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Article

Economic Analysis and Modelling of Rooftop Photovoltaic Systems in Spain for Industrial Self-Consumption

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Abstract: This article has been developed to assess the economic feasibility of a rooftop photovoltaic installation of industrial self-consumption. Numerical models that enable an interested person to obtain the main expected parameters will be generated, with those models being the article's main contribution to the field. To do this, a calculation methodology will be developed through which the reader, knowing the location of the facility and dimensions of the roof, will be able to calculate the maximum installable power, the main parameters related to production, the cost of the installation, and the LCOE of the plant. The use of actual costs will be facilitated in case they are known. Still, it will remain possible to apply the major equipment costs (modules, inverter, and structure) considered throughout the article. This developed calculation methodology will also allow a quick comparison of the forecasts of production, CAPEX, and LCOE of plants designed with different inclinations and different types of modules. Consequently, it will be especially useful in decision-making before developing the plant's basic engineering. Moreover, the calculations used for modeling the LCOE will be analyzed in depth. This analysis will allow evaluating how the different technical variables affect the profitability of a photovoltaic installation, such as the selected tilt, the location, the module's technology, or the available area.

Keywords: sustainability; solar energy; photovoltaic energy; renewable energy; self-consumption; rooftop photovoltaic; clean energy transition; solar energy potential

Citation: Rodríguez-Martinez, Á.; Rodríguez-Monroy, C. Economic Analysis and Modelling of Rooftop Photovoltaic Systems in Spain for Industrial Self-Consumption. *Energies* **2021**, *14*, 7307. https://doi.org/10.3390/en14217307

Academic Editor: Ricardo J. Bessa

Received: 31 August 2021
Accepted: 21 October 2021
Published: 4 November 2021

1. Introduction

Reaching the critical goal of net zero emissions by 2050 will require great efforts from across society. It also offers significant advantages in terms of human health and economic development [1]. Governments must make sure that clean energy transitions are secure, affordable, and fair to all citizens. An unprecedented rise in electricity costs is threatening the economic recovery after the COVID-19 pandemic. This situation affects households and enterprises. Among the latter, those which are energy-intensive in their production processes are particularly affected. One way to mitigate the adverse effects of electricity costs is by investing in renewable energies for self-consumption. Among the existing alternatives, rooftop photovoltaic systems stand out as a feasible choice. This research completes a simplified economic analysis and explores a model's contribution to interested entrepreneurs seeking to control energy costs. The model has been developed for Spain and adapted to its legal framework. It is applied in four different locations covering all the latitudes of the territory of Spain. Due to its simplicity, the model can be adapted for other countries with similar characteristics as Spain.

1.1. Background

The decrease in the cost of commercial modules has been progressive since its appearance in the market, exceeding 4 EUR/Wp in 2001, to become around 1.2 EUR/Wp in 2012. Nowadays, these prices are between 0.2 and 0.3 EUR/Wp for self-consumption installations larger than 50 kW, being the scale's economy and the technology selected very important [1]. Technological improvements in modules, inverters, and structures have also appeared. These technical improvements and the significant price depression enable photovoltaic technology to have prospects to sustain continued growth. Currently, the installed power worldwide is already over 700 GWp.

Albeit part of this installed power is achieved by utility-scale plants, self-consumption systems contribute an important part. The installation company and the owner must compare several plant proposals economically before choosing an optimal solution. For the rooftop photovoltaic systems, the financial parameters are difficult to estimate. After reviewing state of the art, we detected a lack of economic models to predict costs, production, and LCOE for photovoltaic self-consumption systems. In that context, a set of accurate and simple models have been created and verified, allowing anyone to evaluate a self-consumption system.

Therefore, this article develops a series of numerical models that allow the reader to evaluate the technical and economic feasibility of creating a photovoltaic installation on a flat roof. For this, numerous facilities of different sizes, technologies, and inclinations have been designed and economically valued, and they have been simulated in four different locations. The results have been used to develop numerical models that easily calculate the production, power, CAPEX, OPEX, Yield, and LCOE, knowing the characteristics of the roof to be analyzed. In the study, current data on the cost and production of photovoltaic systems of 30 different cases will be extracted. Their production and energy cost for four different locations representing most Spanish geography (Centre, North, and South of the Iberian Peninsula, and the Canary Islands) will be studied. This will allow the generation of a database of costs and production that represents the reality of photovoltaic installations of industrial self-consumption projected nowadays in the best possible way, using devices equipped with the latest advances in the industry.

Regarding what has been mentioned, a set of photovoltaic systems have been designed meeting the following characteristics:

- Located in Spain.
- Intended for industrial self-consumption.
- With an anti-spilling system.
- In flat roofs with high tolerance to loads.
- 100% self-consumption.
- Inverters located in the room of the General Low Voltage Board.
- Absence of obstacles.
- Absence of losses by nearby shading.
- Height of the building of 10 m.

The evaluated variables that have been modified for the photovoltaic generation are:

1. Location: facilities have been simulated for the locations of Bilbao (Basque country), Torrejón de Ardoz (Madrid), Seville (Andalusia), and Lanzarote (Canary Islands). The selected locations can be seen in Figure 1 and the geographical coordinates in Table 1.
2. Technology: 72-cell modules, using PERC monocrystalline modules and polycrystalline modules.
3. The inclination of the modules: leaps of 5 degrees between 10° and 30° inclination.
4. Available area: 1200 m^2 with low voltage connection, 4000 m^2 with low voltage connection and 12,000 m^2 with high voltage connection.

Figure 1. Selected locations, representing different latitudes.

Table 1. Locations coordinates used during the simulations.

Location	Latitude	Longitude
Bilbao, Basque Country	43° 14′ N	2° 55′ W
Torrejón de Ardoz, Madrid	40° 26′ N	3° 38′ W
Seville, Andalusia	37° 22′ N	5° 59′ W
Lanzarote, Canary Islands	28° 58′ N	13° 32′ W

Once the type cases are known, the main equipment has been selected, using Huawei inverters and the manufacturer SunTech modules. The software Helioscope has been used to calculate the maximum power available on each of the installation combinations considered in the study. Afterward, the basic engineering of the facilities was done with the proposed design. The different combinations have been valued economically and then simulated at four locations also using Helioscope. The maintenance cost has been valued and finally the LCOE of the 30 facilities has been estimated for the studied locations. Later, the numerical models were generated. Finally, the calculation methodology has been developed.

As it is mentioned above, a series of numerical models have been generated. The models allow the reader to estimate the maximum power installed and its production, cost, and LCOE. It is necessary to perform a series of steps in which the cost of modules, structures, and inverters can be applied for its use. These values could be changed if prices are known (which allows the models to remain valid even though the cost of modules fluctuates, or its performance is improved).

The models permit the rapid calculation of the LCOE with various inclinations and modules' technologies to check what installation approach will present a lower LCOE (and, therefore, a lower payback period). In addition, it allows the reader a quick idea of the installable power, the cost of the installation, its production, and its LCOE without having to carry out the basic engineering of the different facilities or simulate each case separately. However, it is recommended to use these models as a support, and never as a rigid and absolute calculation methodology, as it simplifies the multiple variables that might appear in a photovoltaic system.

1.2. Economic Evolution of Photovoltaic Energy in the World

Technological advances in photovoltaic engineering have caused a decrease in the investment required per module installed watt. Other factors, such as increased production and improved manufacturing methods, have also influenced this cost reduction. The module cost decreased from 100 $/Wp in 1975 to 10$/Wp in 1985. Subsequently, the cost dropped to 1 $/Wp in 2012. (Those values have been corrected to avoid the distortion caused by inflation, normalizing the values to equivalent units in 1975) [2].

This reduction in the price of modules has been accentuated today. In 2021, the purchase value of the modules is at a normalized cost that can reach 0.2 EUR/Wp under Delivered Duty Paid (DDP) conditions in Spain for plants of more than 10 MWp. In 2020, prices of 0.16 EUR/Wp were born at specific moments of excess supply caused by the COVID-19 pandemic. The values vary significantly from one country to another when including the seller's tariffs to locate the modules in the installation area agreed with the customer.

The decrease in the module's price has been accompanied by a decrease in the cost of all the elements that make up the photovoltaic parks as this technology has matured. In addition, the design of the plants has been optimized, and with new technological advances, it has been possible to improve the Capacity Factor greatly. Figure 2 shows the cost reduction for installations in the United States until 2019, achieving a decrease in the price per installed watt from 4.7 USD/Wp in 2010 to 0.99 USD/Wp in 2019. In countries such as India, these costs were in 2019 at 0.62 USD/Wp [3].

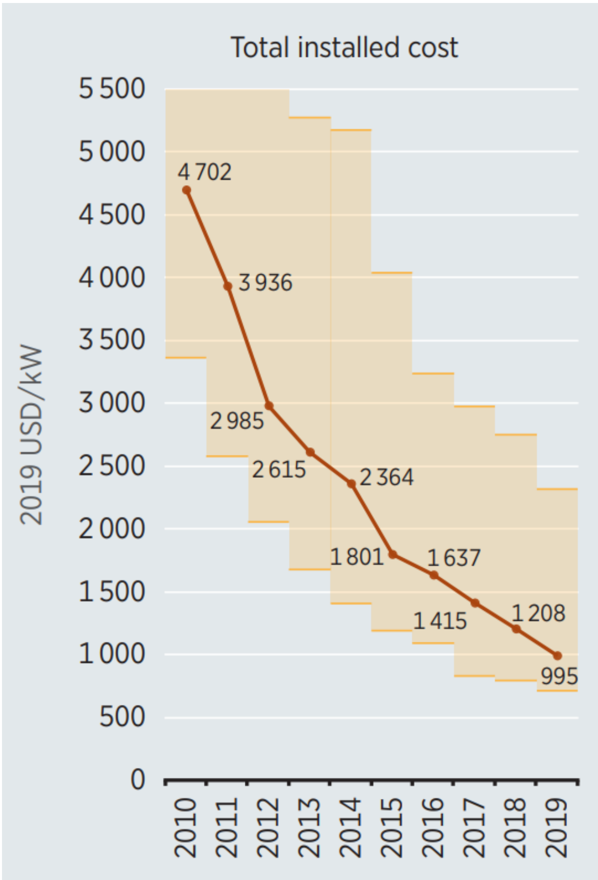

Figure 2. Cost reduction of photovoltaic installations in the United States [3].

As for the LCOE, in 10 years, it has gone from a value of 378 USD/MWh to 69 USD/MWh, even reaching facilities with a value of around 50 USD/MWh in the United States [3]. The decrease in the LCOE value has been maintained for the plants projected today, although with great dependence on the location, the size of the plant, and the technology used [4]. Worldwide, the average sale price of PPAs (Power Purchase Agreements) for photovoltaic plants is 39 USD/MWh [5]. In Portugal's last large renewable energy auction, the award was marked by an average energy sale price of 20 EUR/MWh, representing an LCOE lower even than the prices of conventional energy sources [6].

Regarding the rest of renewable technologies, wind energy was already at competitive prices in most locations, reaching energy prices of 43 USD/MWh of average value in 2021 in the case of onshore technology and 82 USD/MWh in the case of offshore. Geothermal and hydraulic energy have presented a price increase in the approved projects, up to 73 USD/MWh and 47 USD/MWh, respectively [3].

The photovoltaic power installed worldwide had practically anecdotal values until 2005, after which the technology began to be developed commercially. This year, the generation was about 3.9 TWh/year, going in 2010 to 32 TWh/year [7]. In 2020, photovoltaic production reached 837.9 TWh/year [8]. In terms of installed capacity, the evolution went from 15 GWp in 2008 to 40 GWp in 2010. At the end of 2020, installed capacity has exceeded 700 GWp [9].

By country, the most considerable installed power is concentrated in China, which combines subsidies from the local government to the fact that it is the manufacturer of practically all the photovoltaic modules put on the market. In 2020 it had 254 GWp installed. For this year, they were followed in the list of installed capacity by the United States (75 GWp), Japan (67 GWp), Germany (53 GWp), and India (39 GWp), as shown in Figure 3. Spain ended the year with 14 GWp installed capacity [10].

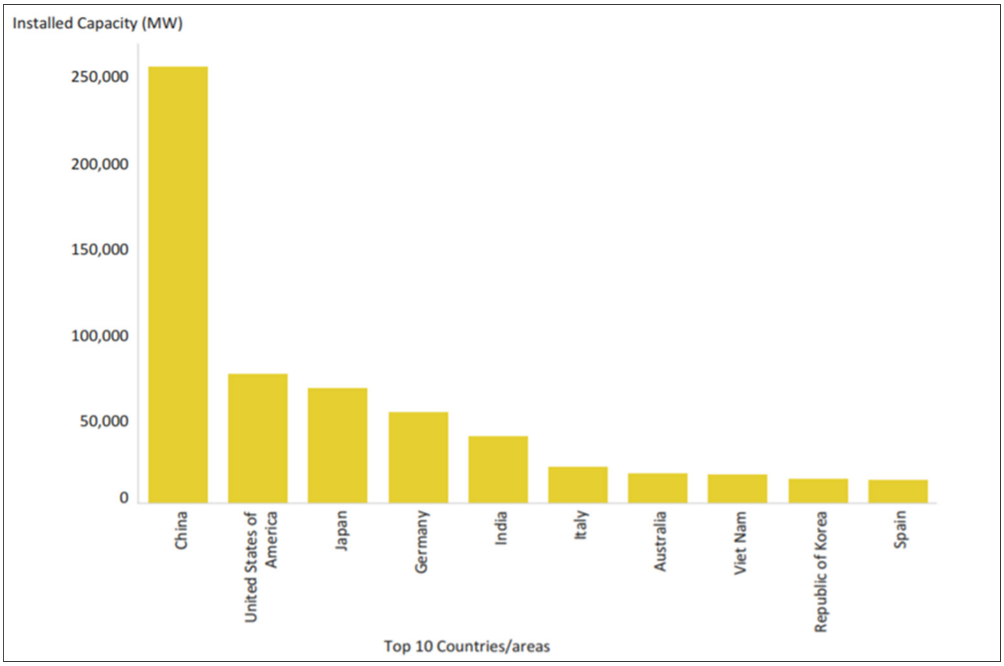

Figure 3. Installed capacity of Photovoltaic Solar Energy in 2020 in selected countries [10].

Regarding the forecasts of photovoltaic production, the IEA estimates that the annual energy generated with this technology will reach 4000 TWh by 2040, representing 10% of world generation if the consumption growth is expected for this year is met.

1.3. Rooftop Photovoltaic Systems

The growth in residential buildings has been at an accelerated rate in the last decade. Methods have been developed to estimate the solar energy potential for residential self-consumption, as shown in [10]. Global energy demand is constantly increasing, and recent projections show that this trend will continue with an average annual increase of

1.2% up to 2040. Since the building sector has emerged as a significant energy consumer, governments worldwide have introduced various policies. The utilization of solar energy conversion systems is at the forefront of attention [11]. PV self-consumption systems at the residential or small business level can be designed to reduce electricity consumption from the conventional local grid and achieve competitiveness with grid electricity prices. [12].

In 2015, the Government of India set a target to achieve 175 GW of grid-connected renewable electricity capacity by March 2022. The national target for rooftop solar PV is 40 GW, and the installed capacity as of 31 August 2020 was just above 3 GW. India is committed to achieving 40 GW of rooftop PV capacity as the accelerated deployment of rooftop PV will be vital to attain India's 2022 renewable energy target. According to the IEA's Sustainable Recovery Plan, rooftop solar has the most significant job creation potential among all clean energy technologies offering substantial opportunities for the economic recovery of India post Covid-19 [13]. The solar PV sector employed 3.1 million people in 2016, mainly in China, Japan, the United States, Bangladesh, and India. Furthermore, IRENA estimates that the solar industry could support around 9 million jobs in 2050 [14].

Some studies in the literature have analyzed the impacts of solar deployment on the economy. They project that the solar industry will generate nearly EUR 6.67 billion gross value added (GVA) with a cumulative installed capacity of almost 139 GW in distributed and large-scale installations and employ more than 136,000 people in Europe in 2020 [15].

The performance of 855 large (⩾10 kW) commercial rooftop photovoltaic (PV) system installations in California has been studied. Drawing on the nonparametric data envelopment analysis (DEA) method, these studies consider the PV capacity, electricity generation, modules, system cost, solar irradiance, and ambient air temperature to provide a unified measure of the PV installation performance [16].

The US Department of Energy (DOE) has recently released the Solar Futures Study detailing the significant role solar will play in decarbonizing the nation's power grid. The study shows that by 2035, solar energy has the potential to power 40% of the nation's electricity, drive deep decarbonization of the grid, and employ as many as 1.5 million people—without raising electricity prices. The study's findings call for the massive and equitable deployment of clean energy sources, underscoring the Biden Administration's efforts to tackle the climate crisis and rapidly increase access to renewable power throughout the country [17].

Rooftop photovoltaic power generation has formed the advantages of less investment, flexibility, efficiency, and environmental protection, with broad prospects for development. Therefore, studying its economic performance is significant to investment decisions and policy improvement [18]. In some countries, however, governments implement energy policy decisions that hinder the growth of rooftop PV installations in industrial buildings as described in [19] for the Philippines.

When developing a sustainability plan in a complex and heavily urbanized territory, one of the most relevant options available is installing rooftop photovoltaic (PV) panels. Thus, it is essential to determine the amount of available surface and the potential impact of such installations on the energy and emission budget of the area [20]. Other studies have been made for optimal sizing of rooftop solar photovoltaic (PV) and battery energy storage systems (BESSs) for grid-connected houses by considering flat and time-of-use electricity rate options [21].

Building integrated photovoltaics (BIPV) is one of the key technologies when it comes to electricity generation in buildings, districts, or urban areas. However, the potential of building façades for the BIPV system, especially in urban areas, is often neglected. Façade-mounted building integrated photovoltaics could contribute to supply the energy demand of buildings in dense urban areas with economic feasibility where the availability of suitable rooftop areas is low [22]. This paper deals with the levelized cost of electricity (LCOE) of building integrated photovoltaic systems (BIPV) in the EU capitals and presents a metric to investigate a proper subsidy or incentive for BIPV systems.

Crystalline silicon photovoltaics are a cardinal and well-consolidated technology for the achievement of energy efficiency goals, being installed worldwide to produce clean electrical energy. However, their performance is strongly penalized by the thermal drift, mostly in periods of high solar radiation where solar cells reach considerably high temperatures. To limit this aspect, the employment of cooling systems appears a promising and viable solution [23].

1.4. Outline of the Article

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    - 5.1 Conclusions
    - 5.2 Limitations of the study and future research

    References

2. Materials and Methods

The main objective of this project is the generation of numerical models that allow a person interested in the economic valuation of a photovoltaic installation to obtain the main expected parameters. For this, a calculation methodology will be generated through which the reader, knowing the location of the installation and the dimensions of the roof, will be able to obtain: the maximum installable power, the YIELD of said installation, the energy production of the first year and the CAPEX, OPEX, and LCOE values of the plant. It will be easier to use actual costs if known, but it will be possible to apply the costs of the main equipment (modules and inverters) considered throughout the project. This developed calculation methodology will also make it possible to quickly compare the production, CAPEX, and LCOE forecasts of projected plants with different inclinations and different types of modules, which will be especially useful for decision-making prior to engineering development.

In addition, the calculations used for modeling the LCOE will be analyzed in depth. This analysis will make it possible to evaluate how the different technical variables that affect the economic viability of a photovoltaic installation influence, such as the selected inclination, the location, the module technology, or the available area. From a financial point of view, the influence of the discount rate and the useful life period of the installation will be analyzed. In addition, it will be evaluated how the reduction in costs of the main equipment may have made some commonly accepted design criteria obsolete, such as the conception that the optimal inclination is the one that generates the highest production per module, studying the influence of the economy of scale by reducing the inclination of the modules.

In this process, the cost and production data of the 30 photovoltaic installations designed to generate the models will be extracted. Its production and the cost of energy will be studied for four different locations that represent most of the Spanish geography (center, north and south of the peninsula, as well as the Canary Islands), allowing to generate a database of costs and production that represents in the best possible way the reality of industrial self-consumption photovoltaic installations that are projected today, using equipment that represents the latest advances in the sector.

The variety of possibilities in terms of modules, structures, powers, and configurations makes the number of cases used for the study unlimited. On the other hand, to carry out a comparison that allows drawing conclusions from the results obtained, it is necessary to determine the type of facilities on which the study will focus and consequently to which the models developed will be applicable:

- Facilities located in Spain: to avoid that different weather conditions or the variation in costs from one country to another may distort the comparison.
- Industrial self-consumption facilities: since the decentralization of the electrical system and the low return on investment generated by these facilities make the installation forecasts very high [24].
- Installations on a flat roof with high tolerance to loads
- Installations with 100% self-consumption: that is, the study is carried out for installations that take advantage of all the energy they generate because their consumption is much higher at all times than photovoltaic production.
- Inverters located in the room of the General Low Voltage Module.
- Absence of obstacles.
- Absence of losses due to close shading.
- Building height of 10 m.

On these conditions, the calculation methodology will consist of the following steps:

1. Selection of standard cases: the variables that will change from one case to another will be defined to represent as many facilities as possible so that conclusions can be drawn on how they affect the different parameters studied.
2. Selection of main equipment: the modules, inverters, and structures to be used will be chosen. It will represent the latest advances in the sector, using modules improved by PERC type treatments, multi MPPT inverters, and structures without the need to drill the roof.
3. Use the Helioscope software to calculate the available power: the selected geometries will be generated in Helioscope, and the sizing of each of the facilities defined in step 1 will be carried out. Helioscope software has similar error ranges that other PV simulation software, while its interface facilitates making 3D simulations for the defined base cases [25].
4. Design and basic engineering of the facilities: to subsequently assess the cost of the plants, the wiring, protections, control equipment, and all the necessary elements for each of the predefined facilities will be dimensioned, always from the point of view of basic engineering. The design has been made according to the Spanish legislation [26].
5. Calculation of CAPEX: Each facility will be economically valued, budgeting with market prices for materials and assembly. The cost of engineering, business structure costs, and any other element that may intervene in the budget of a photovoltaic installation will also be calculated.
6. Simulation of the installations with the Helioscope software: once the photovoltaic plants have been dimensioned, the data input into Helioscope will be completed. They will be simulated for each of the selected locations, compiling the results obtained.

7. Calculation of OPEX and estimation of LCOE: the cost of maintenance will be economically valued. The calculated values of the LCOE for each case can be obtained in the locations studied.
8. Numerical modeling of the LCOE: numerical models will be generated that allow an approximate calculation of the power, production, cost, and LCOE of a photovoltaic installation for a known roof.

2.1. Design and Basic Engineering of the Facilities

Each facility's available power has been calculated using the Helioscope software, and the appropriate number of inverters has been dimensioned in each case. Next, the basic engineering of the installation has been developed, allowing the sizing of the rest of the equipment necessary for estimating the CAPEX of each plant.

2.2. CAPEX Calculation

As a result of the previous section, all the material costs associated with the 30 photovoltaic installations designed have been calculated, together with the assembly time of each piece of equipment or material.

The results obtained for three of the facilities are shown in Table 2.

Table 2. Cost decomposition grouped by items for the three base cases.

Element	10°-Mono-1200 Cost (€)	10°-Mono-4000 Cost (€)	10°-Mono-12,000 Cost (€)
Photovoltaic Modules	41,325	143,034	413,201
Structures	7524	27,462	77,754
Investors and add-ons	9470	25,413	64,037
DC wiring	1811	8900	42,351
AC wiring (LV and MV)	985	2139	59,436
Protections and control	4686	12,480	17,470
Mounting	11,472	36,647	108,428
Structure of work	12,916	22,176	29,918
Miscellaneous expenses	2233	5430	14,514
Cost	92,425	283,685	827,112
Margin	11,091	34,042	99,253
Sale	103,516	317,727	926,366

To compare the results obtained, it is necessary to normalize the EPC sales values, converting them to units per installed power (EUR/Wp) as shown in Table 3:

Table 3. EPC costs, both absolute and normalized, for the three base cases.

Element	10°-Mono-1200	10°-Mono-4000	10°-Mono-12,000
EPC (€)	103,516	317,727	926,366
Power (kWp)	142.5	520.1	1559.3
EPC (€/Wp)	0.726	0.611	0.594

2.3. Simulation of Installations with the Helioscope Software

For each facility, the YIELD, the PR, and the production in the four locations have been calculated.

For this, the installations have been simulated using the Helioscope Software. The procedure used has been:

Step 1: The 30 plants have been dimensioned for the location of Madrid with the Helioscope.

Step 2: The meteorological conditions of the simulation have been generated. The numerical models used in the simulation in base case 1 can be seen in the following image. Dirt losses of 2% have been considered, which correspond to the NREL recommendations for roofs that are cleaned annually [27]. Moreover, 1.5% is included to compensate for the LID (Light Induced Degradation) losses that appear in the plant in year 1 [28].

The results for the province of Madrid of the three base cases are shown in Table 4.

Table 4. Results of the simulation of the three base cases in the province of Madrid.

Parameter	10°-Mono-1200	10°-Mono-4000	10°-Mono-12,000
PR (%)	84.9	84.5	84.7
Yield (kWh/kWp)	1548	1540.5	1544.5
Production (MWh/year)	220.6	801.2	1408

2.4. OPEX Calculation and Estimation of LCOE

2.4.1. OPEX Calculation

The economic valuation of the maintenance depends on the country of installation of the plant, the proximity to urban centers, the annual fouling, and the existing monitoring system. However, for valuations to estimate the plant's LCOE, its calculation can be approximated to 0.5% of the annual CAPEX in plants intended for large-scale generation and 1% of the CAPEX in plants for self-consumption [29]. In the cases studied, the following estimate will be made, recommended by the NREL:

$$\text{OPEX annual} = 0.01 \cdot \text{CAPEX} \tag{1}$$

2.4.2. LCOE Calculation

The calculation of the LCOE can be carried out through the following equation, which is nothing more than an extension of the equation commonly used and including the losses due to degradation of the modules.

$$LCOE\left(\frac{€}{\text{MWh}}\right) = \frac{\sum_{t=1}^{n} \frac{CAPEX+OPEX}{(1+r)^{t}}}{\sum_{t=1}^{n} \frac{Production\ year\ 1\cdot(1-a)^{t}}{(1+r)^{t}}} \tag{2}$$

For the LCOE simulation, the following values will be used:

- *CAPEX*: the cost of the photovoltaic plant in absolute terms. It is obtained from the price of the EPC by adding a 4% surcharge for license taxes in Spain [30].
- *OPEX*: the cost of annual maintenance in absolute terms, approximated according to the NREL at 1% of *CAPEX* (considering that maintenance does not imply an expense in building licenses).
- Production year 1: values extracted from the simulation carried out.
- *r:* discount rate. As it is a facility intended for self-consumption, this value is quite high since the risk associated with a location change, a decrease in consumption, or other problems related to the company's future that owns the facility is high. A value of 6% will be used, which is between 4 and 8% recommended by Solar Bankability [31] and coincides with the NREL's recommended values [27].
- a: loss of annual performance of the modules. The 0.7% guaranteed by the manufacturer in the characteristics of the equipment will be used. Those values are aligned with academic research on this topic [32].
- *n*: useful life of the plant will be considered 30 years [33].

2.5. Numerical Modeling of the LCOE

The LCOE depends on a series of parameters that have been described in previous sections, and that in any case are known before the design of the installation, so the calculation of the LCOE can be modeled based on these data, allowing to see a guide value for an available area.

Therefore, obtaining the LCOE will be achieved as a result of the modeling of the variables that feed it. In the calculation method outlined in the Results section, an attempt will be made to guide values to work with the models in the event that some values are unknown.

The variables to be modeled are, in this order:

1. Peak power of the installation:

$$Pp(\mathrm{kWp}) = \mathrm{f}\left[A\left(\mathrm{m}^2\right),\ \propto(^\circ),\ \eta_p(\%)\right] \tag{3}$$

where,

Pp: peak power of the installation, in kWp

A: available area on the roof, in m^2

$\propto$: module inclination, in degrees

η_p: performance of the module, which can be obtained directly from the technical data sheet of the equipment, and which can also be obtained from the power of the module and its area.

2. Yield of the installation:

$$Yield\left(\frac{\mathrm{kWh}}{\mathrm{kWp}}\right) = \mathrm{f}\left[GHI\left(\frac{\mathrm{kWh}}{\mathrm{m}^2}\right),\ \propto(^\circ), location\right] \tag{4}$$

Being:

GHI: Radiation in the Horizontal Plane in $\mathrm{kWh/m}^2$.

location: Situation of the installation.

3. Installation CAPEX and OPEX

$$CAPEX\ (€) = \mathrm{f}\left[Pp\ (\mathrm{kWp}),\ Pmodule\left(\frac{€}{\mathrm{Wp}}\right), Pinv\left(\frac{€}{\mathrm{Wp}}\right), Pest\left(\frac{€}{\mathrm{Wp}}\right),\ GM(\%)\right] \tag{5}$$

where,

Pmodule: module cost in EUR/Wp.

Pinv: inverter cost, in EUR/Wp. If only the cost of the inverter is known, an undersizing of 80% of the inverters with respect to the modules can be assumed. This value corresponds to an inverter loading ratio of 1.25, which minimizes clipping losses [34].

Pest: cost of structures provided by the manufacturer

GM (%): Gross Margin of the plant, in %.

Given the market variability for modules, inverters, and structures, their value will be based on the EUR/Wp ratio of these teams, which is how the sector usually works. In addition, the rest of the costs will be modeled based on the peak installed power for reasons of economy of scale since significant variations cannot be expected from these costs. The OPEX, due to its little relevance concerning the CAPEX, will remain as 1% of the annual CAPEX [33].

4. LCOE of the installation:

$$\begin{aligned} &LCOE\left(\frac{€}{\mathrm{MWh}}\right) \\ &= \mathrm{f}\left[CAPEX(€),\ OPEX\ (€), Production(\mathrm{MWh}), L(\%),\ r(\%), a(\%), n(\mathrm{year})\right] \end{aligned} \tag{6}$$

where,

L: cost of the building license compared to the cost of the EPC (%)

r: discount rate (%)

a: annual performance loss of the modules.

n: useful life of the plant.

2.5.1. Numerical Modeling of Peak Power

For the generation of a numerical model that predicts the installed power of a plant based on the variables collected in Equation (3), the following analytical equation can be reached:

$$Pp(\mathrm{Wp}) = n^\circ modules \cdot P_{module} \rightarrow \mathrm{Pp(Wp)} \qquad = n^\circ modules \cdot A_{module} \cdot \eta_p \cdot G \tag{7}$$

G is the radiation value for evaluating the module's performance under STC conditions of 1000 W/m^2.

The peak power only depends on the area of installed modules and their performance. It is independent of the module's dimensions since an increase in size leads to a proportional reduction in the installed modules.

Therefore, we are left with Equation (8):

$$Pp(\mathrm{kWp}) = A_{modules}\left(\mathrm{m}^2\right) \cdot \eta_p \cdot G\left(\frac{\mathrm{kWp}}{\mathrm{m}^2}\right) \tag{8}$$

With the results collected from the different simulations carried out, an equation can be generated that predicts the installable module area based on the surface area and the inclination to be given to the modules. The Module Area/Useful Area ratio will be modeled for the cases of the 12,000 m^2 area, which will have lower distortions due to module removal. This ratio can be modeled with a second-degree numerical function. The area of the modules is a function of the useful area of the roof and its inclination, and can be calculated with the equation:

$$Amodule = A \cdot \left(1.75 \cdot 10^{-4} \cdot \alpha^2 - 0.175\alpha + 0.826\right) \tag{9}$$

Combining Equations (8) and (9), the numerical model is obtained that predicts the peak power of the photovoltaic installation based on the previously mentioned variables. The G is multiplied directly by the constants of Equation (9) to simplify the equation:

$$Pp = A \cdot \eta_p \cdot \left(0.175 \cdot \alpha^2 - 17.5\alpha + 826\right) \tag{10}$$

The error generated by this equation has been calculated by predicting the 120 simulations carried out. The mean error of the equation is 3.7%, mainly due to eliminating modules to adjust the number of modules per string in roofs with a smaller area. The calculation of the error generated by the model is detailed in the Results section.

2.5.2. Numerical Modeling of YIELD

Obtaining the Yield for the installation not only depends on the radiation in the horizontal plane and the inclination of the modules but also deviations are expected depending on the location of the modules within the national territory, as shown in Equation (4). To consider how other location variables affects production, four different models have been generated. This differentiation of production models gathers the effect of the other locations variables such as latitude, temperature, and seasonal production variations. That is the reason why those variables are not directly included in the models.

Variations in module technology, inverters, and even the presence of step-up transformers influence plant performance. However, the model will be simplified not considering these variables:

The effect of module technology was very relevant in equipment manufactured at the beginning of the decade. However, in the latest technology equipment the differences between monocrystalline and polycrystalline modules are very small. In the total of the simulations carried out, the accumulated difference is less than 0.1%.

The effect of the inverter technology depends on the approach in the distribution of strings and the number of MPPT of the inverter. The variation from one model to another is also relevant. In any case, the gain of having multi MPPT systems compared to inverters with a single MPPT is less than 2% [35].

The transformers do not present losses of more than 1%, so their presence can be considered that they do not significantly affect the plant's production.

Therefore, the equations that allow obtaining the Yield of the plant as a function of the GHI value and the selected inclination, for a given plant, result:

$$\text{Center (Madrid)}: \quad Yield = GHI \cdot \left(-1.119 \cdot 10^{-4} \cdot \alpha^2 + 7.752 \cdot 10^{-3} \cdot \alpha + 0.8552\right) \tag{11}$$

$$\text{North (Bilbao)}: \quad Yield = GHI \cdot \left(-1.295 \cdot 10^{-4} \cdot \alpha^2 + 7.567 \cdot 10^{-3} \cdot \alpha + 0.8546\right) \tag{12}$$

$$\text{South (Seville)}: \quad Yield = GHI \cdot \left(-1.309 \cdot 10^{-4} \cdot \alpha^2 + 8.083 \cdot 10^{-3} \cdot \alpha + 0.8352\right) \tag{13}$$

$$\text{Canaries (Lanzarote)}: \quad Yield = GHI \cdot \left(-8.67 \cdot 10^{-5} \cdot \alpha^2 + 4.625 \cdot 10^{-3} \cdot \alpha + 0.8648\right) \tag{14}$$

2.5.3. Numerical Modeling of CAPEX and OPEX

As previously mentioned, the numerical modeling will be based on the costs in EUR/Wp of modules, inverters, and structures, since their price fluctuates a lot in the market. The rest of the costs of a plant are more linked to the number of modules of the plant than to its power, since the costs associated with the same number of monocrystalline and polycrystalline modules are similar. That is why the cost of the rest of the low voltage elements has been calculated for the cases studied, and a potential regression has been generated that represents the cost variation in €/Module as a function of the number of modules [36].

In the generation of the previous graph, the cost of the TS has been discounted, to include only the costs that would be expected in low voltage. If the presence of a transformation center is necessary to increase tension, its price should be considered separately.

On the other hand, in the case of using modules of 60 cells, which are proportionally smaller and less powerful than the modules of 72 cells, the equation will have to be corrected with a correction factor.

Therefore, the equation developed that allows calculating the sale price of a photovoltaic installation results:

$$CAPEX\ (€) = \frac{1000 \cdot [Pmodule + Pinv + Pest] \cdot Pp + 439.9 \cdot Nmod \cdot (fc \cdot Nmod)^{-0.259} + HV}{(1 - GM)} \tag{15}$$

where,

Pmodule: Module cost, in EUR/Wp.
Pinv: Inverters' cost, in EUR/Wp
Pest: Structures cost, in EUR/Wp
Pp: Total peak power of the installation, calculated in step 1.

fc: Correction factor. Values:
60-cell modules, fc = 5/6
72-cell modules, fc = 1

This correction factor allows that in the plant's final cost, it is considered that the 60-cell modules present less power. Therefore, the cost of wiring, grounds, and protections that they entail is proportionally lower than the 72-cell modules.

Nmod: number of modules of the plant, calculated by clearing Equation (7).

HV: cost of the voltage raising system if necessary

GM: gross margin of the facility, office costs, and industrial profit. 12% (6% + 6%) is proposed as a reference value

The OPEX is obtained directly from Equation (1).

2.5.4. Numerical Modeling of the LCOE

The calculation of the LCOE for the case of photovoltaic energy is translated into Equation (2). When developing a numerical model, the complication is that this equation is decomposed into a set of elements in both summations of the equation, so its calculation cannot be developed quickly.

However, some equations simplify the calculation, generating an error associated with the discount rate value. The developed equation has a capital recovery factor, CRF, which corrects the depreciation effect over time caused by the discount rate. This CRF has the equation [37,38]:

$$CFR = \frac{r(1+r)^n}{(1+r)^n - 1} \tag{16}$$

Multiplying this factor by the elements of the equation that enter the cash flow in year 0 (CAPEX) The following equation is generated:

$$\mathbf{LCOE}\left(\frac{€}{\mathrm{MWh}}\right) = \frac{(1+L)\cdot\frac{r(1+r)^n}{(1+r)^n-1}\cdot CAPEX(€) + OPEX\left(\frac{€}{year}\right)}{Production_{year\ 1}(MWh)} \tag{17}$$

where L is the cost of the building license with respect to $CAPEX$, r the discount rate, and n the years of the useful life of the installation.

The following approximation has been made:

$a = 0$

In other words, the effects of the degradation of the modules are not considered. This simplification increases the precision of the model since the tendency for high discount rates is to give LCOE values higher than the expected value. Therefore, eliminating the effect of the degradation of the modules in the equation, the values predicted by the model are closer to the actual values [38].

3. Results and Discussion

3.1. Installable Power Analysis

Figure 4 shows the installable power for each of the 30 simulated installations obtained from the results of the Helioscope software.

As can be seen, an increase in the inclination causes a decrease in the installable power for flat roofs since it is necessary to increase the space between rows of modules.

Figure 5 shows the percentage of installable power over the maximum, with 100% being the maximum installable power for a 10° inclination. The results are only collected for the case of monocrystalline installations with an area of 12,000 m^2, but the result can be extrapolated to other cases.

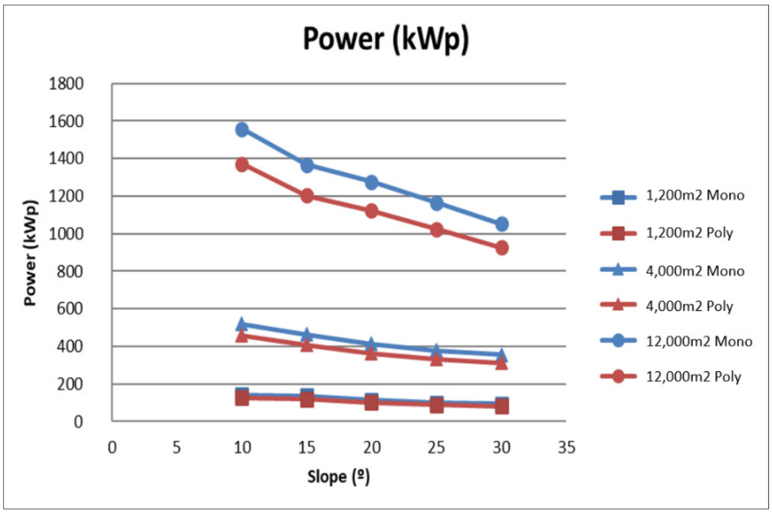

Figure 4. Installed power as a function of module inclination and surface available.

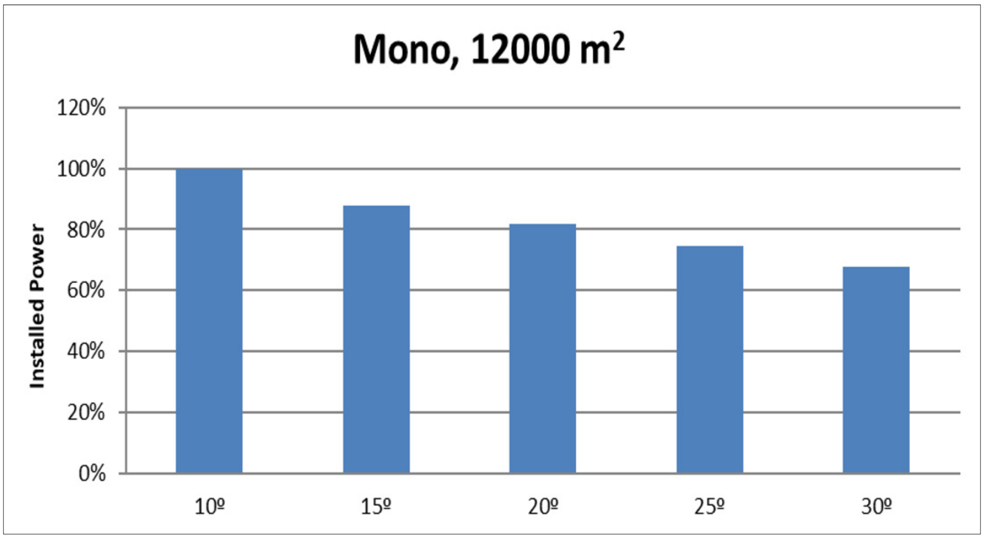

Figure 5. Installed capacity as a function of module inclination.

Tilting the modules at 30° means that only 68% of the installable power can be installed with a 10° slope. The maximum power that can be installed is directly proportional to the performance of the module. Switching to 375 Wp monocrystalline modules instead of 330 Wp polycrystalline modules implies an increase in power of 14%. Finally, an increase in the area implies a directly proportional increase in the maximum installable power since proportionally more modules fit.

3.2. Yield Analysis

The Yields depend directly on the Global Horizontal Irradiation of the location, which is the energy that reaches the horizontal plane per unit area in a calendar year. Figure 6 shows the GHI for each of the studied sites:

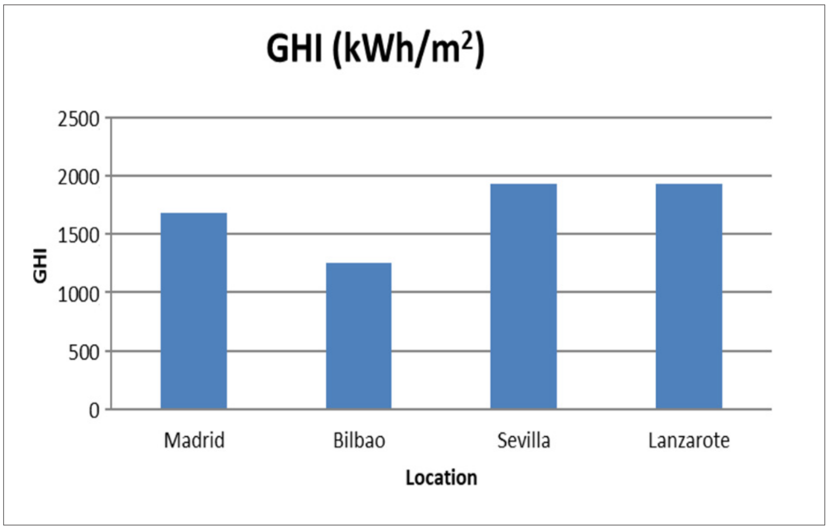

Figure 6. GHI for each of the studied locations.

As shown in Figure 6, the GHI is lower in the North of the peninsula than in the South. This is because the sun has a higher trajectory throughout the year, increasing the horizontal projection. On the other hand, the less cloudy weather in the locations increases the GHI considerably. By latitude, Lanzarote should have a higher GHI. In this case, this increase in the hours of the sun is not translated into radiation due to its weather. On the one hand, it indeed has less rainfall than Seville, but on the other hand, if we analyze cloudy and partially cloudy days, the proportion is considerably higher than in Seville (only 73.6 days a year are considered completely sunny in Lanzarote, compared to 193.2 in Seville) [39].

Figure 7 shows the variation of Yield as a function of the inclination for each of the studied locations, collecting the results of the 1200 m^2 installations with monocrystalline modules:

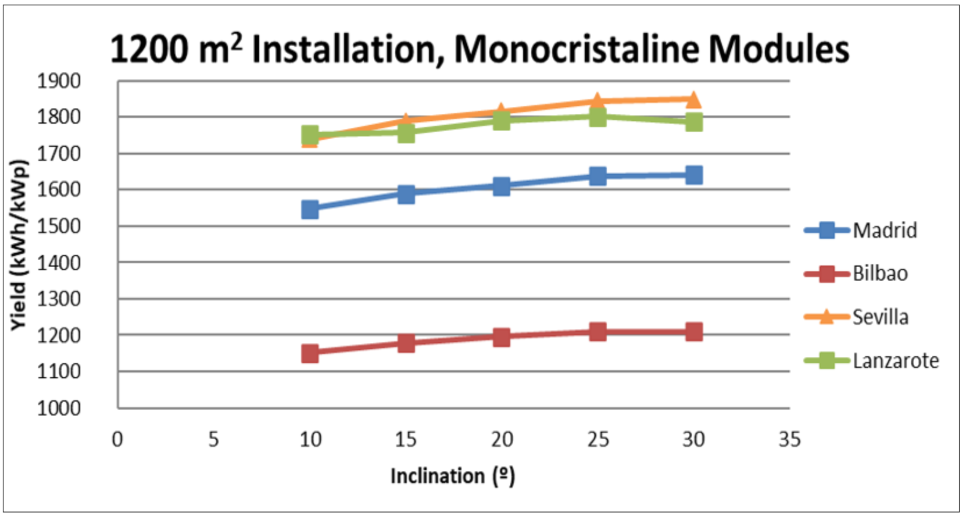

Figure 7. Yield as a function of inclination for each of the studied locations.

The maximum production is found in those locations with the higher GHI, since it is the main parameter that affects photovoltaic production. Figure 8 shows the increase in Yield compared to the base case of 10° for monocrystalline facilities with an area of 1200 m^2. This figure is presented to show in more detail the effect of module inclination on production.

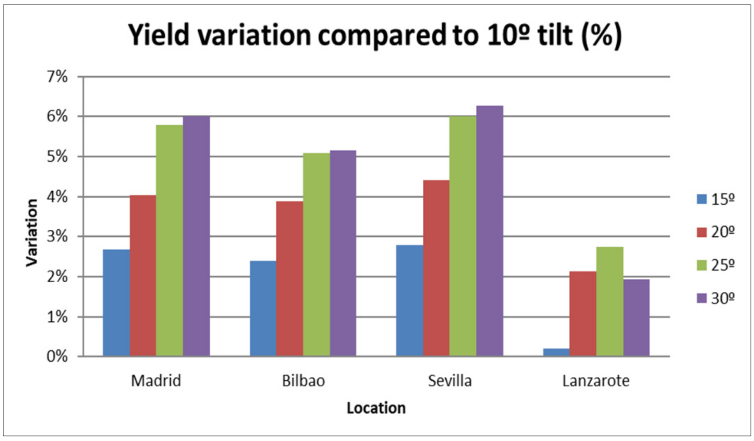

Figure 8. Variation of the Yield with respect to 10º for the studied locations.

As shown in Figure 8, in peninsular locations, the maximum production is obtained with slopes of around 30°, achieving a gain of between 5% and 6% compared to the 10° installation. Slopes of less than 10° are not considered recommended as they favor the accumulation of dirt. Furthermore, the gain is especially relevant when increasing the inclination from slightly inclined arrangements (from 0° to 10°, the gain is around 8% for all cases, according to Helioscope reports). Still, the difference between 25° and 30° is practically negligible in peninsular cases. This behavior is perfectly described by means of a second-degree polynomial equation with a maximum of around 30º, as can be seen in Equations (11-14). In Lanzarote (Canary Islands), which is in a considerably more southern location, the variation in production with inclination is very small, and only gains are achieved compared to 10° of less than 3%. Furthermore, in this case, the optimum inclination is less than 25°. Figure 9 shows the variation of the mean PR for the two types of modules studied in the 1200 m^2 facilities:

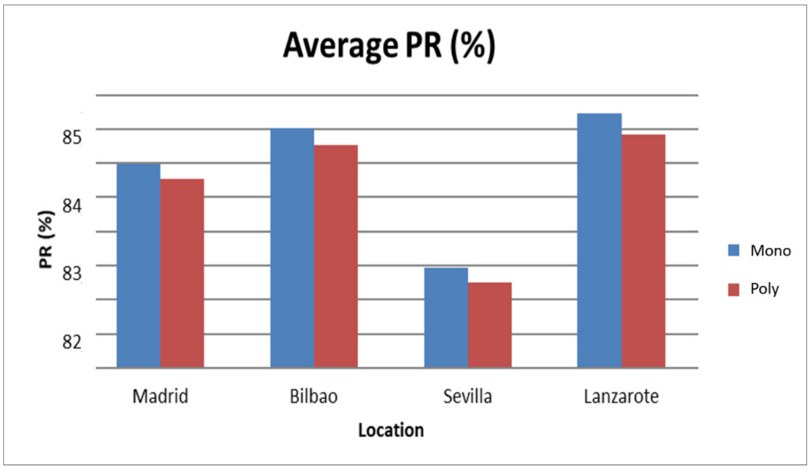

Figure 9. Average PR for each of the studied locations.

The PR for monocrystalline module installations is generally higher than for polycrystalline installations. In general, facilities with a monocrystalline module tend to have a worse PR due to the worse behavior that the modules have with higher temperatures. However, the fact of having PERC monocrystalline modules makes it possible to reverse this situation. PERC cells prevent unused radiation from being absorbed by the metal contact of the frame, allowing this radiation to reflect and pass through the cell again. In the case of the polycrystalline cells used, which do not have this technical improvement, the absorption of radiation by the frame heats the modules, which causes a decrease in production. This effect is attenuated in the case of cells with PERC technology.

3.3. CAPEX Analysis

To make an adequate comparison of how the different variables affect the CAPEX of the plant, both the effects on the total CAPEX (in this case, not including the building license) and the normalized CAPEX per installed peak watt have been analyzed. Figure 10 shows the cost of normalized CAPEX per installed peak watt.

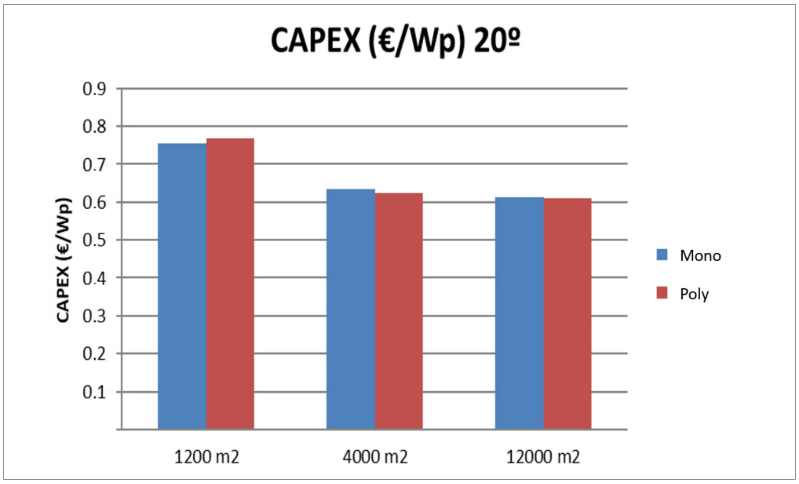

Figure 10. Normalized CAPEX for installations with a 20° tilt.

For economies of scale, an increase in the available area (and, therefore, the installed power) causes a decrease in the cost per installed peak watt. In this case, two effects can be observed. On the one hand, in lower power installations, the economy of scale and the importance of structural costs make monocrystalline modules the best alternative in small installations. On the other hand, the difference between the studied facilities with an area of 4000 m^2 and the facilities of 12,000 m^2 are less significant, mainly due to the costs of the high voltage transforming system, which distort the effects of the economy of scale. Figure 11 is expanded with all the cases studied.

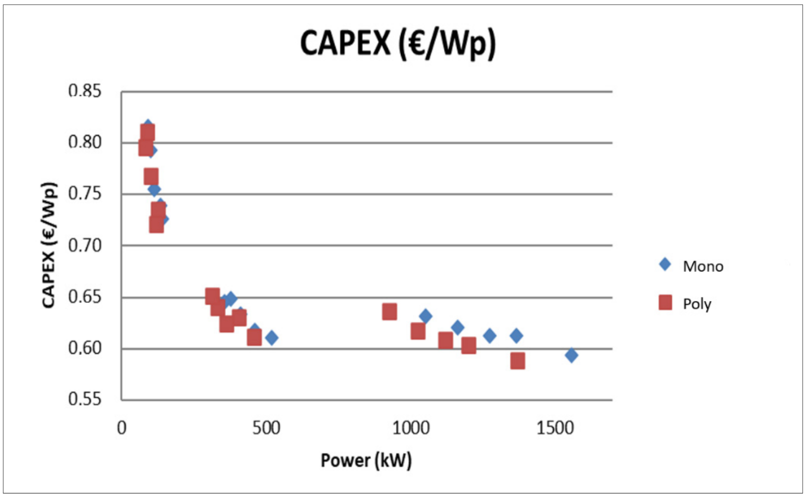

Figure 11. Normalized CAPEX as a function of installed capacity.

As can be seen, the standardized cost of the installation decreases with power. However, in plants in which the voltage elevation system has been considered (areas of 12,000 m^2), there is an increase in costs for the transformation center. It is important to bear in mind that the usual thing for more than 700 kWp is to inject into the medium voltage network since it is not usual to find a module that continuously produces this power in low voltage. Table 5 shows the costs of the main equipment of the installations with 20º inclination:

Table 5. Normalized costs for installations with 20° inclination.

Case	Module (€/Wp)	Inverter (€/Wp)	Structure (€/Wp)	Assembly (€/Wp)	Other (€/Wp)
1200 m^2—Mono	0.290	0.063	0.086	0.086	0.231
1200 m^2—Poly	0.250	0.072	0.097	0.097	0.251
4000 m^2—Mono	0.275	0.053	0.073	0.073	0.159
4000 m^2—Poly	0.240	0.050	0.083	0.083	0.169
12,000 m^2—Mono	0.265	0.042	0.072	0.072	0.163
12,000 m^2—Poly	0.230	0.043	0.081	0.081	0.174

Different aspects can be analyzed from this table. On the one hand, the costs included representing the effect of the economies of scale of the equipment. In small installations, the modules are received directly from warehouses within the peninsula, so the cost is higher. For larger sizes, shipments are made directly from China, which lowers the cost of intermediaries. In inverters, the price per installed peak watt is lower for larger plants, especially since more powerful equipment is used, and it is cheaper.

Both assembly and structure of work represent the effects of economies of scale, and the assembly of monocrystalline modules is more economical. This second effect is because the cost is the same for the same number of modules, but in monocrystalline modules, it is distributed over a higher power. The rest of the costs are much higher for small installations (the execution of the project requires many more hours per installed module and the fact that there are many expenses that are independent of the power of the plant. This cost increases from the surfaces of 4000 m^2 to 12,000 m^2, but this is due solely to the cost of the Transformation Center.

As shown in Figure 12, the cost of the modules continues to account for most of the cost of photovoltaic installations (on average 40%). However, its lower cost compared to previous years has generated that the rest of the costs are more and more decisive. Therefore, the optimization of these expenses plays a fundamental role in the competitiveness of the current installers and developers.

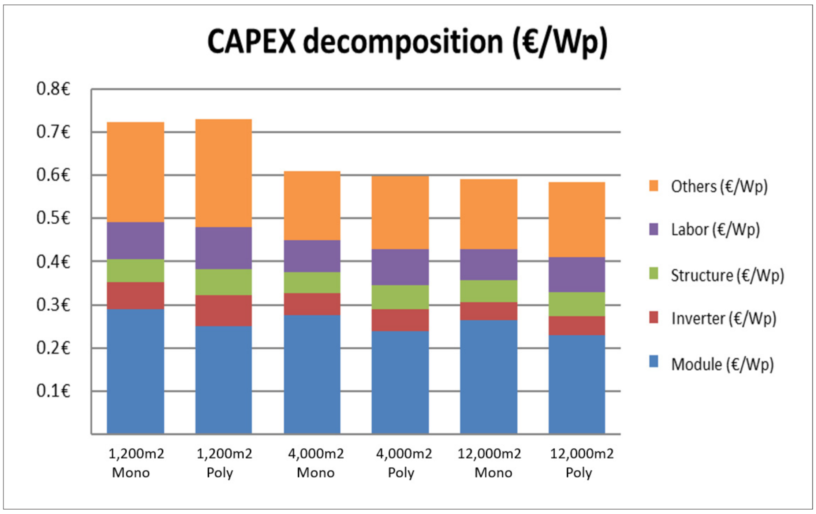

Figure 12. Normalized CAPEX decomposition.

3.4. LCOE Analysis

The CAPEX, OPEX, and production calculated for the photovoltaic installations studied have been used to calculate the LCOE of the different cases. Figure 13 shows the range of values obtained for each of the locations of the 30 cases studied, considering a discount rate of 6% and a useful life of 30 years.

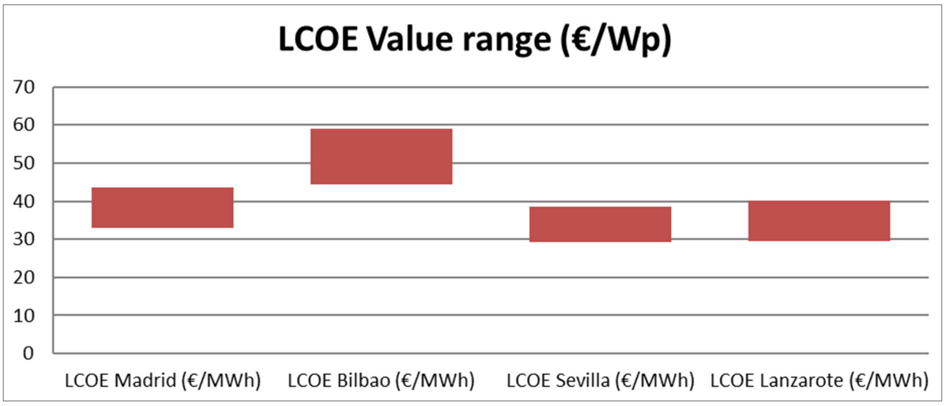

Figure 13. LCOE value range for each of the locations studied.

As can be seen in the previous graph, the LCOE obtained depends to a great extent on the location of the plant since the variation of the available resource is very important from one location to another. On the other hand, there are variations in the LCOE of up to 25% within the same location depending on the rest of the variables studied. Figure 14 shows the results for the case of Madrid with an inclination of 20°.

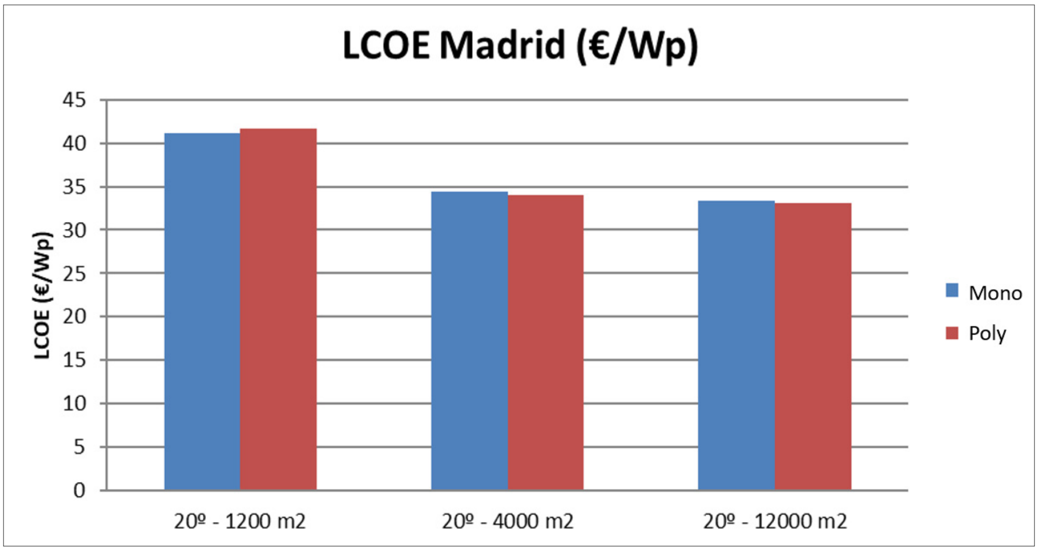

Figure 14. LCOE in Madrid for installations with an inclination of 20°.

The reduction in CAPEX (EUR/Wp) generated by a larger plant size has a significant impact on the LCOE obtained. Furthermore, with the module prices considered, the difference between installations with monocrystalline modules and those with polycrystalline technology is minimal. In smaller plants, plants with monocrystalline modules have a lower LCOE since the impact of the economy of scale is more significant. Therefore, the increase in installed power caused by monocrystalline technology can offset the higher cost of the module. For larger plants, a lower LCOE is generally observed in polycrystalline module installations. The results obtained for the different inclinations studied are represented in Figure 15 below:

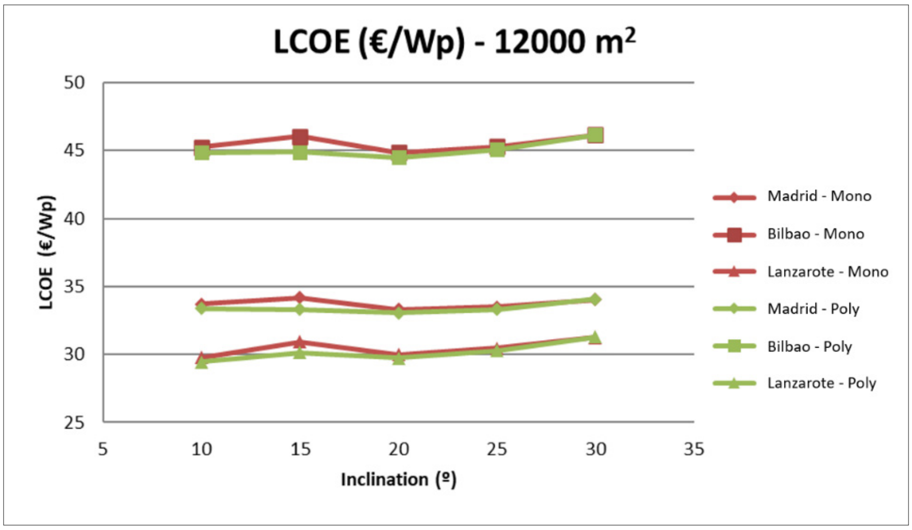

Figure 15. LCOE variation as a function of inclination.

It can be observed that the greater inclination of the modules, which causes an increase in the Yield of the plant, conflicts with the greater CAPEX per Wp generated by issues of economy of scale (the greater the inclination, the greater the separation, and therefore the lower available power). This means that, contrary to the usual recommendations to plan an installation with an inclination that optimizes the Yield, it is better to find the best approach by calculating the LCOE of the different alternatives. The high reduction in the price of the modules in recent years has caused the other costs studied to be increasingly important, so the best solution will not necessarily coincide with the inclination of higher production per installed watt. It compensates for increasing the power at the cost of sacrificing part of the Yield. In those cases, the lowest LCOE is obtained in installations with an inclination of 10° in Lanzarote and 20° in the rest of the locations, different from the 30° that is recommended to maximize the Yield.

Figure 16 studies the influence of the economic variables considered for the Madrid facilities (monocrystalline module, 10°, surface of 1200 m^2):

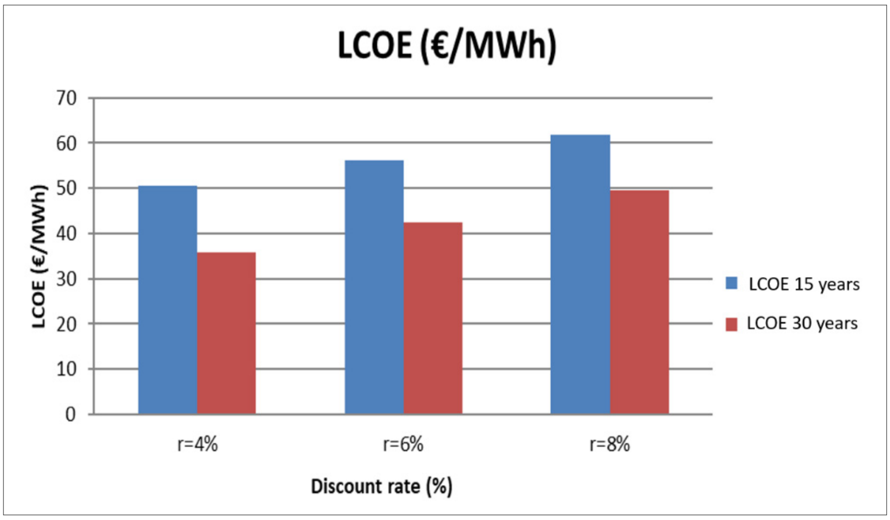

Figure 16. Variation of LCOE as a function of the discount rate and the years of useful life considered.

As can be seen, the discount rate considered is a variable of great importance for calculating the LCOE of the facilities since it depreciates the value of production progressively over the years. The installation's lifetime is also essential when calculating the LCOE of the facilities because the cost is the same. Still, this expense is spread over a greater number of years of use.

4. Procedure Developed for the LCOE Calculation

4.1. Procedure Compilation

As a result of the calculation developed in Section 2.5, an estimate of the LCOE of a flat roof photovoltaic plant can be made that meets the following requirements:

Plant located in Spain.

Flat roof on which the modules will lean.

Injection system 0.

The useful surface of the roof limits the design power and not the customer's consumption.

If the target power for customer consumption reasons is lower than the power obtained in Section 2 (in which the limiting factor is area), it is recommended to continue directly in Step 2 with the target power since it will be the most restrictive design criteria.

Step 1. Installed peak power estimate

The peak installed power can be obtained through the following equation:

$$Pp(\mathrm{kWp}) = A\cdot\ \eta_p\cdot\left(0.175\cdot\alpha^2 - 17.5\alpha + 826\right)$$

where A is the area of the roof in square meters; η_p is the performance of the selected modules under STC conditions and both by one, and α is the degree of inclination to be given to the modules.

To optimize the LCOE of the plant, values in the 10°–20° range should be considered, as it will be proved in the discussion sections. However, an iteration process must be carried out, as the size and the locations influence the optimal value.

The module's efficiency can be obtained from the technical sheet of the equipment to be used. As an example, some guideline values for modules of 72 cells are collected in Table 6:

Table 6. Expected efficiency for different types of modules.

Module	Dimensions (mm × mm)	η_p
320 Wp, polycrystalline	1960 × 992	16.5
325 Wp, polycrystalline	1960 × 992	16.7
330 Wp, polycrystalline	1960 × 992	16.9
370 Wp, monocrystalline	1960 × 992	19.0
375 Wp, monocrystalline	1960 × 992	19.3

The efficiency of the module can also be obtained with the data of the peak power in STC conditions and its dimensions, through the equation:

$$\eta_p = \frac{Pmodule(\mathrm{Wp})}{1000(\mathrm{W/m^2})\cdot Amodule(\mathrm{m^2})} \tag{18}$$

Step 2. Calculation of the Yield and the generated production

The equations that allow obtaining the Yield of the plant can be calculated for guidance only knowing the inclination of the modules, the location in which they are located and the GHI of this location. It can be estimated using one of the following equations:

$$\text{Zone 1}:\ Yield = GHI\cdot\left(-1.119\cdot10^{-4}\cdot\alpha^2 + 7.752\cdot10^{-3}\cdot\alpha + 0.8552\right)$$

$$\text{Zone 2}:\ Yield = GHI\cdot\left(-1.295\cdot10^{-4}\cdot\alpha^2 + 7.567\cdot10^{-3}\cdot\alpha + 0.8546\right)$$

$$\text{Zone 3}: \ Yield = GHI \cdot \left(-1.309 \cdot 10^{-4} \cdot \alpha^2 + 8.083 \cdot 10^{-3} \cdot \alpha + 0.8352\right)$$

$$\text{Zone 4}: \ Yield = GHI \cdot \left(-8.670 \cdot 10^{-5} \cdot \alpha^2 + 4.625 \cdot 10^{-3} \cdot \alpha + 0.8648\right)$$

With the Yield in kWh/kWp and GHI in kWh/m^2 for one year. As the Yield depends not only on the GHI and the inclination but also on the effects of latitude and temperature, the Spanish territory has been sectorized into four zones. Each zone can be considered as:

Zone 1: corresponds to the central zone of the Iberian Peninsula. It is applied in the communities of Castilla y León, Extremadura, the Community of Madrid, Castilla la Mancha, the Valencian Community, and the Balearic Islands.

Zone 2: corresponds to the northern part of the peninsula, made up of Galicia, Asturias, Cantabria, the Basque Country, La Rioja, Navarra, Aragon, and Catalonia.

Zone 3: corresponds to the southern zone of the peninsula, made up of the communities of Andalusia, Murcia, and Ceuta and Melilla.

Zone 4: Canary Islands.

It is recommended to use data from weather stations close to the plant site. As a query, the ADRASE data (Access to Solar Radiation Data in Spain) can be used once converted to kWh/m^2.year [40].

The production generated in year 1 of the plant is calculated directly by multiplying the Yield (calculated in this step) by the installed power, obtained from Step 2:

$$Annual\ Production\ (\text{kWh}) = Yield\ \left(\frac{\text{kWh}}{\text{kWp}}\right) \cdot Peak\ Power\ (\text{kWp}) \tag{19}$$

Step 3: Calculation of the CAPEX and OPEX of the plant

The calculation of CAPEX does not include the building license, which the owner of the project generally pays. Therefore, its cost is considered in the calculation of the LCOE but not in the calculation of the cost of the installation. For the CAPEX assessment, it is necessary to calculate the number of modules in the installation, through the equation:

$$\mathbf{Nmodule} = \frac{Peak\ Power}{STC\ Module\ Power} \tag{20}$$

The equation developed that allows estimating the sale price of a photovoltaic installation results in Equation (15), Pmodule: cost of the module, in EUR/Wp. As a guide, these values are proposed in Table 7, which shows those that have been considered for the elaboration of this project:

Table 7. Proposed Module cost in €/Wp (year 2019).

Module	330 Wp/Polycrystalline	375 Wp/Monocrystalline
75 kWp–250 kWp	0.25	0.29
250 kWp–750 kWp	0.24	0.28
750 kWp–2500 kWp	0.23	0.27

Pinv: the cost of inverters, in EUR/Wp. If the power of inverters is unknown, the following relationship can be considered valid:

Power inv (Wn) = 0.8·Pmod (Wp)

The following values in Table 8 are proposed in case there is no guide value:

Table 8. Proposed cost of inverter in €/Wp (year 2019).

Power	Cost (€/Wp)
75 kWp–250 kWp	0.070
250 kWp–750 kWp	0.055
750 kWp–2500 kWp	0.045

Pest: cost of the structures, in EUR/Wp. To work with normalized values, the total cost of the structures must be divided by the power of installed modules. As a guide, the values in Table 9 are proposed, which are those that have been considered for the elaboration of this project, with the costs of the option with aluminum strips:

Table 9. Proposed cost of structures in €/Wp (year 2019).

Power	Counterweight, 330 Wp Module	Counterweight, 375 Wp Module	Battens, 330 Wp Module	Battens, 375 Wp Module
75kWp–750 kWp	0.060	0.053	0.121	0.106
750kWp–2500 kWp	0.057	0.05	0.115	0.101

The counterweight solution being the support system patented by Solarbloc, which is only recommended for roof installations that support a high additional weight. The batten solution is a metallic aluminum structure that is anchored to the roof straps. In any case, it will always be more accurate to have a formal quote from a frame manufacturer.

Pp: the total peak power of the installation, calculated in Step 1.

fc: correction factor, value:

Modules of 60 cells: fc = 5/6

Modules of 72 cells: fc = 1

This correction factor allows that in the final cost of the plant, it is considered that the 60-cell modules present less power. Therefore, the cost of wiring, grounds, and protections that they entail is proportionally lower than the 72-cell modules.

Nmodule: number of modules in the plant.

HV: cost of the voltage elevation system if necessary. Its value is zero for any installation connected in Low voltage. The following value is proposed for estimating calculations, but it is more advisable to have a formal offer from an installation company of transforming systems:

If it is a low voltage connection$\rightarrow$HV = 0

If it is a high voltage connection$\rightarrow$HV = 56,450 €

GM: gross margin of the facility, office costs and industrial profit. 12% (6% + 6%) is proposed as a reference value

The OPEX is obtained directly from Equation (1):

annual OPEX = 0.01·CAPEX (1)

This value being the maintenance price for year 1.

Step 4: Calculate the plant's LCOE

If desired, Equation (2) can be used with the help of a spreadsheet. However, the simplification used in the Equation (17) can be considered valid.

Production in year 1 is calculated in Step 2, while CAPEX and OPEX have been calculated in Step 3. The rest of the parameters are:

L: cost of the building license compared to the cost of the EPC (%). If it is not known, it can be considered 4% for installations in Spain, although it can be consulted directly at the City Hall of the building in which the installation is carried out.

r: discount rate (%). For EPC type photovoltaic installations, it is recommended to use 6% [10,35].

n: useful life of the plant: It is recommended to use a value of 30 years [41].

4.2. Accuracy of the Developed Models

The models described in the previous section have been compared with the results of the simulations carried out:

Installed peak power

In Figure 17, the actual results are compared with those obtained through Equation (7) with the results of the model:

As can be seen, the actual results practically overlap with the values obtained with the model. This deviation increases in area 1 since the calculated values are less conservative than the real ones due to the need in the actual case to eliminate modules to adjust the number of modules per string. The mean relative error is 4.2%.

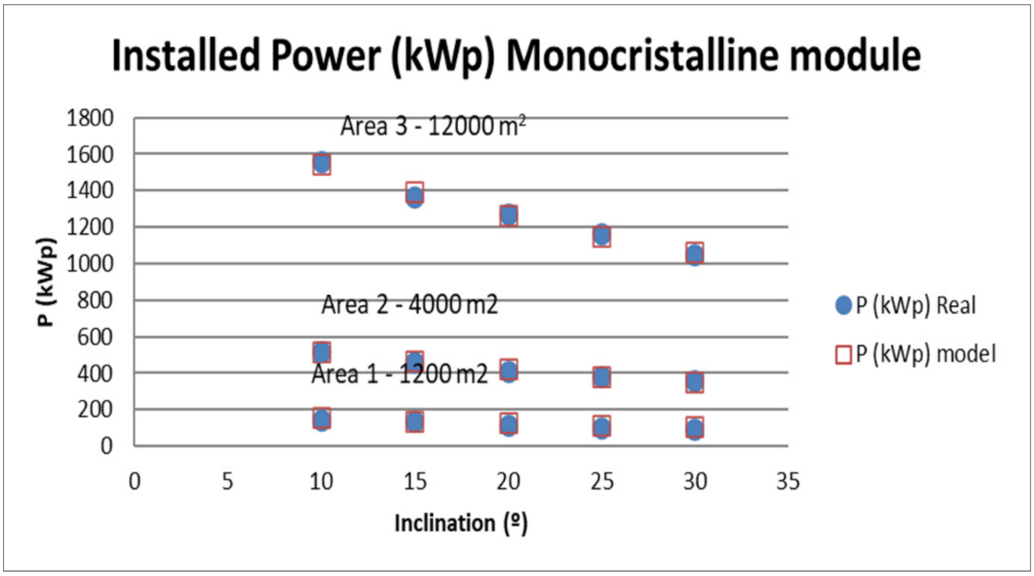

Figure 17. Real installed power and power estimated by the model.

Yield

The Yield that the model predicts has been calculated for the 120 cases studied. The mean relative error of the 120 cases is 0.44%. However, the precision has been verified for the same location, so this result does not allow us to verify its precision in other locations within the same range. However, it is important to bear in mind that the result depends on the Global Horizontal Irradiation introduced into the equation and is the main climatological variable.

Plant CAPEX

To verify the accuracy of the plant's calculation methodology, the cost of each of the facilities has been recalculated based on the desired power. In this case, the precision of the variable part is compared on the one hand (that is, without considering the costs of modules, inverters, and structures) and on the other hand, the final result, to see the precision of the part whose cost is obtained from the regression and see how it affects entering the proposed values for the main equipment. Table 10 presents these results:

Table 10. Model error for the three base cases in the calculation of normalized costs.

Case	Model Error–Other Costs	Model Error—CAPEX
10°-Mono-1200	5.01%	3.92%
10°-Mono-4000	6.51%	5.61%
10°-Mono-12,000	2.22%	2.61%

The mean relative error of the 30 cases for the calculation of CAPEX (discounting modules, inverters, and structures) is 3.47%. In the case of including all costs, this error drops to 2.57%. For its calculation, the costs proposed by the model have been considered, not the actual costs used, which vary in the case of investors.

LCOE Calculation

As previously described, the LCOE modeling has been carried out using an analytical approach proposed by the NREL, neglecting the effect of module degradation. In Figure 18, it can be seen that the differences between the real LCOE and the one predicted by the analytical model proposed in Equation (17) are quite small:

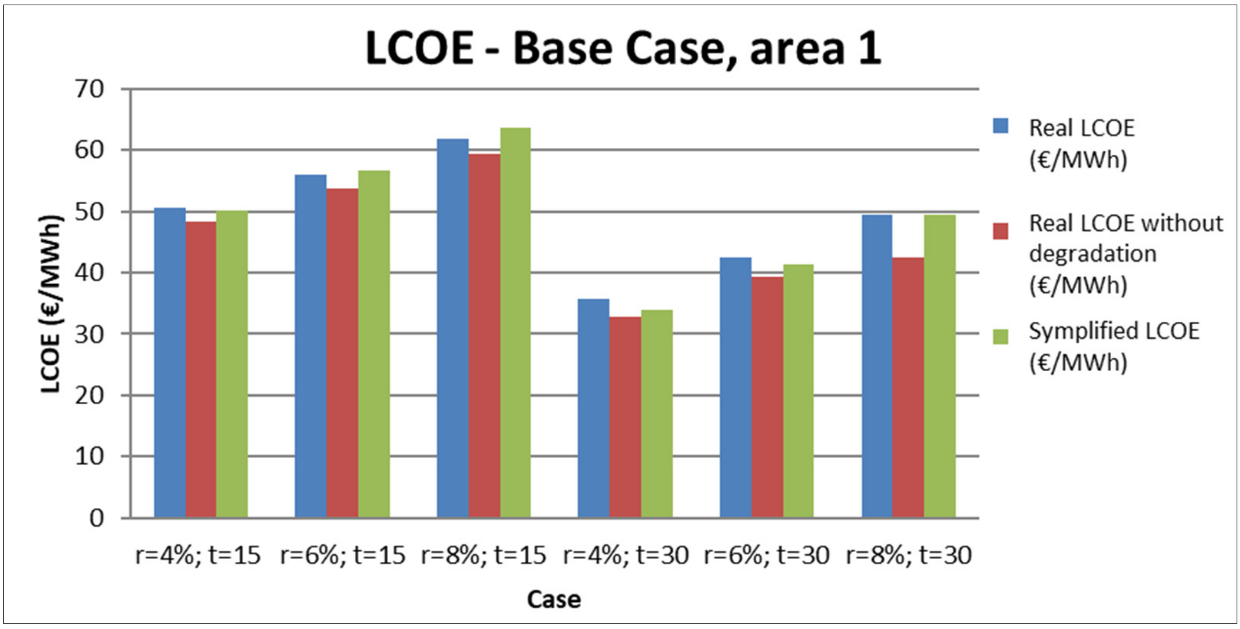

Figure 18. Deviation of the model LCOE with respect to the calculated LCOE.

These differences have been calculated for the base case of area 1 and are equivalent to those obtained for other facilities, since the precision of the approximation used causes the error. Table 11 shows the relative error of the LCOE calculation.

Table 11. Relative error of the LCOE calculation approximation as a function of the parameters involved.

r (%)	Years	Relative Error (%)
4	15	0.95
6	15	1.09
8	15	3.16
4	30	5.01
6	30	2.33
8	30	0.26

That is, the mean relative error of this approximation is 2.13%.

5. Conclusions, Limitations of the Study and Future Research

5.1. Conclusions

The conclusions obtained after carrying out the calculations of the cases analyzed, and the modeling are:

The maximum installable power increases linearly with the area used. In the area of 1200 m^2, its value ranges between 81.5 kWp and 142.5 kWp, while for installations of 12,000 m^2 this range of values is multiplied by 10. The oscillations within the same area are due to the inclination (the greater the inclination, the greater the separation between rows, and therefore the lower the installable power) and the peak power of the installed modules, the installable power being almost 14% higher in the case of installations with PERC monocrystalline modules.

The yield depends fundamentally on the location, mainly due to the variation in Global Horizontal Radiation (which in the cases studied goes from 1255 kWh/m^2. Bilbao year to 1935 kWh/m^2. Lanzarote year), and by temperature, which decreases production by lowering the performance of the modules. The yield also increases with the incline, obtaining the maximum in the 30°. The PR of the installation is higher in the monocrystalline modules used since the improvement implied by having PERC cells increases their performance in the first hours of the day and at high temperatures. This improvement was not included in the polycrystalline modules considered.

The CAPEX of the plant increases with the available surface, but to make a correct analysis, it is more appropriate to normalize its value to EUR/Wp. In comparing normalized values, the CAPEX of the cases studied ranges between 0.72 EUR and 0.83/Wp for 1200 m^2 facilities and between 0.59 EUR and 0.64/Wp for facilities of 12,000 m^2. There is a decrease in this ratio with power due to the economy of scale, which is especially significant for small plants. The variation with the type of module is not very significant, while the inclination does affect the ratio since it modifies the installable power.

Breaking down the CAPEX by cost components, the PV module represents approximately 40% of the cost, while the inverter represents an average of 8%, the structure 10%, and the assembly 12%. The rest of the elements, which include wiring and protections and the costs of the business structure, engineering, and industrial profit, account for an average of 29% of the total. This dependence on the cost of the modules and inverter is much lower than in previous times, which had module prices more than ten times higher than today. The decrease in the dependence on the cost of the modules partly explains why the inclinations currently used are lower or why two-axis tracking systems are not used.

OPEX has been estimated at an annual cost of 1% of CAPEX, representing its minor importance in estimating the LCOE of facilities, especially in industrial self-consumption plants with high discount rates.

For the calculation of the LCOE of the plant, it affects both the normalized CAPEX of the facility and the yield. For this project, fixed discount rates of 6% and useful life of 30 years have been considered, and LCOE values of between 29 EUR and 39 EUR/MWh are obtained for the best location (Seville), and values between 45 and 59 €/MWh for the worst location studied (Bilbao). This range within the same location is mainly due to the size of the plant due to economies of scale. It also affects the variation of the inclination used (The optimum is 10° in Lanzarote and 20° in the rest of the locations since, on the one hand, the inclination improves the yield but makes the installed Wp more expensive). Comparison of the two types of modules used does not show significant differences in terms of LCOE.

The other parameters considered, the discount rate and the plant's useful life, also have great importance in calculating the LCOE. The same installation with a discount rate of 4% presents an LCOE of 36 EUR/MWh. A discount rate of 8% would have an LCOE of 49 EUR/MWh. On the other hand, an installation with a 15-year useful life presents an LCOE of 56 EUR/MWh, if studied at 30 years, its energy cost would decrease to 42 EUR/MWh. That is why correctly assessing the risk of self-consumption facilities to apply the appropriate discount rate and period of life is one of the most important parts to evaluate this type of asset as a financial product.

A series of numerical models have been generated that quickly estimate the maximum installable power for a flat roof intended for self-consumption and its production, cost, and LCOE. For its calculation, it is necessary to carry out a series of steps in which proposed costs of modules, structures and inverters can be applied, but these values can be modified in case of having known prices (which allows the models to remain valid even if module cost fluctuates or module performance improves).

To estimate the maximum installable power, it is only necessary to know the area, the performance of the module, and the desired inclination. For the yield, the variables come down to location, the GHI of that location, and the slant of the modules. The production is obtained as the product of the two previous results.

The calculation of CAPEX requires six calculation variables, for which current values are proposed if they are unknown. The analysis of the LCOE can be simplified to a single analytical calculation, which in turn implies a loss of precision concerning the usual calculation methodology. As in CAPEX, most variables are left for the reader to enter, proposing values if they are not known.

The relative error of the numerical models for estimating the installable power with respect to the cases evaluated in the project itself is 4.2% on average, while the relative error of the yield is less than 1%. Naturally, the very low error of the Yield is partly because the precision has been evaluated with the cases that have served to generate the model. Still, no significant deviations can be expected if there are modules and investors of similar technology and the appropriate wiring sections are respected in the design phases. The mean relative error of the normalized CAPEX is 3.5% on average concerning the cases studied, while the simplification in the calculation of the LCOE leads to an error of 2.1%.

The developed models allow to quickly calculate the LCOE with various slopes and module technologies to check which installation approach will have a lower LCOE (and consequently a shorter payback period). In addition, it allows the reader to have a quick idea of the installable power, the cost of the installation, its production, and its LCOE, without having to carry out the basic engineering of the different installations or simulate each case separately. However, it is recommended to use these models as support and never as a rigid and absolute calculation methodology since it simplifies the multiple variables that can appear in a photovoltaic installation.

From an academic or commercial point of view, the article will allow estimating the power that can be installed in a specific location, the cost of said installation, its production, and its LCOE. This makes it possible to increase the transparency of the available resources and make preliminary decisions on the economic viability of developing such a facility. A potential owner will be able to evaluate the LCOE of the potential plant and compare, based on the results obtained, the proposals received from installers. A potential installer will know the specific production in a preliminary way without resorting to design software and optimizing the inclination of the modules based on the LCOE obtained.

5.2. Limitations of the Study and Future Research

This study tries to generate models that facilitate the estimation of the main parameters of a photovoltaic installation. However, the scope of this work is limited to flat rooftop installations intended for industrial self-consumption and which have anti-drift systems.

The methodology developed can be partly applied to rooftop coplanar installations if the costs of the structures are known. However, for the study of production, the azimuth of the installation in coplanar roofs is a fundamental parameter to consider since the azimuthal angle has a relevant influence on the production of a PV plant. However, the article assumes a flat rooftop in which the standard solution is to incline the modules facing south. In that case, the azimuth is always 180°, considering 0° North orientation. It would not have practical interest to give a different azimuth to the solution. If the PV-plant has a solution parallel to a rooftop -for example, if it is installed in a roof with a significant slope- the azimuth should be included in the yield numerical model as a new variable. Other parameters, such as temperature, latitude, or seasonal radiation distribution, have been indirectly included by modeling production in four different locations. One of the aspects that could be studied in the future would therefore be applying the models to coplanar installations, including the azimuth variable to the modeling of the yield of the installations.

Another way to improve the models developed would be to generate a final calculation step to obtain both the installation payback and annual savings. For this, it would be necessary to leave the owner's electricity rates and the expected degree of self-consumption of the installation as an input variable. It could also be possible to compare the proposal with anti-spilling systems with that with compensation systems. The cost of connection and access fees would conflict with the income from the export of unused energy.

Finally, a previous step of the model would be of great interest that allows knowing the recommended power to install according to the owner's consumption (which should be a known variable). The developed model covers the entire available area, but this step would help size the installation, the available area, and the owner's consumption according to two criteria.

It could be interesting to define a method that could be extended to other countries However, in that case, the models would have been too complex, and the goal of the article -allowing a reader to quickly estimate the main technical and economic parameters for a PV Plant-would have been compromised. For example, the latitude affects the GHI and the temperature, and the seasonal distribution of the GHI. The latitude is also related to the influence of tilt in the production, which is the main reason why it was decided to include four production sites, covering different latitudes of Spain.

Regarding cost, import costs and labor costs also depend on the country, so these values would need to be considered variables, compromising the simplicity and accuracy of the models. The country variation would also affect the discount rates to be considered for the discussion. However, we consider that these models could be applied in countries with similar latitudes and labor conditions to Spain. For example, Portugal, Italy, and possibly Greece could be potential locations that could take advantage of this model with acceptable accuracy. However, this has not been checked as it is out of the scope of the article.

To enlarge the analysis focus, we consider engaging in two main topics. The first one is entrepreneurship which we find particularly relevant for the Spanish situation where the current legal framework provides adequate incentives since the new legislation regulating solar energy for self-consumption was introduced in 2019 (Royal Decree 244-2019) [42]. The conditions can be similar to those of other countries where rooftop PV facilities for industrial self-consumption are clear drivers of entrepreneurial activities, as we have detected in recent scientific literature [43–45]. The second topic relates to technological innovation, which also offers the possibility of optimizing electricity production within the limitations of the available resource.

Author Contributions: Conceptualization, Á.R.-M. and C.R.-M.; methodology, Á.R.-M. and C.R.-M.; software, Á.R.-M.; validation, Á.R.-M., and C.R.-M.; formal analysis, Á.R.-M.; investigation, Á.R.-M. and C.R.-M.; resources, Á.R.-M.; data curation, Á.R.-M.; writing—original draft preparation, Á.R.-M. and C.R.-M.; writing—review and editing, Á.R.-M. and C.R.-M.; visualization, Á.R.-M.; supervision, C.R.-M.; project administration, C.R.-M. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: All data used in the study are publicly available. The repositories are refenced in the text.

Conflicts of Interest: The authors declare no conflict of interest.

Abbreviations

AC	Alternating Current
BIPV	Building Integrated PV
CAPEX	Capital Expenditures
CRF	Capital Recovery Factor
DC	Direct Current
DDP	Delivered Duty Paid
EPC	Engineering, Procurement, and Construction
G	Radiation value in kW_p/m^2
GHI	Global Horizontal Irradiation
GM	Gross Margin
HV	Cost of the voltage raising system
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Electricity
LID	Light Induced Degradation
LV	Low Voltage
MV	Medium Voltage
MPPT	Maximum Power Point Tracker
NREL	National Renewable Energy Laboratory
OPEX	Operational Expenditures
PERC	Passivated Emitter Real Cell
PPA	Power Purchase Agreement
PR	Performance Ratio
PV	Photo-voltaic
STC	Standard Test Conditions
TS	Transforming Station

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