Full-spectrum economic optimization of a solar PV park

António Miguel Gonçalves Farracho

Thesis to obtain the Master of Science Degree in

Electrical and Computer Engineering

Supervisor: Prof. Rui Manuel Gameiro de Castro

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Declaration

I declare that this document is an original work of my own authorship and that it fulfills all the requirements of the Code of Conduct and Good Practices of the Universidade de Lisboa.

- Audaces fortuna juvat

Acknowledgments

I would like to start by thanking Professor Rui Castro for all the guidance, availability, and opinions on the key stages where I started to lose focus on the objective and target of this work.

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O que me move é poder deixar-vos orgulhosos.

Abstract

With the strong growth of the solar industry and utility-scale PV parks - both in number and installed capacity - project finance and engineering are getting an increasingly important role in the future performance definition of the asset to be developed. Optimization of a solar PV park is usually performed with a view to maximize the annual energy yield. However, the main goal of power plant owners is maximizing the profit of the investment. This dissertation aimed at using simulation data based on the real-case scenario of a large-scale PV park under development to conduct and link the above-mentioned approaches, analysing the problem and developing tools/instruments that directly relate input parameters with economic variables. Conducted works cover tracking systems deployment, DC/AC ratio definition, string length sizing and the usage of bifacial modules. The developed economic model, complemented by PVSyst simulations shows that in the studied case the strongly adopted configuration of horizontal single-axis tracking underperforms a fixed-tilt configuration, with a decrease in IRR and NPV from 7.56% to 4.03% and from 4.64 M€ to -8.83 M€. DC/AC Ratio optimum point was found for ratio values in the 1.30 to 1.35 range. The optimization from a 1.24 ratio to the mentioned range translated into an NPV increase from 4.64 M€ to 4.92 M€, with similar IRR. String length extension from 25 to 28 modules resulted in a 11.80% Energy Yield increase, and IRR and NPV grew from 6.71% to 7.56%, and from 1.96 M€ to 4.64 M€, respectively. Fixed-tilt bifacial was found to improve project IRR from 7.56% to 7.66% if a 10% cost premium is considered on the bifacial module when compared to a similar monofacial solution.

Keywords: Utility-scale solar PV park, optimization, technical parameters, economic variables

Resumo

Com o forte crescimento da indústria solar e dos parques fotovoltaicos de grande escala - tanto em número como em capacidade instalada – a estrutura financeira dos projetos e a engenharia estão a assumir um papel cada vez mais preponderante na definição do desempenho futuro do ativo a ser desenvolvido. A otimização de um parque solar fotovoltaico é geralmente realizada com o objetivo de maximizar a sua produção anual de energia. No entanto, o objetivo principal dos proprietários passa por maximizar o lucro do investimento. Esta dissertação teve como objetivo utilizar dados de simulação baseados no caso real de um parque fotovoltaico de grande escala, em desenvolvimento, para conduzir as abordagens acima mencionadas, analisando o problema e desenvolvendo ferramentas e instrumentos que relacionem diretamente os parâmetros técnicos com as variáveis económicas. O trabalho desenvolvido cobriu a utilização de seguidores solares, a definição do rácio DC/AC, o dimensionamento da *string* de módulos e a incoporação de painéis bifaciais no sistema. As simulações realizadas mostram que, no caso estudado, a configuração cada vez mais adotada com seguidores de eixo horizontal apresenta um desempenho económico pior que uma configuração de estrutura fixa, com uma diminuição da TIR e do VAL de 7.56% para 4.03% e de 4.64 M€ para -8.83 M€. O ponto ótimo para o rácio DC/AC foi encontrado para valores entre 1.30 e 1.35. A alteração de um rácio de 1.24 para o intervalo mencionado traduziu-se num aumento do VAL de 4.64 M€ para 4.92 M€, a uma TIR constante. A extensão do comprimento da string de 25 para 28 módulos resultou num aumento de 11.80% na energia produzida anualmente, sendo que a TIR e o VAL aumentaram de 6.71% para 7.56%, e de 1.96 M€ para 4.64 M€. Concluiu-se ainda que a utilização de módulos bifaciais em estrutura fixa resultou num aumento da TIR de 7.56% para 7.66%, considerando um aumento do custo do módulo bifacial em 10% comparativamente com uma opção monofacial.

Palavras-chave: Parque solar PV de larga-escala, otimização, parâmetros técnicos, variáveis económicas

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List of Acronyms

AC	Alternate Current
APREN	Portuguese Renewable Energy Association
BG	Bifacial Gain
BoS	Balance of Systems
CAPEX	Capital Expenditure
COD	Commercial Operation Date
DC	Direct Current
DGEG	Directorate-General of Energy and Geology
DL	Degradation Loss
DPBP	Discounted Payback Period
EIA	Environmental Impact Assessment
ESG	Environmental, Social and Corporate Governance
GCR	Ground Coverage Ratio
HSAT	Horizontal Single-Axis Tracking
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IRR	Internal Return Rate
KPI	Key Performance Indicator
LCOE	Levelized Cost of Energy
LID	Light Induced Degradation
MPPT	Maximum Power Point Tracking
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
OPEX	Operation Expenditure
PAC	Provisional Acceptance Certificate
PPA	Power Purchase Agreement
PR	Performance Ratio

PV	Photovoltaic
RAN	National Agricultural Reserve
REN	National Ecological Reserve
RTB	Ready-to-Build
SCADA	Supervisory Control and Data Acquisition Systems
SEIA	Solar Energy Industries Association
SEN	National Electric System
STC	Standard Test Conditions
TMY	Typical Meteorological Year
TRC	Capacity Reserve Title
USA	United States of America

1. Introduction

1.1. Motivation

Over the last ten years, photovoltaic solar energy industry has assumed a central role in the global energy scene, being recognized as one of the greatest weapons against climate change [1]. Since 2015, the cost of the elements required for producing solar energy has been declining significantly [2].

Levelized Cost of Energy (LCOE) has also reflected this consensus. This indicator allows measuring and comparing the total cost of producing a unit of energy using a given technology. In 2020, the LCOE of large-scale solar production technologies dropped, for the first time, below the LCOE for Combined Cycle Power Plants. As shown in Table 1, along with wind power, it is today the cheapest technology available to produce electricity [3].

Table 1 - LCOE evolution between 2010 and 2020 [3]

Energy Source	2010 Cost per MWh [USD]	2020 Cost per MWh [USD]	Change at Midpoint
Wind	99 - 148	26 - 54	(68%)
Solar (Utility)	226 - 357	29 - 42	(88%)
Gas Combined Cycle	67 - 96	44 - 73	(28%)
Nuclear	77 - 144	129 - 198	71%
Coal	69 - 152	65 - 19	1%

According to IRENA[1] data, collected from more than 17,000 projects in 2019, solar production costs have fallen by 82% since 2010. In what regards to photovoltaic modules, the cost has fallen by 90% since the same year, accompanied by a decrease in the Balance of Systems (BoS) costs – the set of costs associated with wiring, mounting racks, solar inverters, among other necessary elements – making the entire value chain more competitive [4].

Figure 1 illustrates the evolution of the different costs involved in a photovoltaic project. As observed, these have been decreasing strongly in the last decades.

[1] IRENA – International Renewable Energy Agency.

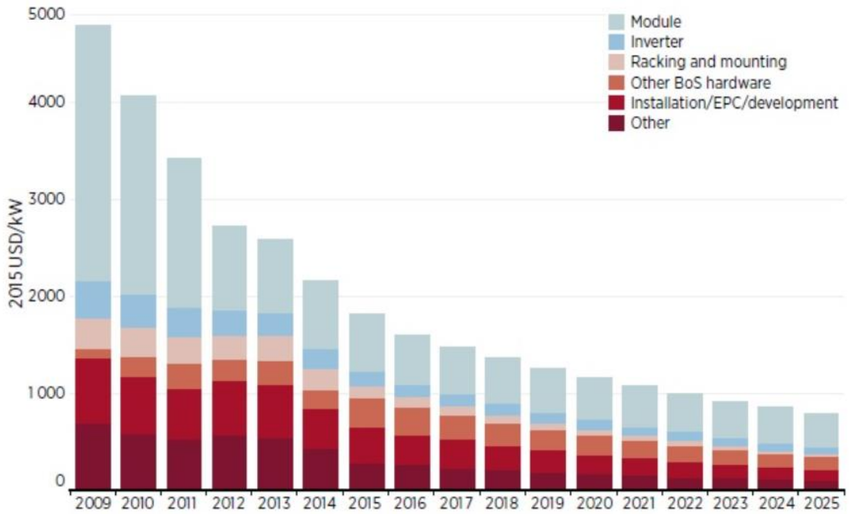

Figure 1 - Global weighted average utility-scale PV installed costs, 2009-2025 [4]

The year of 2015 is also key for energy policies. On top of the technological developments, Paris Agreement brought the need for a renewed effort from signing countries to incorporate a greater percentage of renewable energies in their energy mix. In Portugal, this means emitting a maximum of 11.9 million tons of CO_2 equivalent – an 80% reduction of current emissions, of which around 70% are originated in the energy sector [5].

Today, solar energy is gathering interest from all sectors, including investors typically dedicated to financial assets in the past. Most of the investors are now looking at large-scale photovoltaic projects as low-risk opportunities where they can allocate dozens of millions of euros with guaranteed returns. This is achieved via Power Purchase Agreements (PPA), contracts signed for long periods standing as investment alternatives with no obvious competitor [6].

In 2019 and 2020, the Portuguese Government has launched solar capacity auctions, reiterating this appetite. Portugal established a new record-low price for electricity selling in 2019, by assigning a development lot for a solar project with a guaranteed sale price of 14.76 € per MWh. In 2020, this record was renewed with a sale price of 11.14 € per MWh [7]. These values allow one to understand the current panorama of production costs and how competitive it can become to produce photovoltaic energy at an utility scale. In comparison, in 2019, the average Iberian price on the wholesale market was around 50 € per MWh [8].

All aspects considered, a race for solar energy is on the run, a phenomenon that Portugal has not been indifferent to. In the first half of 2021, more than a dozen projects, each with an installed capacity exceeding 50 MWp, entered the process for environmental licensing [9]. During this six-months period, the Portuguese Environment Agency has assessed the licensing of a photovoltaic capacity higher that the capacity already built and currently operating in the country [10].

Among this uproar, arises Galp. Historically an oil company, Galp was impelled by the free market and consumer trends - accelerated by the Covid-19 pandemic - into a new area of business. In 2020, the company purchased a stake in a pipeline of photovoltaic projects from the Spanish company ACS, becoming the largest photovoltaic energy player in the Iberian Peninsula, with a portfolio of 2.9 GW of projects in different development stages [11]. One of the most relevant projects in Galp's portfolio is Alcoutim Solar Photovoltaic Park, which entered construction phase in March 2021. With 144 MWp, it comprises Pereiro, Albercas, São Marcos and Viçoso plants - the latter being the plant this dissertation focuses on. Following the same footsteps, other majors in the sector already have some projects underway in Portugal [12].

The structural changes affecting solar energy industry are not exclusive to Portugal. Although the country's endogenous resources can leverage solar technology very efficiently, the same happens across most of Mediterranean countries, North Africa, and the Middle East. Also, most of these countries have less restrictions and more available area for implementing this type of projects. For this reason, the growth pains in the solar industry have been even more significant, with thousands of GW yet to be licensed, developed, and built.

Auction procedures like the ones mentioned above also translate in the lack of time to develop and mature the engineering phase, due to tight deadlines to accomplish all licensing phases. This combined with the absence of a solid historical record for solar technologies, appear as authentic Achilles' Heels, symptoms that the existent parks may not have been developed to the fullest of their capabilities. Although these projects have an average lifespan of 30 years, technology evolution is striking from year to year. The sharp fall in the cost of equipment used in photovoltaic power plants, especially during the last 5 years, makes all previous economic studies almost obsolete. Projects that are now entering exploration phase are conceived, on average, 3 to 4 years in advance, which is enough time to make some of the initial permissions unfeasible and force the review of multiple choices made along the way.

In early 2010's, increasing the efficiency of large-scale parks was particularly dependent on increasing the efficiency of photovoltaic cells. At the time, technology was relatively simple and well documented. Nowadays, the available options and different possible configurations for the construction of a park are tremendously higher and the design decisions in the engineering and feasibility phase can significantly impact the plant's efficiency.

This thesis aims to break this challenge into segments and present an objective analysis, while safeguarding project constraints such as geography, terrain topography, etc., that limit the range of techniques that can be used in different locations.

1.2. Objective

The profitability of a solar energy park is closely linked to its Energy Yield. However, most references that discuss the same technical decisions to be presented in this thesis solely focus on increasing energy production at any cost. The introduction of bifacial modules that use irradiance reflected on the ground is naturally linked to more energy produced. The same applies to the use of one-axis and dual-axis trackers, which inevitably increase the Energy Yield of the parks. The existing literature discusses and clearly explains this variation (Table 11), but references that incorporate its impact on the LCOE are scarcer, and this is precisely the most significant parameter for investors.

This dissertation aims at analysing the sensitivity of economic parameters to the variation of the most important technical parameters in the design phase of a large-scale photovoltaic park. A technical and economic optimization will be presented, to quantify and discuss the trade-offs between additional yield and additional investment. For this, PVSyst software is used to carry out multiple simulations using data provided or validated by Galp Energia for the Alcoutim Solar Photovoltaic Park. The project decisions to be discussed in the subsequent chapters are the most relevant technical options to be made, during the design phase of a large-scale photovoltaic park, namely:

- use of single-axis or dual-axis solar trackers;
- definition of DC/AC Ratio – ratio between installed peak power and grid injection power;
- definition of the number of modules in series in each string;
- use of bifacial modules.

In each scenario, the financial model developed is used in parallel with PVSyst simulations for Annual Energy Yield (in MWh). This model – which comprises an Excel spreadsheet designed specifically for this purpose – is used to analyse the following economic parameters:

- Net Present Value (NPV);
- Internal Return Rate (IRR).

As a result, a complete analysis is obtained that brings together the technical and economic components. Merging all these elements, this dissertation also intends to:

- Detail the background and conditions associated with the several considered technical options;
- Calculate and model the economic variations caused by each technical decision;
- Conclude on the economic feasibility of each technical configuration;
- Analyse the impact of the technical options on the project's economic feasibility;
- Benchmark the project against industry standards and examples in Portugal.

1.3. Thesis Outline

This thesis is divided in seven distinct chapters. In this first chapter the motivation and objective of the work are described, and the reader is also introduced to the context in which this study appears.

Chapter II provides a review of the state of the art through the analysis of studies that have already been carried out with the aim of cross cutting the financial performance of the various technical decisions.

Chapter III addresses the applied method by describing the developed financial model, as well as the parameters used for the simulations carried out in PVSyst software.

Chapter IV comprises two sections, the first making a quick overview of left out important technical decisions, and the second dedicated to providing a theoretical framework for each of the considered technical variations, together with the analysis of the studied technical options and their corresponding impact.

Chapter V contains the simulation offtakes of this work. Here, results are analysed, and the economic model parameters are studied and compared.

Chapter VI compiles information on all major photovoltaic projects that entered the environmental licensing phase during 2021 in Portugal, providing an overview of the technical decisions currently being taken by promoters and subcontractors in projects under development, framing them against the results obtained in this study.

Chapter VII includes the conclusions and some indications on relevant future work.

2. Literature Review

The existing literature regarding solar energy production parks focuses mostly on the optimization of Energy Yield – or other technical parameters –, without providing relevant insights into the economic impacts associated with such optimization. Moreover, the existing literature is comparatively much sparser in studies that integrate both components. Still, some studies reviewed in this chapter cover this analysis, even though one parameter is exclusively focused at a time. There is an almost transversal absence of studies that concatenate multiple parameters in different areas and project timings to offer an integrated view of the various challenges during the engineering phase of this type of plants.

This difficulty in finding relevant articles is also related to the scale of the parks being the object of study, since it is possible to observe several works published with application to projects for self-consumption (up to 3 kW) [13], self-sufficient communities or commercial rooftop photovoltaic modules (PV) (up to 100 kW) [14], and small power plants (with a few hundred kW, but less than 1 MW) [15]. Applications to practical cases of utility-scale plants are scarcer, given that their proliferation is a more recent advent, and their study is still quite limited to the industry itself. This work seeks to help fill this gap.

Another factor of inadequacy of the studies already published is the aggressive change in the costs associated with the technological elements of the project, in line with the data seen in the introduction to this work. A 90% drop in the cost of photovoltaic modules since 2010 makes the permissions of most technical-economic analysis obsolete. In one of the studies to be detailed further ahead, also carried out on a large-scale project in Portuguese territory, Miguel Silva [16] presents a value for the cost of PV modules of 0.306 € per Wp, corresponding to 51% of the total cost of installed power. This value contrasts with just 0.18 € per Wp of market values validated by Galp[2], corresponding to only 30% of total costs.

Given that this is a type of project with capital expenditure (CAPEX) in the range of several dozens of millions of Euros, the weight of policy mechanisms and country financial support is also addressed by some studies [17]. These approaches consider both the perspective of feed-in tariffs and of support for initial investment. The specific realities of each country in terms of support policy have, as expected, a strong impact on the results obtained and on the feasibility of implementing the different technologies available. Augusto Bianchini, Michele Gambuti et al. [18] analysed the performance and economic parameters of eight small photovoltaic systems with different tracking mechanisms in Italy, to conclude that tracking systems can be a more viable option considering the Italian tax deduction of 50% applied to the initial investment.

After overcoming the limitations in the nature of the analysed studies, there are still some publications with relevant components. Miguel Silva [16] conducts an optimization study of a Large-Scale Power Plant, although in a different approach regarding some of the technical parameters – DC/AC ratio was

[2] All economic data published in this dissertation was based on literature and market values validated as applicable by Galp Energia and do not necessarily imply real project data.

not optimized, for example, following instead a standardized approach. Also, the economic viability maximization and specifically the values for the variation of CAPEX and operational expenditure (OPEX) with the different technologies were directly supplied by the partner company without an analysis and benchmarking of the industry values having been carried out.

In another study, Hayat Ullah, Ijlal Kamal et al. [19] evaluate and compare several possible sites for solar projects from a technical and economic point of view, a component that this study did not consider as the land for the Alcoutim Photovoltaic Park project was already leased and is always distance dependent to the substation where the company obtained a Capacity Reserve Title (TRC), which in this case was the Tavira substation. Proposing alternatives would involve an extensive bureaucratic process of new electrical licensing with the Directorate-General of Energy and Geology (DGEG), which would make the process unfeasible. Once again, a change in the proposed land would also imply a more appropriate assessment concerning spatial planning.

Some studies have tried to include an even broader approach, but in different directions: Lisa Ryan, Joseph Dillon et al. [20] propose a multidisciplinary approach that considers, in addition to the technical and economic component, the maximization of social welfare and benefits for the final consumer, presenting contributions made by the projects in this aspect as important advantages to be taken into account, together with a LCOE based analysis. The interest in conducting this type of approach has already been mentioned by the Portuguese Renewable Energy Association (APREN) [21] as one of the relevant criteria that should be implemented in the Portuguese Government's Solar Auctions.

Regarding the DC/AC ratio, several studies aimed at perceiving the effect of oversizing on the economic viability of projects. Jayanta, Deb & Mondol et al. [22] explored the optimization of PV/inverter sizing ratios in multiple locations in Europe, concluding that the optimum ratio varied from 1.1 to 1.3. The takeaways were obtained changing the inverter's input rated capacity and keeping PV rated capacity constant, an approach that is substantially different from the one carried out in this study. In this context, the inverter rated capacity was kept the same while more modules were added or removed from the PV array. A similar approach was proposed by Tamer Khatib [23] using an iterative method to obtain an optimum DC/AC Ratio *of 1.42 for a 30 kWp* PV array, although the optimization process used was based entirely on the maximization of conversion efficiency based on irradiance and temperature values and did not consider any economic input.

In what the maximum number of modules in series is concerned, thoroughly developed studies are scarce and the subject appears often as an under explored optimization in specialized magazine articles. Charles Ladd [24] explores maximum voltage calculations based on manufacturer-provided temperature coefficients, stating that they are unnecessarily conservative, and offering room for optimization. A statement supported by Bill Brooks [25], that explains that the record low temperature is usually too conservative for design calculations because temperature is only one of two major factors that impact array open-circuit voltage – the other being irradiance. These are theoretical concerns that raise relevant points but do not translate into a practical exercise of optimization. That type of practical approach is developed in the work conducted by Karin, Todd and Jain, Anubhav [26]. Here, a new methodology is proposed to develop longer strings and therefore lowering total system costs. Using historical weather data, strings are projected with a size around 10% longer while still maintaining system voltage within the electrical limits.

Regarding the optimization of systems using bifacial modules, most of the research work focused on developing tools to quantify Bifacial Gain (BG) and Bifacial Systems Energy Yield, without considering the associated economic impact on project costs. M. Tahir and Sojib Ahmed [27] explored different combinations of monofacial and bifacial modules with fixed-tilt and tracking configurations, considering the effect of latitude on the gains. For latitudes less than 50º, an East/West horizontal single-axis tracking bifacial PV farm is the best design in terms of Energy Yield. The study misses the opportunity of including a fixed-tilt monofacial option, and only computes LCOE in a module to land perspective used to calculate optimum pitch, without considering the impact of tracking or bifacial technologies on the costs.

Rodriguez-Gallegos, Haohui Liu et al. [28] computed single-axis tracking bifacial LCOE in multiple locations across the globe, comparing it to dual-axis tracking bifacial. Although the energy produced was higher on the second type of system, the LCOE was lower for single-axis given the associated initial investment and operation and maintenance (O&M) cost. Talavera, D.L. & Muñoz-Cerón et al. [29] also studied the cost-competitiveness of five PV projects with the same objective as the present study: understand the optimum balance between the additional costs of trackers and yield increases. Although the study has the merit of being conducted with the novelty of including reference to electricity tariffs, that information is not relevant to the present study as a fixed PPA price is assumed for electricity in this case. Conclusions state that all five projects registered a lower or equal LCOE for the fixed-tilt solution, but the study points out that for similar LCOE, it is preferable to install a single-axis tracking PV system due to its higher Energy Yield.

The higher costs of tracking systems are also addressed in a study from the American National Renewable Energy Laboratory (NREL), by Lars Lisell and Gail Mosey [30], that emphasizes the difference in O&M expenditure between fixed and tracking systems. The work concludes that the necessary moving parts and higher rate of demanded maintenance was found to result in a 100% increase in the operational expenditure of tracking systems when compared to fixed ones. Regarding extra unusual variables to be analysed while assessing the viability of fixed versus tracking systems, Adinoyi, M. et al. [31] point out that tracking systems can be beneficial in reducing dust accumulation by 50% due to the motion, an effect that helps counter-balance the higher temperature of modules that use trackers.

As mentioned on the section opening, complete approaches that include multiple parameters of the wide range of technical decisions available are scarce. By proposing four different variations to the base-case of a project under development, this work aims at making a bridge between scattered techno-economical optimizations and industry knowledge, with a full-spectrum approach that measures the sensitivity of economic variables to selected technical parameters.

3. Simulation Conditions

3.1. Technical Assumptions

This work had the main objective of proposing an approach that could integrate multiple components of the engineering process of a solar PV park, using PVSyst software as a simulation tool.

PVSyst is a widely adopted software in the photovoltaic industry, by both companies and academics. Its models are highly accepted by entities that conduct due diligence work for financing and M&A[3] operations, ensuring a strong adoption by project sponsors [32]. Several studies have compared other software alternatives, to conclude that PVSyst is one of the most accurate when considering simulation results with actual plant operation data [33]. The software allows one to recreate distinct configurations of a photovoltaic park with great technical detail, importing characteristics of modules and inverters, and then simulating key parameters such as Energy Yield, Specific Production and Performance Ratio.

The Performance Ratio (PR) is an important parameter and often used to evaluate and compare the efficiency of PV parks, as its results include the variation on irradiance across different sites. It consists in the ratio between effectively produced energy (E_{grid}) and the energy that would be produced at module rated efficiency (STC), as described by equation ((1)):

$$\mathrm{PR} = \frac{E_{grid}}{H_t \times \mathrm{A} \times \eta} \tag{1}$$

where η is the module efficiency on STC, A is the module area and Ht is the total in-plane irradiation.

Additionally, PVSyst also incorporates the option to import data from meteorological databases. In this dissertation, and as it will be further seen ahead, meteorological details to be considered were collected by a partner company and converted into a reference meteorological year for the project site. This includes data such as the hourly values of irradiance, temperature, and other meteorological parameters.

The inputs required by PVSyst were provided by Galp, and are the following:

- PV module: JKM570M-7RL4-V by Jinko Solar[4] (technical specifications shown in Table 2)
- String Inverter module: Sungrow SG250HX[5] (technical specifications shown in Table 3)
- Sub-array configuration, i.e. different distributions of strings between inverters

[3] M&A – Mergers and Acquisitions
[4] Jinko Solar is one of the world's largest PV manufacturers, considering exported total power [111].
[5] Sungrow is one of the largest manufacturers in producing inverters for the photovoltaic industry [112].

Table 2 - Technical characteristics of the module as configured on file sent by Galp Energia

Electrical specifications: PV Module	
Size (mm)	2411×1134×35mm
Maximum Power (P_{max})	570 Wp
Maximum Power Voltage (V_{mp})	44.09 V
Maximum Power Current (I_{mp})	12.93 A
Open-circuit Voltage (V_{oc})	53.32 V
Maximum system voltage (V_{DC})	1500 V
Technology	P-type Mono-crystalline
Short-circuit Current (I_{sc})	13.61 A
Temperature coefficients of Pmax	-0.35%/℃
Temperature coefficients of I_{sc}	0.048%/℃
Temperature coefficients of V_{oc}	-0.28%/℃

Table 3 - Technical characteristics of string inverter Sungrow SG250HX [34]

Electrical Specifications - Inverter	
Max. PV input voltage	1500 V
Min. PV input voltage	500 V
Start-up input voltage	500 V
No. of independent MPP inputs	12
Max. PV input current	30 A x 12
Nominal PV input voltage	1160 V
MPP voltage range	500 V – 1500 V
MPP voltage for nominal power	860 V – 1300 V
Max. input connectors per MPPT	2
Max. DC short-circuit current	50 A x 12

This information allowed one to structure the base-case, a concept that will be referred to several times across the sections of these works. The base-case consists of the project configuration as it was originally projected and as it will actually be built[6]. The base-case is a 47,992 kWp project, using fixed-tilt structures at an angle of 20º with 28 monofacial modules in each string. The DC/AC Ratio[7] is of 1.24, and considered albedo value is of 0.2.

PV System Degradation Rate

The goal of this dissertation is to study the impact of several technical variations in terms of energy production and economic impacts across project lifetime. To do this, not only the Energy Yield value in the first year of operation should be determined, but also its value over the 30-year period that follows the Commercial Operation Date (COD) of the park. To accomplish this, a key component of PVSyst to be used is the PV Degradation Rate, which allows the simulation of equipment aging, considering a progressive loss of efficiency, represented in the simulations as the Degradation Loss (DL) factor.

The causes for this degradation are numerous and mostly related to the adverse environmental conditions to which the photovoltaic modules are exposed during its operation lifetime. Moreover, the decrease in production occurs due to the aging of every component in the system and is strongly dependent on local conditions, being subject to different types of mechanisms. The influence of heavy rain and exposure to high temperatures, for example, has a significant impact on antireflection coating deterioration, hardening of the crystalline silicon, microcracks on the panel, frame corrosion, and cell contamination. The correct degradation rate prediction is a complex computation task dependent on a high number of variables, as subsequently discussed [35]–[38].

To limit these uncertainties, as industry standard, the warranty provided by brands ensures a maximum loss of efficiency of 20% after 25 or 30 years of operation, depending on the manufacturer. This limit represents the worst-case scenario for the degradation loss factor, which corresponds to an annual loss of 0.8% in the case of 25 years. Variations to this progression are common and depend on the model and manufacturing process, as per the different slopes presented in the charts illustrated on Figure 2.

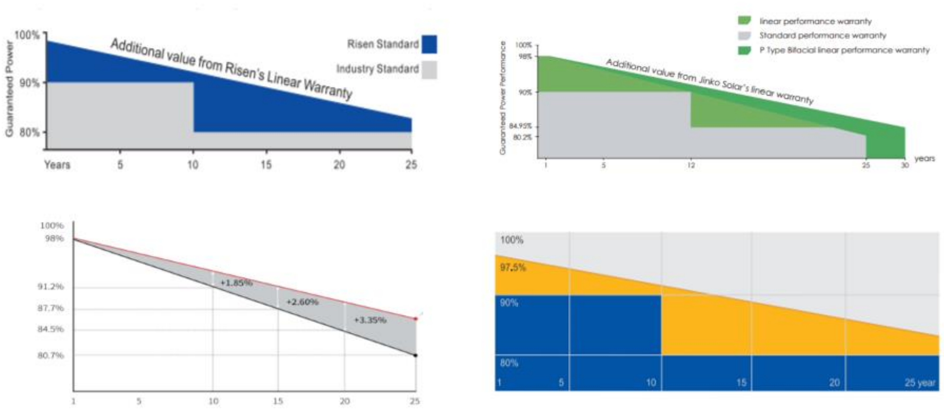

Figure 2 – Examples of efficiency loss representation in terms of percentage per year, estimated from multiple manufacturer's warranty charts

[6] Changes during development phase can still occur.
[7] DC/AC Ratio is the quotient between the DC power installed in PV modules and AC power installed in inverters, a concept that will be further develop on Chapter 4.

Over the lifetime of a project, the initial loss is referred to as Light Induced Degradation (LID). It consists in the loss of performance in the first operation hours, until stabilization is reached, derived from the initial exposure to the sun that affects the functioning of the crystalline modules. In this period, there is a discrepancy between the actual power and the power measured in the factory under Standard Test Conditions (STC[8]). According to PVsyst documentation, this value ranges from 1 to 3%.

PVSyst also allows defining additional parameters for the Gaussian distribution of the different degradation factors in each module, since not all have the same rate. These discrepancies in the individual degradation factors cause the so-called "mismatch losses", determined by the software via a Monte-Carlo stochastic method. For simulation purposes, the default values of the program were considered. The impact of these parameters on the modules' efficiency in a 30 years simulation is depicted in Figure 3, where "Basic degradation" is the user-defined annual degradation slope in percentage per year, to which the mismatch effect is added, being depicted by the orange line. The black line represents the bottom limit of the manufacturer warranty.

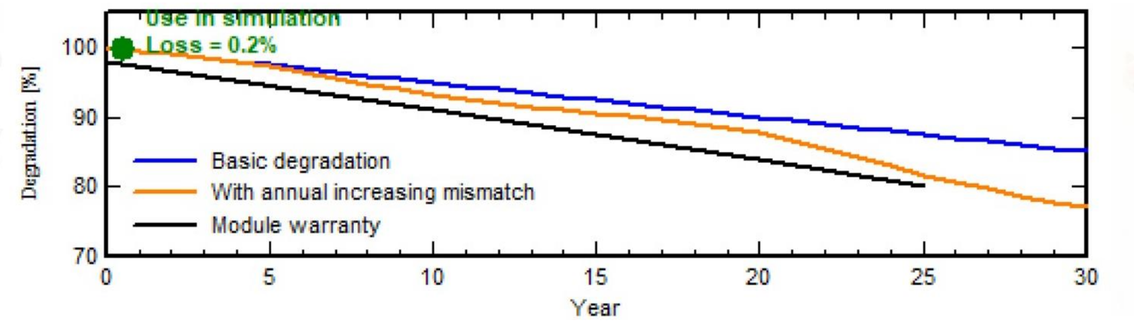

Figure 3 - Module degradation evolution over project lifetime – PVSyst Project

The range of values predicted in literature for the annual degradation factor is wide. A 2016 study by the American NREL [39] found that, on average, production drops 0.5% each year. Some manufacturers guarantee, in fact, lower degradation rates - around 0.3% - and the industry trend is to further minimize this value. Although the analyses with real data on the effects of the long-term degradation are still scarce, some studies considered the possibility of obtaining degradation rates in the order of 0.3%/year [40]. Others actually measure these values after long term exposure of PV modules, as the example of the analysis on the performance of a 70 polycrystalline silicon array of the same manufacturer which concludes that after almost 20 years of outdoor exposure, the average yearly degradation of the PV modules was only 0.24% [41].

However, these low value degradation rates and the 0.4% PVSyst assumption are questionable considering studies published in recent years - several publications show some concern about the real value recorded when modules are installed and operating. A report recently prepared by kWh Analytics [42] – and summarized in Table 4 – explores the main risks incurred by large-scale projects, and warns

[8] STC - 25°C of cell temperature, 1000 Watts of solar irradiance per square meter.

that solar assets have been recording degradation rate values higher than expected, approaching 1%. The data present in the report point to a median annual degradation for residential solar systems of 1.09% and non-residential systems of 0.8%.

Table 4 - Summary of recent studies conclusions on PV Degradation Rates [42]

Authors & Date	Analysis Type	Site Type	Measurement Point*	Yearly Degradation
Current Industry Assumption				
NREL (Jordan et al.) 2016 [39]	Meta-analysis (200 studies)	Commercial & Industrial, Residential, and Utility	25% System 75% Module	Median: -0.5%
Latest Research				
NREL (Deceglie et al.) 2018 [43]	RdTools	Commercial & Industrial and Residual	System	Median: -1.2% residential -1.0% non-residential
LBL (Bolinger et al.) 2020 [44]	Fixed effects regression	Utility	System	Mean: -1.1% Sigma: +/-0.2%
NREL (Deline et al.) 2020 [45]	RdTools	Commercial & Industrial and Utility-scale	Inverter	Median: -0.72%
kWh Analytics 2021 [42]	RdTools	Commercial & Industrial and Utility-scale	System	Median: -1.09% residential -0.80% non-residential

The same issue is confirmed by Phinikarides [46], who considers an annual degradation rate of 0.78 to 1.3% under Mediterranean weather conditions, and by Ishii [47], who refers an annual degradation rate of 1.9 to 2.8% under icy desert conditions. Such a wide range – from 0.27 to 2.8% – has a significant long-term impact. As per these figures, a module with a degradation rate of only 0.3% will operate in the second year with an efficiency of 99.7% if LID effect is not considered, and in the 29th year at around 90%. Likewise, a module with a 1% degradation rate will be operating in year 29 with an efficiency of only 70%. If the degradation rate is 2.8%, efficiency would drop below 75% in ten years, making the project unfeasible. Therefore, the impact of this variation on the economic results of a project can jeopardize its viability.

Given the absence of a paradigm establishing an accurate value to be considered, this dissertation keeps in line with industry-standard value of 0.5%, slightly above the 0.4% PVSyst standard value. There is also a value of 1% considered for LID losses.

Other section-specific assumptions in PVSyst were considered during simulations carried out for configurations using trackers, bifacial modules, and others. They are described in due course as they get relevant in each chapter.

The software then allows running a simulation for a specific year, presenting the results in terms of Energy Yield and considering the degradation factor for that year, as well as exporting the values in batch for the 30 years of the project, as performed in this dissertation.

3.2. Economic Assumptions

In order to analyse the economic performance of each simulation carried out and to calculate all the parameters mentioned in Chapter 1, an economic model was developed with Microsoft Excel tools. This choice was made at the expense of the economic analysis tools that PVSyst incorporates. The use of a spreadsheet allows greater flexibility and the manipulation of considered assumptions, as well as a better understanding of the calculations to be carried out, with much more documentation and support than what is available for the economic module of PVSyst.

The economic assumptions for the project were literature and market values validated as applicable by Galp and considered in the analysis as a starting point for the optimization. These assumptions are listed in Table 5 and consist of the three main pillars for the economic analysis of a project.

Table 5 - Project economic assumptions

Project Parameters	
Discount rate [%]	6%
Project's lifetime [years]	30
Energy price [€/MWh]	38

Discount Rate

The discount rate of a project allows for the manipulation and comparison of cashflows – positive or negative – at different moments in time. The value of a cashflow obtained today is different from the same cashflow obtained within 30 years. Thus, given the long-term profile of photovoltaic projects, the discount rate plays a preponderant role in the economic analysis. It reflects the temporal impact on the various cashflows as time goes by, converting this depreciation into cashflow value at the present time.

From a different perspective, the discount rate also represents the opportunity cost of capital, as it represents the minimum revenue expected by investing the same amount in a different asset. Establishing the discount rate for a project is a complex task. The approaches to its calculation are varied, depending heavily on the risk associated to the allocation of capital in this type of investment. This risk arises for several reasons, namely, the possibility of a project that is never materialized, the possibility of the technology to become obsolete, the risk of a project that fails the development phase, that is not feasible or ends having construction or operation errors. All these factors must be considered when determining the discount rate, making it a widely used variable when comparing the financial viability of different ventures.

In this study, the discount rate considered was 6%, which is within the standard values considered in utility-scale PV solar projects [48].

Project Lifetime

Photovoltaic projects include few moving parts, favouring their planning and operation uninterruptedly for at least 25 years. This project duration is related to the degradation factor of the photovoltaic cells and was the standard considered for several years. As seen before, this value derives from the fact that most manufacturers guarantee 80% of the initial production of the modules after 25 years of operation, after which they start to incur significant efficiency losses. This average life expectancy of the project is also mentioned in the lease agreements established with the owners of the land in which a project is to be developed.

Today, the standard has shifted to 30 years [49] – as considered in this dissertation. Financial models now normally include maintenance budget reserves, dedicated to replacing specific equipment such as inverters, which tend to fail sooner than solar modules. As will be discussed in Chapter 6, every project currently undertaking licensing procedures by the Portuguese Environmental Agency foresees a minimum operation lifetime of 30 years. This period is being further extended in projects developed in Spain, where some financial models already predict operation lifespans of 35 to 40 years [50].

Technically, photovoltaic modules continue to operate for many more years than initially foreseen, although at a lower efficiency – a fact that is rarely reflected in the project financial model, as it conditions the necessary financial approvals. As stated before, actual data on the operation of solar plants over 25 years are scarce since current technology did not exist in late 90's and the scale of the projects is changing strongly. Long-term operational data with state-of-art technology is in fact null, but asset lifetime could possibly be extended from the original 25-30 years, to beyond 40 or 50 years [51], [52].

Energy Price

The energy pool value is the price at which the project sponsor believes energy will be sold once operation begins, and is an assumption made still in the design phase of a project. Nowadays, in Portugal, solar energy produced in photovoltaic parks can be sold in one of two ways besides the normal Iberian wholesale market operation.

First, by undergoing a bilateral negotiation of a PPA contract with a buyer – usually a business customer – who has a need for energy supplying with renewable origin. It is a market in large expansion, due to the growing pressure for Environmental, Social and Corporate Governance (ESG) policies, in which this type of contracts based.

Second, via solar energy auctions, as those launched by the Portuguese Government in 2019 and 2020 and in which - in simplified terms and without going into the details of the competition model - companies are legally obliged to sell energy at the price negotiated at the auction, which also includes additional contributions to the National Electric System (SEN).

This solar auction option is not as simple as it may appear since there are several modalities for auctions to be executed. Also, it should be noted that the contracts are established for 15 years and there are companies accepting to operate at a loss in that time just to guarantee a virtual lifetime worth network injection point. The detailed analysis of these conditions is beyond the scope of this work and it is assumed that a PPA contract will be negotiated during the construction phase, which satisfies this initial assumption of 38 €/MWh.

3.3. Project Costs

In addition to the economic assumptions described in the previous section, the most important variables to carry out a complete economic analysis are the values of investment in CAPEX and OPEX. CAPEX was based on literature and market value validated as applicable by Galp, while OPEX value was calculated based on a literature review. These values are then determined in each section considering the proposed variations to the base-case previously described.

CAPEX Costs

The value for the initial investment considered in the calculations is obtained by multiplying the number of peak watts (Wp) installed by the cost per Wp. This cost totals 0.5985 €/Wp and includes the components described in Table 6.

Table 6 - Breakdown of CAPEX costs

PV Costs Breakdown		
Category	**Value [$€/Wp$]**	**Value [%]**
PV Modules	0.18	30.1%
Support for PV Modules	0.095	15.9%
Grid Connection	0.08	13.4%
Settings and Others	0.055	9.2%
Electrical: supply and installation	0.05	8.4%
Inverters	0.045	7.5%
Civil Works	0.045	7.5%
Mechanical Assembly	0.03	5.0%
Insurance	0.013	2.2%
Studies and Analysis	0.0055	0.9%
Transport, Accessories	Included	n/a

As per Table 6, the most significant component is the price of photovoltaic modules, which contributes with almost a third of the total cost. This is followed by racking and mounting structures (identified as “Support for PV Modules Price”), as well as grid connection costs.

As discussed in Chapter 1, despite PV modules costs constituting a considerable portion of the total expenses, these costs have been falling sharply over the last few years. Table 6 serves the purpose of comparing them with a market benchmark, and the percentages presented fit perfectly into the distribution previously presented in Figure 1.

The total value of the investment, however, is much more cost effective than the average for Portugal, which according to IRENA is circa 0.935 USD/W, which corresponds to 0.795 €/Wp at an exchange rate of 1 USD = 0.85 €. This data is further detailed in Figure 4.

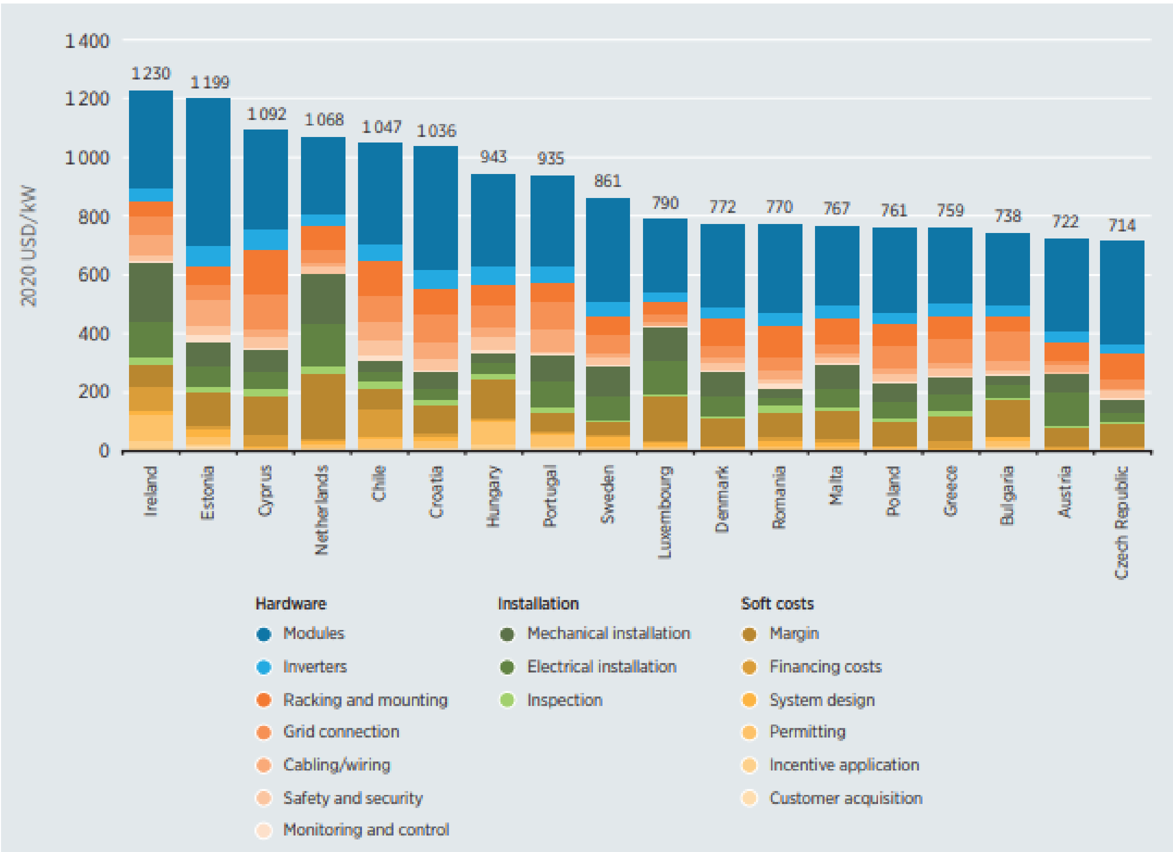

Figure 4 - Breakdown of utility-scale solar costs in selected countries, in 2020 [2]

OPEX Costs

Considered O&M costs were obtained from a literature review of several sources, as shown in Table 7. The average value, which will be considered for fixed-tilt systems, is of 17.039 €/kWp/year.

Table 7 - Literature Review: O&M costs for fixed-tilt systems

O&M Costs	
Source	**Fixed-Tilt [€/kWp/year]**
[53]	20.000
[30]	8.500
[54]	14.195
[29]	2.250
[55]	21.250
Average Value	17.039

Starting from CAPEX and OPEX costs mentioned previously, each technical variation considered in this case-study is accompanied by the respective variation in economic parameters. As an example, O&M costs for tracking systems are higher than those fixed-tilt systems since any moving part entail additional maintenance and replacement cost when compared to a fixed-tilt system. This type of constraints and the assumptions made are explained in detail in Chapter 5, in the results analysis.

3.4. Economic Model

The economic model developed for this case-study includes, as main parameters to be evaluated, the Net Present Value (NPV) and the Internal Return Rate (IRR) already mentioned in Chapter 1. These are the most common indicators considered in the evaluation of such investments and are widely referred in the literature. In this model, the NPV and IRR are sequentially determined, through the respective functions provided by Microsoft Excel.

Net Present Value

NPV is given by equation (2), which consists of the difference between positive and negative cashflows over project lifetime, updated to the current moment as a function of the discount rate defined for the project.

$$NPV = \sum_{j=1}^{n} \frac{R_{N_j}}{(1+a)^j} - \sum_{j=0}^{n-1} \frac{I_J}{(1+a)^j} \tag{2}$$

where n is the analysis period, equal to 30 years, I_j is the investment in year j, and R_{N_j} is the net revenue for year j calculated according to equation (2),

$$R_{Nj} = R_{B_j} - d_{OMj} I_t \tag{3}$$

where $d_{OMj}I_t$ are the O&M costs on year j considering the total installed capacity, I_t. R_{B_j}, the annual gross revenue, was obtained by multiplying the assumed value for the electricity price and the annual simulation obtained through PVSyst, as represented in equation (3). This process was applied for each of the 30 years of project lifetime. The result is progressively lower, with the reduction of the annual Energy Yield of the plant affected by the degradation factor.

$$R_{B_j} = E_{grid_j} \times Energy\ pool\ price \tag{4}$$

The calculus for determining the NPV includes considering the negative cash flow in the first year of the project, as proportional to the initial investment. Again, the value for the initial investment was obtained from literature and market values validated by Galp Energia for the base case to be considered, but it varies widely for the remaining technologies proposed and its analysis is detailed in Chapter 5. Assumptions and references considered in determining a value on Euro per kWp installed for the various technologies are detailed in Chapter 5.

A positive NPV represents three events: 1) a full recovery of the initial investment; 2) earning a premium for risk and opportunity cost - introduced through the discount rate; and 3) earning an additional profit.

Internal Return Rate

The IRR consists of the discount rate to be considered to obtain a null NPV, as shown in Figure 5.

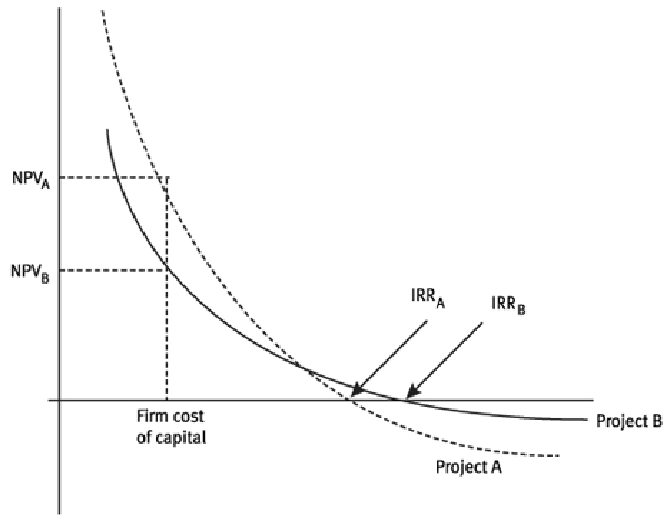

Figure 5 - NPV and IRR relation

A null NPV represents the discount rate that allows for recouping the initial investment and receiving an associated premium, without any additional monetary benefit. As shown in Figure 4, this instrument allows for comparing different projects, in order to improve the allocation of the available capital (from an opportunity cost comparison perspective).

An IRR higher than the discount rate considered in the NPV calculation indicates that the project has a rate of return higher than the minimum required by the investor. The contrary, represents a non-recovery of the minimum amount required as a premium for capital allocation. The expression for the iterative calculation of the IRR, derived from the expression for the NPV, is given by the equation (5).

$$\sum_{j=1}^{n} \frac{R_{N_j}}{(1+IRR)^j} - \sum_{j=0}^{n-1} \frac{I_J}{(1+IRR)^j} = 0 \tag{5}$$

In some situations, two projects can incur in an IRR vs. NPV conflict, where one project shows a higher IRR and the other shows a higher NPV. This is due to the cashflow distribution across the years and the scale of the associated investments. In practice, NPV is an absolute indicator and will only rank projects according to their capacity to provide higher profits without considering the size of the initial investment. In an different way, IRR is a relative indicator which will compare projects based on their return on investment without considering the profit amount in absolute value.

An example of the developed economic model, applied to the base-case is depicted in Figure 6.

Fixed-tilt configuration with DC/AC ratio of 1.15								
i	Energy Yield [MWh]	Cashflow				Discount Rate [%]	NPV [€]	IRR [%]
		RB (ano j) [€]	dO&M (ano j) [€]	RL (ano j) [€]	Total Initial Investment [€]			
1	85065	3232470	759258	2473212	-26823600	6%	4,217,143.12	7.5164%
2	84571	3213698	759258	2454440				-26823600
3	84077	3194926	759258	2435668.16				2473212.16
4	83583	3176154	759258	2416896.16				2454440.16
5	83090	3157420	759258	2398162.16				2435668.16
6	82596	3138648	759258	2379390.16				2416896.16
7	81940	3113720	759258	2354462.16				2398162.16
8	81284	3088792	759258	2329534.16				2379390.16
9	80629	3063902	759258	2304644.16				2354462.16
10	79973	3038974	759258	2279716.16				2329534.16
11	79317	3014046	759258	2254788.16				2304644.16
12	78883	2997554	759258	2238296.16				2279716.16
13	78448	2981024	759258	2221766.16				2254788.16
14	78014	2964532	759258	2205274.16				2238296.16
15	77579	2948002	759258	2188744.16				2221766.16
16	77145	2931510	759258	2172252.16				2205274.16
17	76639	2912282	759258	2153024.16				2188744.16
18	76132	2893016	759258	2133758.16				2172252.16
19	75626	2873788	759258	2114530.16				2153024.16
20	75120	2854560	759258	2095302.16				2133758.16
21	74613	2835294	759258	2076036.16				2114530.16
22	73654	2798852	759258	2039594.16				2095302.16
23	72695	2762410	759258	2003152.16				2076036.16
24	71735	2725930	759258	1966672.16				2039594.16
25	70776	2689488	759258	1930230.16				2003152.16
26	69816	2653008	759258	1893750.16				1966672.16
27	69098	2625724	759258	1866466.16				1930230.16
28	68380	2598440	759258	1839182.16				1893750.16
29	67662	2571156	759258	1811898.16				1866466.16
30	66944	2543872	759258	1784614.16				1839182.16
								1811898.16
								1784614.16

Figure 6 - Illustrative representation of the economic model developed in this dissertation

4. Assessed technical parameters

The work conducted in this dissertation consists of a transversal analysis of both technical and economical parameters, including the necessary theoretical assumptions. This chapter describes the technical concepts that serve as the basis for the optimization conducted and discussed in the following chapters. The technical parameters hereby described constitute the decisions with the greatest impact on the engineering process of this type of projects, and that can be optimized from a technical-economic point of view. Further topics that may also start to be considered on similar analysis as they gain relevance on the market over the next few years are also proposed as complement in Chapter 7.

An introduction to the concept and definition of the term utility-scale photovoltaic park is also purposed.

4.1. Utility-scale Photovoltaic Park

The designation "utility-scale PV park"[9] or "large-scale PV park" has been widely used for several years to refer to the non-domestic production of photovoltaic energy. However, the scale of the projects has been growing without any adaptation in the terminology, which is increasingly important since, as shown in Figure 7, it is estimated that by 2050 this segment will undergo the greatest development in terms of market-share when compared to all other categories of solar photovoltaic technology.

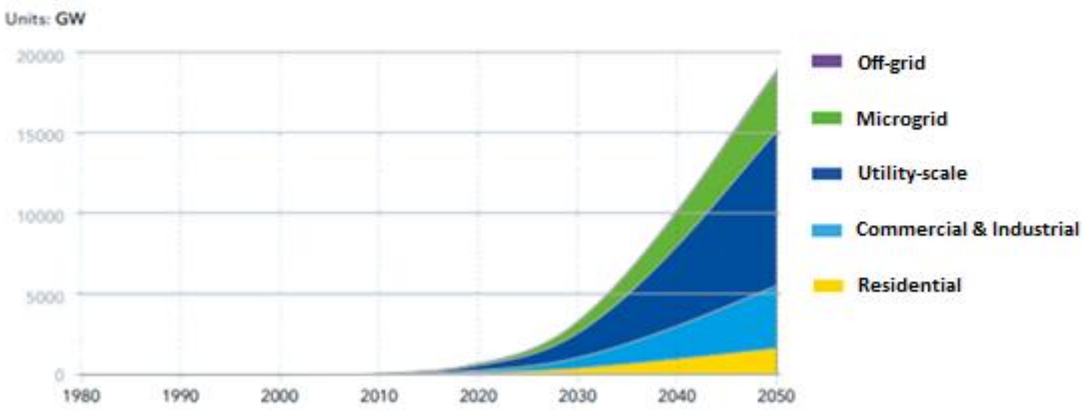

Figure 7 - Global installed capacity estimation by PV category until 2050 [56]

The Solar Energy Industries Association (SEIA), which brings together the main North American producers, defines a project as being "utility-scale" if installed capacity is above 1 MWp [57]. The American NREL considers the threshold of 5 MWp [58], a value reiterated by the World Bank Group, which points out, however, that the classification may vary depending on the country where the project is developed [32].

In Portugal, these values fall under the scope of law decree no. 172/2006, of August 23rd and law decree no. 76/2019, of June 3rd, which classifies all installations with less than 1 MWp as "small production

[9] PV Park stands for "photovoltaic park".

units”. Therefore, 1 MWp is the legal threshold from which the licensing process changes, and a project is classified as a large-scale project. The subsequent legal threshold to consider is the 50 MWp, upon which a project of this nature is subject to an environmental impact assessment procedure.

Nowadays, there are ongoing projects in Portugal in the order of several hundred MWp, and at least one project has surpassed this barrier by proposing the implementation of a solution with 1.2 GWp of installed power [59]. From more than 1 MWp up until 1 GWp there is a significant scale different, but the methodologies to be used are similar and based on the same assumptions and the same economies of scale that make utility-scale projects more cost-effective than the domestic-use cases, as shown on Figure 8. As it will be further detailed, Chapter 6 discusses projects with a scale greater than 50 MWp, due to a matter of information availability, but the conclusions can be extended to any project in the range of a few MWp units up to the large hundreds.

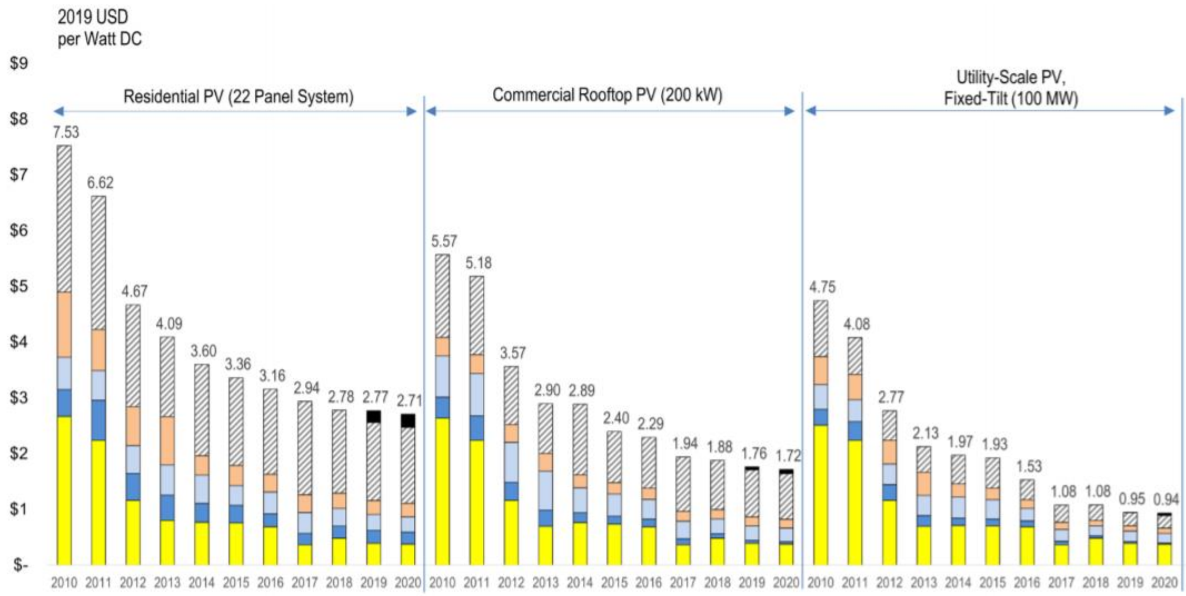

Figure 8 - PV system cost benchmark summary per type of system [60]

Having defined the concept and boundaries of the utility-scale term, an additional review of two usual parameters in the technical definition of these types of projects that are not addressed in the economic study is next presented with the proper explanation for its exclusion from the deeper study. They consist of the string inverter vs. central inverter option, and the fixed structure tilt-angle optimization. After that, the technical background is explained in detail for all four sub-chapters that are considered for the technical-economic optimization: 1) use of tracking structures, 2) DC/AC Ratio, 3) number of modules in series and 4) use of bifacial modules.

4.2. Variables and parameters to be excluded

4.2.1. String Inverters vs. Central Inverters

As it will be further detailed in the next chapters, solar plants are constituted by multiple components that have the ultimate objective of transforming sunlight into usable electricity. In this process, inverters have one of the most relevant roles, as they convert DC power from the PV array into AC power that can be injected into the grid. Two types of inverters are normally used in utility-scale solar power plants: central inverters, which congregate several hundreds of strings and convert the sum of their output power, or string inverters which typically gather only a few dozen strings, converting a much smaller amount of total power.

One of the most impactful decisions in terms of performance and costs is precisely the choice between a string and a central inverter. Although this decision is essential on the engineering process, there are several constraints that make the choice more complex than a simple technical and economical optimization based on an energy yield vs. investment trade-off. Comparing energy yield of both string and central inverters would be possible, but other aspects are harder to compute, namely, size and type of the project, terrain topography, among others, that play an important role and which a simple cost-benefit economic analysis could not reflect. Nonetheless, in economic terms, central inverters are usually more price-competitive (in cost per watt), which leads to greater savings with an increasing size of the project [61]. These constraints are quickly addressed in this section, constituting the main reason why this specification was not considered in this dissertation.

A high number of string inverters offer greater challenges in meeting utility injection requirements such as grid balancing and reactive power injection, nonetheless, the availability of the system is an advantage: a defective string inverter would only result in a small loss of energy production and would not have the impact on a much larger group of modules as it is the case when it comes to the use of a central inverter. In remote locations, such as the building site of the project in scope, service provided by specialized technicians is required for situations when central inverter trips, while string inverters can often be put back into operation by O&M personnel or a qualified electrician. Power electronics are one of the most failure-prone components, and a central inverter trip could cause a capacity unavailability of up to 2 MW in the case of larger central inverters – an anomaly that cannot be left unattended for long periods of times, risking significant energy production losses.

For projects larger than 100 MW, the logistic required for installing thousands of string inverters could jeopardize SCADA[10] integrations, with providers facing complex communication designs and thus offering more expensive contracts dependent on the number of tags to be monitored. In a different perspective, string inverters can add a lot of data granularity and offer a more detailed view on area-specific performance ratios and other relevant KPIs.

[10] SCADA - supervisory control and data acquisition systems.

Site topography is also relevant when choosing between string or central inverters. In sloping terrain construction sites, string inverters can minimize mismatch losses caused by shading and irradiance variance. The reason for this is that, in a string of modules, the lowest current defines the current of the whole string. Therefore, multiple MPPT[11] configurations derived from having multiple strings, tend to minimize mismatch losses as a bigger partition of the system translates into more adaptation to the differences in string performance. In the unfeasible perfect scenario of only one solar module cell per inverter the mismatch would be null.

The decision ends up being a process of weighing preferences and site conditions by the owner or asset manager on a project-specific approach. There is no "one size fits all" framework based on any economical or technical optimization. As mentioned in the previous chapter, the inverter considered in this case-study is a string inverter.

4.2.2. Fixed-tilt optimum angle

The base-case for the simulations to be conducted in this work consists of a fixed structure where modules sit oriented at a specific angle of 20º, usually called the tilt angle. Another point for optimization would then consist of finding the best angle for those structures. Understanding if a different value other than 20º would have an impact on the project economics could be one of the conducted analysis.

This study was excluded since it involves a great component of area related variables. The fixed-tilt angle has an impact on row shading: higher angle values translated in a bigger area covered by shades during some parts of the day. Distance between rows, normally called pitch, would then be an important variable to be analysed on that optimization process. In traditional monofacial systems, this distance is often optimized considering the trade-off between available area limitations, cost of land and the shading caused by additional proximity between modules.

This inter-row shading cannot be fully diminished as at the end of the day shadow lengths usually have an impact on a very long area. Detailed simulations to understand this trade-off can often be conducted considering terrain restrictions and cost of land, but in this case, this type of study would require a complete understanding of terrain limitations, surroundings, and environmental impacts of a higher pitch, reason why it was excluded, with the focus shifting to other 4 important technical decisions. Despite of that, resorting on PVSyst optimization tool, a quick analysis of the best tilt angle considering Energy Yield only was conducted for the base-case, with results presented in Figure 9.

[11] MPPT – Maximum power point tracking.

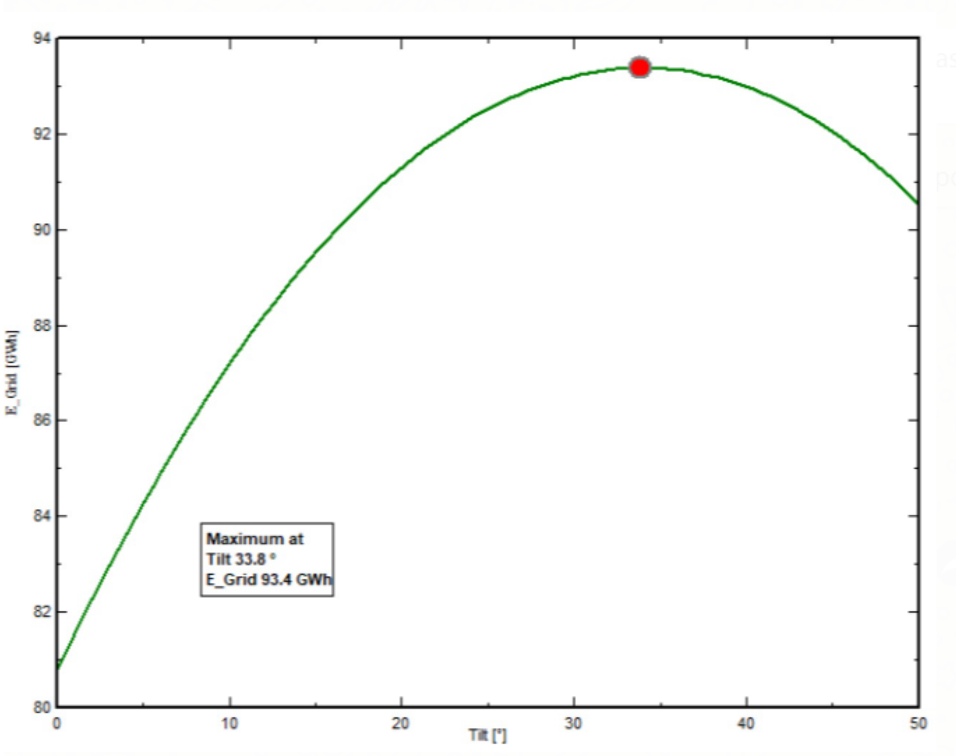

Figure 9 - Tilt Angle vs. Energy Yield as per PVSyst optimization

As one can infer, the result is different from the adopted 20º tilt angle on the base-case, and the difference might be explained for the trade-off reasons explained before.

4.3. Variables and parameters to be studied

4.3.1. Fixed vs. Tracking systems

A common optimization problem associated with photovoltaic modules involves their installation in solar trackers that follow the sun's movement throughout the day.

Trackers are usually the only moving part of a solar park, therefore adding a substantial grade of complexity to the EPC[12] contract and asset management operations when installed. A solar tracker can improve the solar module production by optimizing incident radiation angle, rotating panels around one or two axes throughout the day. The optimization objective is to minimize the angle of incidence between light rays and the panel surface, in a perpendicular line, as illustrated in Figure 10.

[12] EPC – Engineering, Procurement and Construction. EPC contracts are the usual framework used by project promoters to award most of the construction stages to one or more contractors, who will be responsible for materializing the project from ready-to-build stage up to commercial operation.

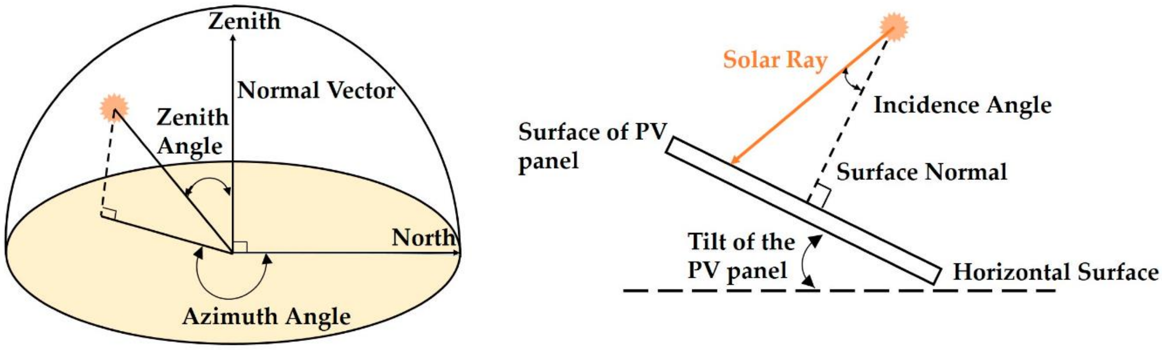

Figure 10 – Optimization goal representation: minimizing the angle of incidence between light rays and the panel surface [62]

To accomplish this, several mechanisms can be designed, that can be split into two categories: one axis and two axis trackers.

One axis trackers revolve around a single line that can be parallel to the ground, tilted, and placed with different orientations as illustrated in Figure 11. This allows the module to follow the sun moving in arc-shape from east to west or from north to south, depending on the axis orientation.

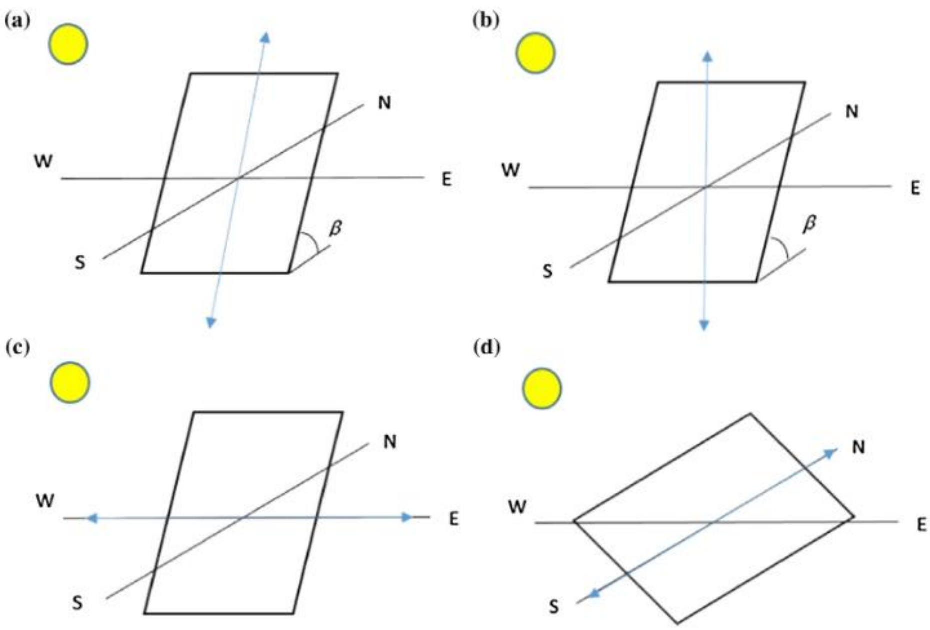

Figure 11 - Single-axis solar trackers: (a) East-West tracker, (b) Vertical-axis tracker (V), (c) Horizontal tracker, (d) North-South tracker [32]

As an alternative, trackers can also consist of a two-axis system, which allow the module to be perfectly aligned with optimum incidence angle at all times as described on

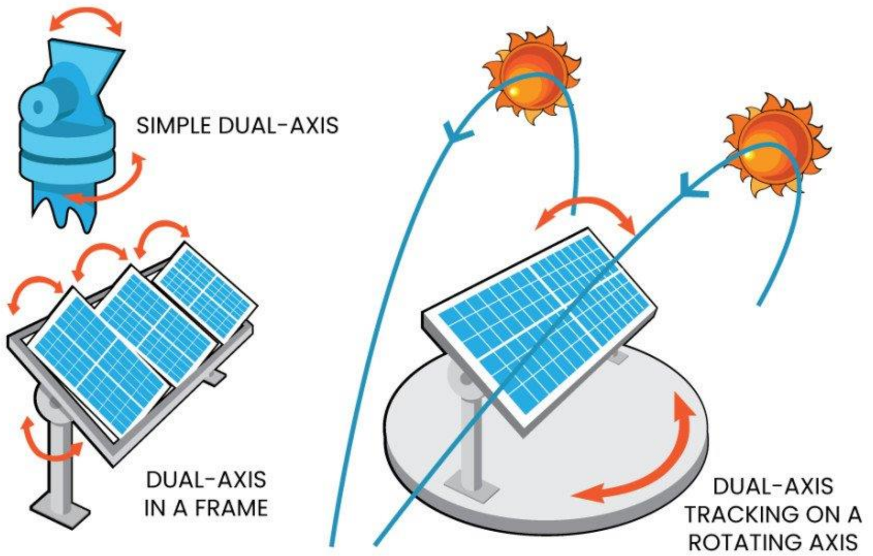

Figure 12 – Different types of dual-axis tracker systems [63]

From a market adoption perspective, forecasts [64] point that over 150 GW of PV tracking systems will be deployed until 2023, accounting for approximately one third of ground-mounted PV installations. Constituting by far the most adopted group of trackers [65], single-axis trackers are the current trend being implemented industry wise. As shown in a report by Berkeley Lab [65], 77% of the projects created in the U.S. market in 2019 include said technology, which accounts for 88% of the total capacity added in the same year.

In the single-axis trackers category, the Horizontal Single-Axis Tracking (HSAT) system is the most implemented, as per the study conducted on Chapter 6. From the universe of projects considered in this analysis, 66% used a tracking mechanism, of which 100% was a HSAT variant. Therefore, an HSAT system will be simulated and compared to a fixed-tilt structure for the purpose of this case-study in Chapter 5.

In a HSAT system, the axis is horizontal, parallel to the ground, and pointing south (ideally with an azimuth[13] equal to 0º), following the sun's movement from morning to evening. This typology allows the structure to be supported in a way that requires less complex construction when compared to other solutions, and considerably less material and labour costs [66], which might justify the high rate of adoption verified in the Portuguese market, as it will be later seen on Chapter 6.

As illustrated in Figure 13, tracking systems typically help creating a plateau at the system irradiance, and therefore at system rated capacity. The ability for following solar movement provided by trackers translates into peak capacity being quickly reached on the first hours of the morning rather than just at midday. The same happens on late afternoon, when trackers allow modules to be optimally orientated to the sun until the available rotating angle is at the system limit. This steady power output might be important in grid connection parameters, offering a solution for a more reliable energy source.

[13] Azimuth – Angular displacement from true south of the sun's rays measured in the horizontal plane.

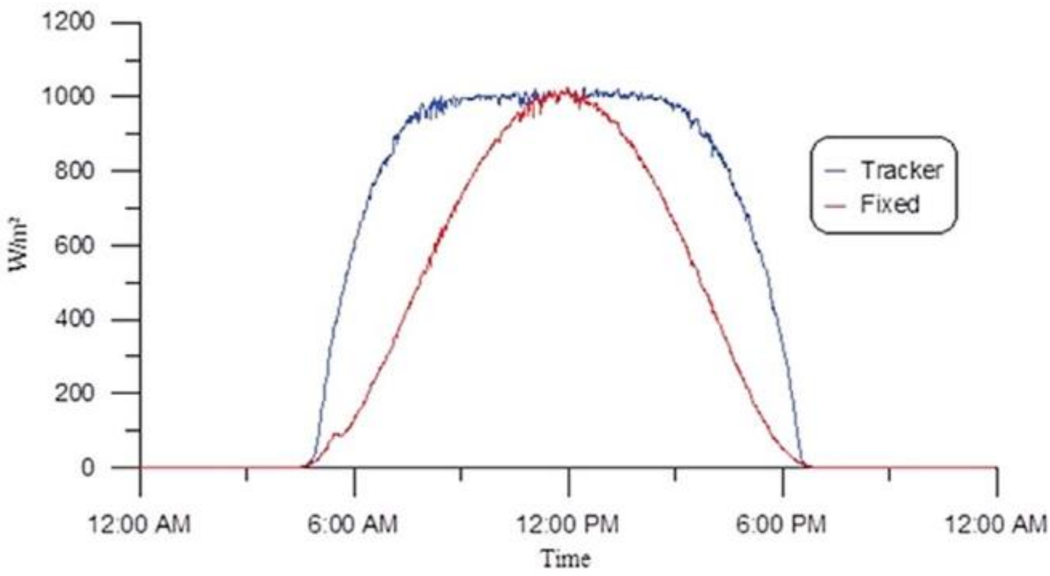

Figure 13 - Instantaneous irradiance on fixed and tracking systems [53]

Nonetheless, external meteorological aspects might affect the tracker performance strategy. In a cloud-covered sky, energy production depends on diffuse light rather than direct sun irradiation. This effect translates into a less effective sun following strategy, as a minimized cosine of the incident irradiation angle would not necessarily represent a gain in energy yield, as it is the case with direct irradiation.

When assessing dual-axis systems, other site and meteorological aspects should be considered, such as latitude. In places where the sun's position across the sky largely differs between summer and winter – the north or south poles are the extreme example –, a dual-axis system can better contribute to the energy yield, as the extra axis allow the module to keep track of not only intra-day variations of sun position, but also across the year. Considering that the Earth's rotation axis is tilted, the movement of the sun in the sky varies in each season, meaning that a dual-axis tracking strategy will register a higher energy yield when compared to a single-axis system.

These strategies coexist in industry from the very beginning of solar technology development [67], and could have been especially relevant in years when module price contributed as an even bigger slice on the CAPEX breakdown. An expensive module structure requires the development of better strategies to maximize the efficiency of solar energy production and goes beyond improving the efficiency of the solar cell alone.

This track record and the extensive installed capacity already in operation, makes projects with trackers easily bankable, although they still involve a greater risk due to the higher system complexity and likeliness to malfunction. Higher mechanical complexity requires the use of small engines, controllers, monitoring equipment, wiring and protections, as opposed to a fixed structure that requires much less maintenance. In addition, projects with trackers also involve a more demanding preparation of the land where they are installed. In some cases, this requirement ends up being an eliminatory factor for the trackers' installation, given the topography limitations that make a site possible for installing trackers or not. Fixed systems do not have the installation limitation on terrains with slopes below 15% that most tracker manufacturers impose. Above this slope level, the recommendation is to carry out earthworks to reduce the uneven shape of the land, but the economic costs, the time and local resources needed – namely in terms of heavy machinery – as well as the environmental restrictions could make these operations unfeasible.

4.3.2. DC/AC Ratio

The development and exploitation of photovoltaic solar projects requires holding of a Production License and an Exploration License establishing a maximum limit for the power to be injected into the public service electric grid [68]. This value is typically defined for the apparent power to be injected, in MVA[14], at the defined connection point. In practical terms, it is normally limited by the AC power defined for the sum of all inverters. Despite this, the value for the rated power of the installed modules (usually represented in megawatt peak, MWp) is unlimited.

DC/AC Ratio is the quotient between the DC power installed in PV modules and AC power installed in inverters. It is also known as Pnom Ratio, Oversizing Ratio, or Inverter Loading Ratio, and is determined as per equation (6):

$$DC/AC\ Ratio = \frac{Installed\ DC\ Capacity}{Installed\ AC\ Capacity} \tag{6}$$

Where Installed DC Capacity accounts for the maximum rated module power output at STC, and Installed AC Capacity is the sum of all inverter rated capacity. Oversizing happens when the value on the numerator is higher than the value on the numerator. This oversizing is typically achieved considering the number of PV modules installed in addition to those the inverter could accept at the rated operation of each module. When the oversized PV array is at its maximum production, the injection is above the inverter's faceplate power rating. The additional power is limited by the inverter, in an event referred to as clipping, that guarantees the safe operation within the inverter specifications. This event originates the so-called clipping losses represented on Figure 14.

The analysis of the daily production profile of photovoltaic solar technology, as illustrated in Figure 14, supports a possible optimization which consists of oversizing the system in order to maximize the average value of solar production.

[14] MVA – Megavolt-ampere.

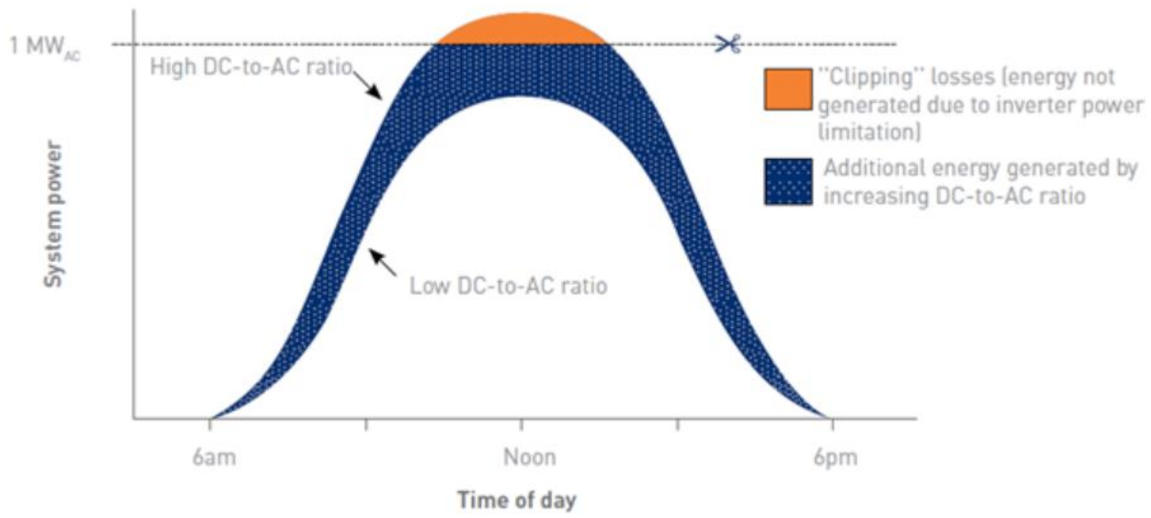

Figure 14 - Oversizing scenarios: differences between low and high DC/AC ratios [69]

In Figure 14, the vantages of oversizing a PV-array are illustrated by the area in blue, which represents additional energy that would not be produced in a system designed to match PV peak power with licensed injection power. In cases where the power generated by the PV-array exceeds the limit, the inverter derating its output to meet either its maximum power rating or the maximum allowable power at the grid connection.

This oversizing need is related to two main characteristics of solar production. First, production is highly variable over the course of a day, and typically only reaches its maximum between 11 am and 1 pm, producing at rated capacity a reduced number of hours a day. If the value of the rated capacity is equal to the maximum power to be injected into the grid, the system will inevitably be far below the maximum power it could be injecting during the rest of the day.

Second, the rated capacity of the solar modules is measured under STC conditions, which implies an operation at 1000 W/m^2 and 25 ºC temperature, which in practical situations hardly happens. If these parameters are not verified, the real power debited is lower than what is rated and there is a loss of opportunity to guarantee the maximum value provided for in the production license. An oversized system minimizes this difference by increasing the average value, in exchange for a cut in production higher than the licensed one. This strategy is thus extremely advantageous for low irradiance values.

Another point that contributes to the advantages of this approach is that an oversizing scenario might originate clipping losses on the first years of operations but will help compensating the system degradation rate on the long term. This way, inverters will not be under-utilized for such a long period of time after PV module efficiency drops beyond a certain point, which means clipping losses tend to be reduced over project lifetime.

Considering these aspects, in PV projects the real economic impact of the DC/AC Ratio is rarely considered. It is usually determined as per the norms and procedures assumed in the industry. Literature predicts values between 1 and 2 [70] with values for between 1.1 and 1.3 being more common and beneficial [22]. Following a standard value between 1.1 and 1.3 is assumed as reasonable in small-scale projects and residential applications, but when it comes to large-scale plants, it represents an optimization opportunity, allowing for understanding its real impacts on project costs and profitability.

The technical-economic challenge is finding the optimal point between additional investment in PV modules and the gains obtained considering the possibility of recording clipping losses that limit the profitability of the oversizing to be installed.

4.3.3. Number of modules in series

As illustrated in Figure 15, a large-scale solar photovoltaic park consists of several pieces of equipment, integrated in a sequence capable of successfully transforming solar energy into electricity usable by populations.

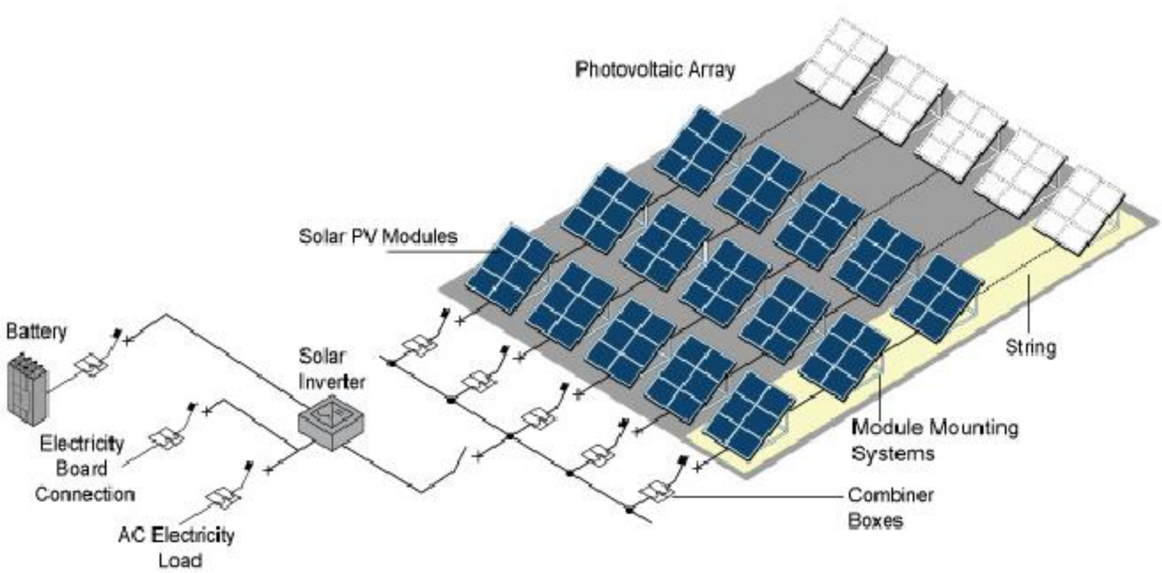

Figure 15 - Illustrative diagram of the integration of the various equipment in a PV Park [71]

The power generated by PV modules undergoes several transformations until it is injected in the grid, most of them related to current and voltage modifications. This process happens with the contribution of multiple auxiliary equipment including inverters, junction boxes, transformers, and others – a group which is usually referred to as Balance of Systems (BoS). BoS has the main objective of assuring the correct, effective, and safe performance of a PV array, which is typically formed by a modular design, based on multiple strings, and composed by several interconnected solar modules.

The number of modules in series in each string is limited by the solar module open-circuit voltage (V_{oc}), which translates the maximum voltage measured at the module level with no current flowing through it. This happens since in a series connection the maximum operating module voltage add up as represented in Figure 16.

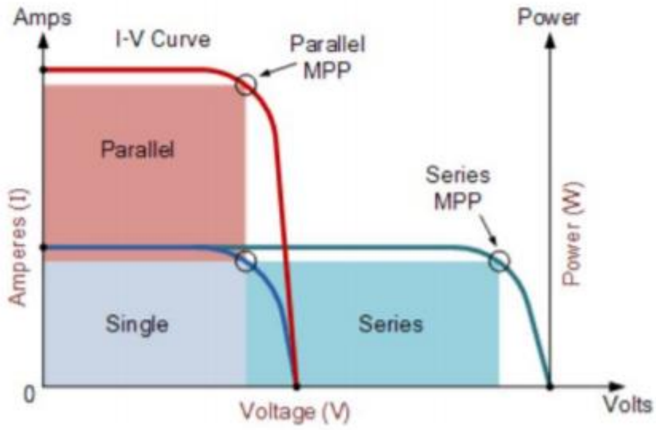

Figure 16 - Influence of Modules Series and Parallel Connections in the IV curve [72]

The maximum value of the connection should stay below the inverter input voltage - which in the case of the Sungrow SG250HX is 1500 V. The maximum voltage corresponds to the referred V_{oc}, and is inversely proportional to temperature, and directly proportional to irradiance. The maximum system V_{oc} will, therefore, be registered at the minimum expected ambient temperature, also depending on the irradiance occurring at that point in time.

Over the years, multiple ways of calculating the number of modules in series that guarantee a proper functioning of solar modules have been developed. Researchers have come up with a simple yet safe framework on which solar array engineers can rely to design the maximum number of modules in series - a component that has great impact on the solar park layout. Each PV string is often associated with a single table structure, which supports the correspondent string modules. The definition of the maximum number of modules in series is used by designers to establish the standard structure unit, which is then multiplied across the available area, impacting the possible arrangements. Utility-scale solar parks tend to have hundreds or thousands of this tables arranged around natural, exclusion areas, sloped terrains, and other occurrences. Their arrangement is, therefore, of great importance in the engineering phase.

The maximum value for V_{oc} is determined based on the values of the temperature coefficients that appear in the module data sheet, and is given by equation (7),

$$Module\ V_{OC_{max}} = V_{OC} \times \left[1 + (T_{min} - T_{STC}) \times \left(\frac{Tk_{V_{OC}}}{100}\right)\right] \tag{7}$$

where $V_{OC_{max}}$ is the maximum value for V_{oc}, to which the module is subjected, V_{oc} is the open circuit voltage specified by the manufacturer at STC, T_{min} is the minimum ambient temperature that is expected to be recorded at the site location, T_{STC} is the temperature under STC conditions and $Tk_{V_{OC}}$ is the open circuit voltage temperature coefficient that specifies how the temperature affects V_{oc}, stating how much module V_{oc} is increased if the ambient temperature decreases by one degree Celsius.

This value obtained for $V_{OC_{max}}$ is then used to calculate the maximum number of modules to be associated in series, as per equation (8).

$$Max\ String\ Size = Floor\left(\frac{Inverter\ V_{max}}{Module\ V_{OC_{max}}}\right) \tag{8}$$

The floor operation rounds the result to the greatest integer less than or equal to it, giving the number of modules to be associated in series. Given the complexity of the said equation, the temperature coefficients offered by the manufacturers appear as a simpler standardized alternative, which is certified to IEC TS 62738:2018 [73] in Europe and Article 670 of the NEC 2017 Code [74] in the USA.

As can be inferred, equation (7) represents an unnecessarily conservative approach as it considers an extreme value for the minimum temperature (T_{min}). Besides that, the mentioned Irradiance influence in V_{oc} is not reflected in this equation in any way. Although this procedure is a common practice on the industry, it assumes a permanent 1000W value for the incident irradiance, which is the assumption for STC conditions.

The above equation is therefore a conservative approach for two reasons: 1) a value of -10ºC is normally used for the minimum temperature value ever registered on site, independently of the recorded historical temperatures. This is also the case for PVSyst standard. And 2) temperature is only one of the two meteorological factors affecting the open-circuit voltage array, the second being the irradiance recorded on site. The following figures demonstrate the variation of this value as a function of temperature (Figure 17) and irradiance (Figure 18), independently. From the analysis and according to the mentioned dependency, one can infer that V_{oc} reaches its maximum point for lower temperatures and for higher irradiance values.

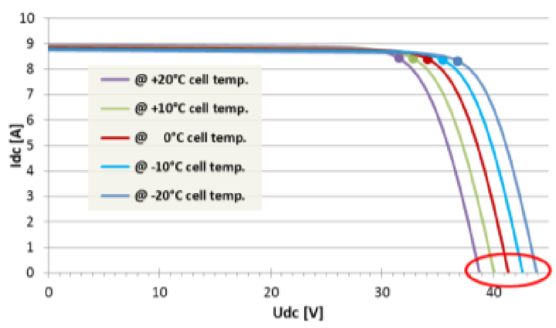

Figure 17 - Temperature dependency of the open circuit voltage at constant irradiation (1000 W/m²) [75]

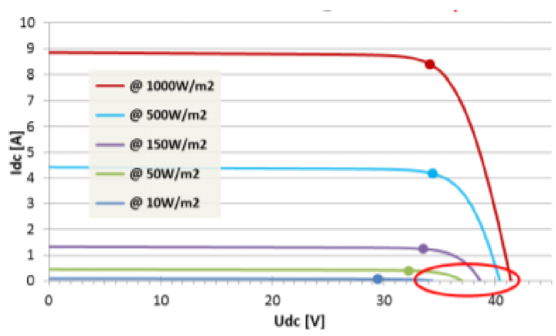

Figure 18 - Irradiation dependency of the open circuit voltage at constant cell temperature (0 ºC) [75]

From a statistical point of view, this approach is therefore conservative since the minimum value recorded for ambient temperature may never again be observed. Furthermore, it does not consider that the minimum temperatures are registered during the night, when the irradiance is null. Therefore, it results in an extreme value of $Module\ V_{OC_{max}}$, that is actually never reached nor approached. The influence of both temperature and irradiance simultaneously is explored in Figure 19 and Figure 20, in which it is possible to verify that, even with an ambient temperature of 0ºC, the voltages V_{oc} do not reach an extreme value when the irradiance decreases, which is common for periods of low temperatures, usually overnight.

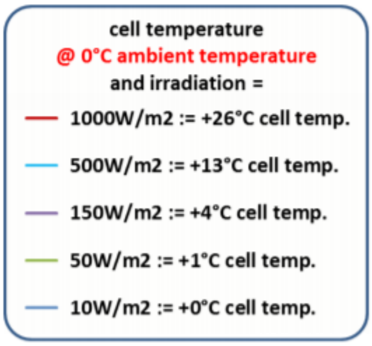

Figure 19 - Resulting cell temperatures at a constant room temperature (0 ºC) at different irradiation levels [75]

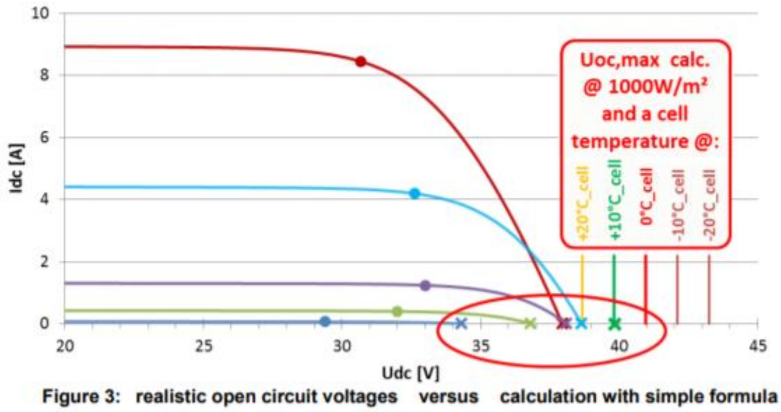

Figure 20 - Realistic open circuit voltages vs. calculation with simple formula [75]

The alternative proposed in this work and which will be further detailed on Chapter 5 entails using equation (9) to calculate V_{OC}, now considering site temperature and irradiance calculated in the reference meteorological year dataset.

$$Module\ V_{OC}\ (G,T) = V_{OC}{}^{\mathrm{Ref}} + \left(Tk_{V_{OC}} \times V_{OC}{}^{\mathrm{Ref}} \times (\mathrm{T} - T_{STC})\right) + \mathrm{m}\ \times V_T \times \ln\left(\frac{\mathrm{G}}{G_{STC}}\right) \qquad (9)$$

where m is the diode's ideality factor, V_T is the thermal voltage, G_{STC} is the Irradiance on STC conditions equal to 1000W, and G, T are respectively the irradiance and temperature registered at any point in time at the specific site. This approach allows one to consider the impact of Irradiance on the V_{OC}, considering the site minimum temperature that was recorded instead of a one size fits all approach.

Applying both methodologies described above, two different values for the maximum number of modules in series are obtained, which, as discussed in Chapter 5, have a significant impact on production values. In terms of economic optimization, the advantages of systems with numerous strings are well described. Also, they are even related to a progression of the industry towards offering equipment solutions with voltages that a few years ago were around 600 V and nowadays are set at 1500 V. This is the case of the Sungrow inverter used in this case-study.

4.3.4. Bifacial Modules

Bifacial photovoltaic technology consists in PV modules that convert light to electricity both in the traditional front side, but also on the back side of the modules.

This type of solution has been known for over 70 years [76], but has gained relevance since 2018, with several players in the module production industry starting to invest heavily in the production of bifacial panels. The market share of bifacial solar modules has increased from a humble 97 MW in 2016 to more than 5.4 GW in 2019 [77], and the industry is still adapting to this fast-paced change. Some forecasts point to a sustained growth in the adoption of bifacial modules, predicting that its market share will reach 40% in 2028 [78]. Other studies point to an implementation of around 30% in 2030 [79].

In what regards to engineering, procurement and construction, technical regulations that guide the measurement of electrical components of bifacial modules are also growing. The first relevant information was only released in 2019 with IEC TS 60904-1 [80], and safety codes are under development to account for the operation at higher DC current levels than those of monofacial modules [81].

When it comes to simulation data, the photovoltaic performance of bifacial modules is a subject yet to be fully addressed by most simulation software. PVSyst itself only included the bifacial modules option in version 6.7.0, released in early 2018, and since then it has continued to release regular updates to fine-tune the details of this simulation. A complete analysis using 3D-scene files generated in other design software is not yet possible. PVSyst calculates bifacial module output power by adding the irradiance on the rear side of the panel with the one on the front side, then calculating power with the one-diode model normally used for monofacial modules.

The main difference of bifacial modules, as the name implies, consists of taking advantage of the radiation reflected in the ground and other adjacent modules, and also the diffuse radiation which originate from separation processes in the atmosphere and after being reflected on the ground. This irradiation is obviously greater than the one harvested by average monofacial modules and allow bifacial PV to convert more sunlight to DC electricity. As a result, more energy is produced per area unit, as represented in Figure 21.

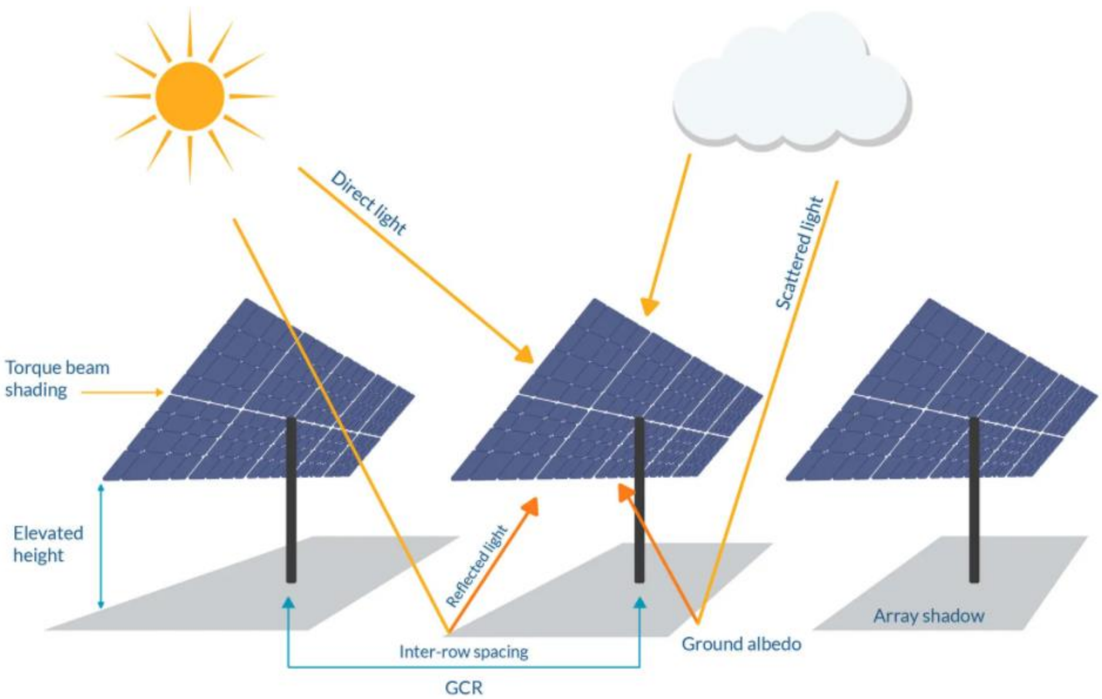

Figure 21 - Key factors that affect bifacial efficiency [82]

Some of the parameters with the greatest impact on the design of projects with bifacial modules are also considered in Figure 21: height to ground, array shadow, inter-row spacing and the Ground Coverage Ratio (GCR)[15].

The module's working principle is related to the distinct encapsulation that is done in the solar cell. In this new technology, the rear part of the module uses metal contacts instead of a fully covered metal layer, allowing sunlight to reach both sides of the solar cell. The backside of the module uses a transparent back sheet instead of the normal opaque solution. This approach is illustrated in Figure 22, which compares the structure of a conventional photovoltaic module with that of a bifacial module, as well as the structure of a conventional solar cell with that of a bifacial cell.

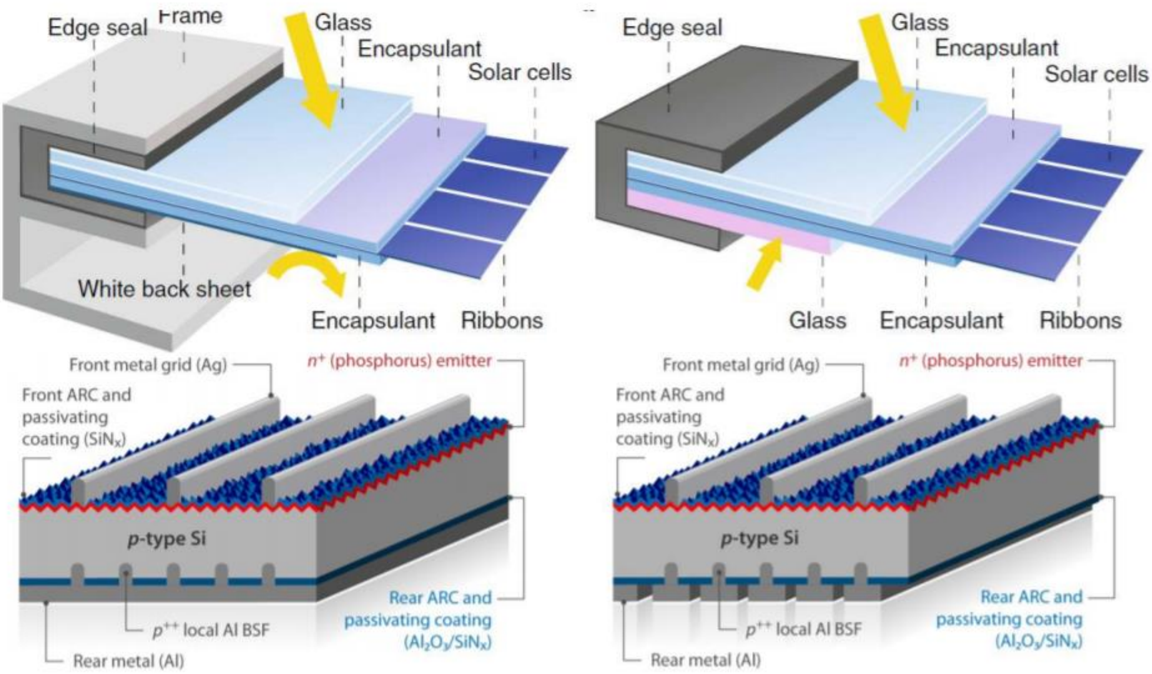

Figure 22 - Experience and Results from International Research and Pilot Applications 2021 [79]

The extra energy produced by the bifacial module is often referred to as the Bifacial Gain (BG), and depends on multiple factors such as module orientation, and site latitude, among others. It is defined as the ratio between the energy produced by the newly included rear side of the module, and the energy produced on the normal front side, as given by equation (10),

$$BG_{mod} = \frac{E_{rear}}{E_{front}} \qquad (10)$$

where BG_{mod} is the module Bifacial Gain, E_{rear} is the energy yield harvested by the rear side of the module and E_{front} is the energy yield of the standard front side.

[15] Ground coverage ratio is the ratio between module area and overall area occupied by the array.

The System Bifacial Gain (BG_{sys}) differs from the traditional module BG addressed before by proposing a comparison between two simulations: one with bifacial modules and one with monofacial modules, with identical properties, as per equation (11),

$$BG_{sys} = \frac{E_{bif} - E_{mono}}{E_{mono}} \quad (11)$$

where BG_{sys} is the system Bifacial Gain, E_{bif} is the Energy Yield simulated or measured on the bifacial solution, and E_{mono} is the Energy simulated or measured on the monofacial solution.

The abstraction level of such a ratio, which only compares the totality of produced energies, allows for including all the factors that influence the behaviour of bifacial panels in a single parameter, which is used to measure and compare the performance of bifacial modules, being extremely important in the analysis of funding to be allocated to new photovoltaic projects. The parameter that most influences the BG is the albedo, which represents the percentage of radiation that reaches the ground and is again reflected to the atmosphere and is heavily dependent on typology and ground cover. It is dimensionless and measured on a scale from 0 (the case of a black body absorbing all incident radiation) to 1 (a body that reflects all incident radiation).

When considering projects above the range of several MW, and which occupy different areas or types of terrains, assessing albedo throughout the available land might therefore be important in the design process. This allows for understanding the occurrence of relevant differences, which may affect the percentage of reflected sunlight. In this work, albedo is assumed to be 0.2 for the entire terrain, although some of the simulations in Chapter 5 address this variation. Table 8 lists the albedo values for different types of surfaces, evidencing the significant differences in reflected light in different types of ground.

Table 8 - Albedo ranges for different surfaces [81]

Surface	Albedo
Grass	0.15 to 0.26
Snow	0.55 to 0.98
Black soil	0.08 to 0.13
Clay soil	0.16 to 0.23
Sand	0.21 to 0.60
Asphalt pavement, new	0.09
Asphalt pavement, weathered	0.18

When comparing the economic viability of photovoltaic projects, albedo is a parameter to be added to the set that characterizes the installation site from a meteorological and topographical point of view. In areas where snowfall is more frequent, the impact of a white surface is considerable, when compared to the grass or clay soil.

5. Optimization: Result Analysis

In this Chapter, an overview and analysis of each PVSyst simulation is proposed. Several simulations were conducted with the objective of testing the technical situations mentioned in the previous chapter, for each one of the four sub-chapters: use of tracking structures, DC/AC Ratio, number of modules in series and use of bifacial modules. Changing one parameter at a time, it is possible to assess the impact of each configuration in the Energy Yield and in the economic figures in an individual way. Building up from the technical background developed on the previous Chapter, and for each of the parameters to be analysed, an overview about cost assumptions and parameter impact on economics is addressed, with the proper industry review to benchmark technology CAPEX and OPEX hypothesis. Results are presented in terms of NPV and IRR to find the best solutions.

5.1. Fixed-tilt vs. Tracking systems

As discussed in Chapter 4, two different tracking strategies are now proposed and reviewed. The first strategy consists of a horizontal single-axis approach and the second of a dual-axis tracking approach. For conducting the economic analysis of both, any terrain conditions that could prevent the installation of such system are not considered, with the objective of understanding if and how they would be more economically beneficial from an NPV and IRR point of view.

Simulations conducted on PVSyst show the impact of trackers in the Energy Yield of PV projects. Table 9 summarizes these results, allowing one to compare Energy Yield and other technical performance data for the case-study and the now purposed additional solutions, all of them for the total installed capacity of the park, equal to $48\ MWp$.

Table 9 – Simulation Results: Horizontal Single-Axis Tracking vs. Dual-Axis Tracking Systems

	Fixed-Tilt (Base-case)	HSAT	Dual-Axis Tracking
Energy Yield 1st Year - [MWh/year]	91,309	99,586	126,668
Variation compared to base-case	-	9.06%	38.72%
Total Lifetime Energy Yield [MWh]	2,479,919	2,726,518	3,502,507

The Energy Yield results obtained confirm the theoretical predictions, with a single-axis strategy being more productive than the fixed-tilt case study, and a dual-axis strategy beating both other solutions with a significant increase in Energy Yield. These results suggest that a horizontal single-axis tracking system would generate 9.06% more energy than the fixed-tilt system. A dual-axis system would be the most beneficial approach from an Energy Yield perspective, with an increase of almost 40%, when compared to the original scenario. These values represent utilization factors[16] of 1902, 2075, and 2639 hours, for fixed, HSAT and dual-axis respectively.

The values reviewed in the literature show a range of 12% to 25% of additional Energy Yield for single-axis trackers implemented in different projects, with a global average value of 16.7%, across several locations with multiple latitudes, as described in Table 10.

Table 10 - Literature Review: Energy Yields values for Single-Axis Trackers

Country	System	Energy Yield	Average Energy Yield Value	Source
USA	Horizontal Single-Axis Tracker	12.0% - 25.0%	18.5%	[83]
Brazil	Horizontal Single-Axis Tracker	11.0%	11.0%	[84]
Italy	Tilted Horizontal Single-Axis Tracker	10.0% - 20.0%	15.0%	[85]
Spain	Vertical Single-Axis Tracker	22.3%	22.3%	[86]

The same happens to dual-axis systems, with literature review values available on Table 11. Energy Yield simulations for the proposed system are therefore sustained by these results.

Table 11 - Literature Review: Energy Yields values for Dual-Axis Trackers

Country	System	Energy Yield Increase	Average Energy Yield Increase	Source
Jordan	Dual–axis tracker	31.29%	31.29%	[53]
Tunisia	Dual–axis tracker	30% - 44%	37%	[87]
Turkey	Dual–axis tracker	30.79%	30.79%	[88]
India	Dual–axis tracker	26.29%	26.29%	[89]
Spain	Dual–axis tracker	25.2%	25.2%	[86]
Nigeria	Dual–axis tracker	20% - 40%	30%	[90]
Multiple Locations	Dual–axis tracker	17.72% - 31.23%	24.48%	[91]
Turkey	Dual–axis tracker	13–15%	14%	[92]

The critical item to be examined besides Energy Yield, is the impact of technology on both CAPEX and OPEX values. Some literature data, as the example illustrated in Figure 23, already show that the difference between both options is becoming inexpressive. In other regions, the price of trackers and associated installation continues to be an obstacle.

[16] Utilization factor: annual produced energy divided by installed capacity.

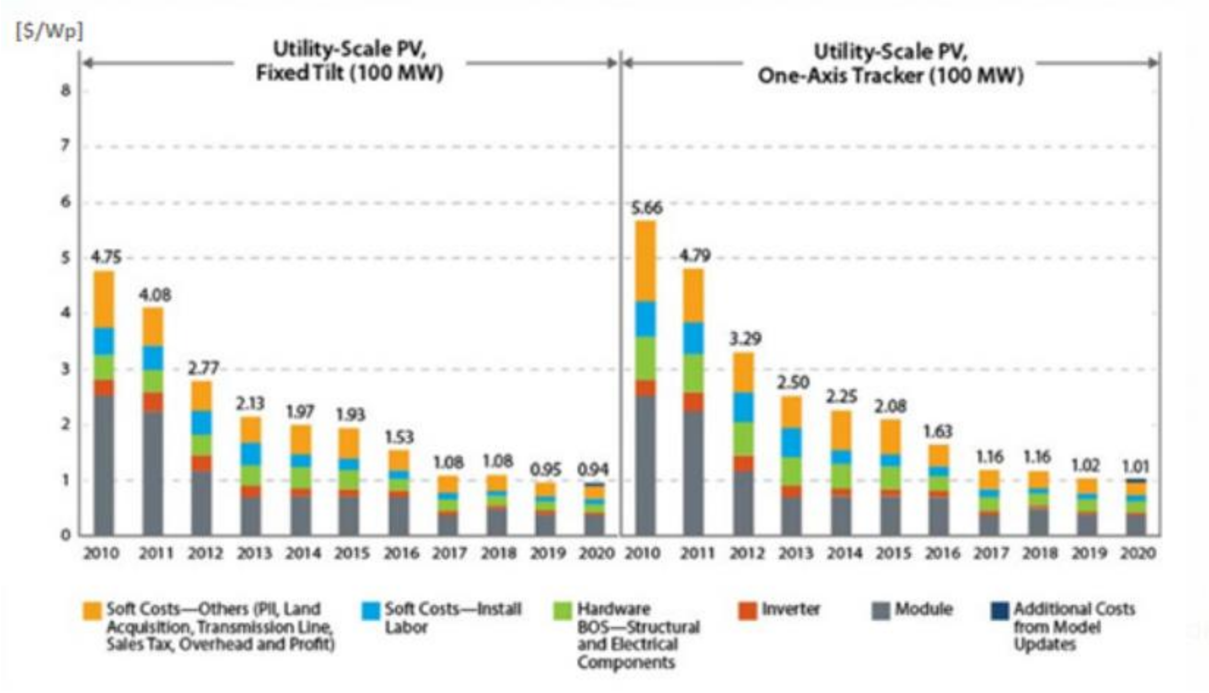

Figure 23 - Fixed-Tilt and Single-Axis Tracker initial cost comparison [93]

Table 12 summarizes values for Additional Initial Investment from reviewed sources. These costs are added to the original CAPEX value, associated with single-axis or dual-axis technologies. An exchange value of 1 USD = 0.85 EUR was considered to convert dollar values from reviewed literature, allowing for the comparison between literature values and the values obtained in this study.

Table 12 - Literature Review: Additional Initial Investment costs for single and dual-axis technologies

Additional Initial Investment [$€/kWp$]		
Source	**Single-Axis**	**Dual-Axis**
[94]	495.80	1,259.60
[28]	120.00	400.00
[29]	345.10	1,237.60
[95]	652.01	992.98
[55]	81.60	1,445.85
[96]	467.50	756.50
Average Value	360.33	1,015.42

For the fixed-tilt scenario, CAPEX values are obtained as per equation (12):

$$Initial\ Investment = Installed\ Capacity \times Total\ Unitary\ PV\ Cost \qquad (12)$$

For the other two scenarios, the average value of the additional initial investment, for each system, is multiplied by the total amount of installed capacity in kWp and the result is added up to the original fixed-tilt CAPEX costs to find the new CAPEX value considering the single-axis and dual-axis installation premium.

Regarding OPEX costs, a similar approach is used, but a total O&M cost in terms of EUR per installed kWp per year is reviewed and compared to the original case-study information presented before on Table 7. Once again, Table 13 summarizes values O&M costs for the different technologies.

Table 13 – Literature Review: O&M costs for fixed-tilt, single-axis, and dual-axis technologies

O&M Costs [$€/kWp/year$]			
Source	**Fixed-Tilt**	**Single-axis**	**Dual-axis**
[53]	20.00	27.625	-
[30]	8.50	17.850	-
[54]	14.195	36.20	-
[29]	21.250	25.50	29.75
[55]	21.250	25.50	33.15
Average Value	17.039	26.54	31.45

The wide range of values shows the lack of consensus that is underlying the definition of item scope and value for O&M costs. As explained before, higher values of O&M in single-axis systems are associated with the most frequent need of sensor and controller checking for alignment and calibration, servicing of motors and actuators, among other periodical necessary activities, an effect that has even greater impacts on dual-axis trackers. Given the recent progresses and cost decreases in O&M associated with a greater adoption of tracking systems [97], and to fully understand their economic potential, best-case scenarios of 17.85€/kWp/year for single-axis and 29.75€/kWp for dual-axis will be considered as inputs in the economic model.

As said, a similar procedure as for CAPEX is then followed for OPEX values, as per equation (13):

$$O\&M\ Costs = Installed\ Capacity \times\ Total\ Unitary\ O\&M\ Costs \qquad (13)$$

Table 14 summarizes these calculations and presents the new CAPEX and OPEX values to be used in the economic model for HSAT and Dual-axis analysis.

Table 14 - New values of CAPEX and OPEX for tracking technologies

	Fixed-Tilt	HSAT	Dual-Axis
Total Installed Capacity [kWp]	47,992	47,992	47,992
Total O&M Costs [€/year]	817,735.69	856,657.2	1,427,762
Additional Initial Investment [€]	-	17,292,957.36	48,732,036.64
Total Initial Investment [€]	28,723,212.00	46,016,169.36	77,455,248.64

As detailed in Chapter 3, the O&M cost is used to determine the net revenue after subtracting O&M expenses from revenue figures. The procedure is applied to the 30-year time interval extracted from PVSyst results to obtain the economic parameters presented on Table 15.

Table 15 – IRR and NPV values for a 30-year period obtained with PVSyst

Fixed-Tilt and tracking systems economic model results			
Configuration	**Fixed-Tilt**	**HSAT**	**Dual-Axis**
IRR [%]	7.56%	4.028%	0.9%
NPV [€]	4,642,188	-8,830,924	-34,322,340

Conclusions point that, assuming it is topographically feasible to install a single-axis tracking system, at this energy pool price, the increased amount of energy production is not enough to cover higher installation and operation costs. The additional gain from an HSAT system has a great traction of attention from researchers and industry-wide adoption, but in this case its deployment appears to be not effective. The situation is even more significant with dual-axis systems, which despite representing a greater benefit from a higher energy selling perspective, require an even higher investment in CAPEX and O&M costs. The tracking strategy represents 9.06% increase on Energy Yield, but initial costs are 60% higher, and O&M costs also increase.

In the case of dual-axis systems, only the initial investment almost triples and O&M costs almost doubles, in exchange for a 40% increase in Energy Yield. In a project with this magnitude of installed capacity, a decision to install dual-axis trackers would make the investment totally inviable, with an associated NPV of -34 M€.

The energy pool price of 38 €/MWh is also an important factor that prevents tracking systems from being viable, as each unit of additionally produced energy is rewarded with a competitive price when compared, for example, with the MIBEL[17] 2019 average price of 50 €/MWh.

[17] MIBEL - Iberian Electricity Market

In the case of single-axis systems, given the adoption rates presented in Chapter 4, the conclusions here obtained may be questionable since the industry trend is trusting single-axis tracking as the alternative to choose when terrain conditions allow, but these conclusions are supported by a BloombergNEF report that gathers data from +700 recently financed projects and 13,000 modelled LCOE forecasts across 25 technologies and 54 countries around the world (Figure 24). Within the Iberian Peninsula, conclusions differ. In Portugal, fixed-tilt projects end up being less expensive to install in terms of LCOE, while in Spain, tracking systems are the most cost-effective solution. The same case as Portugal is verified in France, Italy, India and China, among other countries, proving that the line between beneficial implementation of one strategy or the other is thin and strongly depends on the additional constraints described both in this Chapter and Chapter 4.

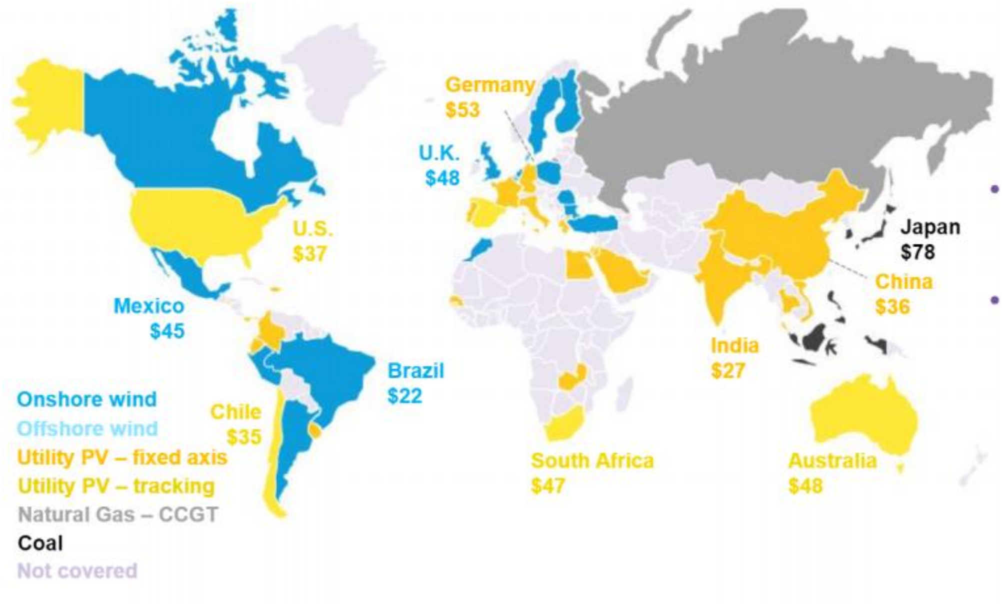

Figure 24 - Less expensive source of bulk generation during first half of 2021[18] [98]

5.2. DC/AC Ratio

With the successive drops on PV module price that were mentioned throughout this work, its representativeness in the total cost breakdown of a PV park has also been decreasing strongly. As a result of this, Figure 25 depicts that the current most advantageous trend in terms of DC/AC Ratio definition is to include an increasing number of modules in each inverter, therefore increasing the said ratio. Still, finding the optimal payback point on ratio definition continues to require an extended analysis that can help maximize optimization potential. The simulation described in this section seeks to find the optimal DC/AC Ratio, considering both technical and economic conditions.

[18] Data kindly sent by author on researcher request albeit being part of a premium service.

Figure 25 - Global average inverter load ratio trend, 2010-2020 [2]

To do this, distinct DC/AC Ratio scenarios are proposed, and compared with the 1.24 original DC/AC Ratio of the base case. New alternatives allow simulations to be performed for ratios that range from 1.0 to 1.50, as included in Table 15. As a strategy to obtain these values, the inverter capacity was maintained at 38,700 kW_{AC} while the number of installed modules was changed to reach the new ratio values, by a process of adding or removing strings of 28 modules.

Table 16 and Table 17 list the technical parameters and overall installed capacity for each scenario implemented to conduct the simulation. Energy Yield results for the first year of operation are presented as an indication of the variation associated with each scenario, although 30-year results are later included in the economic model. Performance Ratio and Specific Production data is also included.

Table 16 - Simulation results: Energy Yield, Specific Prod. and PR for distinct DC/AC Ratios (1/2)

DC/AC Ratio	1.00	1.05	1.10	1.15	1.20	1.24 (base)
No. of Strings	2,434	2,552	2,674	2,784	2,918	3,007
No. of modules	68,152	71,456	74,872	77,952	81,704	84,196
DC installed capacity [kWp]	38,847	40,730	42,677	44,433	46,571	47,992
AC installed capacity [kVA]	38,700	38,700	38,700	38,700	38,700	38,700
Energy Yield - 1st Year [MWh]	74,280	77,845	81,523	84,811	88,718	91,309
Specif. Prod. - 1st Year [kWh/kWp]	1,912	1,911	1,910	1,909	1,905	1,902
Performance Ratio [%]	87.93	87.89	87.85	87.78	87.61	87.47

Table 17 - Simulation results: Energy Yield, Specific Prod. and PR for distinct DC/AC Ratios (2/2)

DC /AC Ratio	1.27	1.30	1.35	1.40	1.50
No. of Strings	3,090	3,143	3,262	3,398	3,640
No. of modules	86,520	88,004	91,336	95,144	101,920
DC installed capacity [kWp]	49.316	50.162	52.062	54.232	58.094
AC installed capacity [kVA]	38,700	38,700	38,700	38,700	38,700
Energy Yield - 1st Year [MWh]	93,379	94,834	97,695	100,748	105,294
Specif. Prod. - 1st Year [kWh/kWp]	1,893	1,891	1,877	1,858	1,819
Performance Ratio [%]	87.08	86.94	86.30	85.43	83.67

As expected, the variation on the Energy Yield values tend to a fixed value, proportional to the inverter capacity, and multiplied by the number of hours of sun considered by the software. Adding extra modules would therefore result in a maximum Energy Yield, dependent on the said assumed number of hours, as represented on Figure 26.

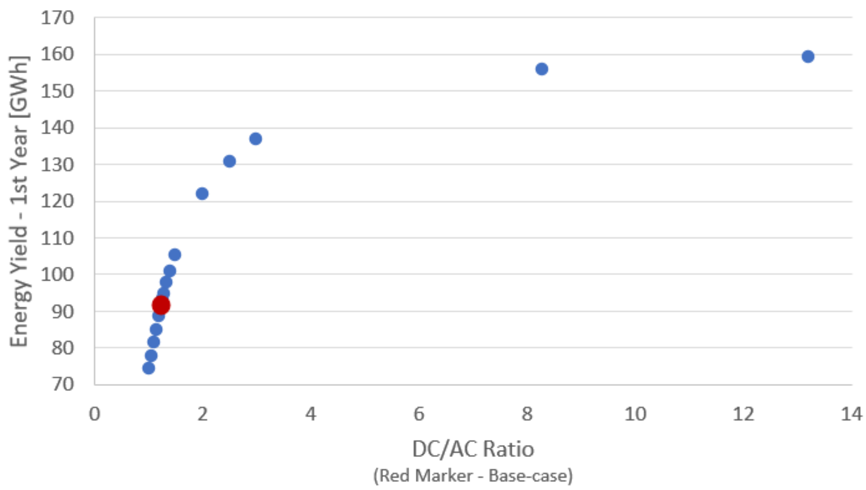

Figure 26 - Simulation Results: Energy Yield values obtained for each DC/AC Ratio, with additional control values for trend setting

Performance Ratio and utilization factor are also heavily impacted by the variation of the number of modules. Both values are studied in Figure 27 and Figure 28, with a clear trend towards zero as more photovoltaic modules are added, therefore increasing $Pnom_{PV}$ component.

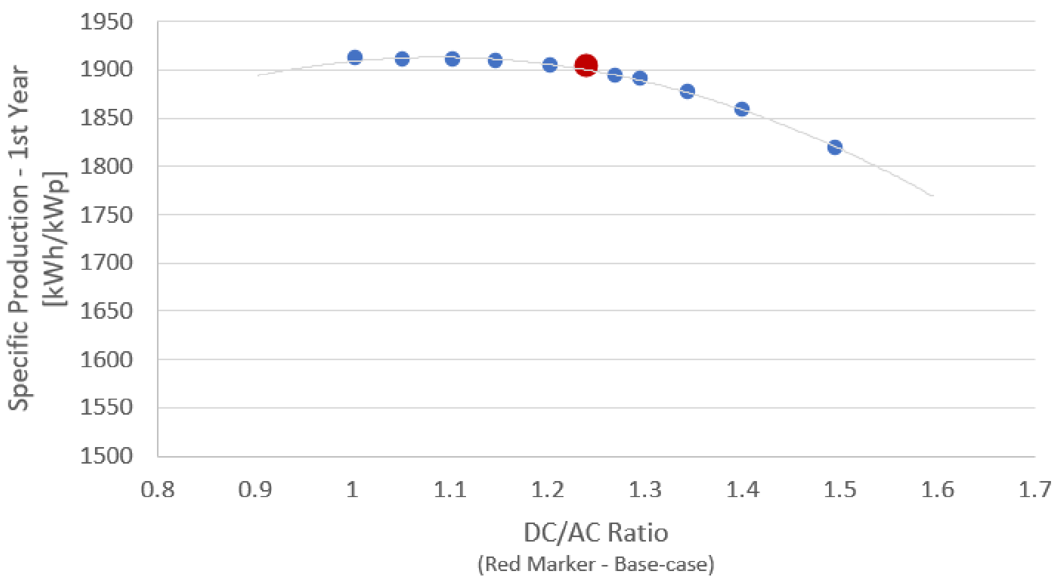

Figure 27 - Simulation Results: Specific Production values obtained for each DC/AC Ratio

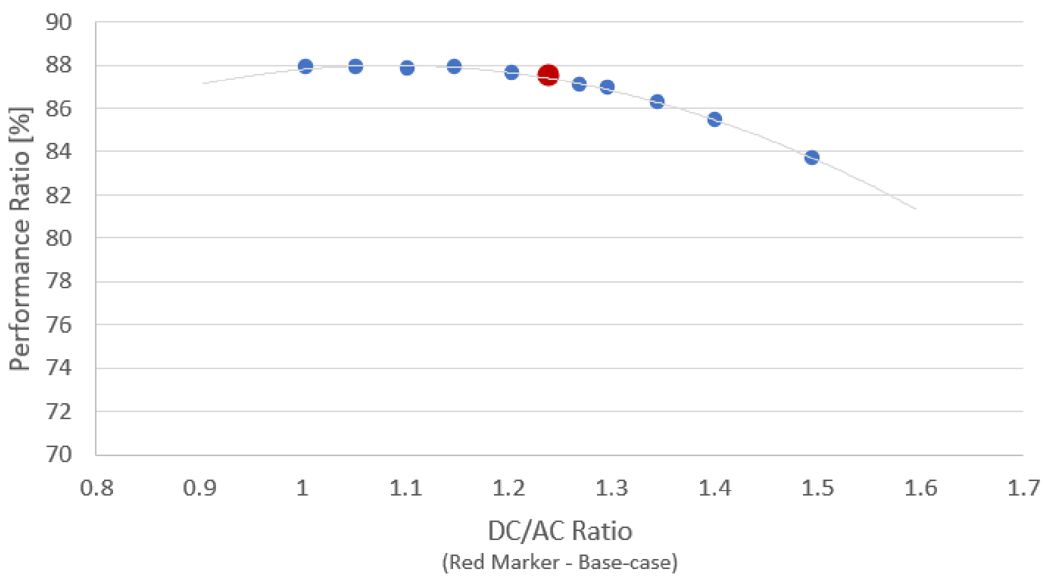

Figure 28 - Simulation Results: Performance Ratio values obtained for each DC/AC Ratio

From a technical point of view, this impact is highly important mainly because of the impact on Performance Ratio, which is typically used as a key performance indicator (KPI) during tests to obtain a Provisional Acceptance Certificate (PAC) - a necessary step into the exploration licensing process of a newly built PV park. For this reason, an oversized ratio that has not been optimized could impact procedures required for asset management takeover. The impact of a high installed DC/AC Ratio should therefore be addressed on contract definition, with the correlated expected impact on the PR. Failing to do so and considering standard PR values might lead to a situation where overly optimistic expected PR values are never attained.

Following the technical optimization, these results are now included in the economic model, with Energy Yield values being directly exported from PVSyst. OPEX values are calculated assuming that the base-case seen on the previous sub-section did not change, as adding more modules will always result in an increasing necessity of conducting maintenance, mainly related to surface cleaning operations and soiling losses and proportional to the added capacity value.

In the case of CAPEX, Table 18 and Table 19 propose two values. The first value is obtained multiplying the new total DC capacity by the total unitary PV cost of the base-case for CAPEX of 0.5985 €/Wp, as seen on the previous section by equation (13).

The second value is an optimized scenario that considers only adding or removing new modules to already installed inverters, which results in a correlated impact on CAPEX costs. For DC/AC ratios higher than the base-case, the lower cost results from removing the inverter cost from the original CAPEX costs breakdown, originating a new value of 0.5535 €/Wp, which is applied to the difference in the installed capacity when compared to the base-case. For DC/AC ratios lower than the base-case, the inverter cost is added to the original CAPEX, to account for the same number of inverters being kept, although installed capacity is diminishing. The optimized CAPEX value is therefore given by equation (14) in the case of lower DC/AC ratios, and by equation (15) in the case of higher DC/AC ratios:

$$Optimized\ Initial\ Investment = Total\ Investment + (Removed\ Capacity \times 0.045 \times 1000) \qquad (14)$$

$$Optimized\ Initial\ Investment = Total\ Investment - (Added\ Capacity \times 0.045 \times 1000) \qquad (15)$$

Table 18 and Table 19 summarize all these results and economic parameters.

Table 18 - Simulation results: Optimized Initial Investment for distinct DC/AC Ratios (1/2)

DC/AC Ratio – Cost Variation						
DC/AC Ratio	1.00	1.05	1.10	1.15	1.20	1.24 (case-study)
Total Installed Capacity [kWp]	38.304	40.730	42.581	44.560	46.412	48.008
Total O&M Costs [€/year]	537,328.51	571,360.44	597,326.27	625,087.68	651,067.54	673,456.22
Initial Investment [€]	22,924,944.00	24,376,905.00	25,484,728.50	26,669,160.00	27,777,582.00	28,732,788.00
Optimized Initial Investment [€]	23,361,624.00	24,704,415.00	25,728,943.50	26,824,320.00	27,849,402.00	-

Table 19 - Simulation results: Optimized Initial Investment for distinct DC/AC Ratios (2/2)

DC/AC Ratio – Cost Variation						
DC/AC Ratio	1.27	1.30	1.35	1.40	1.50	2.00
Total Installed Capacity $[kWp]$	49.157	50.434	52.221	54.200	58.094	77.725
Total O&M Costs [€/year]	689,574.40	707,488.15	732,556.19	760,317.60	814,942.63	1,090,326.30
Initial Investment [€]	29,420,464.50	30,184,749.00	31,254,268.50	32,438,700.00	34,769,259.00	46,518,412.50
Optimized Initial Investment [€]	29,368,759.50	30,075,579.00	31,064,683.50	32,160,060.00	34,315,389.00	45,181,147.50

These new starting points are then used in the economic model to evaluate IRR associated to each configuration. Table 20 summarizes IRR results and Figure 29 and Figure 30 puts these values in perspective to help understand variations and the optimum value for DC/AC Ratio.

Table 20 - Simulation results: IRR and NPV values for distinct DC/AC Ratios

Economic Analysis											
Configuration	**Fixed-Tilt**										
DC/AC Ratio	1.00	1.05	1.10	1.15	1.20	1.24 (base)	1.27	1.30	1.35	1.40	1.50
IRR [%]	7.40%	7.45%	7.48%	7.48%	7.54%	7.56%	7.56%	7.56%	7.52%	7.46%	7.27%
NPV [M€]	3.38	3.71	3.96	4.22	4.46	4.64	4.75	4.83	4.92	4.89	4.58

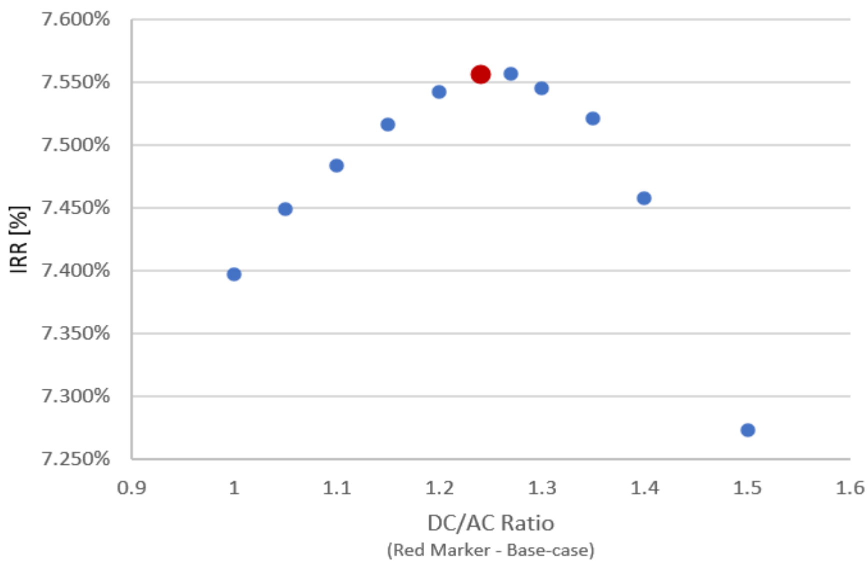

Figure 29 - Simulation Results: IRR values obtained for each DC/AC Ratio

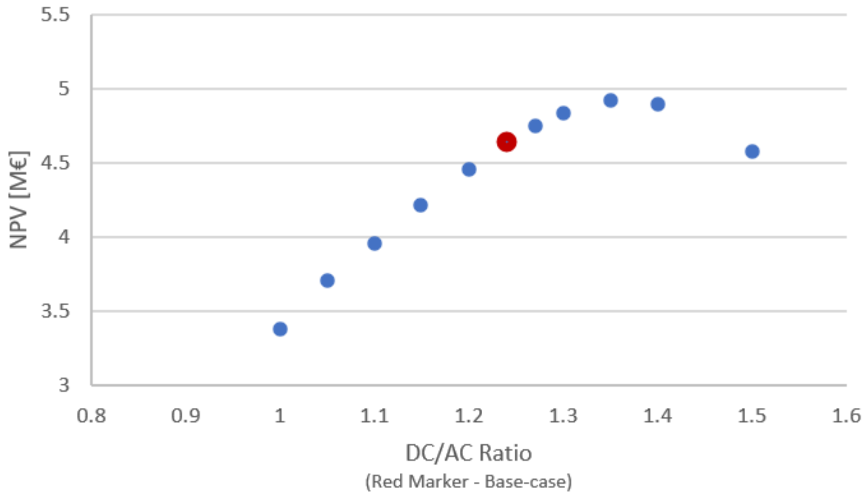

Figure 30 - Simulation Results: NPV values obtained for each DC/AC Ratio

As per the above results, it is possible to conclude that the best configuration in terms of IRR is a DC/AC Ratio of 1.30, and in terms of NPV is a DC/AC Ratio of 1.35.

These conclusions represent an increase to the industry-standard of 1.20. This analysis shows that the cost decline in the photovoltaic module chain might have an impact on the optimal configuration of module to inverter distribution, questioning the one-size fits all approach for defining the DC/AC ratio as 1.20.

As already discussed, the photovoltaic module cost is an important driver on project decisions. The increasing load ratio trend observed since 2010 (Figure 23), can be related to the decrease on module costs, meaning that higher oversizing of arrays would bring a bigger economic benefit. That said, it also allows for understanding that further increasing the number of photovoltaic modules quickly starts to jeopardize the economic equilibrium of the project, with a decline on IRR.

On the near future, DC/AC Ratio average numbers may continue to escalate for two main reasons, one being the said expected decline in module costs, and the second being the growing opportunity for integrating battery systems, which would mean that DC energy that inverters are not able to produce would still be used - in this case, stored.

A report by IRENA [2] has collected DC/AC Ratio data from 2010 to 2020 comprising 202 GW of capacity from 6,836 projects, showing that in the USA the median DC/AC Ratio grew 9% between 2010 and 2019, to reach 1.31 in 2019. The same growing trend is illustrated in Figure 31.

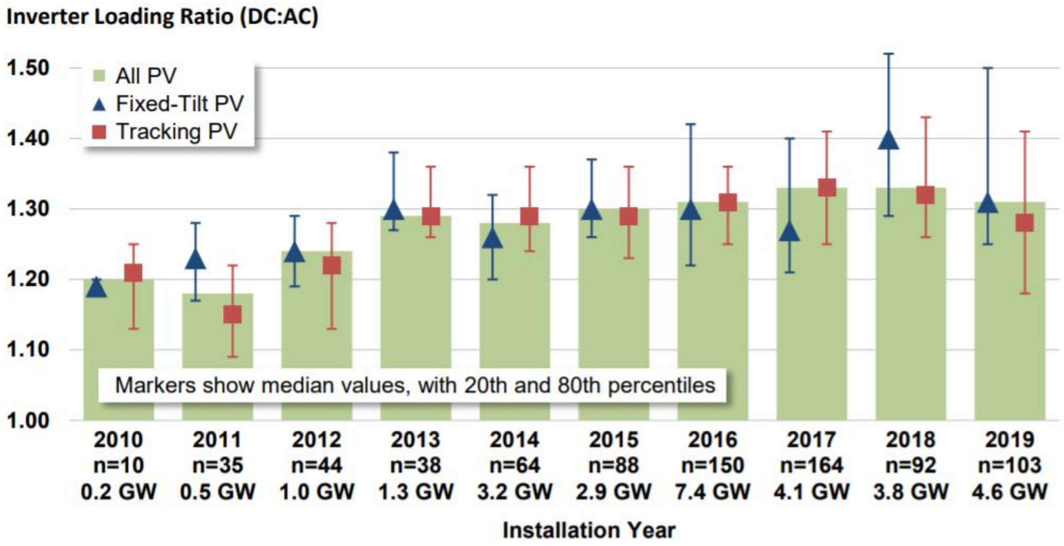

Figure 31 - Inverter loading ratio by mounting type and installation year [65]

The increasing trend on the ratio value is once again notorious and helps sustaining the hypothesis of higher ratios being associated to a breakdown on module costs over the last 10 years.

DC/AC Ratios are also impacted by the technology implemented. Fixed-tilt projects normally benefit more from increased ratios when compared to tracking systems, given their lower capacity factor. As discussed before, tracking systems typically help creating a plateau at the inverter rated capacity off peak hours, meaning higher clipping losses from an oversized photovoltaic array. An optimized tracking system would benefit from selecting a lower ratio relative to a fixed-tilt system [99].

To understand if this expected benefit is reflected on the present case-study, an additional comparison was made using tracker data that will be further detailed and purposed on section 5.4. Figure 32 shows this comparison making it clear than the IRR peak is obtained for lower values of DC/AC ratio in the case of tracking systems, proving that as expected due to the reasons stated above, fixed-tilt photovoltaic projects show better economic performance in terms of IRR for higher DC/AC Ratios than tracking systems.

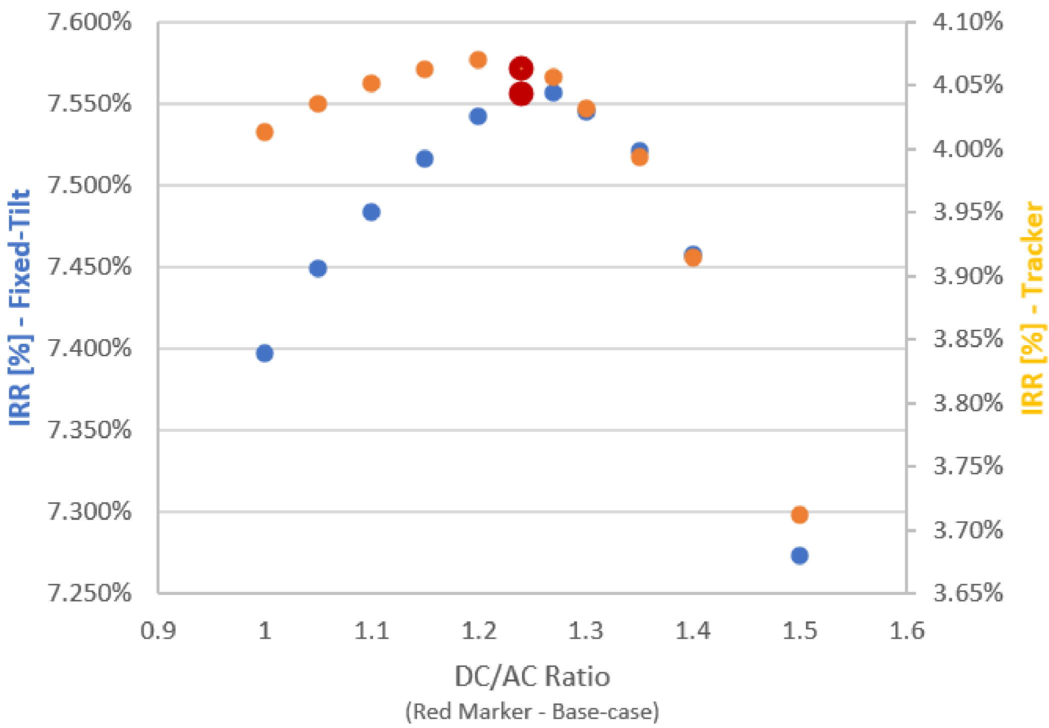

Figure 32 - IRR comparison between DC/AC ratio scenarios for fixed and tracking systems

5.3. Number of modules in series

Applying the methods described in Chapter 3, section 4.3.3, an optimization of the string length is hereby proposed.

The overly conservative industry-standard method early described is firstly used to determine the standard number of modules in series. Considering the purposed Jinko Solar module, a V_{oc} of 53.32 V is used, accordingly with the module file sent. An open circuit voltage temperature coefficient of -0.28%/ºC is also used, to obtain a value of $58.545V$ according to equation (6).

In comparison, PVSyst shows a value of 58.60 V for this parameter, obtained setting the "Internal Model Result Tool" operating temperature to -10 ºC, which is the default setting and industry-standard for the minimum temperature to be registered on site. With these values, and a Sungrow inverter with a voltage specification of 1500 V, one obtains a maximum number of modules in series of 25 units.

Using PVSyst for optimizing the calculation process for the number of modules in series is challenging, since not all variables can be adjusted. In PVSyst, only the minimum temperature value registered in the project site can be modified, and the system will not allow one to perform simulations with a different value of modules in series than the one calculated based on the above method.

The default values in PVSyst, consider the minimum temperature as $-10\ °C$, which is inadequate for the project's location, since a value that low is far from the average night temperature recorded on site (Figure 33).

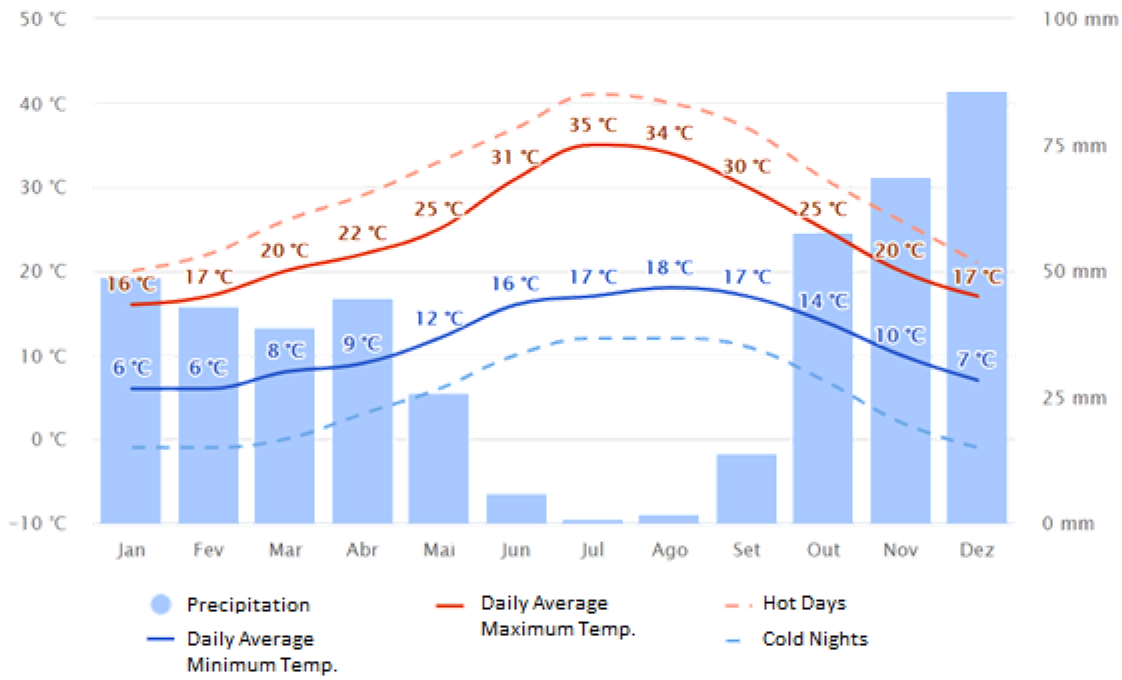

Figure 33 - Mean monthly ambient temperatures in case-study site [100]

The meteorological data provided by Galp consisted of the Solargis method [67] for a Typical Meteorological Year (TMY), which consists of the summarization of a multi-year time series, which reflects the most frequent weather conditions of a location. The dataset is specifically oriented at simulation software that can compute the electricity yield of a solar systems and is constructed by selection of most representative months from the available series which are then concatenated into one artificial and representative year. Processing this data, it is possible to assess that the minimum value ever registered in the TMY was 1°C, a temperature calculated for March 22nd at 04:30 AM, while irradiance was naturally null.

To assess the viability of an extension on original string length based on meteorological data, a value of 28 modules is now proposed, but instead of considering the overly-conservative method applied on equation (8) to calculate V_{OC}, the second method mentioned on Chapter 4 is now applied considering the influence of irradiance on the open-circuit voltage. This process is applied to every temperature and irradiance value available on the dataset for every given hour of the TMY according to equation (8) as follows:

$$Module\ V_{OC}\ (G,T) = V_{OC}{}^{\mathrm{Ref}} + \left(Tk_{V_{OC}} \times V_{OC}{}^{\mathrm{Ref}} \times (\mathrm{T} - T_{STC})\right) + \mathrm{m}\ \times V_T \times \ln\left(\frac{\mathrm{G}}{G_{STC}}\right) \quad (8)$$

At this point, it is important to state that, according to Galp, manufacturers are now certifying operation at a voltage level residually higher than the rated 1500 V, a difference that provides an extra warranty-security buffer that may accommodate sporadic situations where a dramatically low temperature can occur simultaneously with a considerable irradiation. With this in mind, scenarios where the proposed 28 modules V_{OC} exceed in more than 5% the rated voltage are evaluated using the calculation method of equation (16). Meaning, the hours of operation that fulfil the condition:

$$Module\ V_{OC}\ (G,T) \times Number\ of\ modules\ in\ series > Inverter\ Input\ Voltage + 5\% \qquad (16)$$

With these conditions, it is now possible to obtain the new $Module\ V_{OC}$ threshold which allows one to assess the number of hours that violate the condition, corresponding to $Module\ V_{OC}\ (G,T) > 56.339V$, which translates into an inverter input voltage higher than $1577.5\ V$.

TMY data set processed in Table 21 shows situations that verify the above condition, which only occurs in 8 out of 8760 hours in the virtual year. All the 8 occur at periods between 6:30 AM and 7:30 AM at low temperatures (1.6ºC – 3.8ºC), and the maximum inverter input value for voltage never exceeds 1584.31 V. Comparatively, to acknowledge that this is the best scenario, a further extension from 28 to 29 modules in series using the same processes would result in more than 1000 hours filling the condition from inequation (16), recalculated for a new limit value of $54.396V$, making that solution inviable.

Table 21 - Typical Meteorological Year – Processed information from dataset sent by Galp Energia

Day	Time	Irradiance	Temperature	V_{OC}
February 28th	06:30	54	2.6	56.515
March 1st	06:30	30	3.2	56.395
March 19th	06:30	148	4.0	56.357
March 22nd	05:30	11	1.6	56.583
December 4th	06:30	16	3.0	56.393
December 11th	06:30	16	2.6	56.453
December 23rd	07:30	109	2.9	56.506
December 24th	07:30	107	3.8	56.371

In PVSyst, it is not possible to change the irradiance values or ignore the conservative restrictions of the maximum number of modules in series calculated by the system. To bypass this protection, a non-realistic and much higher value of minimum temperature should be used, to account for the impact of irradiance.

Thus, an optimized approach is therefore proposed for overriding the $-10\ °C$ default value on "Project Settings" and "Lower Temperature for Absolute Voltage Limit". A value of $30\ ºC$ is proposed, which naturally does not correspond to the minimum temperature recorded on site but is the threshold that allows for the simulation to proceed with an optimized number of modules in series equal to 28.

The new value of 28 modules represents a significant extension of more than 10% the original size. Its advantages will be discussed in the following paragraphs, with the correspondent simulations and comparisons using the economic model.

Energy Yield simulations were conducted for both configurations of 25 and 28 modules in series, with all other parameters defined according to the case-study specifications. Results are available on Table 22, with the corresponding Specific Production and Performance Ratio.

Table 22 - Energy Yield simulations for baseline scenario (-10 ºC) and optimized scenario (30 ºC)

Energy Yield Simulations		
Scenario	Standard (-10 ºC) Without Irradiance Effect	Optimized (30 ºC) With Irradiance Effect
Modules in series	25	28
Energy Yield – 1st Year [MWh]	81,646	91,309
Specif. Prod. - 1st Year [kWh/kWp]	1,905	1,902
Performance Ratio [%]	87.62	87.47

The advantages of the optimized scenario are mainly related with BoS costs per module, which decrease since the number of modules connected to the same junction boxes and with the same cables is higher, which requires less manpower and reduces the costs associated to cable installation works. Slightly higher operation voltages can also lead to reductions in DC ohmic losses, improving power output, although in a residual way.

That economic benefit would translate in a slight increase in the unitary value for CAPEX in terms of $€/kWp$ in the case of 25 modules. This is because the original considered CAPEX unitary value was calculated based on the assumption of having 28 modules installed. A diminishing of this value would mean a higher value for inverters in $€/kWp$, among other BoS components, as explained in the previous paragraph. A summarized review of technical and economical parameters is presented in Table 23.

Table 23 - Technical and Economic parameters of string length optimization

Technical and Economic parameters of string length optimization		
Modules in Series	25	28
Number of Modules	75,175	84,196
Total Installed Capacity [kWp]	45,437	47,992
Total O&M Costs [€/year]	774,201.043	817,735,.69
Initial Investment [€]	27,194,044.5	28,723,212

The economic model is then applied to the 30 years of project lifetime. The results obtained are presented in Table 24.

Table 24 - Economic parameters variation with string lenght

String length	NPV [€]	IRR
25 modules	1,961,320.61	6.71%
28 modules	4,642,188.34	7.56%

The impact of this optimization on the IRR is an increase of 0.85%, which represents an important variation in a project of this size and reiterates the winning perspective of the optimization approach. The 11.8% increase in the Energy Yield, when compared to the cost increase, reinforces the assumption that the industry-standard calculation is not only unnecessarily conservative in terms of project safety – as demonstrated on this sub-section – but also hides the possibility of greater economic benefit.

5.4. Bifacial Modules

As seen on Chapter 4, bifacial modules are getting traction when it comes to utility-scale adoption. With the reduction in module production costs, the additional value of Energy Yield generated by this type of technology may start to be a viable option from an investment point of view. Once again, the challenge is precisely to analyse this trade-off between added cost and added production and understand if it contributes to increasing the return on the investment.

The small number of projects already commissioned that use bifacial modules makes the answer to this problem somehow complicated. As this technology is at an early stage of adoption, the absence of data means that there is a high degree of uncertainty in the actual performance of projects that are still entering first stages of exploration. Associated with this degree of uncertainty comes some risk, especially when the focus is at utility-scale projects in which there is a need to close procurement deals for the supply of hundreds of thousands of modules of a technology that is still not mature. In some situations, this risk might increase the premium associated with the construction of the project and ultimately make it more difficult to obtain financing from banks or more risk-sensitive investors.

Simulations conducted on this sub-section have the objective of comparing monofacial and bifacial module deployment in terms of Energy Yield and economic parameters. To do this, the equivalent Bifacial model from the same manufacturer was created and the electrical specifications imported to PVSyst according to the manufacturer datasheet for Jinko Solar TR JKM570M-7RL4-TV-D4 module.

Besides this change in the module file, a significant reconfiguration of the project is necessary as the use of bifacial modules is normally associated with different types of strategies to take more advantage of the rear-surface, improving the BG. As seen on Chapter 4, these reconfigurations are normally associated with height to ground and space between rows (pitch). A lower height to ground may cause self-shading on rear side of the bifacial module, while increasing this value increases the reflected light and boosts the energy yield of the system. Row-to-row distance or pitch is not considered as simulations would need a defined 3D-scene that could account for shading components. Pitch variations would also depend on available area and terrain conditions to be executed properly.

To understand this impact in the simulations, Figure 34 shows results obtained using PVSyst optimization tool to find the optimum height for bifacial modules in both fixed and tracking configurations. Albedo is assumed to be equal to 0.2 in line with Table 8, Chapter 4.

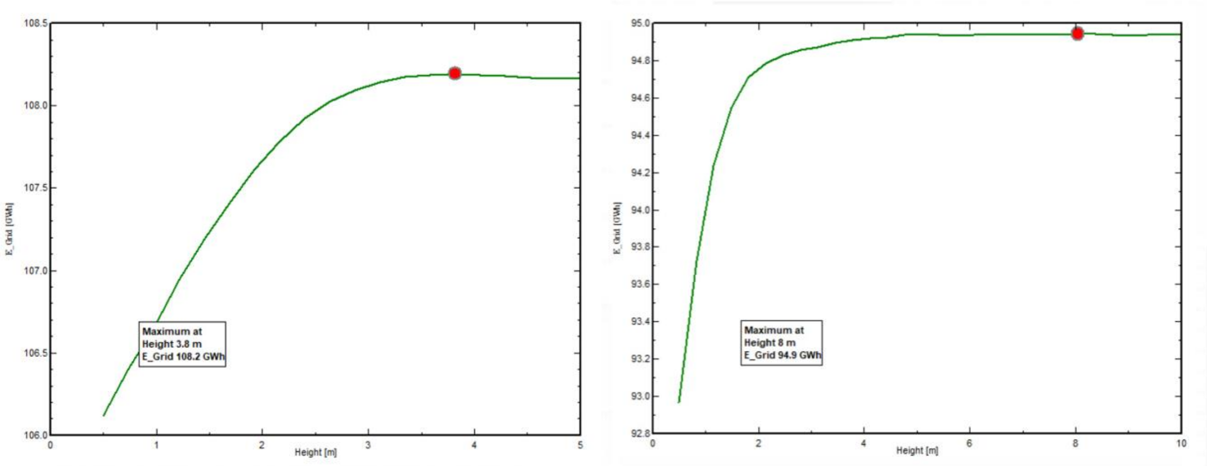

Figure 34 - Bifacial modules Energy Yield variation with height for tracking (left) and fixed systems (right) – PVSyst Simulations

Energy Yield shows a maximum at 3.8m of height for the structure in the tracking system, and a maximum at 8m for the fixed system. The considered value for base-case was of 1.5m, and any significant change on that would necessarily mean an increased expenditure on structure materials and labour. Considering this optimization scenario, the increasing in Energy Yield from the base-case to the optimum height scenario in both the fixed and the tracking options are of less than 1%. This type of gain does not naturally justify an increasing in capital expenditure, reason why the height value is kept on 1.5m for all the simulations in this chapter.

Energy Yield with fixed-tilt angle

Regarding the optimal angle in the fixed-tilt configuration, the results with a bifacial module are slightly different from the ones explored in sub-section 4.2 for monofacial modules, as shown in Figure 35. The result shows a 11.84% variation in the optimum angle. The small variation is expected since rear-face energy yield is significantly low when compared to the main face, with reviewed literature values pointing to values lower than 15% [101]–[104], which means the front face ends up having the bigger impact on the optimization process. Comparing to Chapter 4, the best angle is now of 29.8º.

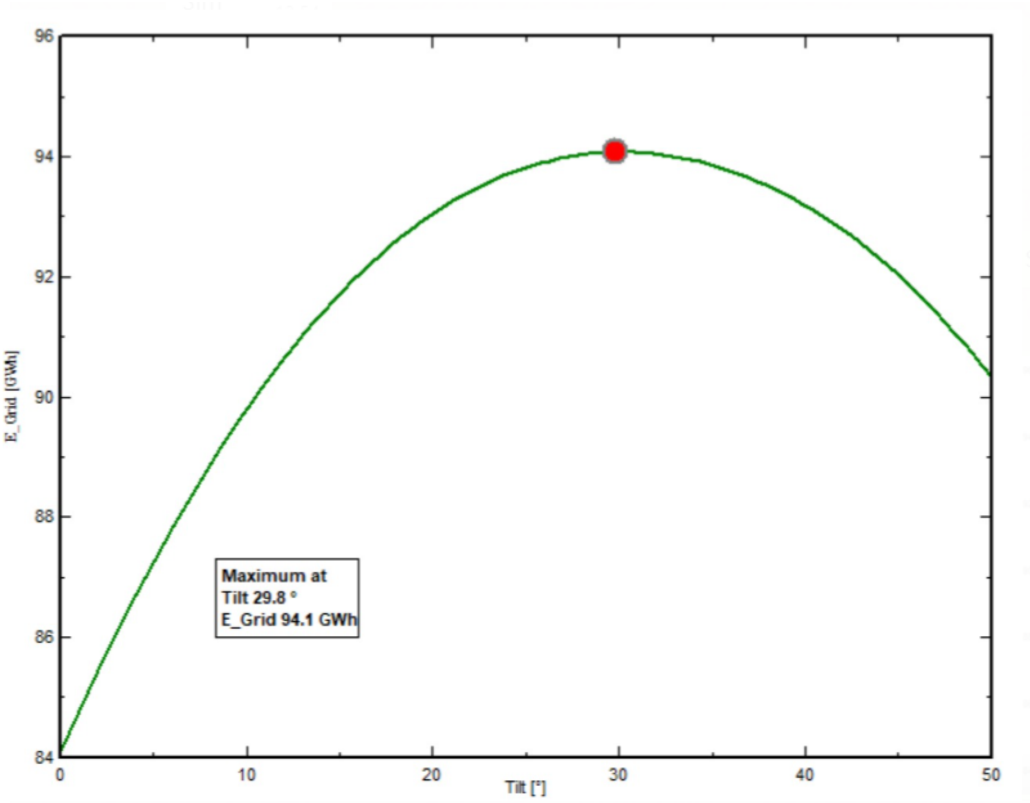

Figure 35 - Energy Yield variation with fixed-tilt angles for a bifacial module and an albedo of 0.2

Simulations shown above reiterate the importance of considering different factors in the analysis of a bifacial system, instead of simply comparing its performance with the configuration used on a normal monofacial system. Despite of that, in this case the impact measured on simulations is residual.

On the contrary, in the case of albedo, the impact is quite significant. Table 25 summarizes and compares Energy Yield for different albedo values and allows one to calculate the BG_{sys} based on the results. At this point it is important to state that Energy Yield values show a small variation (less than 1%) when compared with fixed-tilt monofacial values presented in previous sub-sections. This is because in this case the monofacial simulation is carried out by using the same bifacial module but ignoring the rear-face contribution to the production – simulating a virtual monofacial module, an option that PVSyst itself already presents. This approach makes the BG_{sys} calculation the most accurate possible, with all conditions constant in the two simulation runs, except for the bifaciality. For comparison purposes, a BG_{sys} calculated using the equivalent real monofacial module is also included, although the Energy Yield results are still not the same as in the previous chapters. This happens because the tilt angle is kept the same as the optimized angle for the bifacial system, in order to compare both systems without any further differing variable. The average of the BG_{sys} calculated using these two approaches will later be incorporated into the economic model.

As expected, an albedo closer to 1 will translate into a much bigger BG_{Sys} when compared to the 0.2 albedo case. This results also help understand the potential for dramatically different performances for bifacial systems depending on the geography of the site. As stated before, sites more usually associated with snow fall can then register much higher BG_{Sys} values during certain periods of the year.

Table 25 – Fixed-Tilt: Angle optimized for each albedo value, monofacial results with virtual module

	Albedo 0.2 (Base-Case)		Albedo 0.6		Albedo 0.95	
	Monofacial	Bifacial	Monofacial	Bifacial	Monofacial	Bifacial
Energy Yield [GWh] – 1st Year	90.86	94.07	91.19	99.54	91.48	103.64
System Bifacial Gain [%]	3.53%		9.16%		13.29%	

Table 26 – Fixed-Tilt: Angle optimized for each albedo value, monofacial results with real module

	Albedo 0.2 (Base-Case)		Albedo 0.6		Albedo 0.95	
	Monofacial	Bifacial	Monofacial	Bifacial	Monofacial	Bifacial
Energy Yield [GWh] – 1st Year	92.22	94.07	92.54	99.54	92.82	103.64
System Bifacial Gain [%]	2.00%		7.56%		11.66%	

Energy Yield with Horizontal Single-axis Tracker

Simulations were also conducted for a bifacial system deployed on a horizontal single-axis configuration, which is the most common approach, has seen before on Chapter 4. In this case, simulations were then also conducted both for monofacial and bifacial modules on a HSAT system. Summarized results are presented in Table 27.

Table 27 – HSAT: Angle optimized for each albedo value, monofacial results with virtual module

	Albedo 0.2 (Base-Case)		Albedo 0.6		Albedo 0.95	
	Monofacial	Bifacial	Monofacial	Bifacial	Monofacial	Bifacial
Energy Yield [GWh] – 1st Year	104.08	106.76	104.37	110.44	104.61	113.08
System Bifacial Gain [%]	2.57%		5.82%		8.10%	

Table 28 – HSAT: Angle optimized for each albedo value, monofacial results with real module

	Albedo 0.2 (Base-Case)		Albedo 0.6		Albedo 0.95	
	Monofacial	Bifacial	Monofacial	Bifacial	Monofacial	Bifacial
Energy Yield [GWh] – 1st Year	105.27	106.76	105.57	110.44	105.83	113.08
System Bifacial Gain [%]	1.42%		4.61%		6.85%	

The average value for BG_{sys} using the two methods is of 2.77% for the fixed-tilt system and of 1.99% for the HSAT, considering an albedo of 0.2, used in the base-case. Energy Yield and System Bifacial Gain results are in line with reviewed literature articles: Sun et al [103] state that for an albedo of 0.25, bifacial modules can only achieve a BG up to 10% when compared to monofacial options. Pelaez et al [104] concluded that single-axis trackers can boost energy yield by 4%–15% depending on module type and ground albedo. Lindsay et al. [102] calculated BG in terms of specific production (kWh/kWp) to be between 5% and 15% for albedos of 0.2 to 0.5 on fixed-tilt structures, and between 3% and 11% for single-axis trackers in comparison to standard PV plants. Ledesma et al. [101] simulated two representative fixed and tracker PV plants with an albedo of 0.3, resulting in yield increases of 8% and 7%, respectively. All of these studies sustain the results obtained, both regarding the comparison between fixed and tracking BG_{Sys} which points for an advantage in the fixed scenario, as also in the impact of albedo in the simulations. The calculated values for BG will be considered for impacts on economic model, as it will be seen onwards.

Economic considerations

To correctly compare bifacial systems with their monofacial counterparts, in terms of associated economic impacts, BG_{sys} is now used as described on Chapter 4, equation (11), and accordingly with a variation of the method suggested by the International Energy Agency (IEA) [79]. As stated previously, this approach proposes a comparison between two simulations, one with bifacial modules and one with monofacial modules, with identical properties.

The mentioned IEA method suggest that economic impacts of a bifacial system deployment should be adapted to express these changes in units of +Δ or –Δ, where Δ is roughly equivalent to the percentage of BG_{sys}. Following this approach, we use it to calculate new CAPEX and OPEX values to be incorporated on the economic model following two methods proposed by IEA:

Method A: Keeping the number of modules in the bifacial system as it was on the base-case with monofacial modules, fitting the BoS components to hold the increased current and yield. Associated economic impacts are as follows in Table 29, where Δ is roughly equivalent to the percentage of BG_{sys}:

Table 29 - Economic impacts associated to a bifacial system, as per method A

Cost Affected	Method A: no change in module number; yield increased by Δ
Cables	$+\Delta$
Inverter(s)	$+\Delta$
Transformer(s)	$+\Delta$

In this work, the suggested methodology by IEA is therefore applied to Inverters price, Electrical Supply and Installation and Grid Connection costs, which are all components of the unitary PV costs in $€/kWp$

as explained on Chapter 3. New values for theses 3 components depend therefore on the simulated BG_{sys}.

Method B: Reducing the number of bifacial modules to keep the same annual yield as produced by the monofacial system. Associated economic impacts are translated via the reduced installed capacity which multiplies by the original unitary PV cost, and which then reflects on total CAPEX.

Regarding the PV module component on the cost breakdown, module prices are the most important factor to be incorporated. Figure 36 and Figure 37 show trend in Bifacial module costs when compared to monofacial ones.

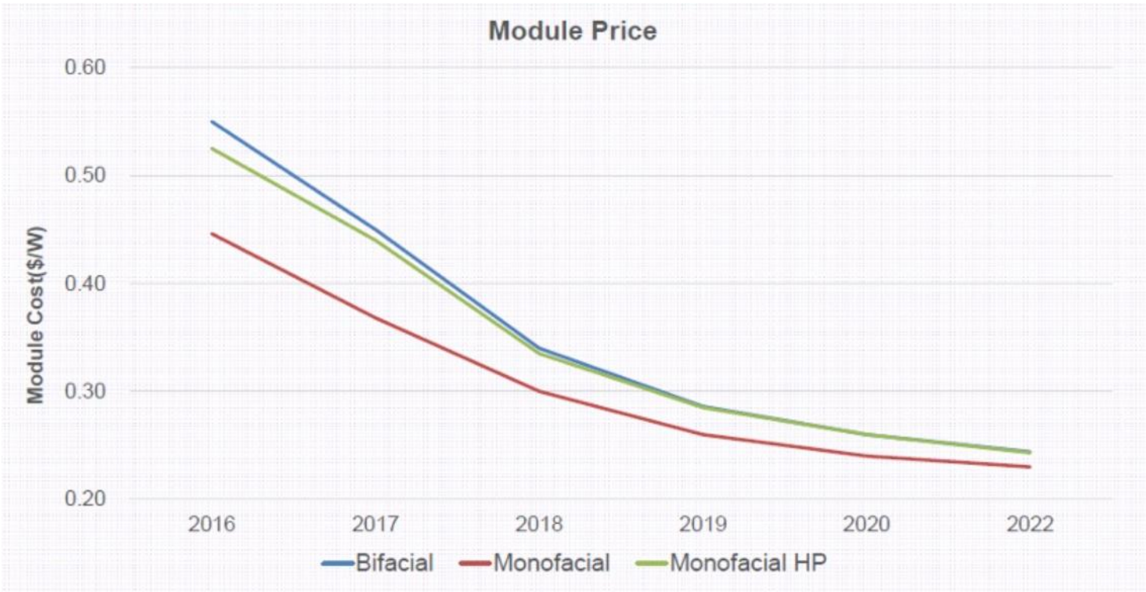

Figure 36 - Cost gap between bifacial and monofacial modules based on manufacturer information (HP stands for High Power) [105]

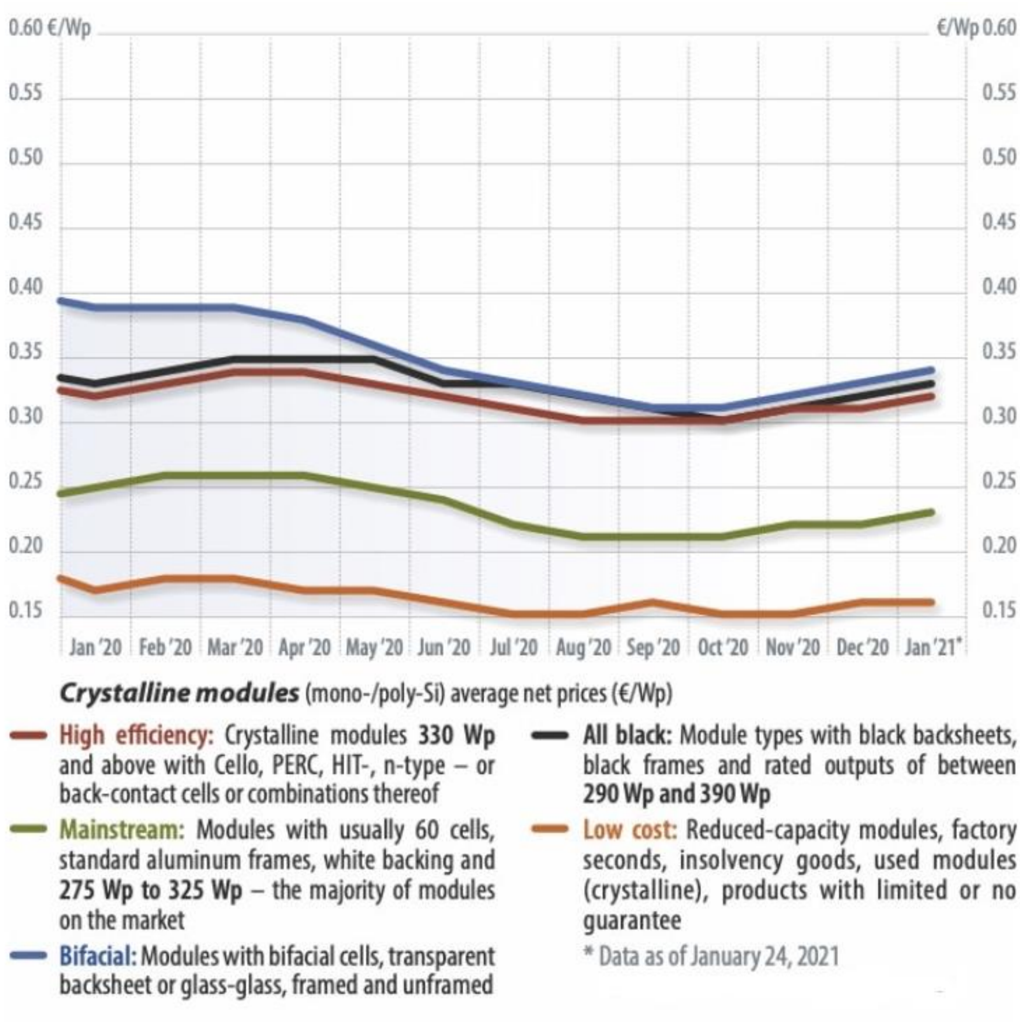

Figure 37 - EU spot market module prices by technology [105]

IRENA annual Renewable Power Generation Cost report from 2019 states that Bifacial module costs were 56% higher than monofacial modules on that year. The same report from 2020 mentions that bifacial crystalline modules sold 21% higher than high efficiency, monofacial modules during December 2019. It also adds that this cost premium fell to 6% during December 2020. Charts presented in Figure 36 and Figure 37 point in the same direction, although in a more conservative way with a bifacial premium between 10 and 40%. To include this range of prices, two pricing positions of 10% and 30% are used in this work, with the objective of understanding the impact of the variation in the bifacial deployment feasibility.

In what O&M costs are concerned, bifacial module use does not imply a significant increasing in operational expenditure. One could argument that a second module surface would mean additional surface to be cleaned, but the module cleaning values as validated by Galp only represent an insignificant percentage of the lump sum fixed fee for the O&M contract, making any increment in this field irrelevant. For this reason, O&M costs are kept constant for both monofacial and bifacial systems.

Table 30 and Table 31 summarize the changes implemented on PV unitary cost breakdown, explained in the paragraphs above. Cells coloured green show the bifacial module premium variation, while cells coloured yellow show the variations included on Method A, depending on the previously calculated values for the BG_{sys}.

Table 30 - Changes implemented on PV unitary cost breakdown as per Method A

Case	Base-case	Method A (BG_{Sys} = 1.99 and 2.77)			
Category	**Base Value [€/Wp]**	**BG_{Sys} = 1.99% 10% Scenario**	**BG_{Sys} = 1.99% 30% Scenario**	**BG_{Sys} = 2.77% 10% Scenario**	**BG_{Sys} = 2.77% 30% Scenario**
PV Modules Price	0.1800	0.1980	0.2340	0.1980	0.2340
Support for PV Modules price	0.0950	0.0950	0.0950	0.0950	0.0950
Inverter price	0.0450	0.0459	0.0459	0.0462	0.0462
Studies and analysis	0.0055	0.0055	0.0055	0.0055	0.0055
Electrical: supply and installation	0.0500	0.0510	0.0510	0.0514	0.0514
Mechanical assembly	0.0300	0.0300	0.0300	0.0300	0.0300
Transport, accessories	Included	Included	Included	Included	Included
Settings and others	0.0550	0.0550	0.0550	0.0550	0.0550
Grid connection	0.0800	0.0816	0.0816	0.0822	0.0822
Civil Works	0.0450	0.0450	0.0450	0.0450	0.0450
Insurance (building, transport, liability)	0.0130	0.0130	0.0130	0.0130	0.0130
TOTAL	0.5985	0.6254	0.6614	0.6226	0.6586

Table 31 - Changes implemented on PV unitary cost breakdown as per Method B

Case	Base-case	Method B	
Category	**Base Value [€/Wp]**	**10% Scenario**	**30% Scenario**
PV Modules Price	0.1800	0.1980	0.2340
Support for PV Modules price	0.0950	0.0950	0.0950
Inverter price	0.0450	0.0450	0.0450
Studies and analysis	0.0055	0.0055	0.0055
Electrical: supply and installation	0.0500	0.0500	0.0500

Case	Base-case	Method B	
Assembly	0.0300	0.0300	0.0300
Transport, accessories	Included	Included	Included
Settings and others	0.0550	0.0550	0.0550
Grid connection	0.0800	0.0800	0.0800
Civil Works	0.0450	0.0450	0.0450
Insurance	0.0130	0.0130	0.0130
TOTAL	0.5985	0.6165	0.6525

Considering this new cost distribution, new values for Initial Investment are obtained. Table 32 and Table 33 shows this summary, including the new installed capacity in the case of Method B columns, which was calculated to result in the same energy yield originally produced by the monofacial base-case system, as explained on Method B above. New values for Initial Investment derive from the application of changes in the unitary PV cost breakdown as previously stated in Table 31.

Table 32 - Initial investment for a Fixed-Tilt system with Albedo as 0.2

	Fixed-Tilt – Albedo 0.2			
System Bifacial Gain	2.77%			
Method	A		B	
Bifacial Module Premium [%]	10.00	30.00	10.00	30.00
Total Installed Capacity [kWp]	47,992		45,662	
Total O&M Costs [$€/year$]	817735.688		778034.818	
Adapted Initial Investment [€]	29819709	31547421	28150623	29794455

Table 33 - Initial investment for a HSAT system with Albedo as 0.2

	HSAT – Albedo 0.2			
System Bifacial Gain	1.99%			
Method	A		B	
Bifacial Module Premium [%]	10.00	30.00	10.00	30.00
Total Installed Capacity [kWp]	47,992		45,821	
Total O&M Costs [$€/year$]	856657.2		817904.85	
Adapted Initial Investment [€]	47047157.5	48774869.5	44759327.4	46408883.4

Considering these new values for economic parameters, simulations were then performed for the 30-year lifespan of the project, with Energy Yield results being implemented on the economic model considering the system degradation rate as conducted for the simulations in the previous sub-sections. IRR and NPV results are presented in Table 34 and Table 35, for fixed-tilt and tracking systems, respectively. Base-case scenario of the original fixed-tilt monofacial system is also added for comparison purposes.

Table 34 - IRR and NPV values for a Fixed-Tilt system with Albedo equal to 0.2

	Fixed-Tilt – Albedo 0.2				
	Base-Case (Fixed-tilt)	Method A		Method B	
		Premium 10%	Premium 30%	Premium 10%	Premium 30%
IRR [%]	7.56%	7.50%	6.91%	7.66%	7.05%
NPV [M€]	4.64	4.68	2.95	4.88	3.23

Table 35 - IRR and NPV values for a HSAT system with Albedo equal to 0.2

	HSAT– Albedo 0.2				
	HSAT Simulations	Method A		Method B	
		Premium 10%	Premium 30%	Premium 10%	Premium 30%
IRR	4.03%	4.65%	4.33%	4.74%	4.42%
NPV [M€]	-8.83	-6.26	-7.98	-5.56	-7.21

Overall results support several important conclusions to be addressed. Firstly, as seen on the case of monofacial modules, horizontal single-axis trackers do not show enough Energy Yield increase to justify the added value in terms of both CAPEX and OPEX, resulting in worst performances in terms of IRR and NPV. Once again, in this type of system the minimum required return rate of 6% is not achieved.

Secondly, fixed-tilt results reiterate the importance of considering a range of values for the bifacial module premium. The system achieves a better IRR and NPV when compared to the base-case if the additional price paid for bifacial modules is only 10% higher, but the conclusion is different if one considers a 30% increase on this cost. This happens for both Method A and Method B, which point to similar conclusions and contribute to the robustness of the model, with two different approaches. This conclusion makes clear the fact that an effective bifacial adoption is highly dependent on the type of procurement deal that companies close with manufacturers. With bifacial module costs continuing to drop in the coming years, this technology might then continue to see greater rates of adoption, with a cost breakdown that can justify the additional investment.

6. Link to the Portuguese case

Table 36 lists the projects that were subjected to the Environmental Impact Assessment (EIA) procedure by the Portuguese Environment Agency during the first half of 2021, whose information has been made publicly available until May 30th, 2021. The procedure is mandatory for all projects with installed power greater than 50 MWp, and may also be necessary for other specific cases - such as the location being close to smaller independent projects but whose sum of total installed power is greater than 50 MWp, or the project location including sensitive archaeological or environmental occurrences.

Table 36 - Large-scale projects subject to EIA between January 2020 and May 2021 [9]

Year	Project	AIA Id. Number	Promoter	Installed Capacity [MWp]
2021	**CSF do Cercal**	3388	Aquila Capital	282.00
2021	**CSF do Fundão**	3385	Dos Grados Capital	126.50
2021	**CSF Douro Solar**	3382	Blowing Glow LDA.	126.40
2021	**CSF de Montechoro I + II**	3375	Iberdrola	36.53
2021	**CSF da Cerca**	3374	EDP Renováveis	200.00
2021	**CSF de Lupina**	3373	Lightsource BP	265.00
2021	**CSF do Carregado**	3371	Enfinity	63.50
2021	**CSF da Falagueira**	3369	Total Portugal	128.00
2021	**CSF Adomingueiros e Nave**	3367	Glennmont Partners	98.00
2021	**CSF de Rio Maior e Torre Bela**	3363	Neoen + Aura Power	284.00
2021	**CSF THSiS**	3362	Prosolia	1,008.50
2020	**CSF dos Arrochais**	3352	SunArrochais	240.70
2020	**CSF de Margalha**	3351	Akuo Energy	144.00
2020	**CSF de Polvorão**	3346	Akuo Energy	100.00
2020	**CSF de Santas**	3345	Akuo Energy	150.00
2020	**CSF de Pinhal Novo**	3340	SmartEnergy	63.50
2020	**Parque Solar Escalabis**	3311	Energi Innovation	189.00
2020	**CSF de São Miguel do Pinheiro**	3305	Fermesolar	558.00

Through the analysis of the environmental impact study, it is possible to obtain information on some technical decisions taken during the licensing phase. It is useful for understanding the projects being currently developed in Portugal, allowing to get a grasp of the formulated engineering choices. In what regards to the engineering project, most of the EIA reports allows us to know the choice of tracking technologies, DC/AC Ratios, number of modules in series and the use of bifacial modules if it exists. Although some of these definitions may change during the time period between the issuance of the Environmental Impact Statement and the project's entry into the Ready-to-Build (RTB) phase, these are small changes and the main decisions are already mature enough to be considered as final – thus if not, they could lead to layout changes and additional environmental assessment procedures.

Among the projects considered are more than 15 different promoters, a diversity that meets the strong demand exposed in Chapter 1 and that allows for a better understanding of the identity of the main players operating in Portugal. The majority are large multinational groups that have obtained licenses through auction procedures launched by the current government in 2019 and 2020. The analysed projects represent a total of 4.1 GW of installed peak power, which means quadrupling the solar photovoltaic power installed in Portugal at the end of 2020 [10].

6.1. Fixed vs. Tracking systems

Horizontal single-axis trackers are a common choice in PV projects, usually combined with bifacial modules as seen further in the last sub-section, in the same type of configuration that was also studied in this work. As presented on Table 37, one third of the projects use fixed-tilt technology, while all the others opt for a tracking strategy. Among this last group, one-axis horizontal systems are deployed universally, sustaining the choice for this type of technology on the previous tracking sub-section of Chapter 5.

Table 37 - Technology implemented in projects subject to EIA between Jan. 2020 and May 2021 [9]

Project	Tracker Type [Fixed Tilt Angle]	Tracker Supplier	Tracker Model
CSF do Cercal	Single-axis horizontal	Soltec	SF7
CSF do Fundão	Fixed tilt [20º]	N/A	N/A
CSF Douro Solar	Fixed tilt [20º]	N/A	N/A
CSF de Montechoro I + II	Fixed tilt [18º]	N/A	N/A
CSF da Cerca	Single-axis horizontal	Not disclosed	Not disclosed
CSF de Lupina	Fixed tilt [20º] + Single-axis horizontal	Not disclosed	Not disclosed
CSF do Carregado	Single-axis horizontal	Soltec	Not disclosed
CSF da Falagueira	Single-axis horizontal	Ideematec	safeTrack Horizon
CSF Adomingueiros e Nave	Single-axis horizontal	Soltec	SF7
CSF de Rio Maior e Torre Bela	Single-axis horizontal	NEXTracker	NX HORIZON
CSF THSiS	Fixed Tilt [15°]	N/A	N/A
CSF dos Arrochais	Fixed Tilt [Not disclosed]	N/A	N/A

Project	Tracker Type [Fixed Tilt Angle]	Tracker Supplier	Tracker Model
CSF de Margalha	Single-axis horizontal	Not disclosed	Not disclosed
CSF de Polvorão	Single-axis horizontal	Not disclosed	Not disclosed
CSF de Santas	Single-axis horizontal	Not disclosed	Not disclosed
CSF de Pinhal Novo	Single-axis horizontal	Not disclosed	Not disclosed
Parque Solar Escalabis	Single-axis horizontal	Scorpius	SRT 60 ROW
CSF de São Miguel do Pinheiro	Single-axis horizontal	Not disclosed	Not disclosed

The use of trackers is heavily dependent on the slopes of the terrain where the project is located. A flat terrain is more suitable for installing trackers since manufacturers generally require a maximum slope up to 15% [106], [107], depending on the tracker model. In terrains with uneven topography, earthmoving may be a solution to keep trackers as an option, but this type of terrain changes would greatly increase the project costs, and maybe prevent the use of such technology.

Results obtained in this work indicated that HSAT adoption is not cost-effective, but it is important to understand that economic modelling considered a specific discount rate and energy pool price, which may vary on the projects addressed in the table. A different location will also result in different Energy Yield results, as irradiance and hours of sun can be different. All these factors may be responsible for a different optimization solution and reiterate the fact that research and simulations need to be carried out in all cases when closing technical decisions.

As it will be further shown on sub-section 6.4, projects that use bifacial modules are in all the studied cases except one installed using a horizontal single-axis tracking strategy.

6.2. DC/AC Ratio

Regarding the ratio between installed peak power and grid injection power, the values recorded oscillate between 1.11 and 1.41. The average value of 1.24 is close to the optimal range calculated with the economic model in this work and it is exactly the base-case value, as discussed in Chapter 5. This average value reiterates the consistency of the economic model used to demonstrate that industry-standard of 1.20 needs an update and to be evaluated in a case-to-case scenario.

The reasons for such a wide range of values can be varied. At the lower limit, with a ratio of just 1.11, the cause may be related to the lack of usable area that prevents the placement of a greater number of photovoltaic modules for a given licensed power of injection into the grid. As an example, if the terrain topography does not technically allow the installation of structures in a certain area, the maximum value for the installed peak power would therefore be limited.

At the upper limit, the involved variables would need to be further analysed to understand the reasons behind such an oversizing, but low irradiance locations could be one of the factors that impact this type of configuration. A higher DC/AC Ratio can help mitigating this site problem. Low additional investment could even make more sense in the case of fixed-tilt projects, even though this is not the case for the two projects in the 1.40 tier (both with HSAT configurations), as shown by Table 37 and Table 38. Despite that, all the addressed fixed-tilt projects have a ratio significantly higher than their tracking counterparts, with 1.26 vs. 1.19 average ratios, respectively.

Table 38 – Portuguese projects: Installed Capacity, Grid Connection and DC/AC Ratio values [9]

Year	Project	Installed Capacity $[MWp]$	Grid connection $[MVA]$	DC/AC Ratio
2021	**CSF do Cercal**	282.00	223.6	1.26
2021	**CSF do Fundão**	126.50	110	1.15
2021	**CSF Douro Solar**	126.40	100	1.26
2021	**CSF de Montechoro I + II**	36.53	30	1.22
2021	**CSF da Cerca**	200.00	142	1.41
2021	**CSF de Lupina**	265.00	220	1.20
2021	**CSF do Carregado**	63.50	50	1.27
2021	**CSF da Falagueira**	128.00	100	1.28
2021	**CSF Adomingueiros e Nave**	98.00	84	1.17
2021	**CSF de Rio Maior e Torre Bela**	284.00	215	1.32
2021	**CSF THSiS**	1,266.00	1143	1.11
2020	**CSF dos Arrochais**	240.70	206	1.17
2020	**CSF de Margalha**	144.00	120	1.20
2020	**CSF de Polvorão**	120.00	100	1.20
2020	**CSF de Santas**	180.00	150	1.20
2020	**CSF de Pinhal Novo**	63.50	48.9	1.30
2020	**Parque Solar Escalabis**	189.00	135	1.40
2020	**CSF de São Miguel do Pinheiro**	558.00	480	1.16

6.3. Number of modules in series

Most environmental impact studies do not go into detail regarding the technical decisions associated to the number of modules in series in each of the strings, and some of them do not even disclosed the string length. In the few that do, the technical information that allows for calculating the V_{oc} value, as described in Chapter 4, is not always available, as one must know the specified module electrical specifications to perform the calculation. Nonetheless, of the 10 projects in which it was possible to apply the proposed approach - meaning, in which the module model was disclosed - it was found that only two of them propose a string length with more modules than the conservative -10ºC scenario previously described on Chapter 4 and Chapter 5.

Table 39 – Portuguese projects: String sizing calculations with module and inverter information [9]

Project	Module Model	Inverter Model	V_{OC}	$Tk_{V_{OC}}$	Max V_{OC}	Inverter Max Input Voltage	Max String Length	Proposed String Length	Max String Length Floored
CSF do Cercal	Jinko Solar JKM510M-7TL4-TV Bifacial	KACO Blueplanet 125 TL3	49.14	-0.0028	53.956	1450	26.874	26	26
CSF do Fundão	LONGi LR5 – 72HBD-530M	Huawei SUN2000-185KTL-H1	49.2	-0.00284	54.090	1500	27.731	26	27
CSF de Lupina	Trina Solar TSM-500 Deg 18	Sungrow SG2500HV	51.5	-0.0025	56.006	1500	26.783	28	26
CSF do Carregado	Trina Solar TSM-550 Deg 19	Sungrow – SG 3125HV	37.9	-0.0025	41.216	1500	36.393	34	36
CSF da Falagueira	Trina Solar TSM-DEG17M.20(II)	Ingecon Power Max Dual B Series	49.7	-0.0025	54.049	1500	27.753	27	27
CSF Adomingueiros e Nave	Jinko Solar JKM460M-7RL3-V	Sungrow – SG 3125HV	51.7	-0.0028	56.767	1500	26.424	26	26
CSF de Rio Maior e Torre Bela	LONGi LR4 – 72HBD	SG250HX	49.4	-0.00284	54.310	1500	27.619	28	27
CSF THSiS	LONGi LR5 – 72HBD-530M	HEMK FS3670k	49.2	-0.00284	54.090	1500	27.731	28	27
Parque Solar Escalabis	Suntech Superpoly STP	Delta Electronics M88H	46.2	-0.0033	51.536	1100	21.344	22	21
CSF de São Miguel do Pinheiro	First Solar FS-6440	SMA SC 2500	220	-0.0028	241.560	1500	6.210	6	6

A thoroughly analysis considering meteorological studies for each site location would have to be conducted to acquire values for temperature and irradiance and consequently calculate new thresholds for number of modules in series. Instead, projects most likely rely on the normal fixed irradiance approach. These studies, thus, follow an ultra-conservative perspective of the maximum assumed value for the voltage in the inverter, which represents a potential loss in the order of 12% of the annual Energy Yield, as already discussed in Chapter 5.

The reason for this lack of optimization may be related to outdated industry practices, but the number of modules in series might also be calculated exclusively using an automatic calculation software such as PVSyst, which, as we have seen, assumes an unnecessarily conservative scenario as well. An additional point may be related with the bankability of the projects – if not done properly, the calculation might not be certified and end up representing an obstacle for strict project financing rules, which is why a conservative approach by the book might be used.

6.4. Bifacial Modules

Regarding the use of bifacial modules, although only a few projects are already built and in operation, the adhesion to this recent technology is surprisingly high, as shown in Table 40. Also, simulation software such as PVSyst are still developing and further fine-tuning their Energy Yield prediction tools associated with bifacial modules, making the design of this type of technology still shrouded in some uncertainty.

Table 40 – Portuguese projects: module characteristics [9]

Project	Module Technology	Module Supplier	Module Model	Module Peak Power
CSF do Cercal	Bifacial	JinkoSolar	JKM510M-7TL4-TV Bifacial	$510\ Wp$
CSF do Fundão	Bifacial	LONGi Solar	LR5 – 72HBD-530M	$530\ Wp$
CSF Douro Solar	Monofacial	Not disclosed	Not disclosed	$450\ Wp$
CSF de Montechoro I + II	Monofacial	Not disclosed	Not disclosed	$400\ Wp$
CSF da Cerca	Bifacial	Not disclosed	Not disclosed	$440\ Wp$
CSF de Lupina	Monofacial	Trina Solar	TSM 500 Deg 18	$500\ Wp$
CSF do Carregado	Bifacial	Trina Solar	MA/Vertex 550W TSM-DEG19C.20	$550\ Wp$
CSF da Falagueira	Bifacial	Trina Solar	TSM-DEG17M.20(II)	$450\ Wp$
CSF Adomingueiros e Nave	Monofacial	Jinko Solar	JKM460M-7RL3-V	$460\ Wp$
CSF de Rio Maior e Torre Bela	Bifacial	LONGi Solar	LR4 – 72HBD	$445\ Wp$
CSF THSiS	Monofacial	LONGi Solar	LR4 – 72HPH-440M / LR5-72HPH-530	$440\ Wp$ e $530\ Wp$
CSF dos Arrochais	Not disclosed	Not disclosed	Not disclosed	$435\ Wp$
CSF de Margalha	Bifacial	Not disclosed	Not disclosed	$525\ Wp$
CSF de Polvorão	Bifacial	Not disclosed	Not disclosed	$405\ Wp$
CSF de Santas	Bifacial	Not disclosed	Not disclosed	$405\ Wp$

Project	Module Technology	Module Supplier	Module Model	Module Peak Power
CSF de Pinhal Novo	Not disclosed	Not disclosed	Not disclosed	$410\ Wp$
Parque Solar Escalabis	Monofacial	Suntech Power	Superpoly STP	$330\ Wp$
CSF de São Miguel do Pinheiro	Monofacial	Firstsolar	FS-6440	$440\ Wp$

Despite the results obtained with the economic model proposed in this dissertation, the price of the components, considered in the Initial Investment (in €/Wp), is one of the factors to which the economic parameters are more sensitive. Projects in environmental licensing phase have not closed procurement deals yet and may propose bifacial integration as worst-case scenario, that allows them to go back to a monofacial option in a later development stage if necessary.

As seen on this work, it is now possible to get a better economic performance using this type of technology and some sources already mention an increase in costs of 10% or less, so project promoters should shoot for the objective of closing procurement deals with manufacturers that allow then to meet lower price premiums. Contracts signed for several projects simultaneously might be an important strategy to capitalize scale economies and influence the cost of technologies such as bifacial modules.

7. Conclusions

The solar energy industry is bound to experience some of its most impacting changes on the upcoming years. While this work was on the last stages of development, a new report by BloombergNEF [108] stated several milestones that will need to be achieved by 2030 for the society to be on track to reach net zero emissions by mid-century – one of them is the need of building at least 455 GW of solar generation capacity annually, until 2030. This happens as the same time as Europe makes progress in implementing a roadmap for decarbonisation with the presentation of the new Fit for 55 climate package [109]. This set of legislative proposals aim to ensure that the European Union fulfils the target of a 55% reduction in net greenhouse gas emissions by 2030, compared to 1990.

Work conducted on this dissertation had the objective of contributing to this new reality by developing new analysis and optimizations to be incorporated on developing solar projects. Conducted work sustains the thesis that after a technical analysis and optimization, it is essential that the associated economic impact is also addressed to opt for the most viable option. Alternatives that increase energy yield are not always translated in greater economic benefits and a failure to incorporate this component might endanger project viability. This is especially relevant in the four subjects covered on this work: the use of tracking mechanisms, DC/AC ratio definition, string length sizing and the use of bifacial modules.

The strongly adopted configuration of including horizontal single-axis trackers was shown to underperform in terms of economic behaviour when compared to the original fixed-tilt base-case. HSAT represented a 9.06% increase in Energy Yield, but the trade-off meant a reduction in the IRR and NPV from 7.56% to 4.03% and from 4.64M€ to -8.83M€. Dual-axis technology usage was shown to be totally unfeasible with an IRR of 0.9% and an NPV of -34.32M€ and justifies the fact that this technology is not being deployed at utility-scale projects in Portugal.

In terms of DC/AC Ratio, simulations show that Energy Yield is maximized with an increasing DC array oversizing, but the optimum point in terms of IRR and NPV was found for ratio values of 1.30 and 1.35, respectively, with subsequent drops in this indicators for further increased values of DC/AC ratio. The optimized system configurations represented a surge in NPV when compared to the base-case, improving from 4.64 M€ to 4.92 M€, while calculated IRR was similar.

String length extension was also proven to be an effective way of better using the available resources to harvested additional energy without significant additional economic effort. Overriding outdate conservative project methods translated in 11.80% Energy Yield increase, with the corresponding reflection on the economic model, increasing IRR and NPV from 6.71% to 7.56%, and from 1.96 M€ to 4.64 M€.

Regarding Bifacial modules, simulations were conducted for both fixed-tilt and HSAT configurations, with the first showing better performance not only in terms of BG but also in IRR and NPV. Fixed-tilt bifacial shown an average IRR of 7.28% and NPV of 3.93 M€ against 4.54% and -6.75 M€ on the case of HSAT bifacial configuration.

One of the most important factors was the bifacial module premium, which severely impacted the results. In the fixed-tilt case, a premium of only 10% when compared to the monofacial counterpart resulted on an average IRR of 7.58% and an average NPV of 4.78 M€, while a 30% increase resulted on an average IRR of 6.98% and an average NPV of 3.09 M€.

All considered results observe the available room for improvement when it comes to the overall quality of deployed projects. The 30-year long nature of projects and the distinct interests shared among project developers and long-term asset managers might sometimes be the root cause for an under-optimized project. The complexity involved in the licensing and development stage often involves tight deadlines to submit project documentation, layouts, and technology specifications to several entities, meaning companies end up opting for standardized approaches and limit optimization. Although this might be a safer approach to guarantee licensing deliverables, it means that less time and resources are invested in research, simulation, and optimization, which may jeopardize further gains along the project lifetime.

Future Work

During May 2021, as this work neared its final form, the IEA published a change in forecasts for the growth of wind and solar energy around the world. The review indicated a 25% increase to what was expected just six months earlier, at the end of 2020. IEA forecasts 40% higher growth in 2021 than the previous year and puts wind and solar energy at the level of the installed capacity for natural gas production in 2022. This demonstrates the strong growth that is being registered in the large-scale photovoltaic solar energy industry, a technology that, put into perspective considering growth forecasts, is still in an embryonic stage.

For this reason, a Future Work of strong academic and business interest would be to compare measured data from photovoltaic parks in operation to the simulations here presented, and further enrich the conclusions. More in-depth work, based on the long-term monitoring of the production of the parks that are now coming into operation, could be crucial to confirm the forecasts here discussed and help to develop tools that can contribute to increasing the effectiveness of this type of projects.

Another aspect that is gaining more relevance is the adoption of large format modules, which are beginning to approach powers around 700 W [110] per photovoltaic solar panel. This technical solution may be relevant in projects where the terrain limitations are several and require a greater allocation of power per area, something that later ends up affecting the entire arrangement and configuration of strings and inverters.

The mentioned growth will also bring new technical solutions that should be considered as hypotheses. An example would be integrating wind turbines and PV capacity in a single location to explore energy transmission infrastructure synergies – something already foreseen in legal terms, and which some promoters are beginning to develop in Portugal, the so-called hybridization of wind or solar parks. Other example is the integration of energy storage solutions in the form of lithium batteries or electrochemical processes such as hydrogen production through electrolysers.

Since this type of projects are all capital intensive, often integrated by multiple entities, the long-term viability must always be evaluated by combining both the engineering and economic perspectives. Thus, before taking any technical decision that impacts resource management, it is important to look beyond technical optimization, carefully measuring the real impacts on revenue that this type of technical solution can bring.

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Appendix A

Newspaper article on covered subject

Pending publishing on Order of Engineers “INGENIUM” magazine.

CONQUISTAS E DORES DE CRESCIMENTO DO SOLAR EM PORTUGAL

Um retrato da indústria solar fotovoltaica portuguesa

ACHIEVEMENTS AND GROWING PAINS OF SOLAR PV IN PORTUGAL

A picture of the Portuguese solar photovoltaic industry

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Resumo: *Este artigo aborda a problemática atual do desenvolvimento da energia solar fotovoltaica em Portugal, nomeadamente as conquistas e as dores de crescimento. De acordo com dados recentes, existem pedidos de instalação de cerca de 17 GW de potência o que corresponde a 17 vezes a potência atualmente instalada em centrais fotovoltaicas. Menciona-se que os próprios promotores estão dispostos a financiar os custos de reforço da rede para permitir a injeção destas quantidades de potência. Aborda-se a solução encontrada para promover esta fonte de energia renovável – os leilões solares. Perspetiva-se o próximo leilão solar dirigido a parques solares flutuantes e analisa-se a possibilidade de combinar a agricultura com a produção fotovoltaica com vista a limitar o espaço ocupado. Finalmente, discute-se a impressionante descida de custos de instalação que tem impulsionado a dinâmica a que se assiste atualmente.*

Palavras-chave: Energia solar fotovoltaica; Rede de transporte e distribuição de energia; Leilões de energia fotovoltaica; Fotovoltaico flutuante; Agri-fotovoltaico; Bairros solares; LCOE.

Abstract: *This article addresses the current development of solar photovoltaic in Portugal, namely the achievements and the growing pains. The available data shows plans for the installation of about 17 GW, which is 17 times the currently installed capacity in photovoltaic power plants. It is mentioned that the promoters are willing to finance the costs of reinforcing the grid to allow the injection of these huge amounts of power. The solution found to promote this renewable energy source – solar auctions – is addressed. Moreover, the next auction dedicated to floating solar parks and the possibility of combining agriculture with photovoltaic production to limit the space occupied are envisaged. Finally, the impressive decrease in installation costs in recent years is analyzed and discussed.*

Keywords: Solar Photovoltaics; Transmission and distribution grid; Solar auctions; Floating Photovoltaics; Agrivoltaics; Solar Neighborhoods; LCOE.

Introdução

O Sol de Portugal é, atualmente, um dos mais desejados do mundo. Nos últimos 2 anos, a indústria das grandes centrais solares fotovoltaicas tem brindado o país com uma verdadeira avalanche de novos projetos a entrarem em fase de licenciamento. Pondo o assunto em números: Portugal tinha, até ao final de 2020, a modesta capacidade solar instalada de apenas 1 GW (contra mais de 5GW instalados em centrais eólicas). De acordo com os dados divulgados pela Direção-Geral de Energia e Geologia (DGEG) [1], existem neste momento mais 80 projetos em fase inicial, elegíveis para conquistar a sua hipótese de injetar energia verde na rede portuguesa. No seu total, esses projetos somam cerca de 17 GW de potência instalada, o que, conforme indicado, representa exatamente 17 vezes a capacidade solar já construída e a operar e praticamente o mesmo que o país já tem de capacidade instalada se somarmos todas as fontes de energia existentes.

Figura 1 – Central Solara4, Alcoutim

Problemas de crescimento – os constrangimentos da rede

O interesse é tanto que são os próprios investidores a assumir os custos de reforço da infraestrutura auxiliar que permite escoar a energia produzida, através de acordos diretos com o Transmission System Operator (TSO), posição que em Portugal é assegurada pela REN (Redes Energéticas Nacionais). Este tipo de acordo resolve um dos problemas que neste momento formam o bottleneck do desenvolvimento solar: a rede de transporte e distribuição de energia em Portugal não está a acompanhar o crescimento das grandes solares fotovoltaicas. Apesar disso, as condições para a produção solar são tão boas em

Portugal que os próprios produtores estão disponíveis para cobrir os custos de melhoramento da rede pública de infraestruturas de elevação de tensão e transporte de energia.

Neste momento, a complexa rede energética nacional está em vias de ser reformulada por um investimento privado total previsto da ordem de grandeza das centenas de milhões de euros, associado a centrais que já produzem em regime de mercado - sem feed-in tariffs, oneração para o consumidor, ou para o contribuinte. Este aparente problema está assim a transformar-se num pequeno jackpot para o consumidor português de energia. A título de exemplo, uma central de larga escala com 250MW faz, em média, um investimento superior a 20 milhões de euros em infraestruturas de transmissão. Estamos a falar de um valor que seria incomportável para os bolsos do consumidor final que desde há décadas tem contribuindo para o desenvolvimento da tecnologia solar através das já extintas feed-in tariffs. A reconfiguração e atualização da rede portuguesa está a ser financiada por privados, que investem milhões de euros em linhas que depois são passadas a custo zero para o TSO e o Distribution System Operator (DSO), neste caso, uma empresa do grupo EDP (Energias de Portugal). Através do investimento em infraestrutura capaz de escoar a energia produzida, a rede nacional está a ver múltiplas subestações a nascer e várias novas linhas de média, alta e muito alta tensão a serem construídas em zonas do país em que o investimento era tipicamente parco.

A forte procura por parte das empresas por contratos de fornecimento de energia limpa está a contribuir para a entrada de cada vez mais investidores multinacionais neste ramo de mercado, com o objetivo de colmatar essa lacuna. A alocação de fundos à construção de projetos fotovoltaicos, assegurando mais tarde contratos de tipo Power Purchase Agreement (PPA) para a venda da energia produzida que resulta em cash-flows estáveis e garantidos associados à venda, faz com que esta seja uma estratégia de investimento difícil de bater.

E há mais, já que os 80 projetos anteriormente mencionados se juntam a um conjunto de 14 outros que já têm um acordo fechado e estão prontos para avançar [2]. Este grupo totaliza já 3.5 GW de capacidade instalada. E mesmo esses estão também a enveredar apenas por uma das várias vias possíveis para obter uma autorização para produzir. Em 2019 e 2020 o atual governo português estreou uma nova modalidade de atribuição de pontos de injeção na rede através de um mecanismo concorrencial, sob a forma de leilão, que deu aos interessados a possibilidade de arrematarem títulos de reserva de capacidade em troca de um contrato para venda da energia a um preço fixado em leilão. A capacidade adicional atribuída foi de mais 2 GW e a ideia passa por manter esta iniciativa ao longo dos próximos anos.

O problema da área ocupada e as soluções fora da caixa

No caso do leilão conduzido em 2020, os lotes lançados pelo governo português também consideravam a possibilidade de associar tecnologias de armazenamento aos projetos e incluíam um sistema de cálculos adicionais para comparar as várias propostas de um ponto de vista do Valor Atual Líquido. A corrida aos pontos de acesso à rede em sistema de livre concorrência tem resultado em sucessivos recordes do preço dos acordos celebrados, já que nesta modalidade de leilão as empresas assumem *que vão vender a energia que produzem durante 15 anos, mas posteriormente ficam com um ponto de injeção na rede sem data de expiração, podendo celebrar contratos em moldes de PPA nos termos em que melhor lhes convier e com a entidade com a qual escolherem negociar. Esta realidade resultou em preços que constituíam, na altura, novos recordes no preço de venda ao atribuir um lote com um preço garantido de venda de energia a 14,76€ por MWh em 2019, renovando esse mesmo recorde no ano seguinte com um valor de 11,14€ por MWh e provando assim o valor daquilo que se transforma num verdadeiro ativo: um ponto de injeção na rede em Portugal [3]. Em perspetiva, no ano de 2019, o preço médio ibérico no mercado grossista rondou os 48€ por MWh.*

A versão de 2021 desse Leilão, que tem vindo a ser conduzido anualmente, vai debruçar-se em exclusivo sobre uma tecnologia distinta e de adoção ainda reduzida: os painéis fotovoltaicos flutuantes. Existem alguns projetos-piloto em Portugal, nomeadamente um sistema instalado pela EDP há cerca de 5 anos na barragem do Alto do Rabagão, em Montalegre, que permite assim complementar a energia hídrica da barragem com a energia solar de 840 módulos fotovoltaicos [4]. Instalação similar está agora em fase de projeto na barragem do Alqueva, com uma escala bastante maior [5].

Figura 2 – Projeto solar fotovoltaico flutuante da EDP na Barragem do Alto Rabagão

Os custos associados a este tipo de instalação são ainda bastante desconhecidos e o know-how para a implementar é reduzido, mas a modalidade vem dar resposta aos anseios de uma fatia da população que começa a ver no desenvolvimento das centrais de grande escala um problema relacionado com a extensa área necessária e consequentes impactes paisagísticos. Os promotores em Portugal têm vindo *a desenvolver cada vez mais medidas para mitigar esta realidade, mas os projetos solares flutuantes constituem uma nova alternativa para recorrer a uma área que de outro modo não seria utilizada. A junção contribui ainda para uma certa simbiose entre os painéis e o espelho de água, por resultarem na diminuição da temperatura dos primeiros e consequente aumento de eficiência, e também pela diminuição da evaporação de água nos segundos. No final das contas, são projetos que se adaptam ao território disponível e em que certamente não veremos serem quebrados recordes ao nível dos preços, mas que são importantes em nome da versatilidade das soluções disponíveis.*

Outras soluções para complementar a forte procura dos investidores em projetos de grande escala têm surgido como cogumelos. A combinação entre agricultura e produção fotovoltaica, com o intuito principal de criar sinergias e limitar a área ocupada, é um dos focos mais recentes de interesse. O Ministério da Agricultura português lançou um apoio especial de 10 milhões de euros para financiar projetos que incluam estas duas áreas de atuação [6]. A combinação de produção agrónoma com módulos pode trazer também ela benefícios simbióticos, por exemplo, através do cultivo de várias espécies de plantas que ficam mais protegidas de fenómenos meteorológicos. Outra vantagem pode passar pela combinação de rebanhos de ovelhas que contribuem para o controlo da vegetação que eventualmente poderia causar sombras nos módulos, recebendo em troca uma bem-vinda sombra debaixo das estruturas, algo que resulta numa redução da quantidade de água consumida pelos animais.

Figura 3 – Exemplo de aplicação do conceito de projeto agrivoltaico

Outras tendências surgem no apoio à produção descentralizada, com o ano de 2021 a tornar-se, muito provavelmente, no ano de arranque de várias iniciativas ligadas ao desenvolvimento de "bairros solares" e de produção comunitária a um nível local. Ainda que a produção em grande escala seja mais eficiente do ponto de vista dos custos envolvidos, estas são também peças importantes de um puzzle *que inclui ainda tecnologias de hibridização entre energia eólica e solar num único ponto de injeção na rede, tirando proveito da complementaridade dos dois recursos para maximizar a utilização das infraestruturas. O mesmo interesse está a ser despertado em investidores nacionais e internacionais para projetos que integrem a possibilidade de armazenamento da energia produzida, seja com o recurso a baterias de lítio, seja através da utilização do excedente para a produção - através de eletrolisadores alimentados por energia solar fotovoltaica - de Hidrogénio verde e/ou Amoníaco.*

A adaptação e o empurrão das petrolíferas

Do ponto de vista ambiental, Portugal afigura-se também como um showcase do impacto que a economia de mercado e a pandemia Covid-19 tiveram no negócio core das petrolíferas. A indústria da extração, refinação e distribuição de Petróleo é desde há várias décadas uma das mais lucrativas do mundo, mas mesmo os players dessa envergadura têm vindo a ser cada vez mais pressionados para se adaptar, reinventar e reestruturar as suas operações, alinhando-se com a consciencialização dos clientes e a alteração nos hábitos de consumo, numa junção de forças em que o ambiente sai a ganhar.

Empresas como a Galp, Repsol, Total e BP têm neste momento em curso operações de avultado investimento para a entrada na indústria da produção de energia solar portuguesa. No caso da Galp, a empresa é neste momento o maior player de energia fotovoltaica da Península Ibérica em termos de projetos em pipeline e iniciou recentemente a construção de um dos maiores parques de energia limpa em Alcoutim. O compromisso que em dezembro de 2020 foi escrito na pedra com a assinatura de um pacto de cooperação entre vários gigantes mundiais do sector, como a BP, Eni, Equinor, Occidental, Repsol, Royal Dutch, Shell, Total e Galp, para acelerar o contributo da indústria petrolífera para as reduções nas emissões de gases de efeito de estufa. Um marco importante dado o peso das petrolíferas em termos de know-how, infraestruturas e capacidade de investimento [7].

Outros fatores impulsionadores – o papel político e o papel da tecnologia

Os últimos anos em Portugal têm também sido férteis em aguerrido escrutínio público com uma perseguição cada vez mais cerrada às grandes indústrias poluidoras. Por conseguinte, a integração de energias renováveis no mix de consumo das populações é hoje um dos principais objetivos do país. O Plano Nacional Energia e Clima para 2030 (PNEC 2030) definiu especificamente a meta de 9 GW de energia solar fotovoltaica instalada e a operar até ao final da década, assumindo um ponto de partida de 2 GW instalados em 2020 [8], algo que já não se confirmou e que aumenta a pressão nesta meta. O objetivo é arrojado e reiterado pelo Roteiro para a Neutralidade Carbónica 2050 (RNC2050), que estabelece a fasquia de atingir 100% de produção de eletricidade renovável em 2050, reduzindo as emissões de gases com efeito de estufa em 85 a 99% do que eram em 2005 [9].

Prevê-se que a Energia Solar Fotovoltaica contribua com peso nesse caminho, catapultada pela forte quebra nos custos da cadeia de produção de energia a partir do Sol - com reflexo imediato no Levelized Cost of Energy (LCOE). Este indicador permite avaliar a performance económica de tecnologias *complexas e cujos custos se estendem muitas vezes ao longo de um período temporal extenso, avaliando qual é a forma mais barata de produzir energia. Em 2020, o LCOE das tecnologias de produção solar de grande escala desceu pela primeira vez abaixo do LCOE das Centrais de Ciclo Combinado, e a tecnologia solar é hoje, a par da eólica, a tecnologia de produção que permite obter energia a um custo mais reduzido [10]. Segundo os dados da IRENA recolhidos a partir de mais de 17 mil projetos em 2019, os custos da produção solar caíram 82% desde 2010 [11].*

No caso das centrais fotovoltaicas de grande escala, o decréscimo do LCOE é rampante: 11% por ano durante os últimos cinco anos [10], um fenómeno causado pela apresentação sucessiva de novas soluções para módulos (90% de diminuição no preço desde 2010), inversores, trackers e metodologias de projeto, que foram forçadas a desenvolver-se por culpa de uma grande competição entre produtores espalhados por todo o mundo. O corte nos custos tem levado a uma corrida ao investimento tecnológico e ao desenvolvimento de soluções técnicas capazes de tornar a tecnologia solar fotovoltaica ainda mais competitiva, mas nem sempre mais sustentável. A produção de módulos com condições de trabalho difíceis de escrutinar tem sido um dos principais problemas na sustentabilidade da indústria, mas contra os quais alguns players-chave da produção de módulos já se insurgiram.

Conclusões

Apesar de todas as dores de crescimento, ainda no mês passado (Maio 2021) a Agência Internacional de Energia (IEA) modificou as suas previsões iniciais para o crescimento global da energia eólica e solar em mais 25% em comparação com os números publicados apenas seis meses antes. A IEA prevê um crescimento 40% maior em 2021 do que o do ano anterior, e coloca mesmo a capacidade de energia eólica e solar ao nível da capacidade instalada de produção a gás natural em 2022 [12]. Os problemas fazem parte de uma tecnologia que se está a expandir de forma explosiva e a indústria como um todo tem que se unir para os resolver. Nesse caso, espera-se um futuro risonho.

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