several PV technologies and different business concepts were described and data analyzed. The full text of all questions asked is supplied in Appendix 1 and the responses are presented in the following sub-sections arranged according to the topics (categories) used in the questionnaire (also summarized in Appendix 3):

1. General project information
2. Solar resource assessment
3. Energy yield estimates
4. Capital expenditures
5. Operating expenditures
6. Business models

More details and extended results from this investigation are available in [2]. Although the intention of the questionnaire was to collect information on current practices in the use of technical parameters in PV financial models in general, it turned out that most of the quantitative and qualitative information was related to energy yield estimation only. Therefore, further results presented in this Section regarding capital expenditures and operating expenditures are complemented with the results from the Solar Bankability project presented in [1] and with general and public domain industry knowledge.

2.2.1 General Project Information

Under this category, general project information is collected in the questionnaire. This information includes the background, purpose, ownership, development history, location, module orientation and module size (power and area). A summary of responses to the questionnaire regarding general project information is shown in Table 1.

Table 1: Summary of general project information.

Topic	Answers to questionnaire[3]
Purpose of project	To generate energy; investment proposals, opportunity for an agricultural cooperation.
Ownership	In several cases the project is owned by a holding company, being often a Special Purpose Vehicle (SPV), with the sole purpose of owning the PV project on a non-recourse basis. Therefore, the collateral is the PV project itself.
Developer	An agricultural cooperative, private land owner, industrial concern or a private building owner.
Installation type	Free field or alternatively fixed tilted on a roof with either aluminum or galvanized steel mounting structures.
Orientation	All projects have the modules facing directly towards equator with tilt angles between 15° and 30°. Only one tracker system is included.
PV modules	Most projects use modules made from mono- or multicrystalline silicon cells manufactured by Tier 1 or 2 Chinese companies. A single project uses a-Si/µ-Si tandem modules. Some examples reference additional certification according to salt-mist, ammonia, PID-resistance and AR coating of the glass.
PV module tolerance	Ranges of ±5 Wp-units symmetrical around the nominal power or as asymmetrical tolerances of -0/+3% or -0/+5 Wp-units. In three cases the average measured power from flash tests including a measured standard deviation was provided.
Warranties	A single case did specify the module product warranty but in all other cases only the performance warranty - which is typically specified as linear over 20 or 25 years – are given. In two cases information is provided that the supplier module warranty has been backed by an external insurance policy.
Stringing	In most cases a detailed description is provided on the total number of modules and the number of modules per string, combiner-box and/or inverter.
Area	In most responses, the exact size of the modules and the total module area is given however the total area utilized by the project or the ground coverage ratio is seldom detailed.

[3] See the full text of the questions asked in the questionnaire in Appendix 1. The summary of responses within this category of the questionnaire are in some cases presented imprecise. This may be a consequence of the arbitrary selection of project examples that cannot be claimed to be representative.

Although not all responses to the questionnaire covered all topics, the information collected in the category of general project description is in general quite detailed and descriptive. This category represents those facts that are often made public and do not reflect technical issues that introduce ambiguity to the calculations. A great number of technical details are provided, but except for the PV module power and tolerance none of these parameters have a direct impact on the calculated energy yield or financial performance.

2.2.2 Solar Resource Assessment

Under this category, the questionnaire was used to collect data regarding the solar resource at the site, and the character and origin of the irradiance data used to estimate the financial lifetime ($T_{\text{L-financ}}$) energy potential of the PV plant. In general, different solar irradiation data sources are available including measured values with local sensors, interpolated values, and estimated values derived from satellite models. These databases use irradiation data obtained by different methods and, sometimes covering different periods. The available solar irradiation at the site is a crucial parameter for a PV financial model as it is used as a basis to estimate the energy potential of the PV plant during its $T_{\text{L-financ}}$ and for verifying the fulfilment of contractual KPIs such as performance ratio (PR) or energy based availability A_E. A summary of the questionnaire answers regarding irradiation data sources is presented in Table 2.

Table 2: Solar resource assessment.

Topic	Answers to questionnaire[4]
Location	In most cases a very precise identification of the project location is given. Projects from the following countries are covered: Chad, Chile, China, Germany, Israel, Italy, Japan, Romania & Uruguay.
Irradiation	A value of the expected horizontal irradiation received is provided with either four or five significant digits - in units of kWh/m^2. The sources of this information are referenced in detail and include data from the following sources: Deutschen Wetterdienstes (DWD) (1981-2012), Meteonorm 6.1 (1981-2000) and 7.0 (1986-2005), NASA (1983-2005), NASA (SSE) (1983-2005), PVGIS (Classic) (1981-1990), PVGIS (CM-SAF) (1998-2010) or UNI 10349. Besides a reference to the yearly period behind these meteorological observations, also an uncertainty in this value is often given, with typical values of ±2.5%, ±3.0%, ±4.5%, ±6.8% or ±8.0%; most values being in the lower end of this range. A monthly breakdown of expected irradiation is also provided in many responses.

In general, it appears that the solar resource data are collected, analyzed and assessed with a great deal of professionalism. This suggests that these data and conclusions – including uncertainty estimates – can be trusted as scientifically based and highly trustworthy. Regarding the historical period used T_{Hist} to calculate the available solar resource; it is clear from the collected data that different T_{Hist} are used depending on the data source. Furthermore, none of the answers in the questionnaire included further explanation regarding the possible effect of long-term trends in the solar resource and how to account for such in the long-term yield assessment (LTYA). These topics are further analyzed and discussed in Section 3.

2.2.3 Energy Yield Estimates

Under this category, information regarding the technical and system design data used for energy yield estimates were collected through the questionnaire. The energy that can be generated by

[4] See the full text of the questions asked in the questionnaire in Appendix 1.

the project is the single most important technical parameter. The calculation of the expected energy yield is typically provided by a cascade of specific models, each solving a particular question regarding energy conversion. Figure 1 illustrates the energy flow from sunlight to the consumer of electrical power for a typical grid-connected PV system highlighting the different sub-models and the related uncertainties in the different steps. The character of each sub-model and the freedom to select input parameters varies considerably depending on the simulation tool in use and the experience of the user. In general, the expected energy production or final system yield Y_f, is reported together with the PR, which quantifies the overall efficiency of energy conversion of the PV system. The PR represents the ratio between the system yield Y_f and the solar energy input or reference yield Y_r, and should be accompanied by an uncertainty, which in turn depends on the uncertainty in the final yield and reference yield quantification.

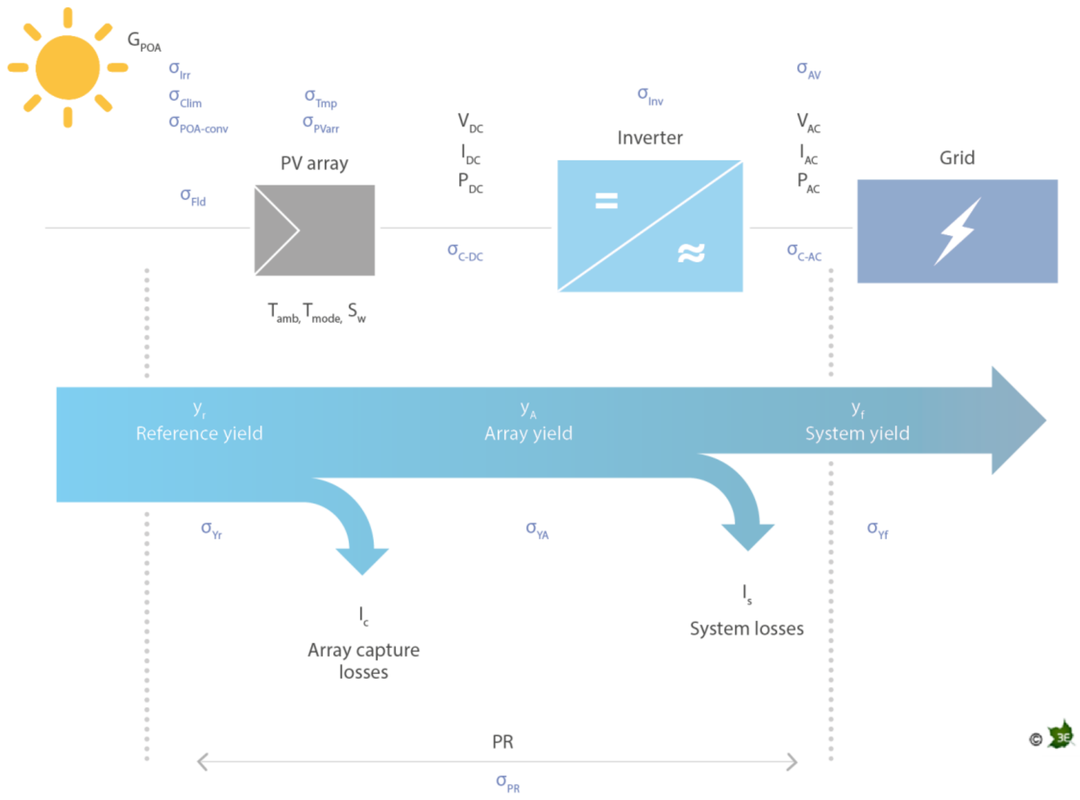


Figure 1: Energy flow diagram in a grid-connected photovoltaic system. In black the calculated parameters and in blue the related uncertainties (σ).

The core of the energy yield estimation process is the PV yield modelling software. PV yield modelling software are used by developers and independent consulting engineers during the design phase of the PV project to estimate the expected energy yield during the financial lifetime of the system. A variety of software programs are available in the market; PVsyst, PVSol, SAM, and PV-Planner, to name just a few of the many software packages available for this application. The output of any PV modelling software strongly depends on the underlying model algorithms and on the chosen input parameters. These parameters include the solar resource and weather related parameters, system design configuration, technical characteristics of the components and several additional inputs that are often based on user estimates or assumptions. Soiling, mismatch, cabling and other field related losses or derating factors are examples of the many user estimates required during the PV energy yield modelling process.

The answers from the questionnaire regarding technical and system design data used for energy yield estimates are summarized in Table 3. In general, these responses contain data values only, with no reference to the source of this information. The numbers and associated uncertainties are most likely chosen by the modelling engineer by considering the energy yield modelling tool used, experience from previous modelling and model validation activity and the availability of information for the specific project in question. It is therefore likely, that some input values may be selected based on general assumptions, modelling experience or traditionally accepted convention and it may be that some loss elements are lumped together into a single generic loss due to lack of project specific information. It is also possible that some calculated losses are divided into parameters not covered in this questionnaire, as the large variation in values describing the thermal loss may indicate.

Table 3: Technical and system design data.

Topic	**Answers to questionnaire**[5]
Soiling loss	Amount of soiling to be expected is often provided and ranges from 1.0% to 3.0% with most values between 1.0 and 1.5%. The uncertainty of this value is often provided and is given as ±1.0 percentage point with only one exception where a value of ±3.0 % is used.
Shading loss	Expected amount of shading is provided with typical values of 0.6%, 0.7%, 1.4%, 2.7%, 2.8%, 3.3% and 3.6%. However, most installations expect 0% shading loss. The uncertainty in this estimate is given as ±0.5% in most examples and as ±1.0% and ±2.0% in two specific projects.
Reflection loss	Expected amount of loss due to reflection from the module surface (also known as Incidence Angle Modifier (IAM) loss) is provided with typical values of 2.8%, 2.9%, 3.0%, 3.2%, 3.6% or alternative with a value of 0.0%. The uncertainty in this estimate is always given as ±0.5% when stated.
Thermal loss	Yearly loss as compared to operation under Standard Test Conditions (STC i.e. irradiance of 1000 W/m^2, air mass (AM) of 1.5 and module temperature of 25 °C) has been calculated as 0.1%, 0.3%, 0.8%, 1%, 1.2%, 4.9%, 5.4%, 11.3% or 14.5 % with uncertainties stated as either ±0.2%, ±0.5% or ±1.0%.
String mismatch loss	Calculated to values of 0.4%, 0.7%, 0.8 %, 0.9%, 1.0%, 1.10% or 2.1% with uncertainty stated as ±0.5% (except for one example of ±1.0%).
DC/AC-cable loss	Calculated as 0.1%, 0.2%, 0.6%, 0.7%, 0.9 %, 1%, 3.4%, 6.2% or 7.4 %, always with an estimated uncertainty stated as ±0.2%.

[5] See the full text of the questions asked in the questionnaire in Appendix 1. The uncertainty values are presented here in the same form as provided in the questionnaire responses. If these percentages shall be understood as an absolute (percentage point) or relative factor is not clear – not in the responses nor in the original investor presentation of the project. These uncertainty values not clearly expressed can lead to misinterpretation and result in under/over estimation of the risk. This may be a consequence of taking uncertainty values from literature or standard practice and not assessed based on first principles for the specific project in question.

Inverter loss	Calculated as 1.1%, 1.6%, 1.7 %, 1.9%, 2.0 %, 2.2 %, and 3.2%, always with an estimated uncertainty stated as either ±1.0% or ±2.0%.
Transformer loss	Calculated as 1.0% and 1.3% with one value at 2.0% and always given with an uncertainty of ±0.5%.
Grid access	For all systems where the information is provided, the full production is expected to be delivered to the grid with no other loss (Power Factor = 1). The combined overall uncertainty in the calculated energy yield is then provided as ±3.2%, ±4.5%, ±5.1%, ±5.9%, ±6.1%, ±6.8% or ±7.3%.

2.2.4 Capital Expenditures

Under this category data regarding the cost to realize the project are collected through the questionnaire. These costs are supposed to include not only the direct engineering, procurement and constructions (EPC) cost that scales with the size of the system but also the fixed project development cost as well as the cost of decommissioning. The intent is to present a breakdown of these costs into categories such as site preparation, civil works, installation of direct current (DC) system, alternating current (AC) system, fencing, safety & security components, waste removal, mounting structures, PV modules, balance of system (BOS) (i.e. cables, monitoring system, etc.), insurance and grid connection cost. The results obtained from the questionnaire are complemented with the findings from the Solar Bankability project reported in [1] and summarized below.

The survey revealed that the EPC cost makes up a significant portion (70-90%) of the capital expenditures (CAPEX). The scope of work of the EPC is defined in the main body of the EPC contract and generally includes the following core services:

1. Design of the plant
2. Procurement and supply of plant components, usually up to the grid connection point
3. Construction, including transportation of components to site, site preparation, and component installation
4. Plant testing and commissioning for owner's takeover, including supply of all relevant documentation

In addition to the core activities, there are optional works which could be included in the EPC service. For example, the EPC will normally provide support to the plant owner or developer in administrative aspects such as obtaining grid connection authorization, use of external roads, or acting as the interface with the component and equipment suppliers before the ownership of the plant is handed over.

Financial models normally only make use of a single number for the CAPEX value. The concept that the CAPEX be represented by a single number in the investment model may not always be correct. It may be advantageous to represent the inherent uncertainty of the CAPEX value in the financial model by adding a tolerance interval or "error-bar" to the value when it is referenced in the text or calculations. This is further discussed in Section 3.

2.2.5 Operating Expenditures

Under this category information regarding the land/roof lease conditions, insurance conditions, organization and extent of operation and maintenance (O&M) activities planned for the plant was collected through the questionnaire. The results obtained from the questionnaire are complemented with the findings from the Solar Bankability project reported in [1] and summarized below.

The survey revealed that the O&M costs make up a significant portion of the OPEX (30-70%). The scope of works for the O&M contractor is defined in the O&M contract and generally includes the following core services:

1. Continuous monitoring of the plant operation and periodic reporting
2. Preventive maintenance
3. Corrective maintenance

In addition to the core activities, there are optional works such as administrative support and warranty claim management assistance. The O&M costs in the surveyed PV financial models are made up of a fixed part and a variable part. As mentioned previously, the O&M costs reported in the questionnaire have a very broad spread (30 to 70%) within the PV project OPEX. This is because the O&M scope itself varies widely, influenced by many factors such as plant size, complexity of design and technology, access to location, and local regulations. When the scope of the fixed O&M is comprehensive, it will consist of complete preventive maintenance activities including 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.

Technical assumptions are important when the OPEX value has to be assigned in the PV financial model. Among the most obvious of these expenditures is the estimate on inverter replacement during the financial lifetime ($T_{\text{L-financ}}$), which is typically addressed, based on the expected average technical lifetime ($T_{\text{L-tech}}$) or detailed failure profile of the chosen inverter. Ideally the OPEX budget should reflect the expected wear-out profile of the individual components as calculated using technical parameters that describe the $T_{\text{L-tech}}$ profile of the equipment.

A core task of the O&M contractor is to monitor the plant operation on an ongoing and continuous basis and report the plant data such as production and operational events to the investor and owner on a regular basis, usually monthly and yearly. The survey revealed that PV plants of commercial scale and larger employ remotely accessed monitoring systems. The initial installation of the plant monitoring system is usually included as standard in the EPC contract. The monitoring of the plant typically focusses on the PR and technical availability (Ta), and is known to be of high importance in ensuring the overall profitability of the project. For this reason, a PR and Ta guarantee is often requested from the O&M provider, which can involve many technical definitions and assumptions that may look simple, but in reality are not at all trivial for implementation in a monitoring system.

PV monitoring systems automatically collect and record all data produced by the plant. The data can then be accessed manually and prepared for analysis of plant performance or trouble shooting. Typical of these systems are automatic calculation of PR and other matrices for ascertaining system health such as inverter comparison. More advanced “smart” monitoring systems look at the characteristics and changes in the PV plant parameters and try to diagnose any issues and identify the associated root causes automatically. This is analyzed further in Section 3.4.1.

Another core task of the O&M contractor is to perform periodic preventive maintenance. Periodic preventive maintenance generally includes visual inspection and general house-keeping of components including cleaning, tightening, and adjusting. Defective components found are repaired or replaced accordingly. Other activities found among the surveyed O&M contracts are module cleaning, PV plant site maintenance such as vegetation control, fence maintenance, and general repairs. Irradiance and temperature sensor calibration are also undertaken periodically. It is also likely that replacing or reconditioning a specific part or a major plant component is foreseen. The time frame is usually based on technical and scientific data on the mean time between failures of the component, such as inverter replacement as described earlier; in this case, a replacement is usually planned just after year 10 of the PV system operation. This period $T_{L\text{-tech}}$ is typically assumed for a PV inverter. This practice is sometimes referred to as predictive maintenance. We did not find predictive maintenance activity in any of the surveyed O&M contracts.

Maintenance frequency can vary from as high as monthly to bimonthly, quarterly, biannually, yearly, and more, depending on the component in question, and the maintenance task, such as the monthly visual inspection of a sensor versus the less frequent sensor calibration. Among the O&M contracts surveyed, annual frequency was the most common time frame for preventative maintenance frequency. Regarding the maintenance of the monitoring system, almost half those surveyed O&M contracts are found to have not included any check or testing of the monitoring system in their O&M preventive maintenance activities.

In our survey, less than half of the contracts included advanced inspection techniques such as infrared imaging (IR) inspection for the modules, electrical cabinets or junction boxes. The frequency of inspection was either annual or biannual. In all surveyed cases, the IR inspection was performed by a specialized sub-contractor. Moreover, none of the O&M contracts reviewed have included electroluminescence (EL) inspection in their scope of works. Finally, almost all O&M contracts surveyed have included spare part supply and management in their scope of works. All these topics regarding preventive and corrective maintenance are discussed further in §3.4.2 and §3.4.3.

Similar to the EPC service, KPIs are important to determine if the O&M services have been performed sufficiently to allow the plant to operate as expected. In addition to guaranteed performance ratio or guaranteed output yield, guaranteed availability is another KPI commonly used in the O&M contract. Our O&M contract survey found no general consensus regarding which KPI should be used: 25% use guaranteed performance ratio and guaranteed availability, 25% use only guaranteed PR, and 12% use guaranteed availability. Interestingly, the remaining 38% of the surveyed projects had not committed to any form of KPI at all. The guaranteed plant availability commonly required is 99%. However, the overall plant availability could be 98% as shown in [1]. This is further discussed in §3.4.4 of this report.

2.2.6 Business models

Under this category information on the nature of revenue generation as well as information about the financial structure, taxation and other financially related aspects of the project is requested in the questionnaire. At a minimum, it should be possible to understand if the power is to be sold under market conditions, subsidized by a feed-in tariff (FIT), green certificates or tax credit or whether the power will be self-consumed in whole or in part, or sold via a private/public grid to a third party according to a power purchase agreement (PPA).

In general, information of this kind was not made available by many of the subjects. Some screened projects included a reference to the FIT scheme in place but otherwise this kind of information has not been extracted from the screened projects.

2.3 Section Summary

The survey of 84 PV projects from a diverse selection of regions around the world revealed that mostly not all technical assumptions influencing the CAPEX and OPEX values are clearly addressed. Although the intention of the questionnaire was to collect information on current practices in the use of technical parameters in PV financial models in general, it turned out that most of the quantitative and qualitative information was related to energy yield estimation only. Most of the data collected from the questionnaire with regard to energy yield estimation represent hard technical facts that seem to be available with a high degree of detail including professional estimates on the uncertainties. A summary of the responses to the questionnaire is available in Appendix 3.

Regarding the solar resource assessment, the survey revealed that solar irradiation data used for the further long-term energy yield estimates seems to be collected, analyzed, and assessed with a great deal of professionalism. However, different historical periods T_{Hist} are used depending on the irradiation data source. Moreover, no further explanation regarding possible effects of long-term trends in the solar resource and how to account for these in the LTYA is typically provided. The overall impression regarding energy yield estimates is that these are calculated by engineers for the specific project and are "topped off" with an uncertainty value that is selected from "experience or installer judgement", which most likely refers to a common praxis/convention within the long-term yield assessment (LTYA) sector. These assumptions are reviewed and analyzed in Section 3 by comparing them with scientific data and state-of-the-art methods and best practices.

Regarding the cost elements, depending on the character of the project the CAPEX represents either the construction cost or the project sale price. In few cases the considered technical assumptions are clear before the final CAPEX value is determined. Furthermore, financial models normally only make use of a single number for the CAPEX value and it seems not to be common practice to account for the inherent uncertainties of the CAPEX value in the financial model. Technical assumptions are also important when determining the OPEX value. These technical assumptions are however often not explicitly presented in the project presentations. Operating expenditures should reflect the expected wear-out profile of the individual components as calculated using technical parameters that describe the technical lifetime ($T_{L\text{-}tech}$) profile of the equipment as often the technical lifetime $T_{L\text{-}tech}$ of the different components differ significantly from the financial lifetime ($T_{L\text{-}financ}$) of the project. The monitoring of the plant typically focuses on the PR and technical availability as these KPIs are of high importance in ensuring the overall profitability of the project.

Finally, there are different business models including, among others, FIT subsidies, green certificates, tax credit, self-consumption (in whole or in part), private or, public sell to a third party according to a power purchase agreement PPA. Unfortunately, the questionnaire responses do not provide more detailed information on this topic.

3 Review and Analysis of Technical Assumptions Used in PV Financial Models

In this section, we review the current practices by comparing the technical assumptions presented in Section 2 with scientific data, state-of-the-art methods and recommended industry best practices. As reported in the previous Section, only the parameters that directly influence the energy yield calculation are typically described in detail. Similar findings were obtained in the Solar Bankability study [1] where a survey was conducted on the financial models of 18 ground mounted PV plants in Europe developed in 2011-2015. Consequently, stakeholders involved in PV project investment find it challenging to determine if the CAPEX and OPEX values used in their PV financial models are correct or at the very least, reasonable.

In order to deal with the lack of tangible technical parameters for CAPEX and OPEX, the authors of the Solar Bankability project have proposed to focus on the technical aspects of the EPC and O&M scopes of work to manage the technical risks linked to the CAPEX and OPEX of PV investments. This suggestion is based on survey findings that the EPC and O&M costs make up to a significant portion of the CAPEX and OPEX (70-90% and 30-70%, respectively). Unfortunately, most of the technical inputs in the EPC and O&M are highly qualitative and therefore subjective. Therefore, when assessing the correctness of the technical assumptions, the most logical approach is to compare them with the recommended industry best practices.

The Solar Bankability project extended their study, analyzing the different technical aspects in the EPC and O&M contracts from a group of ground-mounted and rooftop PV projects in Europe developed between 2014 and 2016. The weaknesses and gaps uncovered by our questionnaire and by the Solar Bankability study are analyzed and summarized in the following subsections. Here, the authors have extracted and summarized the essential findings from the Solar Bankability reports [1] and [3]. In §3.1 the technical assumptions regarding the assessment of the solar resource are reviewed. This analysis is subdivided in three categories, namely the quantification for the solar resource (§3.1.1), the variability and long-term trends of the solar resource (§3.1.2), and the conversion to the plane-of-array (§3.1.3). Then, the technical assumptions used in the different steps of the PV energy yield estimation process are reviewed and analyzed in §03.2. The cost elements involved in capital expenditures and operating expenditures are discussed in §3.3 and §3.4 respectively. Finally, the reliability and failures of PV system components are reviewed in §3.5.

3.1 Solar Resource Assessment

Long-term solar resource related uncertainties are one of the main technical sources of uncertainty impacting long-term energy yield estimates of a PV plant [1], [3]–[5]. The overall solar resource uncertainty is the result of the combination of different uncertainties, such as measurement or model uncertainties (e.g. pyranometer or satellite uncertainty), long-term variability and trends, and any further models used as, for example, the conversion of the horizontal irradiation into the plane-of-the-array. These elements are discussed in the following paragraphs and compared to the findings from the review of current practices presented in Section 2.

3.1.1 Quantification of the Solar Resource

As highlighted in Section 2, different solar irradiation data sources are available including measured values with local sensors, interpolated values, and estimated values derived from satellite models. These databases use irradiation data obtained by different methods and, sometimes covering different periods. The review of current industry practices revealed that many different irradiation databases, and sometimes even different versions of them, are in use.

With regard to the uncertainty, the survey of 84 PV projects revealed that the typical values used ranged from between ±2.5% to ±8%. Uncertainty values for yearly global horizontal irradiation (GHI) reported in scientific literature are within ±2% for high quality pyranometer measurements and up to ±5% for solar reference cells and satellite-derived estimates.

Irradiation data derived from satellite images are increasingly used as input for long-term yield assessment and as reference yield for monitoring and business reporting. The reference yield is usually used as a basis for verifying the fulfilment of contractual KPIs such as PR or energy based availability (A_E). The under or overachievement of these KPIs often trigger penalties or bonuses. Therefore, before relying on a reference yield that is derived from satellite data, asset managers and O&M contractors expect that the fidelity of these data will be confirmed independently and with scientific rigor.

Several scientific studies have evaluated the quality of satellite-based irradiance data in the past and some comprehensive overviews are presented, for example in [6], [7]. Typical normalized root mean square errors are between 4% to 8% for monthly and 2% to 6% for yearly irradiation values.

Recently, several new or improved satellite-based irradiance services have become available. In several of these services, the underlying cloud models increasingly take into account the physical properties of the clouds. A large-scale evaluation has been recently carried out by the Solar Bankability project. Several satellite-based irradiance data services were evaluated. The validation study compared the satellite-based irradiance data with data from meteorological stations for the years 2011 to 2015. The reference data covers measurements from 203 stations in the Netherlands, Belgium, and France. Results of this validation have been presented in [8] and also published in [1].

Results of this study show that the overall systematic error (bias) of most models ranges between 3% and 5% of the measurement. However, for individual sites, the Bias ranges between -5% (under-estimation) and 10% (over-estimation). The random errors are small for monthly irradiation (ca. 4%) and much higher for daily and hourly irradiation values (ca. 10% and 20% respectively). Figure 2 shows the arithmetic average bias over all stations in the Netherlands (31 meteo stations) for the different evaluated models and years. Further results of this validation study are presented in [1], [8].

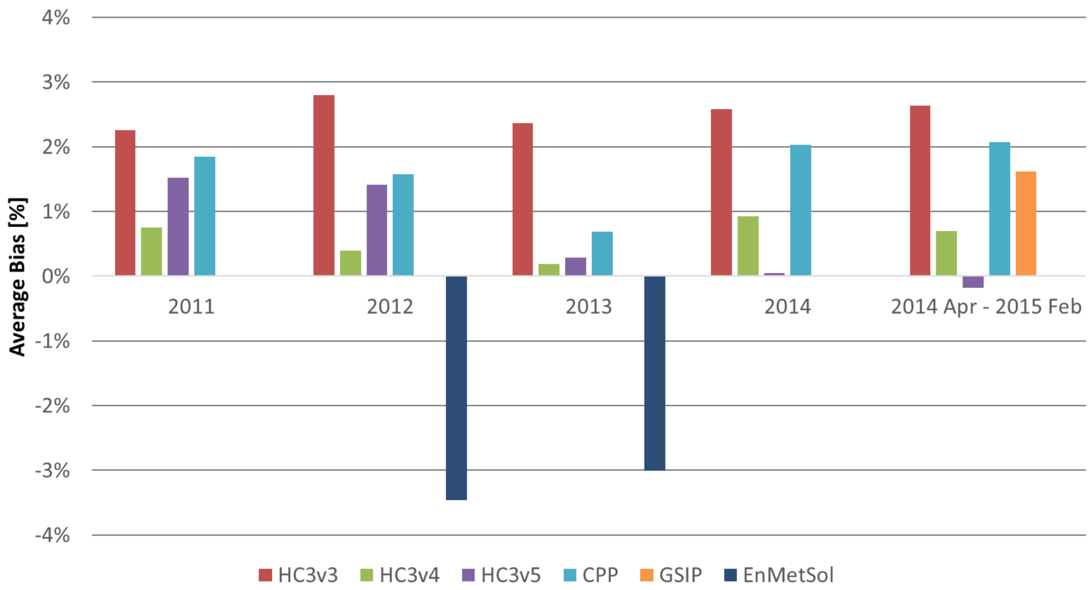


Figure 2: Arithmetic average bias over all stations in the Netherlands for the different satellite-derived models and years [8].

As highlighted in [1], when comparing the results to on-site measurements in the plane of array, it is clear that on-site measurements with calibrated and well-maintained instruments will be much more precise than the satellite-based data. However, for first and second class pyranometers as well as for silicon irradiance sensors which are often used in small to medium size PV plants, the precision of the satellite services is generally comparable and sometimes even better than that of the on-site measurement. The conclusions of this study highlight that satellite-based irradiation today can be a reliable and valuable alternative to on-site measurements for monthly and quarterly performance reporting for small to medium-size PV plants. For fault detection with hourly or daily resolution, on-site sensors are the first choice. Satellite data are less precise and may be considered as back-up when the sensors fail or appear to be poorly maintained.

Another alternative that has been recently highlighted in scientific literature is the use of site adaptation techniques. These techniques combine short-term measured data and long-term satellite estimates. Short periods of measured data but with site-specific seasonal and diurnal characteristics are combined with satellite-derived data having a long period of record with not necessarily site-specific characteristics. Upon completion of the measurement campaign which is typically around one year, 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: 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 [4] 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.

In [1], the authors validated the application of a Measure Correlate Predict (MCP) methodology, a rather simple site adaptation technique, on 32 meteorological stations in the Netherlands. The study concluded that the MCP methodology can yield high accuracies with uncertainties below 2% (bias) if the common reference period used is at least one year. However, if the bias of the satellite is not constant over the year, the application of the MCP methodology based on periods shorter that one year can have considerably lower accuracy. This can be improved by using more advanced site adaptation methods as proposed e.g. in [4].

3.1.2 Variability and Long-Term Trends

The variability of the solar resource is defined as the ratio of the standard deviation (σ) to the average global horizontal irradiation (GHI) over a long-term historical period (T_{Hist}) of typically 10 to 20 years [3]. As reported, for example in [1]and [3], the variability of the solar resource in Europe can range from about ±4% up to ca. ±7% for more complex conditions like e.g. near coastal areas. The review of current practices through the survey of 84 PV projects revealed that this quantity is often extracted from the long-term databases providing yearly data which typically cover a historical period T_{Hist} of at least 10 years. Nevertheless, the effect of long-term trends in the solar resource, which may also impact the overall uncertainty in long-term energy yield estimates, is not accounted for in any of the 84 surveyed projects.

As reported in [3], [9]–[11], the irradiation in several places across Europe shows a dimming period followed by a significant brightening trend beginning around 1990. Positive trend values in the order of +2.5% to +3.5% per decade are reported. There is however no certainty regarding the future development of these long-term solar irradiation trends. Moreover, there appears to be a lack of a clear methodology on how to account for the effects of these long-term trends for the prediction period (T_{Pred}) in energy yield estimates which serve as input for PV financial models.

Recent scientific studies evaluated the effect of long-term variability and trends in the solar resource in [1], [10] and [12]. For example, in [10] three different scenarios of future levels of irradiation T_{Pred} are compared. The result of the analysis shows that using the 10 most recent years T_{Hist} to estimate the future irradiance for the coming T_{Pred} 20 years would be the best estimator even in the case of a complete trend reversal. The study concluded that when using the average GHI from the past to predict the average of the coming T_{Pred} 20 years, the observed long-term trends create an additional uncertainty of about ±3%.

Another recent study that looked into long-term projections of changes in solar irradiation and near surface air temperature worldwide [10], found that projected trends in clear sky and all-sky irradiation are slightly negative or close to zero (between -0.1 W/m^2/year and 0.05 W/m^2/year) for most regions of the world except for parts of China and Europe. Even though it could be expected that irradiation in the coming years remains at a higher level than the long-term 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, and hence the return on investment would also be under-estimated. Moreover, as highlighted in [7], due to the effect of these long-term trends, the solar resource variability may be overestimated. The higher delta between actual irradiation values today and irradiation values from 20 years ago often result in an increased standard deviation of the data. This overestimation of the solar resource variability may negatively impact risk assessment studies.

Recent publications suggest the use of different methods to account for, or to mitigate the impact of the long-term solar resource trends in energy yield calculations. Different statistical techniques can be used to estimate the effect of local trends in the solar resource as for example, standard linear regression models, auto-regressive integrated moving average (ARIMA) methods, classical seasonal decomposition (CSD) or locally weighted scatterplot smoothing (LOWESS). For example, in [1] the authors propose an auto-regressive integrated moving average (ARIMA) method with and without trend effect. The proposed method accounts for the effect of long-term trends as part of the uncertainty (see Figure 3) instead of assuming different trend scenarios or using a shorter historical period T_{Hist} as proposed e.g. in [10]. Nevertheless, as stated in [1], the proposed method is clear for cash flow analysis (uncertainty of single years). However, when assessing the risk of multiple year sums, the method still needs further development.

Independently of the statistical method used for the trend detection and future long-term irradiation prediction, the methodology has to be clearly documented to allow the correct interpretation of the results, especially considering the increasing interest in financial models for PV plants beyond year 25.

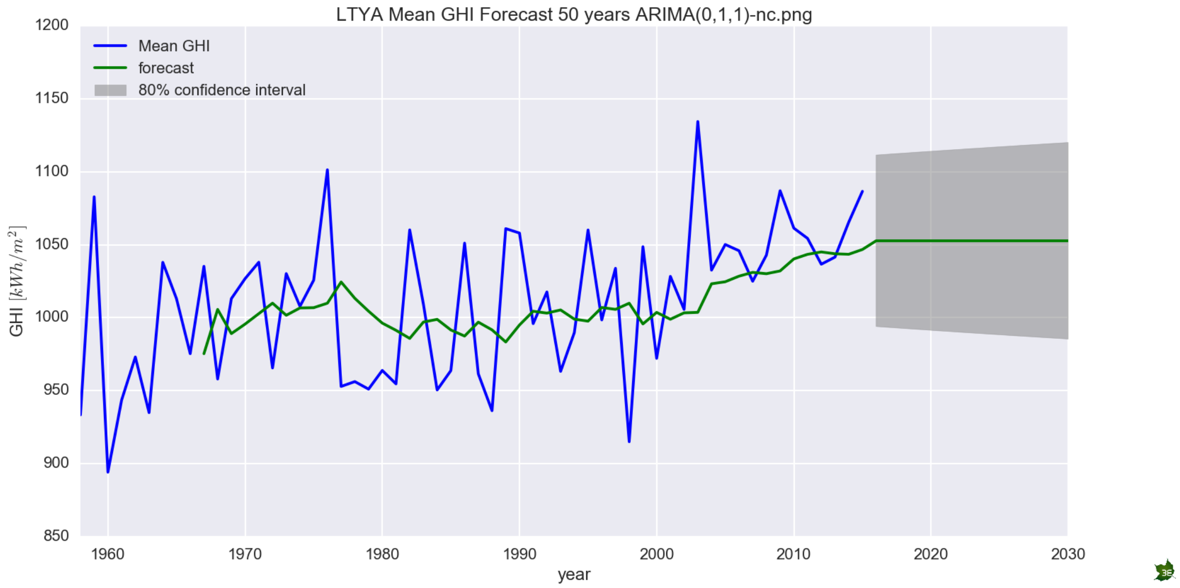


Figure 3: Forecast of future long-term irradiation based on the average of 32 meteorological stations in the Netherlands using the ARIMA (0,1,1) model without trend [1].

3.1.3 Conversion to the Plane-Of-Array (POA)

When the irradiation is not measured in the plane-off-array (POA) of the PV modules, the GHI has to be converted into the POA by using transposition models. The conversion of the GHI into the POA irradiance encompasses two major steps. The GHI is first split into horizontal diffuse irradiance and horizontal direct irradiance by the use of a decomposition model. Then, the diffuse, direct, and ground reflected irradiance components are transformed to the POA and recombined again in order to obtain the global irradiance in the POA.

Typical uncertainty values for the conversion of the GHI to the POA range between 2% and 5% as reported in literature [1], [3], [5].

3.2 Energy Yield Estimates

Our survey of 84 PV projects revealed that the most common PV performance modelling tool used is PVsyst; often augmented by in-house developed tools. In general, most of the data provided in the survey represented hard technical facts with a high degree of detail that also included professional estimates on the related uncertainties as presented in §2.2.3. As previously highlighted, the overall impression is that the values have been calculated by engineers for the specific projects and have been complemented with uncertainty values which are most likely selected from “experience or installer judgement”. In the following paragraphs we review these assumptions and compare them with literature and scientific data for the different elements in the PV conversion chain.

3.2.1 Effective Irradiance Estimation

Optical losses due to reflection in the PV module front surface and, to a lesser extent, due to spectral variations, decrease the POA irradiance that will be effectively converted into DC power. The effective irradiance is estimated by modelling the losses due to these two effects. For crystalline silicon PV modules, the variations in PV module performance that occur during each day and over the seasons effectively average out on an annual basis. Therefore, spectral variations have a minor effect on the annual energy production from a crystalline silicon PV module [3].

Reported values for reflection losses in scientific literature are ca. 1% of the annual energy yield for optimally designed systems as reported for example in [13]. However, the overview of current practices presented in §2.2.3, revealed that for our pool of 84 PV projects spread across several countries and presenting different configurations, the predicted reflection losses range between 2.8% and 3.6%. It appears then that reflection losses, may have a more important impact on the overall annual energy yield. It is important to highlight that the reflection losses increase as the angle-of-incidence (AOI) increases with a significant increase for AOI greater than 60 degrees. In addition, these losses can have a significant seasonal effect depending mainly on the geographical location and orientation of the PV modules (i.e. inclination angle and azimuth).

3.2.2 Temperature Model

The temperature losses calculated for the 84 surveyed PV systems presented in §2.2.3 range from 0.1% up to 14.5% (wide variety of environmental conditions spread across several countries and presenting different configurations) with uncertainties stated as either ±0.2%, ±0.5% or ±1%. The temperature losses depend on different factors including namely the PV module physical characteristics, the environmental conditions, and the installation configuration. Furthermore, different temperature models are available for estimating the cell temperature of a PV module. The uncertainty related with this modelling step will depend on the complexity of the model used. From simple models that neglect both thermal dynamics and wind effects, up to advanced models that take into account both dynamics and wind effects are available. Scientific validation results show that the accuracy of these models can vary from ca. 1 °C to 2 °C and even higher depending on the model used [5].

3.2.3 PV Array Model

PV array simulation software use PV module models to predict the energy yield of a PV system. As introduced earlier in this section, a variety of PV simulation software is available on the market. These software packages often use different PV module models. Comparison studies of different PV module models found error values in the order of ±1% to ±3% [13], [14]. These reported values, often included irradiation model errors and in some cases temperature losses but did not consider additional system losses such as soiling, mismatch, etc. These additional losses are discussed later in this section.

3.2.4 PV Inverter Model

The uncertainty of the inverter measured efficiency is given by the combined uncertainty of the DC and AC power measurements. The European efficiency allows estimating the load dependence of the efficiency and the power level at which maximum efficiency is reached. However, as highlighted in [3], the voltage dependency is generally neglected. The efficiency dependence on the DC voltage is less than 1% for most inverters having a maximum efficiency of 97% and higher [15]. However, inverter with efficiencies of 95% and lower exhibit a significant voltage dependency of ca. 2.5%.

Compared with other models in the PV modelling chain, the inverter model is subject to much smaller uncertainty. Typical uncertainty values reported in scientific literature for the inverter models are in the order of ±0.2% to ±0.5% [5]. These values are considerably lower than what seems to be common practice when it comes to estimating the uncertainty for inverter modelling. The review of current practices presented in Section 2 revealed that uncertainty values in the order of ±1% to ±2% are used instead.

3.2.5 Other Field-Related Losses and Related Uncertainties

Additional losses such as soiling, mismatch caused by row-to-row shading or due to PV module tolerances, degradation over time, snow, DC and AC cabling, availability, and others do occur in the field and are often only partly simulated or accounted for in the simulation software. More importantly, as introduced earlier in this section, users often estimate many of these losses and their effects based on the little information available and on their experience. These estimates are often based on assumptions and therefore may be subject to higher uncertainties. Some of the most important uncertainties associated with these losses are briefly discussed here.

Soiling losses are caused by the accumulation of particles deposited by pollution, bird droppings, agricultural activities, dust, pollen and others. The impact of these losses is strongly site dependent and therefore difficult to extrapolate from case studies. For the surveyed 84 PV systems presented in Section 2, the anticipated soiling losses ranged between 1% and 3% with most values between 1 and 1.5%. Uncertainty in this value is often provided and is given as ±1% to ±3%. Soiling losses are often estimated based on site and system characteristics, rainfall information for the site, eventual snow coverage, and O&M cleaning schedule. Typical uncertainty values reported in scientific literature range between 0.4% for regularly cleaned modules with more than 800 mm of yearly rainfall and around 2.5% for systems located on sites with less than 200 mm of yearly rainfall [5].

Mismatch losses can be caused by different shading conditions over the PV array such as near shading from objects or row-to-row shading, or due to differences in short circuit current (Isc) and open circuit voltage (Voc) of PV modules connected in series in the same string and parallel to the same inverter. These differences in Isc and Voc may cause mismatch losses in the order of 0.5% up to 1.5% [16]. In the survey of the 84 PV systems, anticipated mismatch losses range between 0.4% and 2.1% with uncertainty values stated as ±0.5% with only one exception where a ±1% is assumed.

The nameplate power of a PV module often differs from the measured power. Most manufacturers today provide a nameplate tolerance of 0 W to +5 W. In addition, measurement uncertainties, as given by manufacturers, are typically in the range between 3% and 5%. This uncertainty can be significantly decreased by independent test facilities who typically guarantee the measured values to ca. ±1.6% to ±2% [17], [18]. Furthermore, different degradation behavior of the PV modules within the array (i.e. increased standard deviation of Isc and Voc) would cause further mismatch losses that may change over time. These mismatch losses are unfortunately difficult to estimate or extrapolate from case studies.

The degradation of crystalline silicon PV modules is the result of the combination of two phenomena. The first is the initial decrease in efficiency that happens within the first few weeks of exposure, known as Light Induced Degradation (LID), the second being a long-term gradual decrease in efficiency over the years. An extensive analytical review made by NREL [19], shows that the long-term yearly degradation for crystalline silicon PV modules is around 0.5% a year with a related uncertainty in the order of ±0.25%/a. The initial degradation occurring within the first weeks of exposure (i.e. LID) is in the order of 0.16% with an uncertainty of ±1.7% for multi-crystalline PV modules and 1.31% with an uncertainty of ±0.8% for mono-crystalline (p-type) PV modules [20]. Other references suggest that LID can be slightly higher and reach up to 2%.

Moreover, the effect of the behavior of the PV module degradation over time (i.e. linear vs stepped decline) is emphasized e.g. in [1], [21]. A linear decline is often assumed in current practices with a yearly rate of around -0.5%/a to -0.6%/a per year for crystalline silicon PV modules and around -0.8%/a to -1%/a per year for thin-film technologies. The assumption of a degradation rate and its behavior over time impact directly on the expected yield and therefore may have significant financial consequences.

Note that all the degradation rates discussed in the previous paragraphs refer only to the PV modules degradation and not to the degradation of the entire PV system. In addition to material degradation a PV module or array under outdoor operating conditions, a PV plant is exposed to other factors directly acting on its electric performance. These are, among others, soiling, snow, shading, and modules and cell mismatch. It is therefore more appropriate to speak about performance loss rate (PLR) rather than degradation rate at PV system level [22].

Some other effects such as, for example, snow, shading, reflection, DC and AC cabling, transformer, and availability also have an impact on the energy yield estimates and therefore, have a related uncertainty. As stated in [1], for example, some authors assume a conservative value of ±5% of uncertainty due to the relative uncertainty for the loss values attributed to these additional factors. Moreover, the modelling software packages are not always able to model these effects, which then require further work using a different software solution, or by adding the aforementioned uncertainty.

Typical uncertainty ranges for the different elements involved in the overall estimation of the energy yield as found from review exercises of current industry practices as in [1] and [5] are summarized in Table 4. Further explanation and examples on how these uncertainties are combined are available in [5]. Overall, the collected values from the survey of 84 PV systems, which range between ±3.2% and 7.3% agree with the values presented in Table 4 apart from the lower end of this overall uncertainty range i.e. ±3.2%. This rather small value of total combined uncertainty should not be considered as representative as it may be the result of a very particular case.

Table 4: Overview of uncertainties in the different conversion steps.

	Uncertainties	**Range**
Solar resource	Climate variability	±4% - ±7%
	Irradiation quantification	±2% - ±5%
	Conversion to POA	±2% - ±5%
PV modelling	Temperature model	1°C - 2°C
	PV array model	±1% - ±3%
	PV inverter model	±0.2% - ±0.5%
Other	Soiling, mismatch, degradation, cabling, availability, etc.	±5% - ±6%
Overall uncertainty on estimated yield		±5% - ±10%

3.2.6 Validation of long-term Yield Estimates and their Level of Confidence

The energy yield of a photovoltaic (PV) plant over its financial lifetime ($T_{L\text{-financ}}$) is estimated during the design phase with a long-term yield assessment. The long-term yield assessment usually returns the so-called P50 and P90 yields which represent the 50% and 90% exceedance probabilities, i.e., the energy yields that will be exceeded with a probability of 50% and 90%, respectively. As input for the financial model of the PV investment, the P50 and P90 yields are usually evaluated for the first year of operation and for the overall financial lifetime of the plant.

Consequently, the P50 yield as well as its level of confidence represented by the P90 yield are essential for the correct evaluation of the PV investment. Moreover, when investing into larger portfolios of PV plants, the risk for the investor is finally expressed by the P90 yield of the portfolio rather than that of each individual plant [23]. Up to now, for commercial projects little validated knowledge about the quality of their P50 and P90 yield estimates has been available in the public domain.

The Solar Bankability project explored the quality of the initial P50 and P90 yield estimates on plant as well as on portfolio levels in order to further quantify the potential reduction of risk with larger portfolios. The purpose of this work was to validate the initial long-term yield estimates based on monitoring data for several years. Extended results of this analysis are available in the Solar Bankability report *Review and Gap Analyses of Technical Assumptions in PV Electricity Cost* [1].

The correlation between P50 and P90 yield estimates and the actual electricity production were compared for a portfolio of 41 PV plants. The plants are situated in Italy, in mainland France and in French oversea departments and territories (DOM-TOM). The sample comprises rooftop and ground mounted systems and covers a wide range of plant size from 10 kWp up to 12 MWp. The data sets for the validation cover between one and four years of operational data. The 41 plants with installation type and available data are listed in Figure 4.

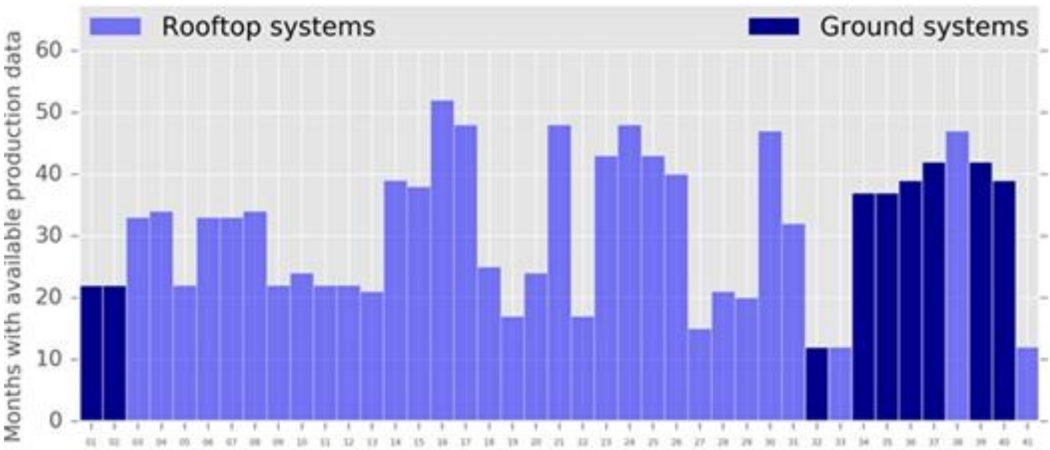


Figure 4: Anonymized list of the 41 PV plants under study with available electricity production data and installation type [1].

Information on PV plant unavailability was collected for each individual plant and analyzed. Figure 5 shows the actual percentage of 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 measured 15-minute data. Unfortunately, it was not possible to determine the unavailability for all 41 PV plants under study, since the detailed O&M report was not available for some plants and some plants only had monthly data available.

Figure 5 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%. This has been further analyzed and it is discussed below.

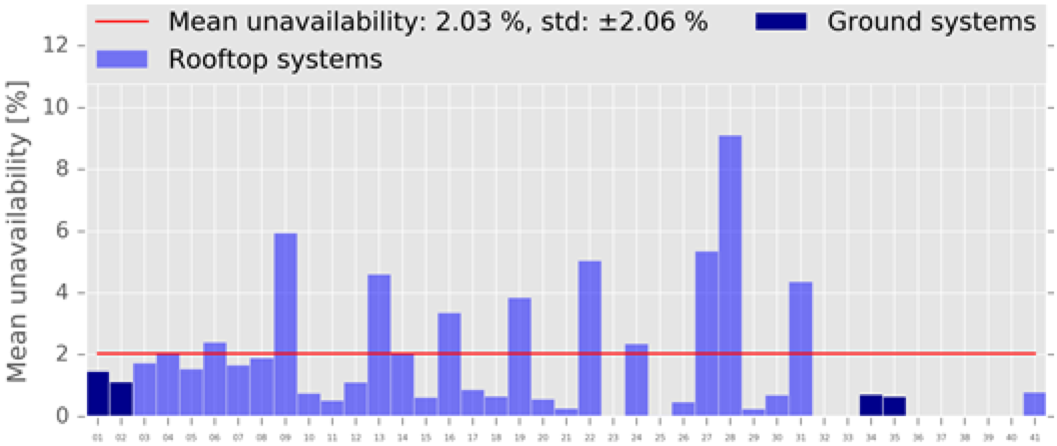


Figure 5: Actual time-based unavailability data from most of the PV plants in the portfolio [1].

The main results are shown in Figure 6. The initial yield estimates for the first year of operation (P50) is represented by the zero line. The red and green background colors represent the initial P90 and P10 estimates, respectively. They are typically situated between ±7% and ± 9% from the P50 for a single site [5]. The difference of the actual electricity production during the first year of operation from the P50 yield is represented by the blue bars. In this case, a negative blue bar means that less electricity was produced than initially expected. Statistically, eight out of ten bars should lie within the red and green region, one should lie above and one below.

At plant level, the yields are close to the ideal scenario but slightly biased negatively by -1.15 percentage points. For most of the PV plants analyzed across the portfolio, the actual electricity production during the first year of operation (blue bars) lies within the expected uncertainty range. However, while only one PV plant is situated above the P10 confidence bound, the portfolio contains six plants for which the actual production was below the P90 confidence bound. These deviations for some plants had to be further analyzed to understand the gaps.

The orange arrows in Figure 6 point at the plants with significant durations of plant unavailability. When correcting the energy yield for the durations of unavailability, the actual electricity production for many of these plants remains within the anticipated confidence range. In other words, their initial long-term yield estimates did not account for the unexpectedly high losses due to the plants being unavailable.

More generally speaking, the distribution of actual energy yields versus the initial long-term yield estimates is relatively narrow when excluding significant durations of unavailability and, hence, the initial long-term yield estimates were quite good.

At portfolio level, the overall (non-weighted) mean difference between initial long-term yield estimates and the actual yield over the portfolio is -1.15%. This means that, over the analyzed portfolio, the yield is slightly lower than initially estimated during the design phase. Furthermore, as shown in Figure 7, the dispersion (NRMSE) is around 4.4% for the analyzed portfolio. These variations lie within the normal expected ranges and are similar to the values reported in e.g. [23]. These deviations are typically expected to be mainly due to the variability of the solar resource and other site specific losses that are not precisely modelled during the design phase. Moreover, some over-estimations are cancelled out with some other under-estimations across the portfolio as shown in Figure 6.

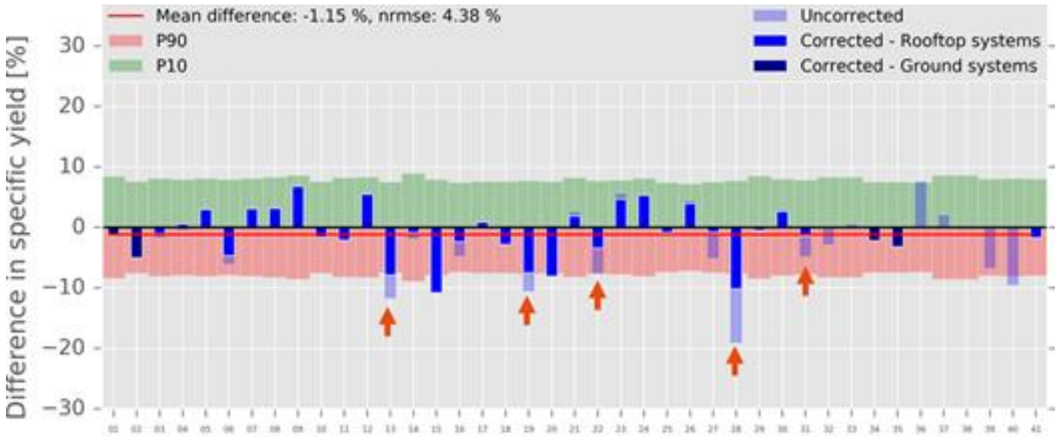


Figure 6: Difference in specific yield corrected for actual unavailability. The orange arrows highlight the effect of the unavailability correction for some examples [1].

The difference and its distribution for plane-of-array (POA) irradiation, performance ratio (PR), and specific yield for the entire portfolio are summarized in Figure 7 below. Such differences are represented using “violin plots” which are a combination of box plots and kernel density plots. 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.

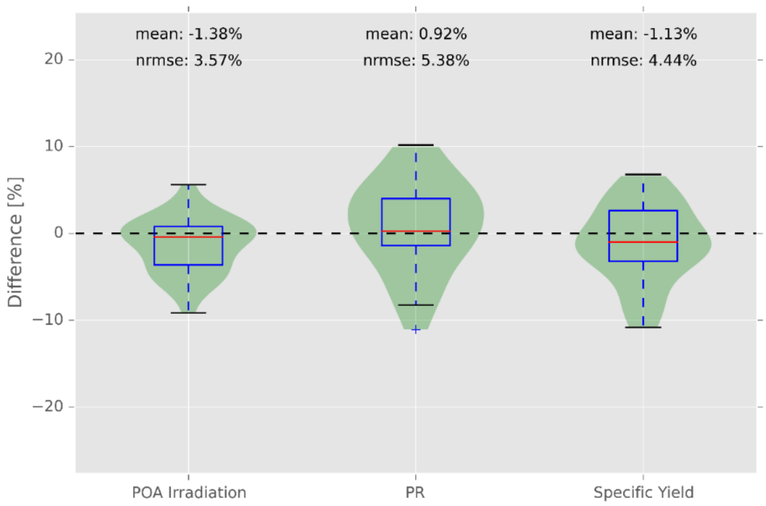


Figure 7: Violin plots for the difference in POA irradiation, PR and resulting specific yield between initial expected yield and actual yield for the analyzed portfolio of 41 PV plants [1].

As shown in Figure 7, the largest gap between initial expected and actual values comes from the performance ratio estimates. As previously highlighted, the initial estimates of system losses depend on several factors. In addition to the PV software modelling accuracy, several user estimates and assumptions affect the yield estimate. Regarding the POA irradiation, the results presented here are the outcome of comparing the initial estimate done during the initial yield estimation against the satellite-derived irradiation from cloud physical property (CPP) [8] for the first year of operation. Unfortunately, not all 41 PV plants in the portfolio had good quality on-site solar irradiance sensor measurements. Therefore, for consistency purposes and to allow an analysis across the entire portfolio, the satellite-derived irradiation data from CPP has been used.

In conclusion, the initial energy yield estimates for the portfolio under study generally agree quite well with the actual electricity production over the first years. The NRMSE across the analyzed portfolio of 41 PV plants is approximately 4.4%. By contrast, the uncertainty in long-term yield estimates for a single site is typically around ±5% to ±10%. The results of this PV portfolio use case show that this uncertainty range could decrease for a statistically meaningful portfolio of several PV systems down to around 4.4%.

The outliers with energy yields below the P90 yield were largely caused by plant un-availabilities. Therefore, the risk of unavailability needs to be addressed next to the resource uncertainty and the uncertainty of the PV system model. This risk can be mitigated through good warranty conditions and operation and maintenance (O&M) contracts as shown, for example, in [24] where an availability of 99.7% is obtained.

Investing in a big portfolio of PV plants may be seen as a risk mitigation strategy for investors through diversification of risks. For an entire portfolio of PV plants, the overall risk of not achieving the expected energy yield decreases with increasing size and spatial spread of the portfolio. Several variables such as the number of plants, their geographical spread, PV module technologies, the type of installations, system configuration, etc. will influence the resulting overall uncertainty. Nevertheless, the practices and potential sources of uncertainties highlighted in this text must be applied on a project-per-project basis to ensure best results.

3.3 Capital Expenditures

The CAPEX value of a PV project depends strongly on the construction cost which in turn is influenced by among others, the complexity of the project. In few cases the considered technical assumptions are clear before the final CAPEX value has been determined. As introduced earlier, the review of current practices revealed that the EPC cost make up a significant portion of the CAPEX (70-90%). When the CAPEX value represents the construction cost, this should reflect the quality of components and workmanship as is considered and agreed upon in the EPC contract. In this way, most of the technical assumptions that influence the CAPEX value will not be visible to the investor until the technical advisor (TA) is consulted to assess these assumptions in a separate technical due diligence (TDD) process in order to verify if there is a reasonable connection between the quality of the plant and the price, and if the various risk elements have been addressed appropriately.

As examples of specific technical issues that will influence the CAPEX value, it is relevant to mention the exact performance criteria, quality control and inspection measures defined for PV modules, inverters, sub-structures, balance of system (BOS) components and the building process itself. Test procedures and acceptance criteria used for commissioning of the finished project on a system level which may include performance warranties often have a direct impact on the CAPEX.

The CAPEX must also set aside realistic reserves for project decommissioning that will cover the costs of removing all elements of the plant, recycling and disposing of them and returning the land or rooftop to pristine condition. Whereas historically, developers have not considered this cost to the project, the European Waste Electronics and Electrical Equipment (WEEE) directive for the collection and treatment of photovoltaic modules across Europe entered into force in August 2012. The modules, inverters and switchgear require specific handling due to their electronic nature. As for the remaining elements of the plant, mounting structures, foundations, buildings, etc., as PV becomes more mainstream it is inconceivable that public opinion followed by legislation will allow obsolete PV plants to simply decay after their useful life.

Large PV installations are considered investment opportunities and will be traded among investors at a price that reflects the generated or expected IRR. As with the EPC-contract, the sales-price should be adjusted according to the realized production or PR during the years of operation since commissioning, based on specially prepared algorithms. Likewise, all other possible deviations from the realized project presented in the marketing prospectus must be accounted for in the CAPEX value.

The weaknesses and gaps found during design phase, plant component procurement and selection, transportation and construction and during plant testing and acceptance are analyzed and summarized in the following subsections.

3.3.1 Plant Design

The plant design should be conceived taking into account all the various technical, financial, legal, and statutory conditions. The choice of site, access to the grid, plant capacity, technology, and the complexity of the design and configuration will ultimately influence the investment capital, cost of operation and maintenance, and the energy yield.

The technology selected for the components (e.g. crystalline silicon or thin film module, fixed or tracking structure, string vs central inverter) should fit the environmental characteristics, available local technical capabilities, and solar resource profiles of the project site. Resource assessment, discussed separately in this report (§3.1), is important from the perspective of obtaining accurate long-term yield estimation. Site assessment is important as this will affect the choice of foundation and mounting structures affecting the CAPEX value of the PV investment and defining construction risks and possible delays. For ground-mounted installations, geotechnical and a soil study should be carried out to assess the ground condition. For rooftop installations, structural, and roof stability studies are a must. Our survey discovered that the geotechnical or stability study costs are either not included or hidden in the CAPEX; there is no clear indication of this cost item in the surveyed financial models. However, most EPC contracts state that the design of the PV plants has taken into account the site conditions and constraints.

Correct sizing and configuration of the PV plant ensures optimal production and yield. When estimating the long-term performance and yield of the PV plant, correct assumptions and relevant losses must be taken into account. These have been discussed in §3.1 and §3.2. Overly conservative or optimistic estimations of the plant yield will affect the numbers in the PV financial models which in turn will influence investment decision.

In summary, the following weaknesses apparent in PV plant design are highlighted:

- The effect of long-term trends in the solar resource are often not fully accounted for
- Exceedance probabilities (e.g. P90) are often calculated for risk assessment assuming a normal distribution for all elements contributing to the overall uncertainty
- Incorrect degradation rate and inaccurate rendering of the system behavior over time is assumed in the yield estimation
- Incorrect availability assumptions are used to calculate the initial yield for the project investment financial model as opposed to the O&M plant availability guarantee as shown in Figure 5

3.3.2 Plant Component Procurement and Selection

The majority of the EPC costs are used to procure the PV plant components, with the cost of modules comprising about half of total component cost. Consequently, it is important to ensure that the procured components are of a quality to ensure high performance and a profitable PV plant.

Since the EPC contractor is the party in the PV project value chain responsible for procuring system components, the technical specifications in the EPC contract should reflect requirements that ensure high quality components. This includes not only the selection of component technologies most suitable for the specific project site and application, but also defining reliable suppliers who are capable of delivering high quality products. The definition of the supplier should also include financial solidity that ensures a high probability that the supplier will remain in existence throughout the operational years of the plant from a warranty (hardware) and guarantee (service and performance) perspective.

In summary, the following weaknesses apparent in the procurement process are highlighted:

- The technical specification of the PV plant components usually consists only of a high-level description. In most cases, only the brand, model, and quantity of the components are listed.
- Requirements for PV modules and inverters extend only to stating that they have to carry valid IEC certifications or CE mark of compliance. Project specific requirements such as salt-mist, ammonia or resistance to potential-induced-degradation, with the relevant IEC certification testing, are not always specified.
- There is a lack of specifications requiring factory inspection or product testing that serve to prevent inadequate manufacturing process or material deviations which could lead to batch specific product defect or failure.
- Batch testing by an independent laboratory are typically included in the factory inspection but this can be considered also separately.

3.3.3 Transportation and Construction

Transportation is a key part of the PV plant construction phase. PV plant components are hardy and resilient enough to last through the financial lifetime ($T_{\text{L-financ}}$) of e.g. 25 years and more. However, until they are installed on site they require some level of care during transportation and handling. PV modules in particular are made of solar cells, glass sheets or polymer back-sheets which could easily be damaged by improper handling [25]. Thin film modules built with a glass-glass structure and without frames are susceptible to glass breakage. For the crystalline silicon wafer-based modules, various studies have confirmed that the mechanical loads induced by transportation could cause micro-cracks in solar cells [26], [27], which can turn into snail track defects, which in turn could affect the long-term module performance. Shaking, dropping or tipping of the shipping pallet or containers have also been known to loosen or break the electrical or mechanical connections in inverters or mechanically damage the inverter housing. Section 3.5 of this report is dedicated to the discussion of failures in PV modules and inverters; Section 3.5.1 especially focuses on module damages due to transportation issues.

Because of the risks associated with transportation, the different players in the PV plant construction value chain must each undertake responsibility for his/her part. For the component manufacturers, having a chosen method for transportation assessed for their quality, e.g. using the test developed to check for module transportation by TÜV Rheinland [28], is recommended. For the owner of the PV plant, it is recommended to request for product inspection upon delivery. This basic level of quality control is still rarely practiced based on our survey findings. Moreover, if any delivery inspection was done, the method used is usually very basic (visual inspection by the naked eye) and only applied to a small sample group which may not be representative of the entire delivered population. These mitigation measures are likely to increase the EPC and CAPEX costs in the PV financial models, however, the long-term gain is highly likely to outweigh the costs of defect repair when the plant is in operation and the losses in revenue due to under-performance or shutdown become evident.

Many technical failures or defects occurring during the operation phase of the plant could be attributed to construction issues. One possible root cause is poor workmanship which can result in misaligned structures, poorly affixed modules, and loose electrical connections, to name just a few. Bad workmanship includes dropping or incorrectly carrying plant components, for example: modules must be handled by the frame, modules must not be lifted using the junction box cables. Another root cause of poor plant performance and high levels of failure is disregard for the engineered design of the plant or the installation guidelines issued by the component manufacturers. Examples such as not leaving adequate space around inverter for ventilation, extreme cable bending radius and mismatch of electrical connectors are just a few bad practices observed. Construction defects, if not fixed, are very likely to affect the long-term PV plant performance. Even if the defects are caught early, there still exists the possibility that the time required to fix the defects could delay the project completion causing the plant to miss a favorable feed-in tariff window, affecting the overall project lifetime revenue.

Although the responsibility of the EPC contractor to deliver a completely functioning and good quality PV system is usually included in the EPC contract, installation errors do happen. From their study of PV plant data from 2014 and early 2015, TÜV Rheinland reported that 55% of the defects in the plants are due to installation errors [29]. Clearly, it is useful to employ construction supervision during the project installation phase. Construction supervision is necessary to check the progress of work, to verify that the installation is according to the contractual technical specifications, and to audit the construction work. Unfortunately, due to the added costs, construction supervision is not widely undertaken, especially for small PV projects. Therefore, at the very least, some form of plant inspection upon completion is called for. Moreover, preliminary plant performance testing upon construction completion should be required by the project owner or investor before accepting the plant from the EPC contractor.

In summary, the following weaknesses apparent in plant construction are highlighted:

- Disregard of published transportation and handling protocol
- Inadequate quality control in component unloading and handling during construction
- Inadequate storage of components on site
- Lack of construction supervision
- Lack of consensus for plant acceptance methodology to be applied after completion of the construction process

3.3.4 Plant Testing and Acceptance

The principal task of the EPC is to deliver a completely functioning PV system with the inherent capability of producing the designated energy yield to deliver the targeted IRR in the PV investment financial model. The testing of the plant upon completion and the commissioning of the plant into operation are therefore very important. The objective is to verify that the PV system has been built according to the contractual requirements. Plant testing and commissioning also serve to catch any transportation or construction defects not detected and fixed earlier before the plant was completed. Good testing and acceptance criteria are therefore critical for avoiding under-performance which will affect the prospects of achieving the revenue defined in the PV financial model.

A comprehensive plant testing and acceptance protocol should include not only a physical inspection and functional check of all systems, but also the initial performance of the PV system. All surveyed EPC contractors have included in their scope of work a completion check which included a visual inspection, mechanical inspection, and functional tests of the different components. Mechanical quality is usually checked in all parts of the installation. The functional testing often includes only testing plant components in open-circuit conditions. All inverters and electrical switchboards are verified. As for PV modules, only sample strings are usually tested. Advanced camera based inspection tools are becoming more prevalent as they allow for detection of defects not visible by plain naked-eyes such as localized elevated temperature zones in the electrical cabinets, inverters and modules using infrared (IR) cameras, and electroluminescence (EL) equipped cameras for finding micro cracks. Despite their increasing availability, IR and EL inspection are still not widely accepted for plant acceptance testing as these tests take time, add cost and also require some skills to operate and analyze. Recent improvements include mounting an IR camera on unmanned aerial vehicles providing a high throughput solution for IR inspection.

Once the visual, mechanical and functional tests are completed, a performance test is needed to verify that the PV plant is functioning as designed. The important aspects to consider in designing the performance test protocol are:

1. Key performance indicator to be used (e.g. performance ratio or output yield) and the corresponding guaranteed value
2. Duration of the test
3. Irradiance threshold
4. Monitoring system to be used, including measurement sampling rate and averaging method
5. The calculation method for the key performance indicator selected

A key performance indicator (KPI) determines if the erected PV plant is operating as expected. The most common KPI used in EPC contracts is the performance ratio (PR) of the plant. Other KPI include output yield while availability is used over a long testing period, usually 12 months. The EPC contractor is normally required to guarantee that the plant will meet an agreed upon level of the selected performance indicator. The guaranteed value is calculated during the plant design phase.

The plant performance test requires operating the PV plant over a contractually agreed upon period of time during which the monitoring system is carefully inspected to ensure accurate readings while the plant PR or output yield is evaluated. To compensate for the effects of testing over a period of time that does not represent the meteorological conditions for the entire year, a corrective method such as the weather-corrected performance ratio [30] are applied.

Ideally the acceptance performance test should span a time period long enough to be representative of seasonal changes, that is, a minimum of one year. However, the performance test results are often used as part of a plant hand-over procedure from the EPC to the owner and as an EPC payment milestone. Therefore, it is necessary for the performance test to take place as soon as possible after completion. In the PV EPC sector, accepted good practice is to conduct a preliminary (provisional) performance test over a short period following completion to check that there are no major technical issues that affect the plant functionality, followed by a one to two-year run-in period during which availability can also be tested. Among the surveyed EPC contractors, the duration of the provisional performance test ranges from 5 to 15 consecutive days. Together with the total duration of the performance test, a minimum number of hours with irradiance above a certain level like e.g. 600 W/m^2 is often specified.

Among the surveyed EPC contracts, we have found that not all contractors have included both the provisional and final performance tests in their plant acceptance criteria. Most of the contractors have opted to undertake the first performance test 12 months after the plant enters into operation. The provisional acceptance of these plants is based on the successful completion of the mechanical inspection and electrical functionality tests. Following this practice encompasses higher risks since many technical issues could appear during the first 12 months of operation and their early mitigation crucial. It is recommended to perform a provisional performance test as soon as possible following industry best practices.

The evaluation of the plant performance PR over the test period is done by comparing the system yield Y_f as measured at the agreed upon metering point to the reference yield Y_r (i.e. $PR = Y_f/Y_r$). The reference yield is the total solar irradiation falling on the plane of the module array during the time of testing. The test period, season, irradiance threshold, plant capacity, and availability are elements affecting the conversion from solar energy to electrical energy and may be negotiated in the EPC contract. Because of the short provisional performance test duration, the calculation should include at least the seasonal effect of the temperature and irradiance characteristics (seasonal angle of incidence) on the plant performance. There are several ways to correct the values of the short-term PR or output, such as the method proposed in [30]. For the final acceptance performance test, the PR or yield should be checked against the initially estimated value calculated during the design phase taking into account module/system degradation.

Since the inverter is designed to turn on at a specific DC voltage that is a direct function of solar irradiation on the panels and since this voltage is achieved through the designed DC system and implemented through good workmanship, the irradiance threshold is an important element in the performance calculation. Disregarding an irradiance threshold can cause a poor PR calculation if the testing period includes long periods of time where solar energy is under the threshold, yet collected by the monitoring system. Setting the irradiation threshold too high will create a PR that disregards the critical operational period when the inverters begin to operate. Since the accepted plant PR is calculated during the design of the plant using a PV simulation program, the testing team must correlate the irradiation threshold with that assumed by the simulation program.

The contractually agreed upon irradiance threshold is implemented using an irradiance data window affecting the calculation of the PR or yield calculation outcome. The cut-off windows where the operational data are excluded from the calculation must be set correctly. A higher irradiation threshold means less production hours are taken into account in the PR calculation. A longer time window means production (and irradiance data) at early or late hours are included. Ideally the thresholds should match the level at which the inverters are designed to start converting the solar energy to electrical energy. Our survey found either an irradiance threshold of 35 and 100 W/m^2 used in projects in France and Benelux and up to 200 W/m^2 in other continents or that no threshold was set which means all recorded values when the PV plants are producing will be used in the calculation.

The calculation of the effective plant performance makes use of plant operational data collected by the monitoring system. Therefore, it is important to have a good monitoring and data acquisition system including meteorological sensors to obtain high quality and reliable plant data. The IEC61724 and Performance Plus project [5] provide some best practice guidelines in terms of the requirement for collecting and using the data for PV plant performance evaluation. In most of the surveyed EPC contracts pyranometers of at least ISO9060 secondary standard and temperature sensors (module and ambient) are used. Two of the surveyed contractors rely on satellite-derived irradiance data for all performance tests since their PV plants are located at sites where the satellite irradiance data are available and of good quality.

In summary, the following weaknesses apparent in plant acceptance procedure are highlighted:

- Inadequate protocol for visual inspection
- Lack of relevant equipment for visual inspection (e.g. infrared and electroluminescence equipped cameras)
- No short-term performance test at provisional acceptance
- Missing final performance test of guaranteed performance
- Incorrect or missing protocol for collecting data for PR or availability evaluations
- Missing final check of monitoring system availability and functionalities
- Incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation

3.4 Operating Expenditures

As introduced earlier, the O&M costs make up to a significant portion of the OPEX (30-70%). In the following subsections, the weaknesses and gaps found during monitoring and reporting, preventive maintenance, corrective maintenance, and the calculation of key performance indicators are analyzed and summarized.

3.4.1 Monitoring and Reporting

As presented in Section 2, the core task of the O&M contractor is to monitor the plant operation on an ongoing and continuous basis and report the plant data such as production and operational events to the investor and owner on regular basis, usually monthly and yearly. PV plants of commercial scale and larger employ remotely accessed monitoring systems.

The monitoring system is installed by the EPC as part of the CAPEX expenditure, yet is used only during the OPEX period. When the monitoring system is not defined carefully the equipment and parameters of the monitoring system can be decided by the EPC contractor with little regard for ease of sustaining the project, focusing on keeping CAPEX costs down. Whereas the CAPEX may be lowered by cutting the quality of the monitoring system, the capability for quickly resolving faults is greatly impeded, lowering availability, performance and plant profitability.

Design of the monitoring system should take into account the defined purpose of the system. For example, in projects where PR is to be monitored constantly, or once a defined period can have different requirements for collecting irradiation data and for writing the values to database. Constant monitoring of PR can be used for ascertaining fault conditions, while monthly or yearly PR evaluation requires a system of less quality.

The frequency with which monitored values are written to database is not a trivial decision. Collecting data every hour enables saving on data storage while greatly reducing the capability for trouble shooting faults and problems. Collecting data every minute will greatly enable trouble shooting, at a high cost for data storage. These considerations along with ease of data manipulation should guide the system designer in defining the most compatible data acquisition for a given project. The manager of a PV plant portfolio would find it useful to view data from the different plants on the same time line. When monitoring systems acquire data at different rates it is not always possible to achieve a meaningful comparison, such as when one plant has 15-minute resolution and another has 10-minute resolution, enabling comparison only twice every 60 minutes. At the height of the winter season the production day can contract to only 5 hours. The number of data points during these production days is small.

In any case, it is of vital importance that the values saved to disk are averaged from the interim sampling since the previous value written to disk. These samplings from which the saved values are averaged should be of a resolution of 15 seconds or better, except for the energy parameter which is always growing.

Some commercially available monitoring systems have capabilities for sending alarms when production drops and when one inverter is producing less than others in the plant. Some of these systems also perform automatic calculations of PR at the end of each day and others simulate what the system should have produced based on the irradiation sensors and the temperature and compare to what was produced. Most of the systems enable downloading data from the system database to a local computer for reporting and troubleshooting; however, the download process for system parameters necessary for trouble shooting is often restricted to specific parameters and a limited time frame, usually a single day.

Data values collected by a monitoring system can be corrupted or inaccurate for a variety of reasons. The monitoring system should vet the values to be stored, warning on values that are not relevant. This is of great importance when the system is automatically calculating insolation from irradiation data and aggregating for PR calculations.

PV monitoring systems collect and record all data produced by the plant automatically. As introduced in Section 2, state-of-the-art "smart" monitoring systems look at the characteristics and changes in the PV plant parameters and try to diagnose any issues and identify the associated root causes automatically. These systems improve efficiency of PV systems using statistical methodologies on collected data such as machine learning statistics and neural networks. Use of such systems requires quality data acquisition of as many parameters as possible. Such monitoring allows proactive detection of faults in real time. Through smart monitoring, fault remediation can be taken promptly to minimize fault propagation and overall financial impact. A study on the performance ratio and availability of a hypothetical 100 MWp PV portfolio at low and high irradiation conditions showed that the move to a smart monitoring system from a standard system enabled early detection of under-performance leading to a PR gain of 0.45% and 2.2% for the P50 and P25 scenarios respectively, and an availability gain of 0.16% and 0.92% for the P50 and P25 scenarios respectively [31].

From the perspective of the PV plant financial model, smart monitoring could lead to a reduction of the O&M costs. Efficient and reliable fault detection could reduce notification and intervention times as well as reducing total plant down-time, increasing availability. By finding faults quickly, the maintenance work can be scheduled optimally.

In summary, the following weakness apparent in operational monitoring is highlighted:

- The monitoring system is not of defined quality to enable effective trouble shooting during project life. The monitoring system should be capable of promptly detect faults, send out alarms, and perform diagnosis on the faults to determine the possible root causes
- Data acquisition is incompatible with attaining good results in the defined reporting requirement
- System data is effectively unavailable for troubleshooting problems
- Data is not vetted for viability
- The subset of data parameters collected is too small or from bad quality to enable the use of advanced statistical tools

3.4.2 Preventive Maintenance

As introduced in Section 2, periodic preventive maintenance is also a core task of the O&M contractor. Preventive maintenance generally includes visual inspection and general house-keeping of components including, among others, cleaning of PV modules, tightening of cables, adjusting parameters, re-calibration of sensors, and replacement of defective components. The replacement of defective components is sometimes referred to as predictive maintenance. The cost of predictive maintenance could either be planned ahead in the CAPEX in the PV financial model, or included as part of the O&M expenses. We did not find predictive maintenance activity in any of the surveyed O&M contracts.

One major O&M issue is related directly to improper maintenance protocols, either from the perspective of maintenance frequency or the maintenance procedure itself. In general, the maintenance works should follow the PV component manufacturer guidelines. A failure to do so could cause not only damage to the component, but is also likely to result in voiding of the manufacturer warranty. The requirement adhere to manufacturer guidelines for maintenance is found in most of the O&M contracts surveyed in our study.

As highlighted in Section 2, among the O&M contracts surveyed, annual frequency is most commonly practiced. Module cleaning frequency is a key in the periodic preventive maintenance because module soiling causes a decrease in the module performance. The cleaning frequency (which will affect the O&M price) should be optimized by considering the rate of soiling and any cleaning effect from the natural rainfall. The most common module cleaning frequency found in our survey was yearly. However, half of the surveyed O&M contracts offered a lower O&M price which excludes module cleaning while offering cleaning services separately as requested at extra cost; i.e. moving cleaning to a variable O&M cost thereby increasing the variability of the OPEX.

As previously mentioned regarding PV plant acceptance, advanced camera based inspection tools such as IR and EL are becoming preferred over naked eye inspection as they allow for detection of defects which are otherwise not visible. Electroluminescence analysis has proved to be useful in detecting micro-cracks in solar cells, potential induced degradation, and by-pass diode failure in PV modules. However, its usage is still somewhat restricted since the standard testing mode requires the module to be tested in a controlled setup at a test laboratory. New alternative solutions are becoming popular such as mobile EL testing labs, handheld EL cameras or EL in a tent that can be used on site. Both options still call for module energization which means disconnection of test modules from the PV array for testing. Infrared thermography is preferred for operational PV plant inspection, as this testing does not interfere with system performance. As highlighted in the review of current practices, none of the O&M contracts reviewed have included EL inspection in their scope of works.

IR scan is used to find hot spots in the plant, including electrical cabinets, inverters, and modules. High-throughput IR scan using unmanned aerial vehicles is now offered by many vendors. As introduced in Section 2, the survey revealed that less than half of the contracts included IR inspection for the modules, electrical cabinets or junction boxes. The frequency of inspection was either annual or biennial. In all surveyed cases, the IR inspection was performed by a specialized subcontractor.

Due to the key role played by the monitoring system in the PV plant operation, its maintenance must therefore be a part of the overall plant preventive maintenance program. Unfortunately, this is sometimes overlooked, as highlighted from the O&M survey where almost half those surveyed were found to have not included any check or testing of the monitoring system in their O&M preventive maintenance activities. If not maintained, the monitoring system will suffer diminished functionality over time, compromising data collection, proactive alarming, and other vital functions. Plant failures during monitoring system downtime are not recorded, alarms are not sent, and data necessary for PR or yield calculations can be missing. The maintenance protocol should check all elements in the data chain, including first and foremost the functionality of the data acquisition devices and the measurement sensors. Moreover, data validation must be carried out and calibration requirements should be defined, as recommended in [32] or other accepted resources.

To repair or replace defective plant components, new parts are needed. Any delay in obtaining the required spare part prolongs the outage and therefore plant availability and production. Spare part supply and inventory management are therefore aspects of the O&M scope that should be carefully planned. Almost all O&M contracts surveyed have included spare part supply and management in their scope of works. The spare part list should be based on the component manufacturers' recommendations. In most cases the EPC contractor develops the O&M manual which includes the minimum spare part list to be handed over to the plant owner and O&M operator during plant take-over. Half of the surveyed EPC contractors agreed to provide both the O&M manual and the spare part list.

In summary, the following weaknesses apparent in the O&M plant preventive maintenance are highlighted:

- Missing or inadequate maintenance of the monitoring system
- Module cleaning missing or frequency too low
- Inadequate or absent devices for visual inspection to find invisible defects and faults

3.4.3 Corrective Maintenance

Even with the best O&M preventative maintenance programme, failures and faults do occur. The second aspect of the O&M services that are to be offered deal with the corrective maintenance required when a fault or failure in the plant occurs. Corrective maintenance requires man hours to identify, analyze, and fix the fault or rectify the failure. The cost of the activity varies depending on the nature of the fault or failure and the quality of the preventive maintenance program. Effective corrective maintenance requires good detection capabilities, starting with the monitoring system that detects the error and can supply plant production and condition data that aid in troubleshooting the problem. A “smart monitoring” system can be especially effective in this way. The speed with which the personnel rectify the problem is a function of the tools at their disposal.

The use of advanced tools and inspections such as IR or EL cameras in the preventive maintenance activities will often find problems early, enabling adjustments before they create faults and failures requiring repair and replacement.

The review of current practices revealed that one of the major weaknesses is that the corrective maintenance cost is often not properly included in the financial model. In some cases, the O&M contract has a fixed price for the first five years and no disclosure of the price after that period is provided. The financial models should consider a very likely increase of the corrective maintenance price in year six when most of the components will be outside their warranty period.

3.4.4 Key Performance Indicators

As introduced in Section 2, in addition to guaranteed performance ratio or guaranteed output yield, guaranteed availability is another KPI commonly used in the O&M contract. The survey of current practices revealed that there seems to be no general consensus regarding which KPI should be used. Only ca. 60% of the surveyed projects reported the committed KPIs: 25% use guaranteed performance ratio and guaranteed availability, 25% use only guaranteed PR, and 12% use guaranteed availability. Interestingly the remaining surveyed projects had not committed to any form of KPI at all. Although not unusual, this practice is usually seen in small installations where the O&M service is offered at a relatively low annual price.

All the considerations in evaluating the performance ratio or output yield during plant acceptance stages previously discussed also apply for the PR or output assessment during the operational years. What plant data are used, how they are collected, the calculation formula, the exclusions etc. should be taken into account, though since the time period in question is usually a year, there is no need for temperature or seasonal correction. Two important inputs not used during the acceptance testing but of importance for yearly evaluation are system degradation and plant availability. In our surveyed O&M contracts, a linear degradation with an annual rate of either 0.3%, 0.7% or 0.8% per year was assumed (all plants are using crystalline silicon module technology). As discussed in § 3.2, the assumption of a degradation rate should consider not only the rate but also its behavior over time as the latter may have significant financial consequences. Moreover, additional factors like e.g. soiling, snow, shading and modules mismatch impact the overall degradation of the PV system. Thus, for the correct incorporation of all these effects a methodology like the one proposed by [22] (i.e. performance loss rate) should be implemented as discussed in Section 3.2.5.

PV plant availability is a KPI used to determine if the plant is operated and maintained properly. It is important to recognize that the availability in the O&M contract is different from the overall PV plant availability (productivity) from the perspective of income generation and PV financial models. Logically, the O&M operator is only concerned about the availability on the PV plant level. They are not liable for any causes of loss in the PV plant availability beyond their control such as force majeure, grid outage due to grid operator’s issues. On the other hand, 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. From the O&M contract survey, we found that the guaranteed plant availability commonly required was 99%. However, the overall plant availability could be 98% as shown in [1].

There are different ways to approach the availability calculation. The most common method found in our survey is the time-based approach. Time based availability (A_T) represents the percentage of time during which the PV plant is producing power, 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; as with PR and yield calculations, any irradiance or time of day window cut-offs will affect the calculation results and must therefore be set correctly. The second approach is availability based on the energy production or energy based availability (A_E) which is calculated as the ratio between the reference yield that has been converted to electricity and the total reference yield.

In summary, the following weaknesses apparent in O&M performance indicators are highlighted:

- Missing guaranteed key performance indicators (PR, availability or energy yield)
- 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 and availability calculations

3.5 Reliability and Failures of PV System Components

3.5.1 Risks Incurred during PV Module Production/Transportation

Raw materials (PV cell, frame, glass, electronics etc.) used for the production of PV modules may be damaged in the production line due to machinery errors or mishandling. Therefore, inspections during production will help to control the quality of the final products by identifying the problematic source and fixing it. Quality inspections also provide the means to directly detect a defective item. Moreover, the conformity of the process with the related standards leads to a production line with higher yields and fewer failure rates.

Examples of failing PV module components due to a lack of quality assurance in the production process include:

1. Failed insulation test - modules with failed or skipped insulation test can cause dispersive and dangerous leakage currents, leading to safety risks
2. Incorrect cell soldering – imperfections in cell soldering can lead to corrosion, undesired electrical resistances, and bad current transmission, to list but a few
3. Undersized bypass diode – increases the chance of hotspots (overheating of cells) or the damage of the bypass diode itself
4. Junction box adhesion - incorrect adhesion of the junction box to the module can cause poor connections interrupting module current, humidity ingress with subsequent corrosion leading to performance losses and increasing risk of electrical arcing leading to fire, to list but a few
5. Delamination at the module edges - water can ingress causing humidity, oxidation and corrosion in cells leading to performance losses
6. Arcing in a PV module - caused by a damaged cell interconnect ribbon - can cause fire during operation of the module
7. Visually detectable hotspots - cells are overheating, which has a negative impact on the energy production of the module (module degradation)
8. Power rating (flash test) is not correctly performed, the sorting of the modules by performance will be incorrect and because of the resulting PV module mismatch losses, the simulation used for the financial model will not be matched. A high uncertainty of the nominal power of total PV plant will lead to uncertainties of the specific energy yield and performance ratio (PR) in the same order of magnitude

9. Uncertified electrical components in production line - life cycle, reliability and quality of PV modules can be significantly reduced

Examples of damage in PV modules due to incorrect transportation and handling include:

1. Module glass breakage
2. Cell breakage
3. Damaged backsheet
4. Damaged wiring (due to lifting module by the cable)

The global transportation of PV modules and the impact of transportation damages on the module performance is a high risk often not considered. Traceability of the impact of these damages on operational failures or failures originated during transport is not always possible. A direct link of the impact of transport damage to the system performance (e.g. solar cell cracks) is not clearly documented. The following statements however can be made:

1. The state of module quality is unclear when delivered (traceable real power, cell cracks)
2. The origin of failures is often not detectable anymore during subsequent years of operation
3. The degree of damages/power losses is not known

This state of affairs can be attributed to the fact that the quality condition of outgoing goods is unclear and/or the packaging and handling requirements are not properly specified or followed at some point in the shipping and transportation process.

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

An extended factory inspection at the manufacturer's site would focus the quality assurance measures, incoming goods inspection, and material handling procedures. A particular focus can then be put on the power measurement and data control, traceability of measurements, and flash tester calibration procedures.

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

The factory inspection usually consists of three main parts:

1. Verification of all raw materials used for the certified products
2. Inspection of the complete production process
3. Review of general quality related issues

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

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

In the third inspection step, general quality related issues are reviewed. For this purpose, corresponding documents such as ISO certificates, the quality manual etc. may be reviewed. It should also be possible to demonstrate procedures that ensure process traceability, how faulty products are handled, etc. Furthermore, measuring and manufacturing equipment is checked in terms of calibration and maintenance status, and the general calibration system is reviewed.

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

For the PV module factory inspections performed by inspectors of TÜV Rheinland Energy, all deviations defined by the auditors have been systematically categorized and statistically evaluated over several years. The plot below (Figure 8) shows the distribution of deviations of all factory inspections during the years 2012 – 2016. The results are based on results from the Solar Bankability project [3] and have been updated for 2016.

The pie chart is based on 368 deviations in total, which were identified during 242 factory inspections resulting in an average of 1.5 deviations per inspection. The fraction of factory inspections without any deviations range from 40% to 56% for the years 2012-2016.

At first glance the chart shows that a big variety of possible weaknesses can be found. There are many categories including uncategorized findings under the "Other" category which summarizes rare or rather peculiar non–conformities (each having a contribution of 2.0% or less to all deviations). Deviations under "**Other**" include sharp module edges, improper edge deletion (only applies for thin-film modules), missing grounding point, bad cell string handling & transportation, non-conforming type labels, improper junction box contacting, incautious framing, broken measurement equipment and others adding up to 14.1% of all deviations.

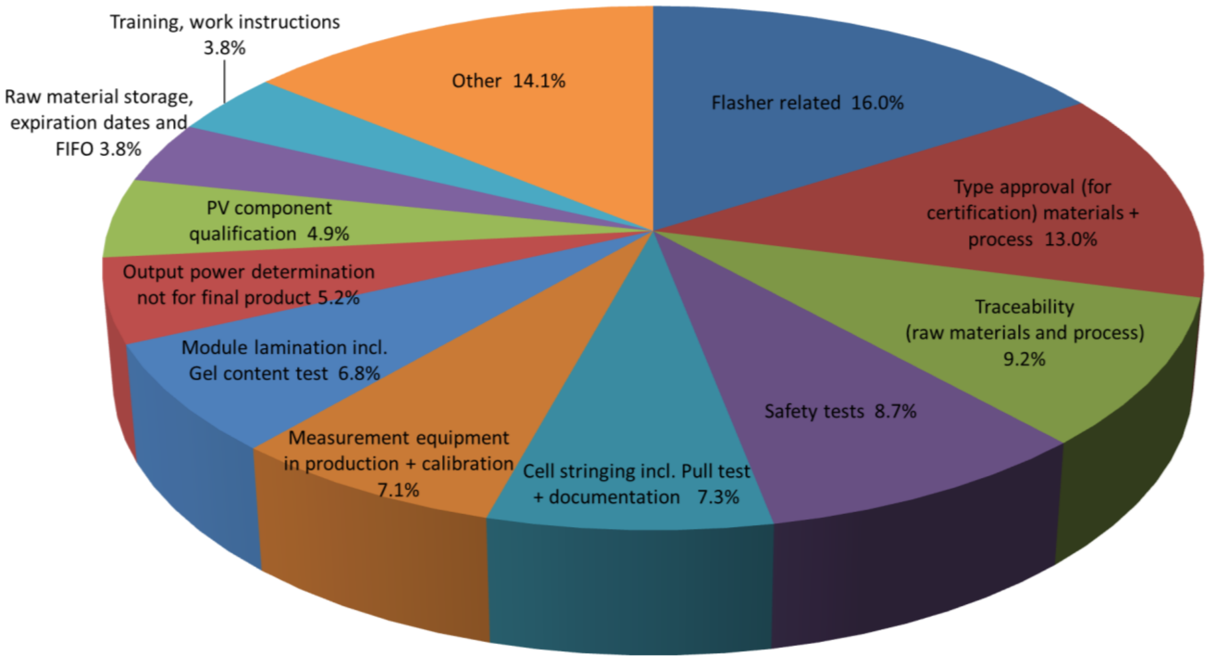


Figure 8: Distribution of deviations of all factory inspections during 2012-2016.

“**Flasher-related**” deficiencies refer to the methods applied to determine the output power of the PV module: adjustment and applied correction procedures to STC in terms of irradiance (5.7%) or temperature (1.6%), calibration of equipment used for the power measurement and general maintenance of the flasher (6.5%), and flasher classification (2.2%). These flasher-related deviations sum up to 16.0% of the total.

Typically, manufacturers indicate a production tolerance of ±5% for the measured output power at STC ($P_{mpp,STC}$). It is assumed by manufacturers that this tolerance fully covers the measurement uncertainty for the measured output power $P_{mpp,STC}$, which is however, in most cases not determined or at least estimated by them. On the other hand, gaps of up to ~10% in measured output power $P_{mpp,STC}$ have been found by TÜV Rheinland Energy by comparing laboratory measurements with the manufacturer label values. Assuming a laboratory measurement uncertainty of ±2%, this would, even in the best case for the manufacturer, mean an overestimation of output power by ~3.5%. An overestimation of output power – as a technical risk generated during the product testing phase – has a direct impact on a business model as it leads to an overestimation of the energy produced.

Among the critical issues, also “**materials used or process steps and machines**” not matching those of the certified product appear to be significant (13.0%); these issues could lead to serious module quality problems, caused, e.g., by lower quality polymeric foils incorporated in the module. The improper “**storage of raw materials**”, material used beyond expiration dates and FIFO (first in, first out) rule not considered may further contribute to quality deficiencies in producing PV modules (3.8 %). **“Production traceability”** (9.2% in total for traceability of raw materials, process, and traceability via serial number) is partly insufficient, leading to problems in meeting the warranty and proving certificate conformity. Also, potential customer complaints after some years of operation cannot be addressed satisfactorily due to lacking records of module specific data.

Further weaknesses have been defined for the core process steps for crystalline silicon module production (“**stringing**”, “**lamination**”) and related standard quality tests (7.3% and 6.8%, respectively). Insufficient performance of “**safety tests**” during production (e.g., missing or irregular high potential test or ground continuity test, insufficient test conditions etc.) is a most critical point (8.7%). This may impose safety risks for installers and operators due to insufficient insulation of current-carrying parts.

Many of the deviations are related to the “**equipment used for the measurements**” in the production line and its regular calibration (7.1%).

Furthermore, the “**output power**” is in many cases not determined for the final constructional product (5.2%); instead, for example, the power is measured at the electrical contacts within the junction box, neglecting the cables, connectors etc., and thus the output power could be overestimated due to reduced series resistance. Consequently, the labelled output power (which essentially defines the module price) is imprecisely determined in those cases.

The inspection of PV modules for possible defects and failures on-site is essential not only to identify any damaged modules, but also for the evaluation of the degradation of the modules after a certain period of time, e.g. one year. To ensure the original product quality at construction site, transparent product quality and certified logistics processes are recommended [3].

3.5.2 PV Module Failures

The IEA PVPS Task 13 has analyzed the impact of various PV module failure modes in operational PV systems. PV system failure data is collected for various climate zones with the focus on both the origin of the failure and the power loss. The failure types are ranked by their impact on the power generation.

The current status of the analysis includes a total of 144 failure-survey-data sets from 18 countries covering different climatic zones including systems in moderate climate (45%), hot and humid (10%), hot and dry (26%), and cold and snowy (19%) climates [33]. PV modules from different technologies were analyzed, including mono-crystalline silicon (28%), multi-crystalline silicon (62%), thin-film (8%), and 2% of unknown PV modules types.

Regarding the occurrence of failures over the years, the first results of this exercise show that cell crack failures are mostly reported in the very early stage of PV system operation, i.e. from year 1 to year 2. Systems with potential induced degradation due to shunting (PID) are mainly reported during year 3 and year 4. Disconnected cells or strings in the PV module are reported after year 4 and spread over the whole operational period. Discoloring of pottant is also spread over the years but power loss relevant discoloring starts only after year 3 with a high accumulation after about 18 years of system operation. Defective bypass diodes are spread over the first 10 years of operation.

In terms of degradation rates of defective PV modules, at the time of collection of the failure reports, only the mean module degradation rates have been analyzed. The degradation rates represent the degradation in the annual power of the part of the system which is affected by the failure. The preliminary results of the analysis show that the highest impact on the performance of PV modules is due to defective bypass diodes in the hot and dry climates, with a degradation of 11% per year, and in moderate climate with a degradation of 25% per year.

Cell cracks in the cold and snowy climates seem to cause a degradation of about 3% per year higher than in the moderate climate (5% per year) and 6% per year higher than in hot and dry climates (2% per year). Cell cracks affect about 3/5 of a system in the moderate climate zone if they cause a power loss. Cell cracks often affect only some modules in a string where a relevant power loss is recorded.

The PID effect shows a mean degradation rate of about 16% per year and affects about 3/5 of a system in the moderate climate. In the moderate climate, it is the most common failure found with a high degradation rate. Unfortunately, there are not enough PID events documented from the other climate zones. Moreover, at this current stage, no correlation between the mean degradation rates and the occurrence of PIDs in the coastal regions/island was found. Furthermore, new PV systems with high system voltages of up to 1500 V should take special care of this failure mode. PID is still not tested in the current IEC61215 standard whether for 1000 V nor for 1500 V.

The discoloring of pottant failure is found in the hot and humid, hot and dry, and in the moderate climates. In these three climate zones this degradation mechanism is, on average, below 1% per year. Therefore, this effect is most often not the cause for warranty claims.

Finally, regarding sudden, or singular events, preliminary results of the effect at a system level of singular events show that the failure caused by “snow load” affects about 20% of the modules in the system and has an impact on power output of ca. 4%. Other events, such as lightning strikes, storm, and hail, only cause a power loss on less than 10% of the modules of the plant and seem to affect less than 1% of the total system power output.

Results of the failure mode analysis show that soiling affects almost the whole system in nearly all cases. However, this type of failure does not really fit into the degradation or the sudden failures category as the power of soiled PV modules degrades over time but can be fully recovered. A dependence of dust soiling on the climate zone has been determined. Moreover, the results suggest that dust soiling is strongly influenced by local conditions. Soiling typically accounts for 6% power loss after soiling events in the moderate climate and ca. 4% in the hot and dry climate.

3.5.3 PV Inverter Failures

The inverter is the link between the PV modules producing DC energy (which is variable by nature depending on meteorological conditions) and the electrical grid serving consumers (a strictly defined sinusoidal waveform). The inverter must control the DC input and AC output efficiently, in line with pre-set parameters and according to a set of rules depending on distribution grid conditions. It is therefore not surprising that the inverter is the major cause for loss of revenue.

PV inverters are often identified as one of the most vulnerable components in a PV system. A previous study carried out by the IEA PVPS [34] highlighted that the inverter was the most troublesome component accounting for about 66% of reported troubles. Similar studies found that between 75% and up to 90% of the reported failures were attributed to inverters as presented in [3].

Inverter failures can be divided into two categories: component failure and configuration error. Inverter failures can be catastrophic, implying that the inverter ceases to operate entirely, or non-catastrophic, a condition under which the inverter operates, but at a lower conversion or MPP tracking efficiency. Catastrophic events are the easiest to deal with since the problem is obvious. On the other hand, non-catastrophic events can lead to larger losses due to the time period necessary to verify that a problem exists, and then to define and correct the problem.

Regarding this general categorization, it is important to understand the warranties offered by the inverter manufacturer, the EPC and O&M contractors, and the transition of responsibility between them. The sudden failure of an inverter which is not caused due to negligent use by the consumer is obviously covered by the manufacturer warranty. The inverter is replaced as soon as possible and the losses are easily calculated.

It is important to ensure that the EPC/O&M contract outlines the procedure for the warranty replacement and clearly allocates the costs of the replacement, and the time frames in which this will occur. These costs and losses due to non-production must be quantified and applied to the risk calculation tables.

Inverter faults due to inaccurate settings, small component failure, or worse, intermittent small component failure, such as a cooling fan with a faulty sensor or any similar failure mechanism that is not easily discovered, can lead to even greater losses, though over a longer period of time. It is crucial that these types of non-catastrophic failures be defined in the EPC/O&M contract in terms of the time to react and the time to repair. Moreover, the framework of the manufacturer's warranty needs to be well specified and understood. No less important is the existence of sufficient monitoring to ensure that such faults can be detected and verified. Based on these contractual agreements, a value for lost revenue due to this type of loss based on the physical parameters should be assumed and applied to the risk calculation tables.

The technical lifetime ($T_{L\text{-}tech}$) of the PV system in general and the inverter in particular, follows the so called "bathtub" failure profile shown Figure 9. It is obvious that the risk of failure in the flat line area of random failures is the lowest. The longer the comprehensive EPC warranty and the longer the inverter manufacturer warranty, the greater the chances that most of the project life is within the low probability of random failures.

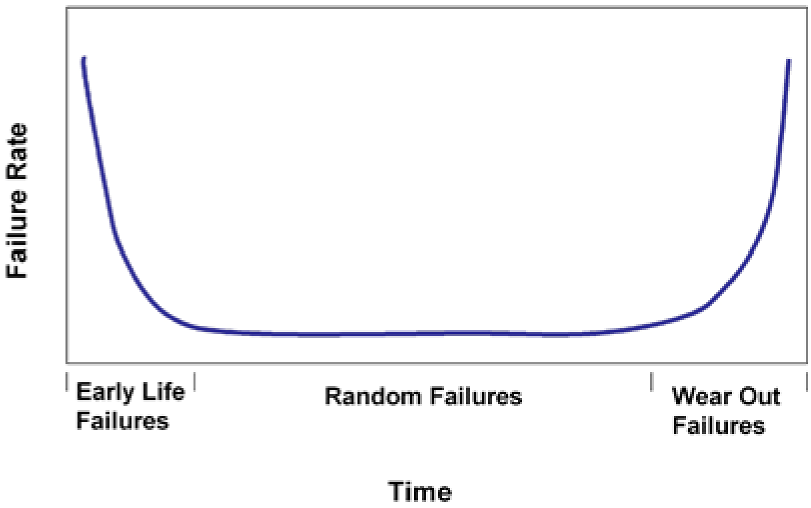


Figure 9: Bathtub curve showing probability of failures over the technical lifetime ($T_{L\text{-}tech}$) of a product or project.

An EPC warranty of two years enables the “burn-in” of the system, allowing those inverters that fail in the first year of operation to experience a full year cycle of climatic conditions under the new replaced or recalibrated conditions. An extended warranty may increase the inverter purchase price; however, the greatly reduced risk achieved by extending the warranty period should offset this increase in price.

At the other end of the bathtub curve, we encounter the wear-out failures. The life of an inverter is considered to be between 10-15 years. An assessment of operational $T_{L\text{-tech}}$ of PV inverters until replacement carried out by the Solar Bankability project [3] analyzed monitoring data from ca. 2000 commercial PV plants using recorded data since 2010. The study found that about 10% of the inverters have already been replaced after 6 years. The vast majority of those inverters replaced were prior to 3 years of operation. Starting from the fourth year, the replacements seem to level off. Inverter replacement records were used in addition to generate the first part of a bathtub curve. The first phase of the bathtub curve (early-life failures in Figure 9) is clearly visible in Figure 10 with the replacement rate decreasing from more than 4% in the first year to less than 1% in the fifth year.

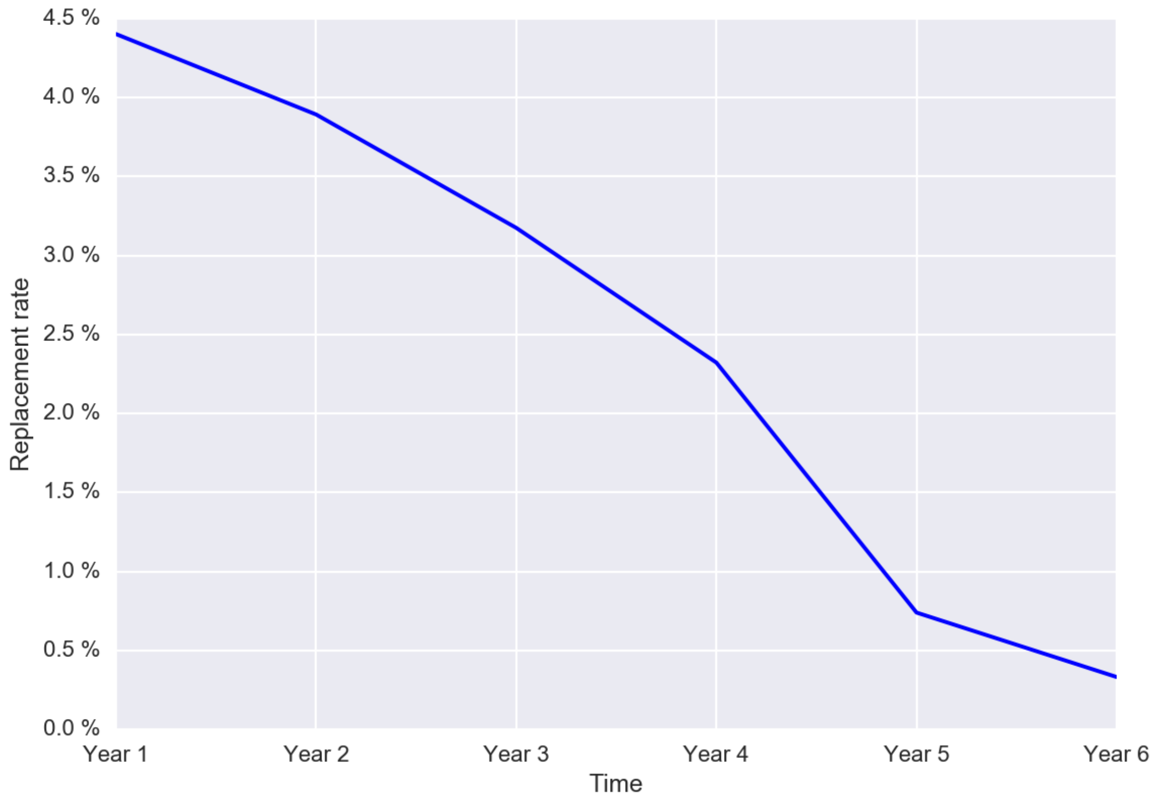


Figure 10: Inverter replacement rate as function of operational technical lifetime, showing the initial phase of the so-called "bathtub curve" [3].

Figure 10 suggests that the vast majority of replacements are due to early failures. It seems that the onset of the second phase (identified as random failures in Figure 9) occurs the earliest in the fifth year. No estimate could be made yet of the constant replacement rate during this second phase. However, the data suggests that this should be lower than 1%. Regarding the third phase (identified as wear out failures in Figure 9), the onset of this third phase may still be far off. In any case, it does not seem to start before the first six years of operation.

It is wise to consider the offered warranty as the life span of the inverter when calculating the O&M costs. Extended warranties theoretically would "take the risk out of the bathtub". However, the cost of the extended warranty can be higher than the early replacement cost when calculating the IRR for a 20- or 25-year project. Another consideration is the conceived longevity of the inverter manufacturer in the PV market as it is perceived today.

When evaluating the possible loss of revenue due to inverter faults during the early life of the inverter it is important to evaluate the technical design of the system and to ascertain the risks of downtime on the revenue flow and the business plan. The following examples of failure situations offer suggestions to pinpoint the technical parameters of the system to evaluate the possible costs of downtime due to failure, with or without the EPC covering the loss:

1. Inverters require ventilation to work efficiently. As the temperature rises, the efficiency of the inverter drops, requiring de-rating of the power output. Positioning string inverters in the field is straight forward; often mounted on the non-sun-facing side of mounting structures, the maximum temperature of the inverter is known and the local meteorological data is available. They are exposed to the atmosphere and the heat dissipates effectively. However, central inverters are housed in enclosures, often locally manufactured. Some central inverters are in fact derivatives of industrial motor drives. As robust and proven as these products may be, they are not designed from the base up to be solar inverters. Careful attention to the heat dissipation calculations is necessary to understand if and

when the inverter will have to de-rate due to high temperatures, then to calculate the losses for a typical year. In large PV systems, linking the inverter guarantee to a PR or plant availability is sometimes offered. However, attention must be paid to the cap on liquidated damages and the energy that can be lost due to overheating.

2. The frequency of inverter filter replacement should be evaluated and monitored in the first year of operation to ensure that the inverter is not losing power due to errors in recommended filter replacement time; the cost of additional filter replacement should be included in the O&M contract.
3. Inverter voltage turn-on and operational window settings must be evaluated for the entire year, taking into account the entire daily and annual cycle under both cold and hot conditions. A high turn-on set-point designed for a cold start-up in the morning may not enable a restart later in the day if the inverter shuts down for any reason. Conversely, lowering the setting may result in possible false starts, which affects, among others, the inverter switchgear which is rated for a definite number of switching cycles. This is an example of financial optimization between the probability of shutting down during midday and staying down with some consequential losses versus the drop in the lifespan of the inverter switching mechanism. Many such settings exist in the operation of the system and each has possible optimization decisions to be made.
4. Lightning protection is a matter of a decision process defined generally in the IEC 62305-2 Protection against lightning – Part 2: Risk management, and for PV arrays specifically in the IEC 62548 Photovoltaic (PV) arrays. The decision to protect against lightning damage, and if so, to what extent and with what quality of elements is left to the designer. The quality of installation is no less important in lightning protection than the elements themselves. Attention must therefore be made to the installation method and quality of workmanship. These risks can be mitigated by insurance coverage such that as long as the lightning protection chosen and installed are accepted by the insurance underwriter, all that must be taken into consideration are the losses due to down time.

In a similar fashion, all aspects of the inverter's interface with the grid on one side and the PV array on the other hand should be studied to ascertain the operating parameters, which can then be analyzed to understand what can go wrong and what the associated cost of this error will be.

4 Mitigating and Hedging Financial Risks of a PV Investment

The purpose of this Section is to demonstrate how the information and knowledge collected on the technical assumptions often used in PV financial models can be made useful to project developers in supporting a chosen strategy to mitigate and hedge the identified risk factors.

At this point we should emphasize that not all failures and technical problems need to be considered a financial risk. As with all technical installations, incidents do happen that affect the performance of the PV plant. Some of these issues have the character of a failure or breakdown that is known to occur from time to time and can be dealt with by purchasing appropriate insurance. This could be the case for grid outages, module theft, glass breakage due to hail storm and all incidents known to happen with a certain statistical frequency which can be mitigated by insurance contracts. We do not consider such incidents as financial risks.

It is relevant at this point to discriminate between uncertainty and risk. Some risks can be mitigated to an extent by understanding the uncertainty and acting to reduce the uncertainty or to calculate for the uncertainty in evaluating the risk before adding the input to the risk factor.

In the next section we will discuss how the uncertainty of input parameters to the financial models can be dealt with (or even reduced), followed by suggestions for dealing with these uncertainties in the financial model itself, after which we suggest a method for hedging the resulting risks at the organizational level.

4.1 Mitigating the Risk Inherent in Technical Assumptions

PV financial models are used to calculate the cash-flow of the project based on the project specific details. The level of details and number of parameters used can be quite different depending on the model(s) used. In the following paragraphs we discuss the uncertainty of those technical parameters that we find most important, best understood, and for which in some cases, appropriate mitigation measures can be applied in order to reduce the overall uncertainty in the PV financial model outputs.

4.1.1 Solar Resource Assessment

As discussed in Section 4, the main risks arising from the long-term solar resource assessment during the planning phase of a PV plant are related to the quantification of the solar resource, its variability, and the effect of possible long-term trends.

Uncertainty values for yearly global horizontal irradiation are within ±2% for high quality pyranometer measurements and around ±5% or more for solar reference cells and satellite-derived data. Furthermore, the variability of the solar resource and the effect of long-term trends are also significant sources of uncertainty. The variability of the solar resource in Europe can range from about ±4% up to ca. ±7% for more complex conditions like e.g. near coastal areas. Moreover, in the presence of long-term trends, the overall uncertainty in the solar resource estimation can be impacted by an additional uncertainty in the order of ±3%.

Table 5 presents some mitigation measures that should be applied to reduce the risks associated with the solar resource estimation during the planning phase.

Table 5: Mitigation measures for risks associated with the assessment of the solar resource during the planning phase of a PV project

Mitigation measure	**Impact / explanation**
✓ Use high quality state-of-the-art satellite-derived irradiance data to reduce the uncertainty in the quantification of the solar resource	The use of state-of-the-art satellite-derived products that make use of advanced cloud physical property models or other methods, can have a significant impact in decreasing the uncertainty in long-term yield assessments.
✓ Apply site adaptation techniques for further uncertainty reduction if high-quality local measurements (pyranometer) are available	When high-quality local measurements (e.g. taken with a pyranometer) are available, these measurements can be used for the application of site-adaptation techniques to reduce further the uncertainty of satellite-derived estimations. Upon completion of typically one year, the uncertainty of the long-term solar resource estimation can be reduced from 5% up to ca. 2%, for example
✓ Account for the effect of long-term trends in the solar resource	In cases where long-term trends in the solar resource are present, the application of advanced methods to account for the effect of these trends can avoid under/over-estimating the resource for the financial lifetime of the project. Moreover, the uncertainty of this estimation is also reduced. This topic will increasingly require more attention from the industry as the PV plants are going to extend very likely their expected financial lifetime.

4.1.2 Energy Yield Estimation

Further uncertainties arise from the estimation of the long-term yield of a PV plant during its financial lifetime. These uncertainties are related to the different modelling steps which rely on several user assumptions, often based on user experience or judgement.

As introduced in Section 3, the design parameters of the project typically include the number of main components (PV modules, combiner boxes, inverters, transformers, etc.), the nominal product characteristics (PV module power, inverter rating, grid voltage etc.), the PV module installation method (fixed tilt, tracker), area covered by the PV modules and plant etc. In general, such technical project description parameters do not represent a significant uncertainty when the project is in an advanced design phase. However, some technical parameters such as the nominal PV module power and tolerance, are based on approximations and therefore will have an impact in the overall uncertainty when calculating the expected energy yield of the PV plant.

Several modelling steps such as the calculation of the effective irradiance after reflection losses, thermal losses due to PV module physical characteristics and environmental conditions, conversion from DC to AC (i.e. inverter model), are well described and when using state-of-the-art models, the uncertainties of these modelling steps are rather small compared for example with the solar resource related uncertainties. However, other additional losses occurring typically in the field such as soiling, mismatch, degradation profile over time, snow effects, and others, are often only partly simulated or accounted for by the simulation software. Therefore, users often have to estimate many of these losses and their effects based on the little information available and on their experience.

In general, it is not a simple task to evaluate several of these losses that occur in the field since they are often influenced by external parameters. Therefore, it becomes even more difficult to assess the uncertainty of these estimations. For example, when estimating soiling losses in addition to assessing the surrounding areas for the presence of potential soiling issues, one should also use models that account for monthly rainfall, humidity information, and cleaning schedule among others. Furthermore, a good alignment between the planning phase and the maintenance schedule during the operation phase can mitigate the risk of under/over estimating the effect of soiling losses considerably.

Table 6 presents some mitigation measures that should be applied to reduce the risks associated with the energy yield estimation during the planning phase.

Table 6: Mitigation measures for risks associated with the energy yield estimation during the planning phase of a PV project

Mitigation measure	Impact / explanation
✓ Use state-of-the-art modelling software to calculate the expected energy yield of the system	Lower uncertainty in the overall energy yield estimation
✓ Verify nameplate power of the PV modules used in simulations with the flash test reports supplied with the modules	The uncertainty on the nominal PV module power and tolerance can be significantly decreased by performing flash tests. For example, independent test facilities typically guarantee the measured values to ±1.5 to ±2%.
✓ Use methods to account for the effect of different degradation behavior over time (e.g. linear vs stepwise degradation)	PV module degradation over time may not always be linear. Using models to simulate the effect of different degradation profiles during the financial lifetime of the project can mitigate risks arising during the operation phase.
✓ When estimating soiling losses, use models that account for different factors including, cleaning schedule, monthly rainfall profiles, and humidity information among others	The use of models that account for monthly rainfall, humidity, and cleaning schedules can help to reduce significantly the uncertainty and to improve the OPEX during the operation phase. For example, for a PV plant located in a tropical desert climate (e.g. Dubai) the combination of the high dust particles occurrence and the high humidity may drastically reduce the yield with soiling rates of up to 0.5%/day and up to 60% losses after a sand storm. The use of advanced models during the planning phase can help to determine a cost optimization of the cleaning schedule. For example, the soiling losses can be reduced from 7% by a factor of two to 3.5% by increasing the cleaning schedule for some critical periods. Moreover, the overall cash flow of the project can improve thanks to a cost optimization between operating expendi-

	tures due to increased frequency of PV modules cleaning and a gain in yield due to reduced soiling losses.
✓ Use the expected overall unavailability for the calculation of the initial yield for the project investment financial model instead of the O&M guaranteed values	When calculating the financial income from electricity production of a PV plant, the availability assumption in the PV financial model should reflect the overall plant availability. This means, an additional unavailability beyond the O&M service should be considered and added to the overall plant unavailability. This additional unavailability may be caused e.g. due to grid issues or other external factors that cannot be controlled by the operator and thus, may not be covered by guarantees.
✓ Take into account the technical lifetime of the devices as this can often be different than the financial lifetime of the project	The technical lifetime of some PV components may be shorter than the financial lifetime of the project. For example, PV inverters often have a technical lifetime of 10 years which in many cases would be shorter than the financial lifetime of the project.
✓ Use empirical methods for risk assessment calculations (e.g. P90) when possible	When calculating exceedance probabilities for risk assessment (e.g. P90), empirical methods based on actual available data should be used instead of assuming a normal distribution for all parameters. The assumption of a normal distribution does not necessarily apply to all parameters and assuming this behavior can result in serious deviations. For example, results in [1] show that when using the normal distribution approximation for the solar resource uncertainty, differences up to 3% were observed when compared with the empirical method approximation. This could result in important over/under estimation of the risk.
✓ Consider re-assessing the long-term yield estimate of the plant using actual operational data	Using actual production can allow a very precise prediction of the long-term yield with a considerably reduced uncertainty. The adjustment of the financial models after e.g. one or two years of operation could potentially reduce the long-term estimation uncertainty by a factor of two.

4.1.3 Capital Expenditures

Some specific technical issues that can influence the CAPEX value as discussed in Section 4 include the exact performance criteria, quality control and inspection measures defined for PV modules, inverters, sub-structures, and balance of system (BOS) components. In addition, test procedures and acceptance criteria used for commissioning of the finished project on a system level which may include performance warranties often have a direct impact on the CAPEX.

As highlighted in the review of current practices, the majority of the CAPEX is made up by the EPC costs. The majority of the EPC costs in turn are used to procure the PV plant components, with the cost of modules comprising about half of total component cost. Therefore, it is important to ensure that the procured components are of high quality to ensure high performance and a profitable PV plant. Table 7 presents the mitigation measures that should be applied to reduce the risks related with the plant component procurement and selection phase. Some of the risks that can be reduced by the application of these mitigation measures include among others, potential induced degradation, defective backsheet, delamination, bypass diode and junction box failures [35].

Table 7: Mitigation measures for risks associated with the PV plant component procurement and selection

Mitigation measure	Impact / explanation
✓ Describe as detailed as possible the technical specifications of the PV plant components	A detailed description of the technical specification of the PV components will ensure the selection of components and the required testing to ensure business plan expectations
✓ Consider project specific requirements such as, salt-mist, ammonia, or resistance to potential induced degradation and ensure that the relevant normative certifications apply	Not considering some specific requirements for some special conditions can result in component underperformance or even failure. The application of this mitigation measure avoids surprises during operation phase and thus the undesired increase of OPEX
✓ Require factory inspections and/or product testing to prevent inadequate manufacturing process or material deviations	This mitigation measure can help identify some batch specific product defects or failures that could results in underperformance or component failure during operation phase
✓ Calculate and allocate sufficient funds for decommissioning the plant	Though developers historically seldom considered this cost to the project, the WEEE directive for recycling PV modules is already in place and PV energy is becoming main-stream. It is not conceivable that obsolete PV plants will be allowed to simply decay in situ.

Table 8 presents the mitigation measures that should be applied to reduce the risks associated with the plant testing and acceptance phase after installation.

Table 8: Mitigation measures for risks associated with the plant testing and acceptance

Mitigation measure	Impact / explanation
✓ Implement a standardized transportation and handling protocol, clear procedures for component un-packing and handling during construction, and construction supervision	The incorrect handling of the PV components can potentially cause serious damage which can result in issues during operation phase. Ensuring the correct transportation and handling will

	significantly reduce future operating expenditures.
✓ Follow best practices for plant acceptance after completion of the construction process	The application of this mitigation measure can timely identify potential issues that could increase the operating expenditures. This mitigation measure will ensure among others, a clear determination of KPIs calculation, test durations, threshold of input parameters, monitoring system to be used including measurement sampling rate and averaging method, and a clear protocol for visual inspection including a definition of all relevant equipment.

4.1.4 Operating Expenditures

As highlighted in the review of current practices, the majority of the OPEX is comprised of O&M costs. Among the specific technical issues that can influence the OPEX as discussed in Section 4 are the monitoring and reporting activities, the preventive and corrective maintenance operations, and the determination of the KPIs in the O&M contract. Therefore, it is important to ensure that these activities and procedures are clearly defined and follow best practices to ensure high performance and a profitable PV plant operation.

Table 9 presents the mitigation measures that should be applied to reduce some of the risks during the operation phase.

Table 9: Mitigation measures for risks during the operation phase of a PV project

Mitigation measure	**Impact / explanation**
✓ Define clearly the guaranteed KPIs such as PR, availability, energy yield and their calculation procedures following best practices	In addition of defining the KPIs absolute values, the calculation procedure and input parameters threshold should be clearly defined to avoid misinterpretations and guarantee claims.
✓ Define clear and detailed preventive and corrective maintenance activities with related costs spread throughout the financial lifetime	A clear definition of preventive and corrective maintenance activities should include drill down descriptions of visual inspection techniques, module cleaning frequency, maintenance of the monitoring system, bolt tightening and cleaning, etc. A schedule should be supplied for all tasks. This will not only allow a more efficient operation but can also help identify flaws and potential issues on time.
✓ Use adequate devices for visual inspection	Adequate devices for visual inspection include IR and/or EL cameras to find invisible defects and faults in modules, string boxes and electric panels.
✓ Include spare part management system	A spare part management system can help to minimize the downtime and repair times in the occurrence of failures, underperformances, theft, etc.

✓ Use an appropriate monitoring system designed to deliver the necessary data and perform the necessary calculations for the selected KPIs and to monitor plant status and notify on fault and failure.	A monitoring system allows the timely detection of performance issues. State-of-the-art advanced monitoring systems can automatically detect and diagnose some failures and abnormal performance degradation, limiting the related losses. For example, for a ground-mounted PV plant, the growing vegetation can cause up to 20% losses due to shading on the arrays during spring/summer months. An advanced monitoring system can timely detect the effect of the growing vegetation during spring months and alert the O&M contractor to perform a gardening intervention. By use of advanced monitoring, the shading losses are reduced to 0% after grass cutting. The gain in energy yield during summer months compensate the small additional operation costs related with the grass cutting intervention. This same principle can be applied for other losses such as increased soiling, inverter derating, vandalism or theft, etc.

4.2 How to Calculate with Uncertainty in PV Financial Models

4.2.1 The Basic Structure of a PV Financial Model

A PV financial model is designed to calculate the financial profitability of the PV project by considering the calculated expected energy production, revenue from power sales, expenses from operation, maintenance of the plant, and cost of financing the investment including tax and depreciation. As this report focuses only on the technical assumptions used in these models, the example below will only discuss how the technical assumptions in the model can be addressed by the methods discussed in previous sections.

In Figure 11, a text extract of a spreadsheet based generic financial model for a 10 MWp plant to be sited in Denmark is provided to demonstrate the overall calculation flow and structuring of such a model in 7 main sections. This demonstration is an early feasibility financial model, made before the final site has been chosen, therefore ground coverage is also a value with an uncertainty. The energy yield input section presents parameters one would find in a detailed energy yield calculation from a state of the art PV solar simulation program. The input values are in the right column; greyed cells are calculated by the spreadsheet from the cells above.

The output of the spreadsheet is the first year's production based on the input parameters supplied. This spreadsheet calculation takes into account the input values as they appear with no accounting for the variable uncertainty that produces the P50 and P90 values offered by some simulation programs for the first year or for the life span of the plant as will now be demonstrated.

1. Project	DK reference
Project type:	Fixed tilt
Inaguration year	2017
Project lifetime [year]	30
dc/ac power ratio [Wp/Wn]	125%
Module Power [Wp]	270,0
Module Area [m2]	1,65
Number of modules [pcs]	37.037,0
Total park power (at STC) [kWp]	10.000
Total nominal ac-power [kWn]	8.000

2. Site		
Horizontal global irradiation (GHI)	[kWh/m2/year]	1.050,0
Irradiation increase due to tilt angle (Transposition Factor)	[%]	15,00%
Ground Coverage Ratio (GCR)	[%]	40,7%
Area required for power plant	[ha]	15,00
Energy received by the PV generator	[kWh/year]	12.075.000
Reference Yield (Irradiation in the POA) (Yr)	[h]	1.207,50

3. Energy yield assessment		
Irradiation loss due to shading	[%]	2,00%
Module loss due to incidence/reflection (IAM)	[%]	3,00%
Irradiation loss due to soiling	[%]	1,00%
Array nominal energy (at STC efficiency)	[kWh/year]	11.363.710
Module loss due to spectral deviation/irradiance level	[%]	0,00%
Module loss due to temperature	[%]	1,50%
Module shading loss	[%]	0,50%
Module power loss due to LID/power rating error	[%]	2,00%
Array mismatch loss	[%]	1,00%
Array dc-cable loss	[%]	2,00%
Array virtual dc-output at MPP	[kWh/year]	10.589.289
Inverter loss during operation	[%]	1,50%
Inverter loss MPPT	[%]	0,50%
Inverter loss due to power threshold	[%]	0,00%
Inverter loss over nominal inverter voltage	[%]	0,00%
Inverter loss due to voltage threshold	[%]	0,00%
ac-cable loss	[%]	1,00%
Transformer loss	[%]	1,00%
Other loss	[%]	0,00%
Energy delivered to the grid	[kWh/year]	10.171.769
Specific energy yield (Yf)	[kWh/kWp]	1.017,2
Performance Ratio (Yf/Yr)	[%]	84,2%

4. Capital expenditures		
Turn-key installation cost in total	[EUR/kWp]	700,00
CAPEX in total	[EUR]	7.000.000,00

5. Power production & power sales		
Technical unavailability	[%]	1,0%
PV system (module) degradation	[%/year]	0,50%
Feed-In-Tarif - price year #1	[EUR/MWh]	53,8
Feed-In-Tarif - number of years to be applied	[#]	20
Market price scenario	25€/MWh@2016 2%/year escalation	
Balancing cost	[EUR/MWh]	12,0
6. Operational expenses		
Land lease - fiexed yearly fee per ha	[EUR/ha]	2.000
O&M - fixed yearly fee	[EUR/year]	40.000
Insurance - fixed yearly fee	[EUR/year]	10.000
Other cost - fixed yearly fee (Monitoring portal)	[EUR/year]	50.000,00
7. Financing		
Economical operational lifetime	[year]	30
Real discount rate for LCOE calculations	[%]	1,00%
Loan #1 - Depth ratio	[%]	50,0%
Loan #1 - Interest	[%]	3,00%
Loan #1 - Maturity	[year]	20,0
Loan #1 - Type		Serial
Equity - levered		3.500.000
Tax depreciation (accelerated)	[%]	15,00%
Tax rate	[%]	22,00%

Figure 11: Input parameters and calculation flow of a hypothetical 10 MWp PV project in Denmark.

4.2.2 Uncertainty in Estimating Input Parameters Values

As discussed in Section 3 most input variables used in a PV financial model will be specified by the best estimated (target) value and a level of uncertainty as a percentage value or range. However, the financial calculations are computed using the uncertainty value with no reference to the range of uncertainty. For example, horizontal global irradiation is defined as 1050 kWh/m^2 with an uncertainty of ±5%. Irradiation loss due to soiling is 1% with an uncertainty of -0%/+3%. This is the case for the technical parameters that directly enter the energy yield calculations but will also be the case when OPEX and CAPEX input values are calculated. To illustrate how it is possible to make financial calculations where such input parameter distributions are taken into account, we have selected the 12 input parameters from Figure 11 that have uncertainty values attributed to them and presented them in *Figure 12* with the addition of each variation and its distribution function.

1. Project	Best estimate	Risk/uncertainty distribution function	Illustration see Figure
Module Power [W_p]	270,0	Uniform distribution: Min=270,0; Max= 278,1 (-0/+3%)	13 a)
2. Site			
Horizontal global irradiation [kWh/m^2/year]	1.050,0	Normal distribution: μ=1050; σ=5% of 1050	13 b)
Irradiation increase due to tilt angle [%]	15,00%	Normal distribution: μ=0,15; σ=2% of 0,15	13 c)
Ground Coverage Ratio [%]	40,7%	Triangular distribution: Min=30%; Mode=41%; Max=50%	13 d)
3. Energy yield assessment			
Irradiation loss due to shading [%]	2,00%	Normal distribution: μ=0,02; σ=1.5% of 0,02	14 a)
Irradiation loss due to soiling [%]	1,00%	Uniform distribution: Min=0,0%; Max= 3,0%	14 b)
Module loss due to temperature [%]	1,50%	Normal distribution: μ=0,015; σ=1.0% of 0,015	14 c)
Module loss due to LID/deviation from nominal power [%]	2,00%	Triangular distribution: Min=0,0%; Mode=2,0%; Max=5,0%	14 d)
4. Capital Expenditures			
Turn-key installation cost in total [EUR/kWp]	700,00	Uniform distribution: Min=600; Max= 750	15 a)
5. Power production & power sales			
Technical unavailability [%]	1,0%	Triangular distribution: Min=0,0%; Mode=1,0%; Max=3,0%	15 b)
PV system (module) degradation [%/year]	0,50%	Triangular distribution: Min=0,0%; Mode=0,5%; Max=0,8%	15 c)
6. Operational expenses			
O&M - fixed yearly fee [EUR/year]	40.000	Normal distribution: μ=40.000; σ=5% of 40.000	15 d)

Figure 12: Selected input parameter distribution functions describing the target value and uncertainty (function and amount) of the technical parameter in question.

As described in [2], the distribution of input values was calculated for each of the parameters by a Monte Carlo algorithm using 10,000 iterations (we used ModelRisk from Vose Software). For each iteration, the program generates 12 different input values to the excel model and calculates a set of 4 output variables, shown in Figure 16. In Figure 13, Figure 14 and Figure 15, we provide illustrations of these input distributions as generated by the Monte Carlo algorithm according to the various functions defined in Figure 12.

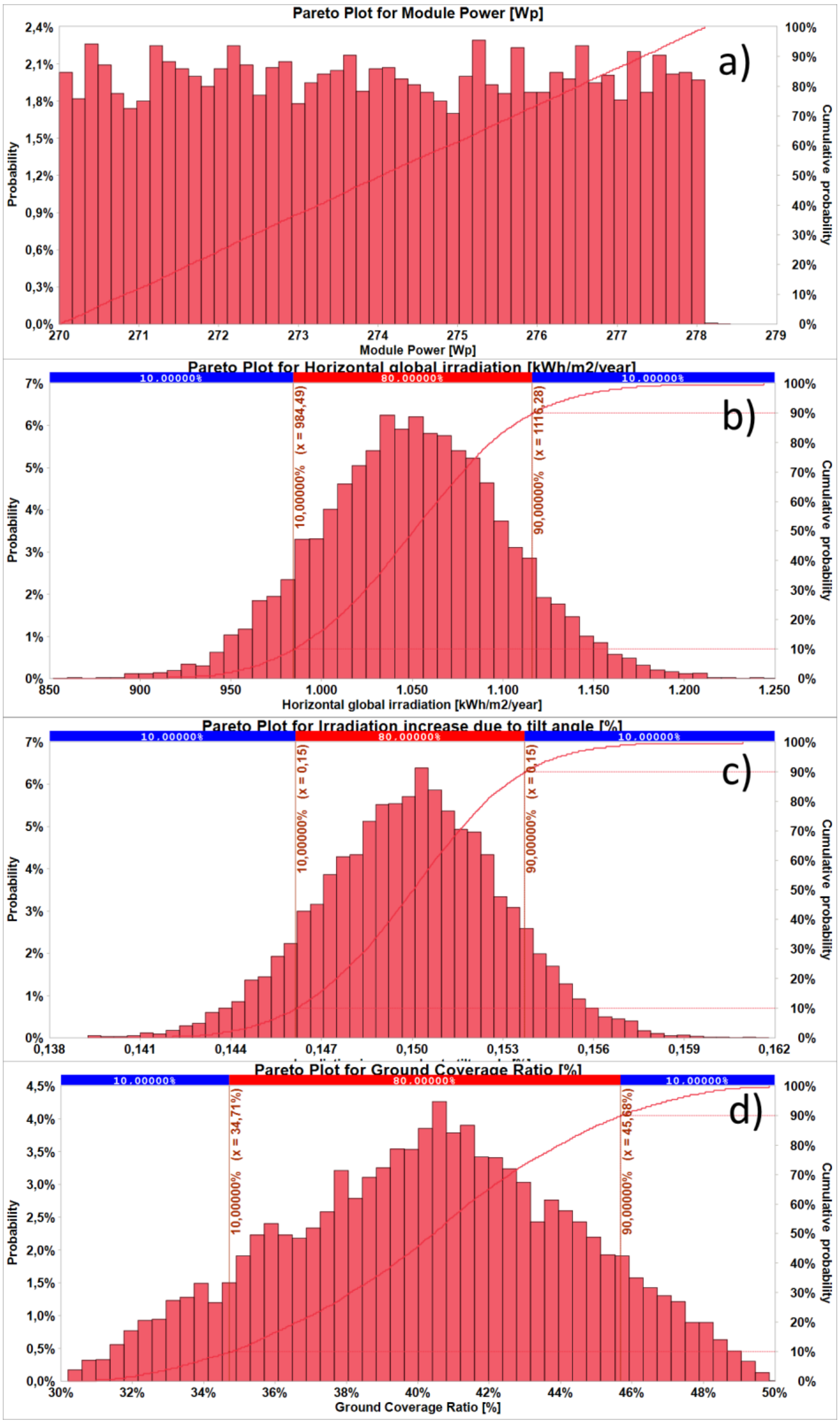


Figure 13: Examples of possible input parameter distributions a) Module power (Uniform) [W_p] b) Horizontal global irradiation (Normal) [$kWh/m^2/year$], c) Irradiation increases due to tilt angle (Normal) [%] d) Ground Coverage Ratio (Triangular) [%].

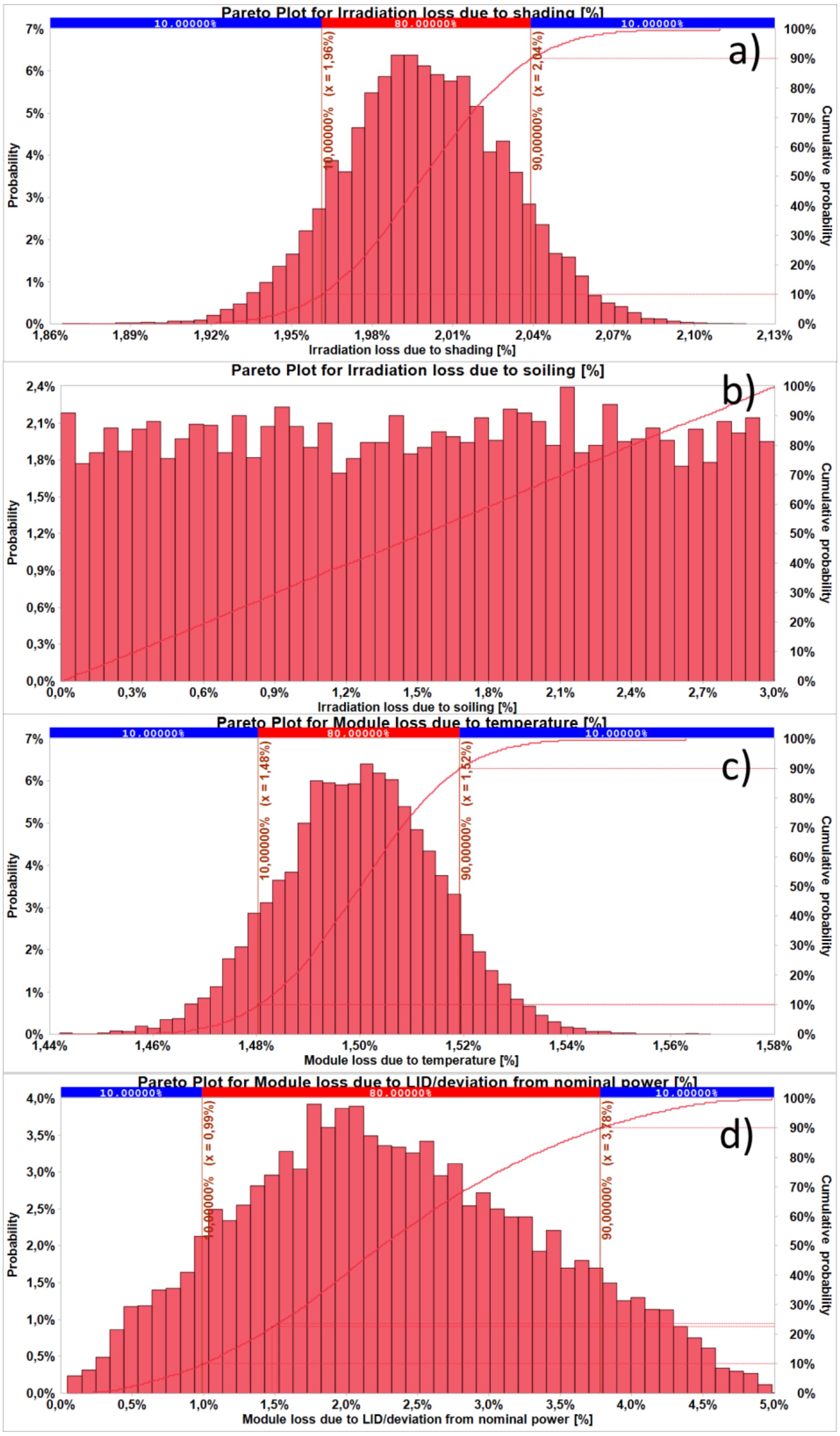


Figure 14: Examples of possible input parameter distributions a) Irradiation loss due to shading (Normal) [%], b) Irradiation loss due to soiling (Uniform) [%], c) Module loss due to temperature (Normal) [%] and d) Module loss due to LID/deviation from nominal power (Triangular) [%].

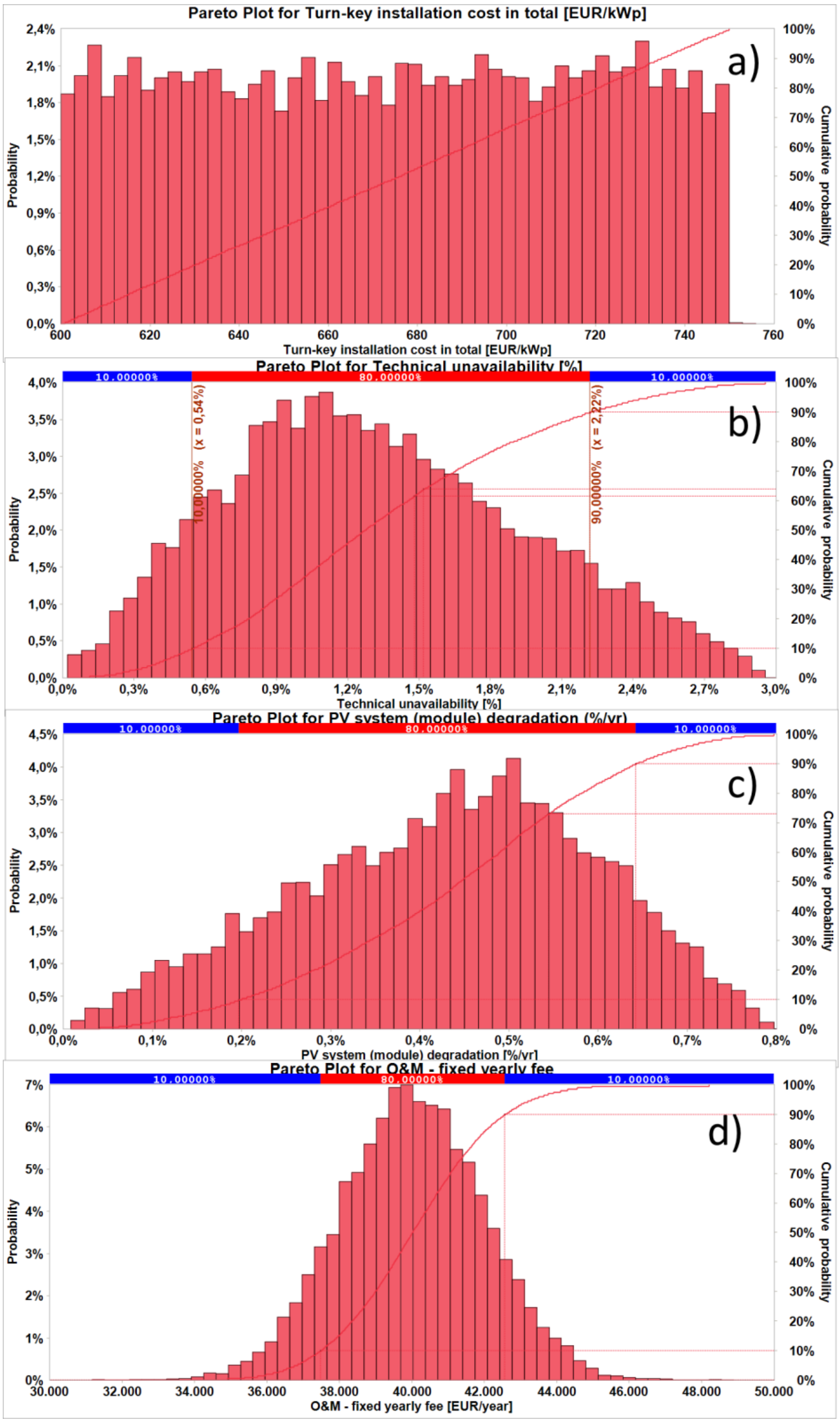


Figure 15: Examples of possible input parameter distributions a) Turn-key installation cost in total (Uniform) [EUR/kWp], b) Technical unavailability (Triangular) [%], c) PV system (module) degradation (Triangular) [%/year] and d) O&M - fixed yearly fee (Normal) [€/year].

4.2.3 Monte Carlo Calculations of Key Output Parameter Distributions

When the input parameters are provided as distribution functions and not by a single value, the calculations for the key output values such as lifetime production, revenue, CAPEX and OPEX cannot be calculated as simple linear implementations of single values, particularly not for a lifelong calculation. Instead we apply once more a Monte Carlo simulation using not the single input values, but the entire input value set in order to handle the output variables in the same way, as distribution functions.

10,000 iterations for each year of production based on degradation values were applied for each output value, on each of the four output values. Figure 16 presents the output of the four different parameter distributions – lifetime production, revenue, CAPEX and leveraged project IRR after tax and depreciation by equity – for the PV financial calculations introduced in Figure 11 and Figure 12.

From these graphs the developer can understand the probability of achieving the values for these important parameters. Each of the graphs shows the P50 and P90 probabilities for the calculated parameter. The P50 probability is at the apex of these normal functions and the P90 is seen on the left of the graph marked as 10%.

This example shows the value of using state of the art simulation algorithms for calculating important project values as opposed to simple linear spreadsheet calculations for first year energy production.

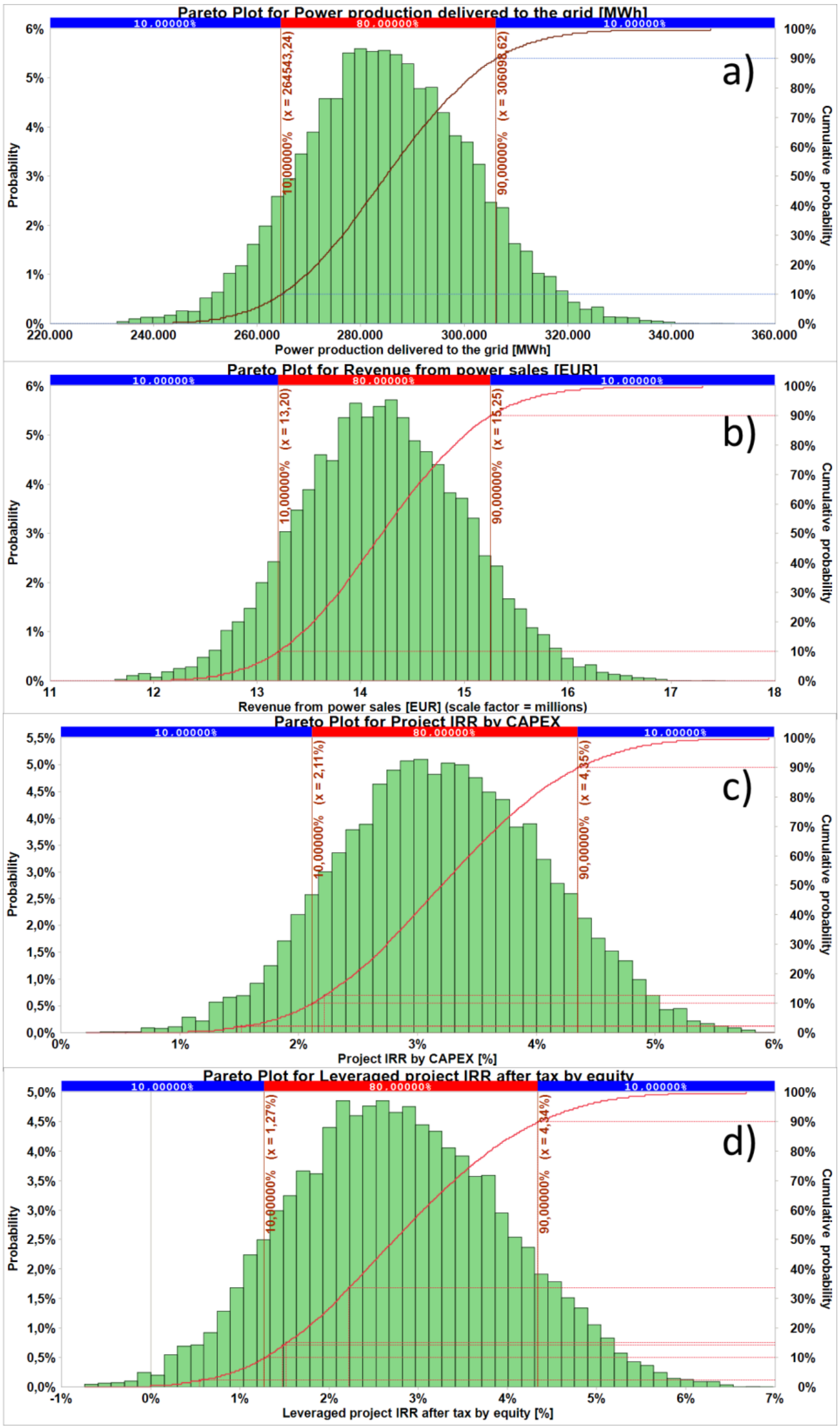


Figure 16: Examples of probability distributions of four selected output parameters: a) Project lifetime energy yield [MWh], b) Project lifetime sum of revenue [€], c) Free cash-flow IRR by CAPEX [%] and d) Leveraged project IRR after tax and depreciation by equity [%].

In addition to a direct interpretation of the graphical output distributions shown in Figure 16, it is also possible to qualify the assessment of the uncertainty impact by other common diagrams like the tornado plot (Figure 17) and spider plot (Figure 18).

In the tornado plot we see that the two parameters that impact the energy production most (within the estimated uncertainty range), is the horizontal irradiation and the PV module degradation. However, when we assess what affects the IRR of the project most, we see that the turn-key installation cost is ranked as more important than PV system/module degradation; it is instructive to graphically see the relative effects the input parameters from Figure 12 on the outputs of the project. Nevertheless, how significant will the output be affected if the value of an input parameter is changed by e.g. 10%? For this the spider plot (Figure 18) can be instructive.

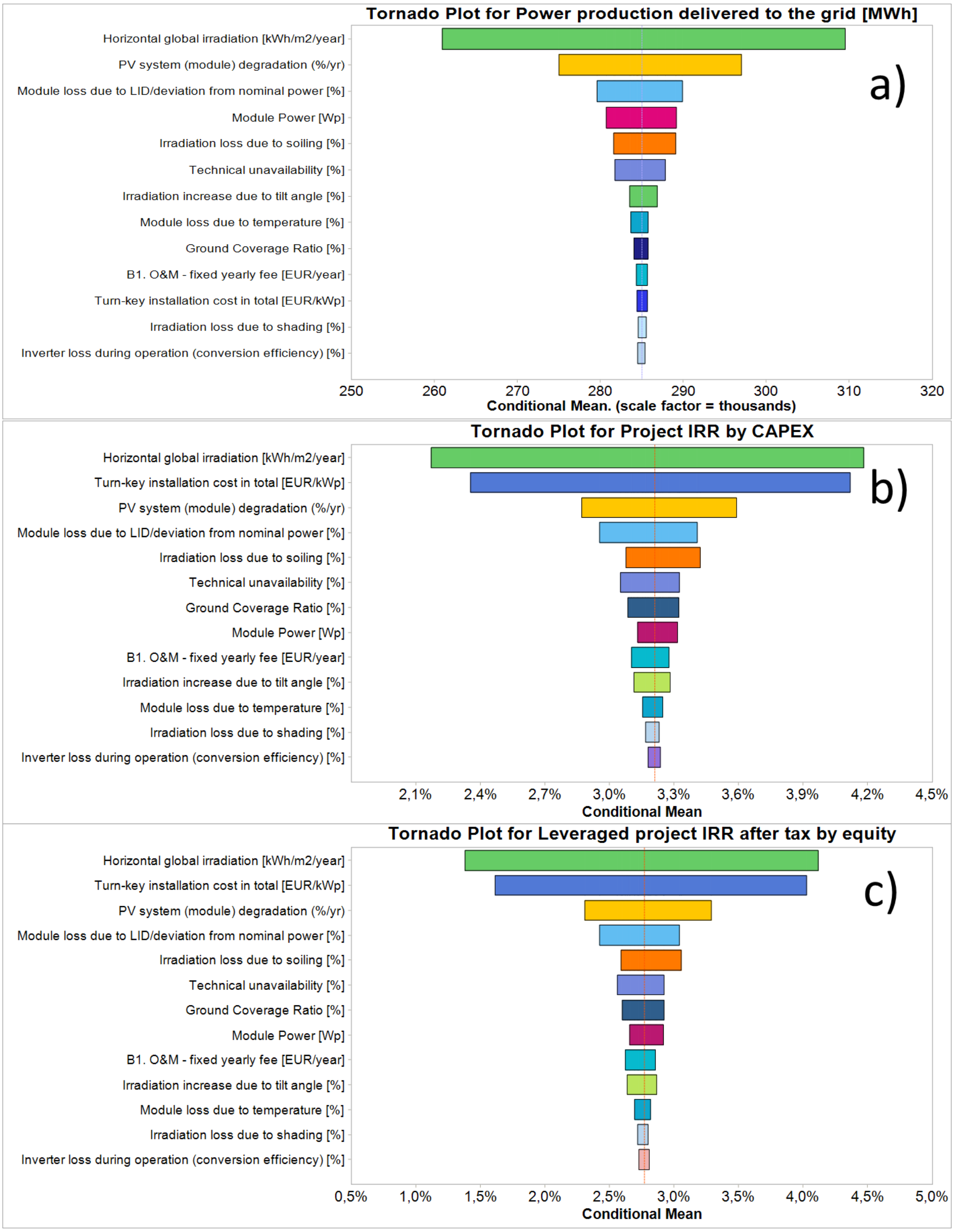


Figure 17: Tornado plots illustrating the ranked contribution of each input variable distribution to the overall variance of the output parameters.

The spider plot is a standard method for illustrating the impact of any input parameter on the selected output parameters. The spider plot directly relates the input parameter value (given in percentage of the reference or best estimate value) to the change of the conditional mean of the output value in question, when applying a large number of iterations in the Monte Carlo simulation. Two examples of such relationships are presented in Figure 18. From the spider plot on *Revenue from power sales [EUR]*, it is observed that only the *Horizontal global irradiation [kWh/m2/year]* has a significant impact (green line, positive slope), whereas the second most important influencer is the *PV system (module) degradation [%/year]* (yellow line, negative slope). As for the spider plot on *Project IRR by CAPEX [%]*, it is again the *Horizontal global irradiation [kWh/m2/year]* that has the largest impact (green line, positive slope) followed by the *Turn-key installation cost in total [EUR/kWp]* (blue line, negative slope).

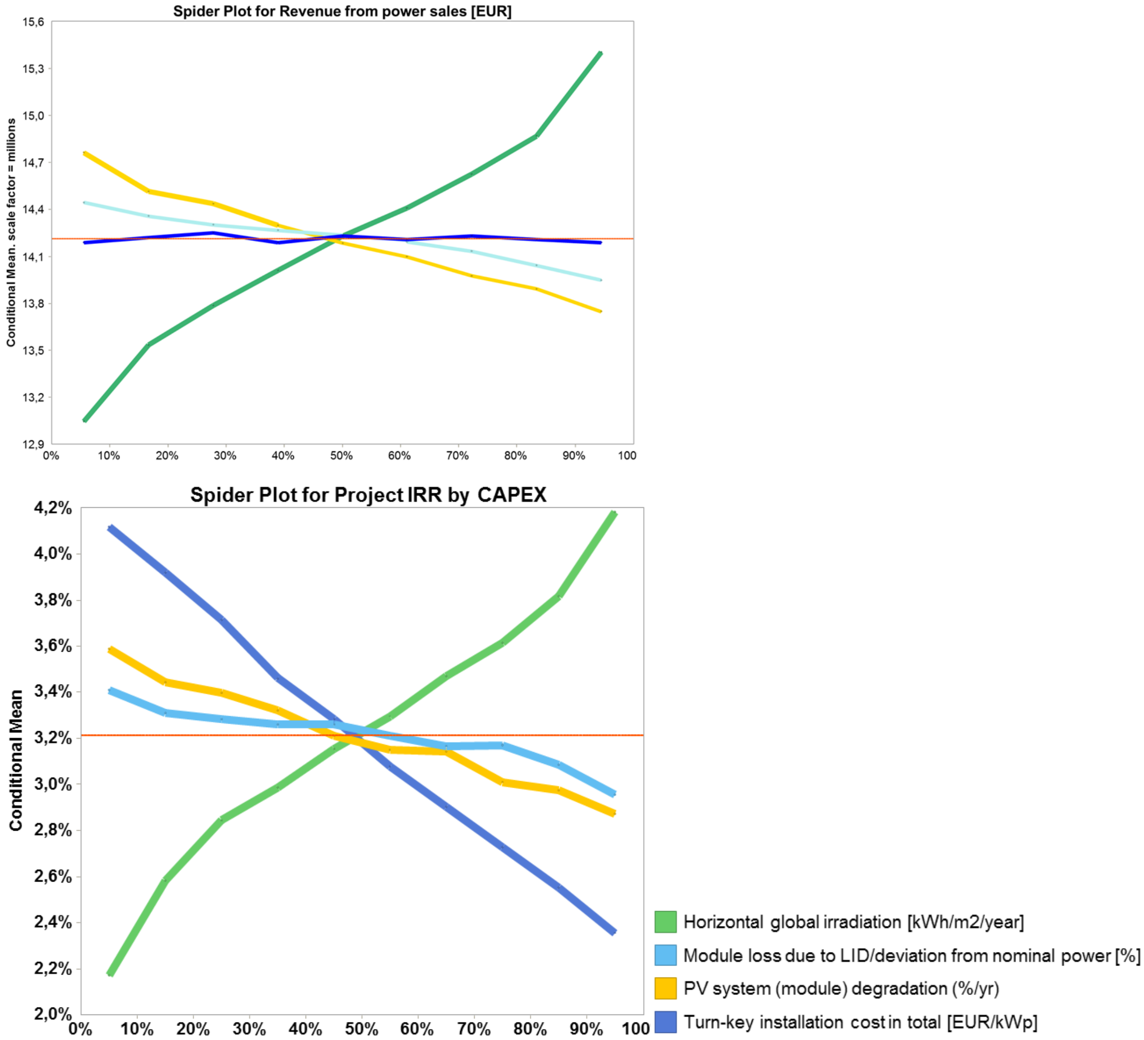


Figure 18: Spider plot demonstrates how the revenue from power sales measured in units of million EUR (top) and Project IRR by CAPEX as given by non-unit values (below) varies as a function of a percentagewise change in the input variables that have been selected as object for investigation of being uncertain.

In summary, whereas it is straight forward in a standard PV financial model to evaluate the impact of the absolute values of all input variables on the output parameter in question (Question: How will an increase in the global horizontal irradiation by 10% influence the energy yield? Answer: By an increase of 10%), it is more difficult to assess the impact on an uncertainty of the same input variable (Question: How will an asymmetrical +0.5%p/-0.2%p uncertainty on the module degradation rate influence the final project IRR? Answer: The uncertainty will transform the single IRR value into a (non-normal) distribution function that must be evaluated statistically and visually as accumulated distribution functions and associated numerically determined P50 and P90 values).

4.3 Opportunities for Mitigating and Hedging Financial Risks

A typical PV project involves many actors with various skill sets. The functions required to realize a project from inception to operational status are not uniformly distributed the same in every project. The developer may also be the financing institute. The EPC may be the developer. The bank may be the sole Technical Advisor (TA). The overall responsibility for mitigating risks may become unclear. It is not uncommon for a developer to avoid hiring a TA, assuming the bank will do so. In some larger projects, many parallel advisors are hired by various investors in addition to the TA of the developer. It is therefore evident that there are projects in which the opportunity for mitigating risks is not undertaken due to lack of clarity as to upon who bears the overall responsibility.

In general, the task of mitigating and hedging financial risks in a PV project could be addressed at the following levels:

1. **Strategy**: A prerequisite for any successful risk mitigation strategy is to ensure that the overall process is recognized by the top-level decision makers and that this management level takes responsibility for defining an appropriate strategy and assignment of the necessary resources to undertake this process.
2. **Classify**: Set a team of experts that includes a wide variety of skills and experiences; brainstorm and use checklists to make sure all potential risks are identified; assess and classify the risk factors according to expected occurrence frequency, severity in terms of financial impact and overall risk ranking.
3. **Understand**: Analyze the root cause(s) of the various risk factors including possible interrelations between different factors. Identify the specific most important influencer that may challenge the financial performance of the project.
4. **Manage**: Introduce and follow-up on actions to mitigate the identified risk items.

4.3.1 Strategy

As an example on how to mitigate and hedge financial risks at a strategy level, one may consider how it is possible to convert the “risk appetite” of the investor for a preference for either a high quality project where technical problems are considered unlikely to emerge during the project lifetime or a lower quality project where the amount of post-construction troubleshooting, repairing and replacing may be more substantial. The cost of building cheap with the intention of fixing things if and when they go wrong is simply calculated by the “times 10” rule-of-thumb [36], which states that it costs 10 times more to find and repair a defect at every consecutive stage of a PV project. Table 10 portrays the cost of fixing a fault in each consecutive phase.

Table 10: Description of the Anderson Rule of 10

Project Phase	Cost
✓ Component manufacturing	X 1
✓ Design process	X 10
✓ Component selection	X 100
✓ Installation	X 1,000

- ✓ Commissioning and operation X 10,000

4.3.2 Classifying, Understanding and Mitigating Risks

Classifying and understanding the various sources of risk require a good level of understanding for all components and their interconnection and interaction. A Technical Advisor must represent all disciplines embodying the PV project. Statutory and regulatory issues are usually attributed to the legal profession, while geologists and construction engineers are required for preparing the ground work. Mechanical engineers take responsibility for the physical structure, while electrical engineers must hail from many disciplines; PV module behavior, direct current distribution, inverter technology, alternating current distribution, power transformation, medium voltage protection and grid protocols, supervisory control and data acquisition monitoring, database management; the list continues.

It should be self-evident that for all of these elements to work together well, a level of independent quality control must be enforced.

Section 4.1 describes a range of practical guidelines that can be used to manage the risk mitigation activities.

For the financial investor, the list in Section 4.1 can be taken as a suggestion to engage a skilled and competent Technical Advisor (TA). Because of the high importance that this TA will have executing a mitigation and hedging strategy for the investor, it is critical to ensure that the TA has the necessary liability insurance in place. This insurance should have a sufficient coverage to ensure financial compensation in case the TA has failed to identify an issue that turns out to be critical to meeting the financial target.

5 Guidelines and Recommendations

The technical assumptions used in PV financial models are the subject of this work. The purpose of discussing these assumptions is to present the current understanding of what assumptions are being used by developers and to then make recommendations based on the analysis presented here.

The overall purpose of analyzing and improving assumptions is to ensure that the financial model prepared during the feasibility and early development stages of a project will continue to reflect the financial activity of the plant over the 20-30 years of operation. To this end we cannot ignore the necessity for ensuring that the design and construction of the plant will enable the assumptions to be realized. To this end, the guidelines and assumptions necessary to fulfil this task must also include suggestions regarding the design, construction and operation of the plant.

We shall suggest guidelines and recommendations as per the following project stages:

1) Project pre-feasibility
2) Plant design
3) Procurement and construction
4) Acceptance
5) Operations

5.1 Project Pre-Feasibility

This stage of the project defines the cost of the project and the income expected by the project. This stage also carries most of the assumptions discussed in this report and is directly dependent upon the next stage – plant design, where the quality of the hardware and the design feed back directly to whatever conclusions the feasibility study produced. Whereas the assumptions for solar resource assessment are not effected by future stages of the plant design, unless the site itself is not yet finalized, the feasibility assumed production and costs are directly related to the future stages of the project.

It is of importance, therefore, for the feasibility stage report to define the level of quality for the equipment and design. For example, the cost of implementing string monitoring versus array level monitoring impacts CAPEX as a higher component cost and OPEX as higher yield and lower down-time. The use of thin-film modules versus crystalline silicone modules affect the land coverage ratio, installed power, degradation assumptions and other input parameters. The uncertainty variables are very different, rendering the original feasibility study invalid.

Changing design concepts and equipment characteristics in the early stages of plant design is a common practice that leads to optimization of the PV plant. It is important that a financial model is undertaken at the end of the design process, since likely many key parameters have changed.

It is the nature of many projects to start with developers having little or no in-house technical capabilities. The initial feasibility is often heavy on financial methodology with little of the above mentioned technical methodologies in use. It is therefore of importance for the developer to be aware of the changing output parameters (IRR, ROI, etc.) as the project develops through the design and implementation phases, rerunning financial models as the plant takes physical shape on the design table.

5.2 Plant Design

During plant design phase the quality of the plant is decided. Optimum plant quality is a function of the financial model upon which the developer wishes to operate. From the previous sections it is obvious that when a choice is to be made for reducing cost, that choice should be the element with the easiest calculable uncertainty. Module power or inter-row shading have uncertainties easily calculable using the methods described in this report, while removing string monitoring from the monitoring system introduces higher OPEX uncertainty that is much more difficult to calculate.

Quality control during the design process is critical for enabling the realization of the financial plan. A well designed and specified plant that is modelled correctly in the financial model as described in this report should enable realization of the financial plan. However, the levels of design granularity required for financial modelling and that required for ensuring that the actual quality of the workmanship and installed equipment are disparate.

A poorly specified hardware that enables the use of an element that is not optimum for the specific function, or the lack of a detailed design drawing depicting correct installation practice can lead to the inability of a project to achieve the defined financial plan as defined by the financial model.

Finding and correcting errors at the design stage are inexpensive, at most embodying the cost of quality control methodology that may not have been calculated in the design costs, however, as per the “Anderson Rule” described in Section 4.3.1, errors not found during this stage will cost ten times more during the next stage, procurement or construction.

The design process must include the detailed design of all elements of the project, including the monitoring system, sensors and all software running the system as well as the integration between them. Since most of the PV plant is hardware centric, the software is often oversimplified and underspecified such that the final product cannot fulfil the requirements necessary for calculating KPIs integral to adhering to the business plan.

If a TA or “owner’s engineer” has not yet been appointed, this is the latest stage one can comfortably begin service. The TA will validate the final financial model and should ensure quality control at this design stage. Once the project continues on to the more solid phases of operation that lock in the design, such as tender or procurement, depending the nature of the project, the TA can do little to obviate errors that will affect the financial model.

The model for building infrastructure projects in general and PV projects in particular is that of the EPC (Engineering, Procurement and Construction). The inherent conflict of interest between designing (engineering) and procurement and construction can only be absolved by the employment of a well-qualified TA or owner’s engineer. Even in the instance of an EPC as a shareholder in the project, an Owner’s Engineer is of importance to ensure that the project is designed to meet the business plan and built to design, since the overall independent business plan of the EPC shareholder is possibly different from the other shareholders.

When implementing the EPC model for building a PV plant, it is suggested that the EPC contractor be required to supply the O&M contract to be signed together with the construction contract, including back to back warrantees and guarantees. Whereas the performance ratio (PR) guarantee is a powerful tool for enabling risk management and at first glance specifying equipment based on the premise that the EPC will have to ensure a level of PR seems a logical strategy, however, the terms of the EPC guarantees and specific equipment warranties (for example, central inverters) must be analyzed and the possibility for events not covered by the guarantee be kept to a minimum. In reality, a PR guarantee seldom covers the revenue loss, only acting to penalize the contractor up to the value of the O&M contract itself. Losses due to the loss of production time while waiting for numerous maintenance visits by all representatives of the supply line, issuance of maintenance reports by each player, international discussions and final delivery, and installation time can far exceed the value specified in the O&M contract. These losses can be alleviated at least partly with a well-planned spare part list for large inverters and a number of replacement inverters in a distributed system design. The additional cost of these spare parts in the purchase price is far easier to calculate than the losses due to supplier disputes.

5.3 Procurement and Construction

This stage, including the procurement aspect of the project, has little to do with the core discussion of this report – technical assumptions used in PV financial models, yet everything to do with ensuring that the plant will adhere to the financial model.

Since correcting mistakes during procurement cost 10 times more than during the design process and 100 times more during the construction process, it is advisable to recall the earlier narrative in this report regarding the nature of the key elements to a PV plant.

The essence of success in any project can be defined as quality control, for the hardware, the workmanship and software. The lessons learned earlier in this report regarding modules and inverters are easily extended to other elements of the project.

Section 3.5 is recommended reading for mitigating some of the risks during this and the previous stage.

Due to the conflict of interest inherent in the EPC method for building infrastructure projects in general and PV projects in particular, due to the innocuous nature of the PV plant 20-30 year lifetime, it is important for a level of QC that is solely responsible to the shareholders of the project.

During the product specification process (procurement), the method of transportation must be defined and verified for each element in the plant. The PV modules, inverters, transformers and other key elements must be transported and handled as per the manufacturer's requirements and suggestions.

Inverters, transformers, switch boards and similar equipment should ideally be examined for compliance by project QC personnel before leaving the manufacturing factory. If this is not possible, they should be carefully examined for compliance upon arrival at the site. In any case, all these elements must be examined upon site arrival to ensure no damage was incurred on route.

PV modules must be specified as being type approval tested by an independent testing facility and that the QC process of the manufacturer has been examined by an independent QC facility.

PV modules must be transported from the manufacturing plant to the site in the manner defined by the manufacturer having tested the modules to the relevant transportation test as in [27] to ensure no damage to the modules. Damage incurred by modules during transportation is not always apparent to the naked eye during installation, indeed not necessarily for the first few years. Therefore, upon arrival on site, it is suggested that a sampling of modules be sent for laboratory testing to discover any latent damages incurred during transportation (using EL for example).

5.4 Acceptance

Plant acceptance is the period during which the plant is examined for compliance to design, quality of work and deemed as functioning as per the specification written to meet the business plan. Acceptance is the most important milestone of the project, and substantial capital is dependent upon successful achievement of this milestone. Neither the contractor nor the developer wish to wait a full production cycle of one year before the quality of the plant becomes legally apparent. There exist two methods for overcoming this problem, performing an acceptance test that enables determination of the yield capability of the plant irrespective of the season or a conditional acceptance that does not determine the final yield capability at time of the acceptance testing, but makes acceptance conditional on first year's operation.

The percentage of payment left until the end of the year would be a function of the quality of the initial yield testing performed during the initial testing period. This yield testing can be achieved by collecting a week or two of data from the plant and calculating a temperature corrected performance ratio and comparing to simulated results from the same time period in the simulation program. The daily insolation levels for the chosen days from the simulation program should be similar to those in reality during the testing.

In any case, an EPC warranty for a solar PV plant should be for 24 months to enable the discovery of deficiencies during the first year and the effect of their correction the second year. Compensation for underperformance can be calculated after the first year, the purchase price being adjusted for the plants inability to reach the designed level of production, based on PR calculations.

During acceptance testing it is advisable to perform IV curve tests on a relatively large sampling of strings and modules. And IR imaging and documentation on all PV modules, string boxes, junction boxes, inverters, electrical distribution panels, transformers etc.

All sensors must be checked for plausibility and their corresponding calibration certificates must be reviewed. The data acquisition system must be verified. All monitoring system reporting must be verified.

Deficiencies found during the acceptance test and subsequent warranty period will cost 10 times more to fix than during the building process, but one tenth what will cost to rectify during the O&M period.

5.5 Operation

The key to successful operation of a PV plant is the monitoring system and the O&M operators who act on the monitoring system's signals. The initial cost of the system is covered in the CAPEX, but the value is only evident to those working on the OPEX. Without accurate monitoring with suitable time resolution that enables downloading any available parameters from any collection of plant elements across any time span, there is little possibility for optimizing operational activities.

The choice of time resolution for writing to data base is a function of cost of data storage and ease of manipulating the data on one hand and the ability to trouble shoot problems on the other. 10 minute values are easy to work with and enable six data points an hour. In any case, the saved values must be constructed of averaged values with a resolution that should be 15 seconds or faster. The only exception to this is the energy parameter which is ever growing.

Monitored parameters should include both DC and AC values for current and voltage. Ground isolation readings have been found to be of value in finding the cause of system faults before plant shutdown. Temperature readings from panels, string box, electric panels, inverter enclosures and the inverter themselves are of value no less than the temperature readings from transformer coils. On the AC side, additional parameters to monitor are power factor, active power, reactive power and apparent power, voltage and current THD (Total Harmonic Distortion) and TDD (Total Demand Distortion).

All these values and any other available parameters should be saved if not for immediate trouble shooting capabilities then to enable performance monitoring based on advanced statistical tools such as machine learning and neural networks that are becoming popular.

With a quality monitoring system, it is possible to optimize maintenance tasks such a module washing frequency and ascertain if string fuses have blown before preventative maintenance activities take place.

The first two years of operation are critical for successfully meeting the financial model. A quality contract with the EPC will include 24 months warranty, and require the EPC to perform the O&M for 36 months. The contract should specify that faults and failures found during the warranty period will be examined by the TA to classify the fault or failure as a one-time isolated problem or faulty design. If the fault will repeat at other points of the plant, the contractor must rectify the problem even before it occurs at other similar points in the field. If the problem shows signs of a batch fault, the contractor must replace all units of the same batch in the field irrelevant of them having failed as yet or not.

The first year, representing a full production cycle, is for finding faults and repairing them. The second year is for verifying that the faults have been rectified.

The third year of contractual obligation will enable a smooth transition from warranty period to the "bottom of the bathtub" curve.

6 Conclusions

In this report, we undertook to clarify the assumptions used by technical advisors in PV financial models, to analyze these assumptions scientifically and to make suggestions for improving the accuracy of these assumptions. The relevance of this undertaking to the market is in that the financial model designed for investors during the early stages of a project is expected to be accurate throughout the 20-30 years of operation. The key to ensuring that the financial model remains correct throughout the project lies not only in accurate assumptions for the future behavior of the plant at the outset of the design process, but also in ensuring that these assumptions are enabled during the design, building, commissioning and O&M. This requirement points to a necessity for a high-level of quality control throughout the plant's life. Therefore, suggestions made in this report are not only regarding the assumptions to be made, but also how to ensure that these assumptions will hold true to realize the business plan.

We began with a survey of 84 PV projects in nine countries that portrayed the current assumptions made by project developers for solar resource and yield estimations, yearly revenue, operating expenditures and financing.

We then reviewed these presented practices by comparing them with scientific data, state-of-the-art methods and recommended best practices. Augmenting our study with findings from the Solar Bankability study it seemed evident that a likely method for managing the risk of losing the validity of an assumption made during the financial planning is to focus on the technical aspects of the EPC and O&M scopes of work to manage the technical risks linked to the CAPEX and OPEX of PV investments.

To this end we described these aspects in each segment of a PV project; energy yield estimates and the solar resources on which these are based and the capital and operating expenditures, summarizing the shortcomings we encountered in survey. We then discussed in detail the reliability and failures of PV system components, specifically the PV modules and inverters as well as the handling and transporting of these and other elements of the project.

After these technical discussions of the realities affecting the assumptions, we discussed methods for increasing the accuracy of our assumptions and for mitigating risks to these assumptions. This was achieved with lists of the shortcomings found in our discussion on the current practices accompanied by methods to mitigate these shortcomings in the technical management of the project during the design, construction and operational stages of the project.

Special attention was paid to mitigating the uncertainty parameters calculated or assumed for the inputs to the business model, presenting a method of calculating final business model values for produced energy, revenue and IRR using statistical tools such as Monte Carlo calculations on the input values, and then again on the output values. This method demonstrates how a P50 and P90 model can be generated.

Further statistical graphic tools, such as the tornado and spider plots were introduced as tools to visualize the relative effect of each of the input parameters on the final calculated output values.

Finally, we presented a summary of what we have presented in this report in the form of guidelines and recommendations for undertaking the design, construction and operation of a PV plant in a manner that will enable fulfilling the calculated financial plan.

References

[1] Caroline Tjengdrawira and Mauricio Richter, “Review and Gap Analyses of Technical Assumptions in PV Electricity Cost,” Public report Solar Bankability WP3 Deliverable D3.1, Jul. 2016.

[2] Jan Vedde *et al.*, “Technical Parameters Used in PV Financial Models: Review and Analysis,” in *32nd European Photovoltaic Solar Energy Conference and Exhibition*, Munich, Germany, 2016, pp. 2892–2897.

[3] David Moser *et al.*, “Technical Risks in PV Projects - Report on Technical Risks in PV Project Development and PV Plant Operation,” Solar Bankability WP1 Deliverable D1.1 and WP2 Deliverable D2.1, Mar. 2016.

[4] Jesus Polo *et al.*, “Preliminary survey on site-adaptation techniques for satellite-derived and reanalysis solar radiation datasets,” *Sol. Energy*, vol. 132, pp. 25–37, Jul. 2016.

[5] Mauricio Richter, Karel De Brabandere, John Kalisch, Thomas Schmidt, and Elke Lorenz, “Best Practice Guide on Uncertainty in PV Modelling,” Public report Performance Plus WP2 Deliverable D2.4, Jan. 2015.

[6] Pierre Ineichen, “Long term satellite hourly, daily and monthly global, beam and diffuse irradiance validation. Interannual variability analysis,” University of Geneva, Geneva, Switzerland, Dec. 2013.

[7] Pierre Ineichen, “Five satellite products deriving beam and global irradiance validation on data from 23 ground stations,” University of Geneva, Geneva, Switzerland, Feb. 2011.

[8] Achim Woyte, Karel De Brabandere, Babacar Sarr, and Mauricio Richter, “The Quality of Satellite-Based Irradiation Data for Operations and Asset Management,” in *32nd European Photovoltaic Solar Energy Conference and Exhibition*, Munich, Germany, 2016, pp. 1470–1474.

[9] Martin Wild, “Global dimming and brightening: A review,” *J. Geophys. Res.*, vol. 114, Jun. 2009.

[10] Björn Müller, Martin Wild, Anton Driesse, and Klaus Behrens, “Rethinking solar resource assessments in the context of global dimming and brightening,” *Sol. Energy*, vol. 99, pp. 272–282, 2014.

[11] Martin Wild *et al.*, “From Dimming to Brightening: Decadal Changes in Solar Radiation at Earth’s Surface,” *Science*, vol. 308, no. 5723, pp. 847–850, May 2005.

[12] Martin Wild, Doris Folini, Florian Henschel, Natalie Fischer, and Björn Müller, “Projections of long-term changes in solar radiation based on CMIP5 climate models and their influence on energy yields of photovoltaic systems,” *Sol. Energy*, vol. 116, pp. 12–24, Jun. 2015.

[13] David L. King, William E. Boyson, and Jay Kratochvil, “Analysis of factors influencing the annual energy production of photovoltaic systems,” in *Photovoltaic Specialists Conference, 2002. Conference Record of the Twenty-Ninth IEEE*, 2002, pp. 1356–1361.

[14] Christopher P. Cameron, William E. Boyson, and Daniel M. Riley, “Comparison of PV system performance-model predictions with measured PV system performance,” in *Photovoltaic Specialists Conference, 2008. PVSC’08. 33rd IEEE*, 2008, pp. 1–6.

[15] F. P. Baumgartner, H. Schmidt, B. Burger, R. Brundlinger, H. Haberlin, and M. Zehner, “Status and Relevance of the DC Voltage Dependency of the Inverter Efficiency,” in *EU PVSEC 2007*, Milan, Italy, 2007, pp. 2499–2505.

[16] W. Herrmann, “Analyses of array losses caused by electrical mismatch of PV modules,” in *Proceeding of the 20th European Photovoltaic Solar Energy Conference*, 2005, pp. 2200–2203.

[17] Steve Ransome, “How well do pv modelling algorithms really predict performance?,” in *22nd European PVSEC Milan*, 2007, pp. 2441–2450.

[18] Frank Neuberger, “Fraunhofer ISE ist Spitzenreiter bei der Präzisionsprüfung von PV-Modulen – Messungenauigkeit im CalLab PV Modules auf 1,6 Prozent gesenkt — Fraunhofer

ISE." [Online]. Available: https://www.ise.fraunhofer.de/de/presse-und-medien/presseinformationen/presseinformationen-2014/fraunhofer-ise-ist-spitzenreiter-bei-der-praezisionspruefung-von-pv-modulen. [Accessed: 12-Dec-2016].
[19] Dirk C. Jordan and Sarah R. Kurtz, "Photovoltaic degradation rates—an analytical review," *Prog. Photovolt. Res. Appl.*, vol. 21, no. 1, pp. 12–29, Jun. 2012.
[20] M. A. Munoz, F. Chenlo, and M. C. Alonso-García, "Influence of Initial Power Stabilization Over Crystalline-Si Photovoltaic Modules Maximum Power," *Prog. Photovolt. Res. Appl.*, vol. 19, no. 4, pp. 417–422, 2011.
[21] Dirk C. Jordan, Sarah R. Kurtz, Kaitlyn VanSant, and Jeff Newmiller, "Compendium of photovoltaic degradation rates: Photovoltaic degradation rates," *Prog. Photovolt. Res. Appl.*, p. n/a-n/a, 2016.
[22] Giorgio Belluardo, Philip Ingenhoven, Wolfram Sparber, Jochen Wagner, Philipp Weihs, and David Moser, "Novel method for the improvement in the evaluation of outdoor performance loss rate in different PV technologies and comparison with two other methods," *Sol. Energy*, vol. 117, pp. 139–152, 2015.
[23] Bjorn Muller, Wolfgang Heydenreich, Nils Reich, Christian Reise, and Boris Farnung, "Investment risks of utility-scale PV: Opportunities and limitations of risk mitigation strategies to reduce uncertainties of energy yield predictions," in *Photovoltaic Specialist Conference (PVSC), 2015 IEEE 42nd*, 2015, pp. 1–5.
[24] Miguel García, Jose A. Vera, Luis Marroyo, Eduardo Lorenzo, and Miguel Pérez, "Solar-tracking PV plants in Navarra: A 10 MW assessment," *Prog. Photovolt. Res. Appl.*, vol. 17, no. 5, pp. 337–346, 2009.
[25] Christopher Olschok, Markus Schmid, Rudi Haas, and Gerd Becker, "Inappropriate exposure to PV modules: description and effects of handling defaults," in *28 th European Photovoltaic Solar Energy Conference, Paris, France*, 2013.
[26] Marc Köntges and Michael Siebert, "Transport und Handling von Wafer-basierten Silizium Photovoltaik-Modulen," 2015.
[27] Marc Köntges *et al.*, "Impact of Transportation on Silicon Wafer-Based PV Modules," presented at the 28th PVSEC, 2013.
[28] Florian Reil *et al.*, "Development of a New Test Standard and Experiences of Transportation and Rough Handling Testing of PV Modules," presented at the 26th PVSEC, 2011.
[29] Willi Vaassen, "Technical Risk Quantification and Assessment Opening Remarks: Some Experiences of TÜV Rheinland," presented at the EC Project Solar Bankability Public Workshop #1, May-2016.
[30] Timothy Dierauf, Aaron Growitz, Sarah Kurtz, Jose Luis Becerra Cruz, Evan Riley, and Clifford Hansen, "Weather-corrected performance ratio," National Renewable Energy Laboratory, Golden, Colorado, NREL/TP-5200-57991, Apr. 2013.
[31] 3E, "Beyond Standard Monitoring Practice," 3E nv/sa, Brussels, Belgium, White paper, Jan. 2015.
[32] Achim Woyte *et al.*, "Analytical Monitoring of Grid-connected Photovoltaic Systems - Good Practice for Monitoring and Performance Analysis," IEA PVPS, Report IEA-PVPS T13-03: 2014, Mar. 2014.
[33] Marc Köntges, Sascha Altmann, Tobias Heimberg, Ulrike Jahn, and Karl A. Berger, "Mean Degradation Rates in PV Systems for Various Kinds of PV Module Failures," in *32nd European Photovoltaic Solar Energy Conference and Exhibition*, Munich, Germany, 2016, pp. 1435–1443.
[34] Hermann Laukamp, Tony Schoen, and Daniel Ruoss, "Reliability Study of Grid Connected PV Systems, Field Experience and Recommended Design Practice," International Energy Agency Photovoltaic Power Systems Programme, Report IEA-PVPS T7-08, 2002.
[35] Ulrike Jahn *et al.*, "Minimizing Technical Risks in Photovoltaic Projects - Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation," Solar Bankability WP1 Deliverable D1.2 and WP2 Deliverable D2.2, Jul. 2016.

[36] David M. Anderson, *Design for Manufacturability: How to Use Concurrent Engineering to Rapidly Develop Low-Cost, High-Quality Products for Lean Production*. CRC Press, 2014.

Appendix 1: Topics & Questions in the Survey on Current Practices in the Use of Technical Parameters in PV Financial Models

Topic 1: Project

Project background

PV project presentation (what is the origin, type and purpose of source-document)

Purpose of PV project (self-consumption; IPP etc.)

Ownership (Developer, Bank, Individual, etc.)

Developer (Private, Industry, Agriculture, Professional developer etc.)

Inauguration year (realised or planned)

Project location

Where's the plant located (country)

Where's the plant located (city)

Where's the plant located (Map coordinates)

Special site information (e.g. polluted area, airfield, dessert, extreme shading, etc.)

Project size

Total dc-power of PV project [Wp]

Total ac-power of PV project [Wac]

Total project size (ground area; remember unit in ha, m2 or km2)

Project type

Type of installation (free field, roof integrated, flat roof, BIPV, tracker etc.)

Type of mounting system (e.g. two pole steel with 3 rows of panels in landscape mode)

Orientation (Azimuth i.e., south=180, east=90)

Tilt

Topic 2: Irradiation & energy production

Solar resource

Average expected yearly solar irradiation [kWh/m2/year]

Type of irradiation data (e.g. horizontal data measured with pyranometer; satellite data etc.)

Information source for solar resource (e.g. pyranometer class, satellite provider)

Energy production

Yearly specific production [kWh/kWp/year]

Yearly Performance Ratio [%]

What is the data- and formula basis for production and PR

What is the expected increase in irradiation received in the plane of array (Transposition Factor)?

Topic 3: Technical data & system design

PV module

PV panel manufacturer

PV panel cell type

Special module features

PV power (Wp) nominal

PV power (Wp) nominal tolerance

PV power (Wp) measured power

What are the product warranty conditions of the modules?

What is the performance guarantee of the modules?

Does the module come with additional insurance?

Module size (length) [mm]

Module size (width) [mm]

Module size (area) [m2]

Module area in total (all modules) [m2]

PV module string configuration

Modules per string

Strings per combiner box or

Strings per inverter

Inverters per sub-system and number of sub-systems within the whole plant

Inverters in total (numbers)

Modules in total (numbers)

Inverter

What type of inverter is used (string, central etc.

What is the ac-power of the inverter

IP-rating of inverter (e.g. IP 64)

Describe inverter installation environment (outside under the panels, inside ventilated room)

Performance calculation/modelling

What modelling tool has been used to calculate the expected yield

What are the assumptions used to describe soiling loss (e.g. dust/dirt sources, cleaning strategy etc.)

Input parameter for model: shading loss

Input parameter for model: shadowing loss

How is the uncertainty in these inputs dealt with?

Input parameter for model: IAM loss

How is the uncertainty in this input dealt with?

What is the thermal loss (comparing STC and actual conditions)

What is the expected loss related to string mismatch

What is the expected dc and ac cabling loss

What is the expected total inverter loss

What is the expected transformer loss

How is the uncertainty in these inputs dealt with?

What percentage of the total energy production is expected to be delivered to the grid?

At what voltage level will the power be delivered

Topic 4: System cost

What is the development cost

What is the site preparation cost

What is the construction cost

Mounting structures cost.

What is the mounting structure cost (hardware cost - or maybe installation of modules are included)

What is the PV module cost (incl. transport, import tax and additional quality inspection)

What is the BOS cost (hardware like fence, lightning protection, and safety system)

What is the grid connection cost (transformer cost, meters, incl. administrative fees)

Construction (incl. civic work, road, dc&ac, module mounting, waste disposal etc.)

Any other costs?

What is the total cost (clarify if this is construction cost or sales price to end-investor)

Topic 5: Business model

What is the business model? (e.g. FIT, IPP, net-metering, partly self-consumption, a mix of these, other)

What is the expected availability of the PV system (e.g. hours of operation)

Expected operational lifetime of the project (years; can be longer/shorter than technical lifetime)

What is the expectations with respect to degradation of components and system

Has the risk of total components failure been assessed?

Has the technical risks been assessed otherwise?

What is the expected power sales price (price first year and price prognosis)

What is the expected inflation in the financial models

How is the project financed

How is the depreciation profile

What is the expected taxation

Does the project receive any subsidy

Topic 6: Operation & Maintenance & Monitoring

What is the land lease/how is the site access paid for

Insurance expected cost

How are the O&M organised?

What services are included in the O&M? (cleaning 2x per year; guaranteed PR, 24 h theft surveillance)

How are the O&M service paid for? (e.g. fixed fee or percentage of income)

Is a break-down of the O&M service available to list?

What is the expected lifetime of the inverter and how is replacement included

What is the guarantee period for the inverter?

Do the budget include expenses for administrative?

Any decommissioning taken into account?

Any other costs?

Monitoring

Monitoring platform (Meteocontrol, Sunny portal …)

Resolution of monitoring data (e.g. 15 minutes, 1 minute, hourly etc.)

Monitored parameters (e.g. DC and/or AC electrical, Irradiation, temperature(s), wind etc.)

Appendix 2: Overview of installations included in the survey

Region	Installed power [kWp]	Mounting	Azimuth (S=180°)	Tilt	PV technology
West Africa	25000 - 30000	free field - fixed	180°	12°	poly-crystalline silicon
West Africa	20000 - 25000	free field - fixed	180°	15°	poly-crystalline silicon
France	10000 - 15000	free field - fixed	180°	20°	poly-crystalline silicon
France	10000 - 15000	free field - fixed	180°	28°	poly-crystalline silicon
France	10000 - 15000	free field - fixed	180°	28°	poly-crystalline silicon
France	5000 - 10000	free field - fixed	180°	28°	poly-crystalline silicon
France	5000 - 10000	free field - fixed	180°	28°	poly-crystalline silicon
France	5000 - 10000	free field - fixed	180°	28°	poly-crystalline silicon
France	5000 - 10000	building attached - fixed	depending on roofs	11°	poly-crystalline silicon
Turkey	7000	N.A.	N.A.	N.A.	N.A.
N.A.	5004	free field - fixed	N.A.	20°	poly-crystalline silicon
N.A.	4001	free field - fixed	N.A.	10°	mono-crystalline silicon
N.A.	3000	free field - fixed	N.A.	12°	mono-crystalline silicon
Indonesia	2500	free field - fixed	0°	15°	N.A.
N.A.	2001	free field - fixed	0°	12°	mono-crystalline silicon
N.A.	2001	free field - fixed	0°	12°	mono-crystalline silicon
N.A.	2001	free field - fixed	180°	12°	mono-crystalline silicon

Japan	2000	free field - fixed	180°	20°	poly-crystalline silicon
N.A.	1109	free field - fixed	0°	24º	CdTd
N.A.	1001	free field - fixed	0°	15°	poly-crystalline silicon
N.A.	1001	free field - fixed	180°	15°	poly-crystalline silicon
N.A.	1001	free field - fixed	90°	15°	poly-crystalline silicon
N.A.	1001	free field - fixed	270°	15°	poly-crystalline silicon
N.A.	1000	free field - season tilt	N.A.	Season Tilt	CdTd
Italy	990	free field - fixed	N.A.	N.A.	N.A.
N.A.	864	free field - tracker	Tracker	Tracker	poly-crystalline silicon
Italy	835.065	N.A.	180°	30°	N.A.
N.A.	790	free field - tracker	Tracker	Tracker	poly-crystalline silicon
Belgium	759	Roof Mounted	depending on roofs	18°	poly-crystalline silicon
N.A.	711	free field - tracker	Tracker	Tracker	mono-crystalline silicon
Germany	428	Roof Mounted	N.A.	N.A.	N.A.
N.A.	327	free field - fixed	0°	30°	CdTd
N.A.	325	free field - fixed	N.A.	9°	mono-crystalline silicon
N.A.	320	free field - tracker	Tracker	Tracker	poly-crystalline silicon
N.A.	318	free field - fixed	N.A.	10°	mono-crystalline silicon
N.A.	306	free field - fixed	160°	3°	mono-crystalline silicon
N.A.	306	free field - fixed	N.A.	6°	mono-crystalline silicon
N.A.	270	free field - fixed	0°	30°	CdTd
N.A.	266	free field - 1-	Tracker	30°	mono-

		axis tracker			crystalline sili-con
N.A.	255	free field - fixed	N.A.	10°	mono-crystalline sili-con
N.A.	255	free field - fixed	N.A.	10°	mono-crystalline sili-con
N.A.	236	free field - fixed	N.A.	17°	poly-crystalline silicon
N.A.	227	free field - tracker	Tracker	Tracker	poly-crystalline silicon
N.A.	221	free field - tracker	Tracker	Tracker	mono-crystalline sili-con
N.A.	221	free field - 1-axis tracker	Tracker	30°	mono-crystalline sili-con
N.A.	220.5	free field - tracker	Tracker	Tracker	mono-crystalline sili-con
N.A.	218	free field - tracker	Tracker	Tracker	mono-crystalline sili-con
N.A.	218	free field - fixed	0°	30°	CdTd
N.A.	217	free field - fixed	0°	30°	CdTd
N.A.	216	free field - fixed	N.A.	15°	mono-crystalline sili-con
N.A.	213	free field - tracker	Tracker	Tracker	poly-crystalline silicon
N.A.	204	free field - tracker	Tracker	Tracker	poly-crystalline silicon
N.A.	177	free field - 1-axis tracker	Tracker	30°	mono-crystalline sili-con
N.A.	161	free field - fixed	135°	17°	poly-crystalline silicon
N.A.	120	free field - fixed	N.A.	10°	mono-crystalline sili-con
N.A.	120	free field - fixed	90° - 270°	10°	mono-crystalline sili-con

N.A.	120	free field - fixed	0°	10°	mono-crystalline silicon
N.A.	60	free field - fixed	90°	10°	mono-crystalline silicon
N.A.	60	free field - fixed	270°	10°	mono-crystalline silicon
N.A.	60	free field - fixed	180°	10°	mono-crystalline silicon
N.A.	60	free field - fixed	0°	10°	mono-crystalline silicon
N.A.	39	free field - fixed	125°	15°	mono-crystalline silicon
N.A.	18	free field - fixed	N.A.	15°	mono-crystalline silicon
N.A.	17.98	free field - fixed	N.A.	3°	mono-crystalline silicon
N.A.	17.98	free field - fixed	N.A.	3°	mono-crystalline silicon
N.A.	6.5	free field - fixed	N.A.	15°	mono-crystalline silicon
Germany	N.A.	Roof Mounted	N.A.	N.A.	N.A.
Israel	N.A.	Roof Mounted	depending on roofs	15° - 24°	poly-crystalline silicon
Romania	N.A.	free field - fixed	180°	22°	poly-crystalline silicon
Israel	N.A.	Roof Mounted	180°	20°	poly-crystalline silicon
Germany	N.A.	free field - fixed	180°	16°	poly-crystalline silicon
Uruguay	N.A.	free field - fixed	0°	15°	mono-crystalline silicon
Italy	N.A.	free field - fixed	180°	25°	poly-crystalline silicon
Italy	N.A.	free field - fixed	180°	30°	poly-crystalline

					silicon
Germany	N.A.	free field - fixed	180°	25°	poly-crystalline silicon
Germany	N.A.	free field - fixed	180°	25°	poly-crystalline silicon
China	N.A.	Roof Mounted	depending on roofs	0° - 20°	Amorphous silicon
Chile	N.A.	free field - 1-axis tracker	Tracker	55°	poly-crystalline silicon
Japan	N.A.	free field - fixed	180°	26°	poly-crystalline silicon
Chad	N.A.	free field - fixed	176°	16°	poly-crystalline silicon

Appendix 3: Summary of Answers in the Survey on Current Practices in the Use of Technical Parameters in PV Financial Models

General Project Information

Topic	*Answers to questionnaire*
Purpose of project	To generate energy; investment proposals, opportunity for an agricultural cooperation.
Ownership	In several cases the project is owned by a holding company, being often a Special Purpose Vehicle (SPV), with the sole purpose of owning the PV project on a non-recourse basis. Therefore, the collateral is the PV project itself.
Developer	An agricultural cooperative, private land owner, industrial concern or a private building owner.
Installation type	Free field or alternatively fixed tilted on a roof with either aluminum or galvanized steel mounting structures.
Orientation	All projects have the modules facing directly towards equator with tilt angles between 15° and 30°. Only one tracker system is included.
PV modules	Most projects use modules made from mono- or multicrystalline silicon cells manufactured by Tier 1 or 2 Chinese companies. A single project uses a-Si/µ-Si tandem modules. Some examples reference additional certification according to salt-mist, ammonia, PID-resistance and AR coating of the glass.
PV module tolerance	Ranges of ±5 Wp-units symmetrical around the nominal power or as asymmetrical tolerances of -0/+3% or -0/+5 Wp-units. In three cases the average measured power from flash tests including a measured standard deviation was provided.
Warranties	A single case did specify the module product warranty but in all other cases only the performance warranty - which is typically specified as linear over 20 or 25 years – are given. In two cases information is provided that the supplier module warranty has been backed by an external insurance policy.
Stringing	In most cases a detailed description is provided on the total number of modules and the number of modules per string, combiner-box and/or in-

	verter.
Area	In most responses, the exact size of the modules and the total module area is given however the total area utilized by the project or the ground coverage ratio is seldom detailed.

Solar Resource Assessment

Topic	*Answers to questionnaire*
Location	In most cases a very precise identification of the project location is given. Projects from the following countries are covered: Chad, Chile, China, Germany, Israel, Italy, Japan, Romania & Uruguay.
Irradiation	A value of the expected horizontal irradiation received is provided with either four or five significant digits - in units of kWh/m^2. The sources of this information are referenced in detail and include data from the following sources: Deutschen Wetterdienstes (DWD) (1981-2012), Meteonorm 6.1 (1981-2000) and 7.0 (1986-2005), NASA (1983-2005), NASA (SSE) (1983-2005), PVGIS (Classic) (1981-1990), PVGIS (CM-SAF) (1998-2010) or UNI 10349. Besides a reference to the yearly period behind these meteorological observations, also an uncertainty in this value is often given, with typical values of ±2.5%, ±3.0%, ±4.5%, ±6.8% or ±8.0%; most values being in the lower end of this range. A monthly breakdown of expected irradiation is also provided in many responses.

Technical and System Design Data

Topic	*Answers to questionnaire*
Soiling loss	Amount of soiling to be expected is often provided and ranges from 1.0% to 3.0% with most values between 1.0 and 1.5%. The uncertainty of this value is often provided and is given as ±1.0 percentage point with only one exception where a value of ±3.0 % is used.
Shading loss	Expected amount of shading is provided with typical values of 0.6%, 0.7%, 1.4%, 2.7%, 2.8%, 3.3% and 3.6%. However, most installations expect 0% shading loss. The uncertainty in this estimate is given as ±0.5% in most examples and as ±1.0% and ±2.0% in two specific projects.
Reflection loss	Expected amount of loss due to reflection from the module surface (also known as Incidence Angle Modifier (IAM) loss) is provided with typical values of 2.8%, 2.9%, 3.0%, 3.2%, 3.6% or alternative with a value of 0.0%. The uncertainty in this estimate is always given as ±0.5% when stated.
Thermal loss	Yearly loss as compared to operation under Standard Test Conditions (STC i.e. irradiance of 1000 W/m^2, air mass (AM) of 1.5 and module temperature of 25 °C) has been calculated as 0.1%, 0.3%, 0.8%, 1%, 1.2%, 4.9%, 5.4%, 11.3% or 14.5 % with uncertainties stated as either

	±0.2%, ±0.5% or ±1.0%.
String mismatch loss	Calculated to values of 0.4%, 0.7%, 0.8 %, 0.9%, 1.0%, 1.10% or 2.1% with uncertainty stated as ±0.5% (except for one example of ±1.0%).
DC/AC-cable loss	Calculated as 0.1%, 0.2%, 0.6%, 0.7%, 0.9 %, 1%, 3.4%, 6.2% or 7.4 %, always with an estimated uncertainty stated as ±0.2%.
Inverter loss	Calculated as 1.1%, 1.6%, 1.7 %, 1.9%, 2.0 %, 2.2 %, and 3.2%, always with an estimated uncertainty stated as either ±1.0% or ±2.0%.
Transformer loss	Calculated as 1.0% and 1.3% with one value at 2.0% and always given with an uncertainty of ±0.5%.
Grid access	For all systems where the information is provided, the full production is expected to be delivered to the grid with no other loss (Power Factor = 1). The combined overall uncertainty in the calculated energy yield is then provided as ±3.2%, ±4.5%, ±5.1%, ±5.9%, ±6.1%, ±6.8% or ±7.3%.

System costs

Topic	***Answers to questionnaire***
Capital expenditures	The survey revealed that the EPC cost makes up a significant portion (70-90%) of the capital expenditures (CAPEX). The scope of work of the EPC is defined in the main body of the EPC contract and generally includes the following core services: 1. Design of the plant 2. Procurement and supply of plant components, usually up to the grid connection point 3. Construction, including transportation of components to site, site preparation, and component installation 4. Plant testing and commissioning for owner's takeover, including supply of all relevant documentation In addition to the core activities, there are optional works which could be included in the EPC service. For example, the EPC will normally provide support to the plant owner or developer in administrative aspects such as obtaining grid connection authorization, use of external roads, or acting as the interface with the component and equipment suppliers before the ownership of the plant is handed over. Financial models normally only make use of a single number for the CAPEX value.
Operating expenditures	The survey revealed that the O&M costs make up a significant portion of the OPEX (30-70%). The scope of works for the O&M contractor is defined in the O&M contract and generally includes the following core services: 1. Continuous monitoring of the plant operation and periodic reporting 2. Preventive maintenance

3. Corrective maintenance

In addition to the core activities, there are optional works such as administrative support and warranty claim management assistance. The O&M costs in the surveyed PV financial models are made up of a fixed part and a variable part. The O&M costs reported in the questionnaire have a very broad spread (30 to 70%) within the PV project OPEX. This is because the O&M scope itself varies widely, influenced by many factors such as plant size, complexity of design and technology, access to location, and local regulations. When the scope of the fixed O&M is comprehensive, it will consist of complete preventive maintenance activities including 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.

Business models

In general, the nature of revenue generation as well as information about the financial structure, taxation and other financially related aspects of the project was not made available by many of the participants. Some screened projects included a reference to the FIT scheme in place but otherwise this kind of information has not been extracted from the screened projects.

For further information about the IEA Photovoltaic Power Systems Programme and Task 13 publications, please visit www.iea-pvps.org.

IEA INTERNATIONAL ENERGY AGENCY

ISBN 978-3-906042-46-6

9 783906 042466 >