Economic viability assessment of floating photovoltaic energy

Michele Barbuscia

Thesis to obtain the Master of Science Degree in

Energy Engineering and Management

Supervisors: Prof. António José Nunes de Almeida Sarmento
Dr. José Joaquim Marques Bação Cândido

Examination Committee

Chairperson: Luís Filipe Moreira Mendes
Supervisor: Dr. José Joaquim Marques Bação Cândido
Member of the Committee: Rui Manuel Gameiro de Castro

November 2017

ABSTRACT (EN) – Solar photovoltaic is one of the most well-established forms of renewable energy, currently showing signs of a significant level of maturity. Its production prices in 2016 reached for the first time the level of those of onshore wind, and, in most countries, are permanently lower than those of conventional energies. Furthermore, there is evidence that, in the next ten years, the global weighted average installed cost of utility-scale solar photovoltaics (PV) could fall by around 60%.

As it is a very modular technology, systems may range from very small scales up to utility-scale power generation facilities, allowing for a wide scope of applications.

The exhaustion of global terrestrial resources and the need to avoid the occupation of large farmlands with ground-based solar plants has encouraged the search for alternative solutions. Such is the case of floating photovoltaic energy systems, which recently started attracting the attention of both the research community and utilities. Until a few years ago, this type of solution, which has the potential to improve PV systems efficiency while, at the same time, addressing the space usage issues, was hardly regarded as economically viable.

The work consists in a breakdown of solar photovoltaic technology and economics, in the study of economic viability of different floating PV configurations, and in a simulation of a floating PV system on a Portuguese dam. For this purpose, a simulation model has been designed to compute the levelized cost of energy and to carry on sensitivity analyses on the most cost-influencing aspects of the power plant.

Key words: Floating Photovoltaics, FPV, Renewable Energy, Sustainability

ABSTRACT (PT) – A energia solar fotovoltaica é uma das formas de energia mais consolidadas, mostrando atualmente sinais de um elevado nível de maturidade. Os valores de preço de produção em 2016 alcançaram pela primeira vez o nível da energia eólica, e na maioria dos países são constantemente inferiores aos das energias convencionais. Para além disso está comprovado que nos próximos dez anos a média global ponderada dos custos instalados do solar fotovoltaico (PV) de larga escala podem cair por volta de 60%.

Sendo uma tecnologia muito modular os sistemas podem variar de pequena escala para sistemas de geração de energia de larga escala, permitindo um grande campo de aplicação.

O esgotamento dos recursos terrestres globais e a necessidade de evitar a ocupação de grandes solos com painéis solares incentivou à procura de soluções alternativas. É esse o caso dos sistemas de energia fotovoltaicos flutuantes, que recentemente começaram a atrair a atenção das comunidades de investigação e das companhias. Até a alguns anos atrás esta solução, que tem o potencial para melhorar a eficácia dos sistemas PV e ao mesmo tempo resolver a problemática da utilização do espaço, era considerada economicamente pouco viável.

Este trabalho consiste numa análise detalhada da tecnologia e da economia dos sistemas fotovoltaico, no estudo da viabilidade económica das diferentes configurações dos PV flutuantes e por fim numa simulação de um sistema PV flutuante numa barragem portuguesa. Para tal, foi criado um modelo de simulação pra calcular o custo de energia (LCOE) e uma análise de sensibilidade (sensitivity analysis) dos aspectos mais influenciadores do custo da energia.

Palavras-chave: fotovoltaico flutuante, FPV, energías renováveis, sustentabilidade

Table of Contents

List of Figures

List of Tables

List of abbreviations

EIA – U.S. Energy Information Administration
OECD – Organization for Economic Co-operation and Development
GHG – Green House Gas
LCA – Life Cycle Assessment
O&M – Operation and Maintenance
PV – Photovoltaic
FPV – Floating Photovoltaic
LCOE – Levelized Cost of Energy
CAPEX – Capital Expenditures
OPEX – Operational Expenditures
BoS – Balance of the System
DC – Direct Current
AC – Alternate Current
STC – Standard Test Conditions
PR – Performance Ratio
CF – Capacity Factor
NREL – U.S. National Renewable Energy Laboratory
R&D – Research and Development
IRENA – International Renewable Energy Agency
UAE – United Arab Emirates
FIT – Feed-In Tariff
USD – United States Dollar
EIA – Environmental Impact Assessment
ROV – (underwater) Remotely Operated Vehicle
HDPE – High-density Polyethilene
PFRP – Pultruded Fiber Reinforced Polymeric
PVC – Polyvinyl Chloride
EDP – Energia de Portugal

1. Introduction

1.1 General Background

The world population was estimated to have reached 7.5 billions in April 2017. The United Nations estimates it will further increase to 11.2 billions in the year 2100 [1]. This trended growth in population results in a relentless sustained demand for the energy industry: the world energy consumption is expected to increase by 28% between 2015 and 2040, with more than half of the increase attributed to non-OECD countries [2]. The limited availability of conventional natural energy resources, as well as their impacts on the environment due to the release of greenhouse gases (GHGs), has meant more focus being put on renewable energy sources. These have various advantages, such as almost infinite energy resources and zero-emissions during operations, but they have several disadvantages too, among which the intensive land-use is often cited as one of the most relevant.

Among all renewable energies, large-scale solar photovoltaic requires a large land footprint to be effective, since its energy generation is directly proportional to the system's unobstructed surface area. But, on a lifetime basis, its land-use is comparable or even lower than that of conventional energy sources. D. Turney et al. [3] showed that a 30-years old photovoltaic plant is seen to occupy ~15% less land than a coal power plant of the same age. In fact, operations for a PV power plant don't have any relevant environmental impact, while those of coal power have, such as land for coal mining and for railways used for coal transportation to the power plant.

The impact of PV power plants' land use is much more relevant where land is a precious resource and installing a PV plant would reduce the land surface addressed to other more profitable uses. As it will be explained in Chapter 4, this is the case of all the first floating PV plants, which were installed on private irrigation tanks by farmers who didn't want to replace their cultivations with PV panels. In these cases, land-use reduction is not the only advantage of FPV (Floating Photovoltaics), which also reduces the water evaporation and the algae formation in the water basin, and has better efficiencies than normal PV modules due to the cooling effect of the water surface. This kind of installations has null costs related to mooring lines – because they can be simply tied to the borders of the artificial lake/irrigation tank – and can be installed on simple (and economic) floating structures, because they don't need to withstand severe environmental conditions, as irrigation tanks usually are little enough not to have currents or waves, and don't have tides or other variations of bathymetry. Further in the Dissertation, it will be demonstrated that cost of energy for this kind of installations differs from traditional large-scale plant for less than 10%.

In recent times, the drastic reduction in cost of solar photovoltaic systems components – whose drivers are well described in Chapter 3 – is moving the interest in floating PV from private to public investors: many countries and public companies are investing in this technology throughout the world. For instance, London's water supply company, Thames Water, has installed in March 2016 a 6.4 MW FPV system (actually the biggest in Europe) on the Queen Elisabeth II water reservoir, near the city. Japan is the country with more big-size FPV plants, 45 of the 70 biggest plants in the world. Japan and

Singapore provide another great example of the relative importance of land-use associated to photovoltaics as they are both little, densely populated countries. In October 2016 Singapore inaugurated the largest solar photovoltaic cell test-bed containing 10 different FPV systems of about 100 kW each, used to study the performance and the cost-effectiveness of the various systems.

Since plants on little lakes are already a reality throughout the world, looking at bigger solutions is permitted. Such is the case of installations on dams, which would potentially present even higher advantages, such as the possibility of coupling solar photovoltaics and hydropower power output, in order to achieve a less variable production, and the savings related to the presence of the turbine's transmission line, which represents a relevant cost for traditional utility-scale PV plants. On the other hand, it has several disadvantages related to the harder environmental conditions, similar to those of the sea, which would require more resistant module mounting structures, a complicated mooring line system, and under-water cabling among the others. A complete analysis of these factors, under both technical and economic perspective, is given in Chapter 4. The fifth and last chapter of the Dissertation is focused on installations on dams. It analyses through a simulation model that has been designed for the purpose the most influencing factors for a floating plant on a Portuguese dam, predicting its cost of energy and discussing all its variables.

1.2 Objectives and Scope

Despite the growing interest in the technology, which is undoubtedly encouraging about its future development, FPV is still a very young technology. In fact, when this study was initiated, just a few studies had already been performed on the technical aspects and challenges of floating PV. But the main challenge in undertaking this research was the lack of literature and material available about its economic viability. This is one of the most complex issues to assess when designing a renewable energy power plant, since it depends on a wide range of factors, from the location to the choice of every component of the system. Consistent validated data is difficult to obtain on the few existing plants, also due to the different natures of these installations. In fact, many of them have not been installed for scientific purposes, meaning that no measurements and results have been published. This is the reason why some of the values used in the simulation described in chapter 5 are assumptions, based on literature and a few interviews with experts.

The main objective of this work is to assess an economic feasibility analysis of floating PV installations on dams. After summarizing photovoltaics technology and economics (Chapters 2 and 3), and analyzing all characteristics and main challenges of floating installations (Chapter4), the simulation of a power plant on the Portuguese Alqueva dam has been developed, and the respective levelized cost of energy has been calculated. A simulation model has been designed for this purpose and used to carry on sensitivity analyses on those aspects of the plant that influence more the cost of energy (Chapter 5).

1.3 Dissertation Structure

The study is structured in 6 chapters.

Chapter 1 is an Introduction to the dissertation; it gives a general contextualization of the technology and sets its objectives and scopes. It also explains the structure of this report.

Chapter 2 is an overview of photovoltaics; it includes a brief explanation of the PV technology, a summary of the rating principles and the metrics used to evaluate PV modules performances, an explanation of PV characteristic curve and the main parameters influencing module's performance, fundamental to understand the main differences between ground-mounted and floating PV power plants, a general outlook of the wide range of materials and technologies that differentiate PV modules and their efficiencies. Finally, it presents forecasts and main challenges of technical improvements for the different technologies.

Chapter 3 is about traditional PV economics. It starts with an overview of photovoltaics global market, its recent increase and its trends and global shares. Secondly, the costs of all the main components of a traditional PV power plant are analyzed, i.e. capital expenditures (CAPEX), divided in modules' costs, inverters' costs and BoS costs, and operational expenditures (OPEX). An explanation of the main economic metric used in this report to evaluate the viability of FPV plants, LCOE, is given, and, finally, future trends of economics of the system's components and of the technology's LCOE.

Chapter 4 introduces the issue of floating PV installations. It starts with a detailed historical outlook of the first FPV plants installed in every part of the world. Then, the main technical differences from utility-scale ground-mounted power plants are listed, with a particular attention given to the floating structures and associated advantages and disadvantages. Here an in-depth study of PV modules' performance in different circumstances is carried out. Finally, the economic differences between FPV and traditional PV are analyzed.

Chapter 5 focus on installations on dams. Firstly, all the environmental conditions of a typical dam are explained, with particular focus on the specific challenges for FPV. Then, a possible configuration of coupling photovoltaics and hydropower is analyzed. The construction of the simulation model is briefly illustrated. A base-case simulation of a floating PV power plant to be installed in Portugal designed with the model is described, and its results are discussed. Some sensitivity analysis performed on the main cost-influencing components are presented. Finally, a verification of the model efficacy is made with values provided from a big energy company.

Chapter 6 summarizes the work done in the Dissertation and sets pros and cons of the main configurations considered during the investigation. Finally, future perspectives of the technology are set, and suggestions for future works are given.

2. Photovoltaic Technology

Solar photovoltaics (PV) is one of the most widely deployed solar electric technologies in the world today. Solar cells operate near ambient temperature, with no moving parts, and they enable generation at any scale: a 10-square-meter (m2) PV array is in theory no less efficient per unit area than a 10-square-kilometer (km2) array. This contrasts with other generation pathways, such as thermal generators or wind turbines, which lose efficiency with reduced scale. A solar PV array consists of one or more electrically connected PV modules, each containing many individual solar cells, integrated with balance-of-system (BoS) hardware components, such as combiner boxes, inverters, transformers, racking, wiring and enclosures. In a grid-connected system, combiners, inverters, and transformers convert the low-voltage direct current (DC) output of many individual PV modules into high-voltage alternating current (AC) power that is fed into the grid. Many off-grid systems also employ charge controllers and batteries to store energy during the day and provide on-demand power during the night.

2.1 Basics of energy conversion

During operation, the front surface of the photovoltaic module is illuminated by sunlight. Solar photons are transmitted to each cell, and those photons with sufficiently high energy, i.e. higher than the material-dependent bandgap, are absorbed. Solar cells are typically made of semiconductor materials, which have weakly bonded electrons occupying the valence energy band. When energy exceeding the bandgap is applied to a cell, the bonds of the valence electron and its positively charged counterpart (a hole) are broken, an internal electric field pulls electrons toward one electrode and holes toward the other, resulting in a DC current. PV

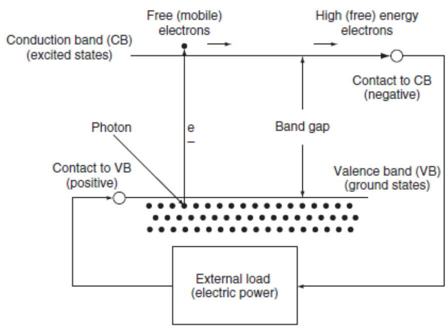


Figure 1: Schematic of a solar cell

Figure 1 shows the idealized circuit run by the electrons from the valence band (ground state), excited by a photon moving to the conduction band, where a selective contact collects them and drives them to the circuit to supply an external load; once the energy needed to cover the cycle is lost, they come back to the conduction band. The potential at which the electrons are delivered to the external world is less than the threshold energy that excited the electrons, and it is independent of the energy of the photon that created it. Thus, in a material with a 1 eV bandgap, electrons excited by a 2 eV (red) photon or by a 3 eV (blue) photon will both still have a potential voltage of slightly less than 1V.
At the heart of almost any solar cell is the pn **junction. This** pn junction results from the “doping” that **produces conduction-band or valence-band selective contacts with one becoming the** n**-side (lots of negative charge), the other the** p**-side (lots of positive charge). Behind the main advantages and disadvantages of photovoltaics are listed:**

Advantages:

• **Fuel source is widely accessible and essentially infinite**

• **No emissions, combustion or radioactive waste**

• Low operating costs (no fuel)
• No moving parts (no wear); theoretically everlasting
• Ambient temperature operation (no high-temperature corrosion or safety issues)
• High reliability of solar modules (manufacturers guarantee over 30 years)
• Rather predictable annual output
• Modular (small or large increments)
• Can be integrated into new or existing building structures
• Can be very rapidly installed at nearly any point-of-use

Disadvantages:
• Fuel source is diffuse (sunlight is a relatively low-density energy)
• High initial (installed) costs
• Unpredictable hourly or daily output
• Lack of economical efficient energy storage

2.2 Rating of PV modules

While conventional power generators are rated in watts because they are designed to produce a certain amount of power continuously, PV modules are rated in watts of peak power (W_p). This is the power the module would deliver to a perfectly matched load when illuminated with 1 kW/m^2 of incident solar radiation of a certain standard spectrum while the cell temperature is fixed at 25°C. These "standard test conditions", or STC, are universally applied to rate peak output of a solar cell in a laboratory or a module out in the field, but rarely occur in real outdoor applications. Usually, the irradiance is smaller and the temperature much higher. Both factors reduce the power that is generated. In addition, in some cases, the match between the load and the modules, or among the modules, is inefficient, which further reduces the power output. To enable useful predictions, the energy in kWh generated in one year (or one month or one average day) is obtained by multiplying the rated power in kW times the number of "effective hours" of irradiance falling on the generator in one year (one month, one average day) times the performance ratio (PR). The PR accounts for the mentioned losses in real operation, those in the wiring, in the inverter (whose efficiency may be 0.90–0.97) and for time for maintenance. In well-designed installations the PR can vary from 0.7 to 0.8, but may be even lower in warmer climates because the efficiency of the cell decreases with the temperature, as will be described in detail in the next paragraph. Since the rating power is 1 kW/m^2, the number of "effective" sun hours is the number of equivalent hours that should be applied to a plane with the same orientation of the PV generator at rating power in order for it to receive the same amount of energy (example: if in real conditions in a day an 1 m^2 module receives 6 kWh during 9 hours, the effective number of hours will be 6 h/d).

The actual AC energy output depends strongly on actual insolation, shading losses (e.g., soiling and snow coverage), module efficiency losses (e.g., at elevated temperatures or low insolation), and system losses (e.g., module mismatch, wire resistance, inverter and transformer losses, tracking inaccuracy, and age-related degradation). The energy yield (in kWh/W) is a module level performance metric that quantifies the lifetime AC energy output per unit of installed capacity, and it is proportional to the capacity factor (Equation 2). The performance of a deployed PV system is typically characterized by its actual

AC energy output per year, relative to the expected DC output. The expected output can be calculated in terms of either ideal or actual insolation, yielding two different metrics: The capacity factor compares system output to the performance of an ideal (lossless) system with identical nameplate capacity under constant peak (1000 W/m2) irradiance. The performance ratio (equation 1) instead compares system output to that of an ideal system in the same location.

(1)

$$PR = \frac{Actual\ AC\ energy\ output\ \left[\frac{kWh}{y}\right]}{DC\ peak\ power\ rating\ [kWp]\ x\ 8760\ \left[\frac{h}{y}\right]\ x\ \frac{Average\ Irradiance\ [\frac{W}{m2}]}{1000\ [\frac{W}{m2}]}}$$

(2)

$$CF = \frac{Actual\ AC\ energy\ output\ \left[\frac{kWh}{y}\right]}{DC\ peak\ power\ rating\ [kWp]\ x\ 8760\ \left[\frac{h}{y}\right]}$$

Capacity factors are commonly used to compare power generation systems. The annual capacity factor for a typical utility-scale solar PV system is around 20%, compared to 22% for solar thermal, 31% for wind, 40% for hydropower, 44% for natural gas combined cycle, 64% for coal, and 90% for nuclear plants. Solar power systems without storage can operate only when sunlight is available; this constraint alone limits the capacity factor to the fraction of daylight hours. By accounting for geographical and temporal variations in insolation, the performance ratio isolates system losses and allows for a comparison of PV systems in different locations.

2.3 Characteristic curve and main parameters

Figure 2 shows the characteristic curve of a PV cell. The important parameters are:

- Short Circuit Current (I_{SC}) – This is the maximum current that the cell can provide, and it occurs when the cells is short circuited. Unlike other small-scale electricity generating systems PV cells are not harmed by being shorted out.
- Open circuit Current (V_{OC}) – This is the maximum voltage that exists between the cells terminals and is obtained when there is no load connected across them.
- Maximum Power Point (P_{Max}) – The point on the I-V curve at which maximum power is being produced by the cell. P_{Max} occurs on the 'knee' of the **I-V curve.**

Figure 3 shows the power output trend of a typical silicon PV cell depending on the cell voltage. It has a maximum value that corresponds to the knee of the characteristic curve. Power output goes to zero whenever one between voltage and current does (open-circuit or short-circuit).

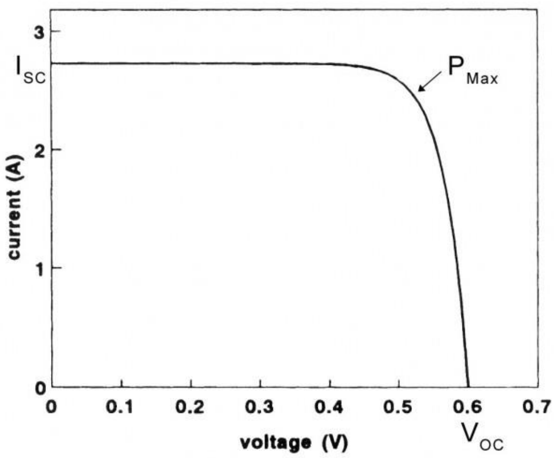


Figure 2: Typical characteristic curve for a silicon PV cell

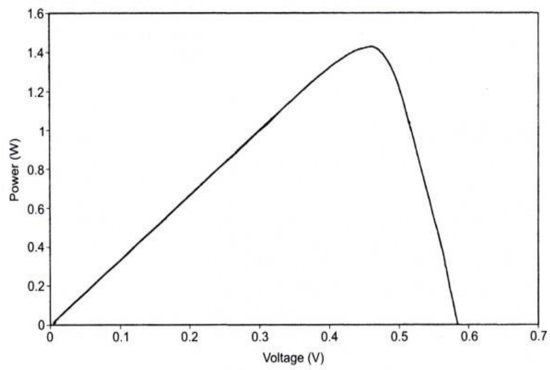


Figure 3: A typical power output VS voltage curve for a silicon photovoltaic cell.

Irradiance Effect

Photovoltaic output power is affected by incident irradiance, which is the power provided by the sunlight per surface unit. PV module short circuit current (Isc**) is linearly proportional to the irradiation, while open circuit voltage (**Voc**) sees little variations that are usually ignored. Figure 4 describes the relation between photovoltaic voltage and current with the incident irradiation.**

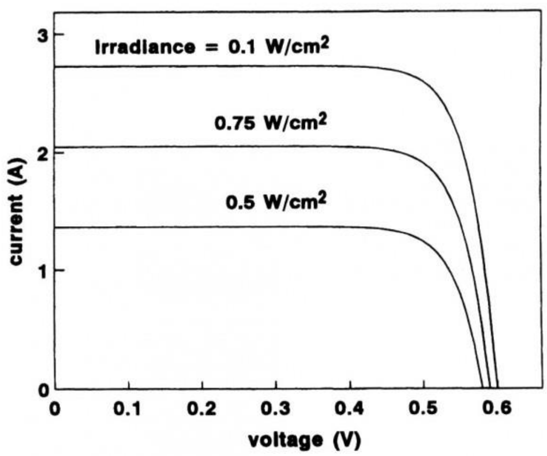


Figure 4: Effect of irradiance on a PV cell characteristic curve

Temperature Effect

Module's temperature is highly affected by **air temperature and sun irradiation. Figure 5 shows the effects of temperature on the I-V curve of a PV cell. I_{SC} increases slightly with temperature by about 6μA** per °C for 1cm^2 of cell, this is so small that it is normally ignored. Temperature has a considerably stronger effect on voltage, which typically decreases by 2.3mV per °C per cell.

Typical working temperatures for PV systems in South Europe are around 60ºC, and could reach up to 80ºC for hotter and more sunny areas like Northern Africa and Middle-East countries, resulting in huge losses in energy production. As will be explained in Chapter 4, one of the most important advantages of floating PV installations is that the presence of the water keeps the modules at a much lower temperature. Depending on the type of structure, the efficiency gain can reach values around 12% [20].

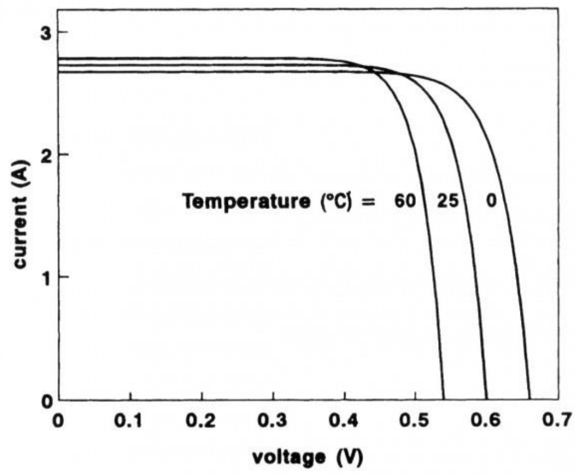


Figure 5: Effect of temperature on a PV cell characteristic curve

Figure 6 shows the power produced under different conditions as a function of voltage. Both Figures 4 and 6 show that the voltage at which P_{Max} occurs does not vary much with irradiance.

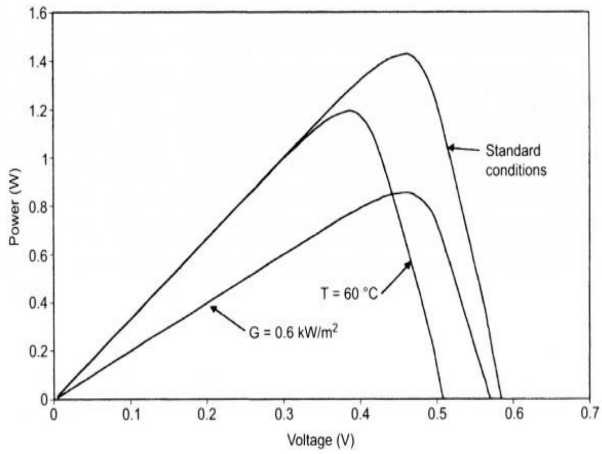


Figure 6: Power output in different operating conditions

2.4 Collecting Sunlight: tilt angle, orientation and shading

The tilt angle is the angle between the plane of the surface in question and the horizontal, and it takes values between 0° and 180°. Usually, the tilt angle to optimize yearly production for fixed non-tracking arrays of PV modules is some degrees below the local latitude (there is more insulation in the summertime). However, the annual output is only weakly dependent on tilt. For example, at mid-latitudes, the difference in annual average effective hours as the tilt angle of the modules varies from horizontal (0°) to the latitude angle is 10% ca. Thus, at the Portuguese latitudes, which go from 38º to

41°, the difference in annual effective hours between a horizontal surface (~4.4 effective hours per day) and the optimum tilt angle (~4.6 h/day) is between 5% and 10% [5]. The reason is that the sun's angle **at that latitude varies from 27° to 72° between winter solstice and summer solstice at this latitude. In winter, a steeper surface will have more output than a shallow slope, and vice versa in summer, so the difference between flat and tilted averages out somewhat during the year. As will be discussed in the last chapter of the dissertation, for the plant simulation has been chosen a tilt angle of 20º, a good compromise between maximum energy production (that would be with a tilt of 35º) and the higher cost of the structure.**

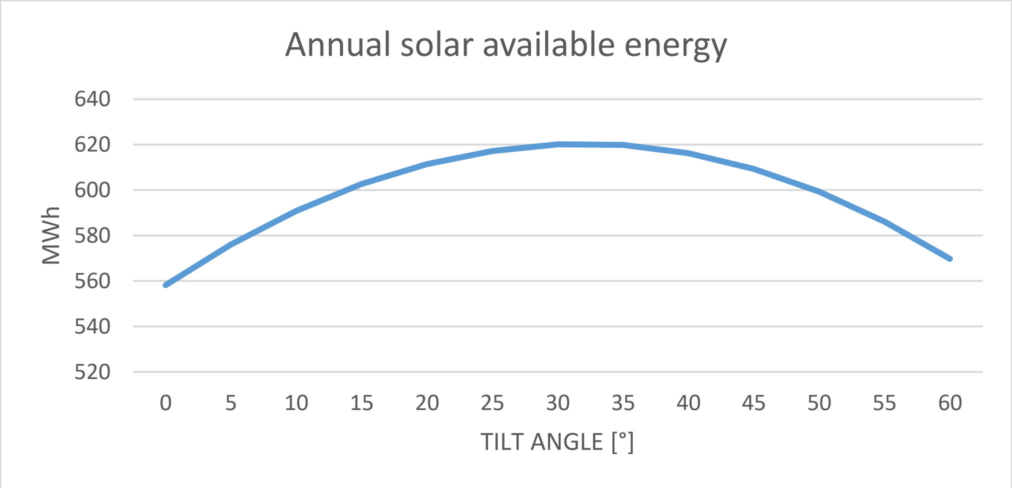


Figure 7: Influence of the Tilt Angle on the annual solar available energy at Lisbon's latitude (data from software RETScreen [33]).

For solar installations in the northern hemisphere, the optimum orientation for fixed non-tracking arrays is true south. But again, it is not very sensitive to minor deviations. An array oriented to the southeast will get more sunlight during the morning and less in the afternoon. Thus, for an array installed at 40°N latitude with 40° tilt and oriented 45° east (or west) from the true south, the annual output will be only 6% less compared to the optimum true south orientation [5]. A way to improve an array in this sense is installing a tracking system, which could increase the sunlight collected by 15-20% for single-axis trackers and by 25-40% for double-axis trackers. Tracking systems are generally employed only in large utility-scale ground-mounted arrays, as their costs are higher than for fixed arrays.

Another important issue to take into consideration when installing a PV array is the shadow. The first obvious reason is that the shaded parts produce negligible energy because, although the PV is able to operate with diffuse light, the amount of energy in diffuse light is smaller. However, there are other more insidious effects. For instance, even a slight shadow on the corner or edge of a module could dramatically reduce the output of the shadowed module but also of the entire array. This is because the modules are connected in series, therefore restricting the flow of current in one cell will restrict the current (hence the output power) of all other cells in that module and thus in all modules connected in series with it. The use of bypass diodes in series strings reduces these losses to very acceptable values; this technique is already widely used in at every size PV system.

2.5 Classification of Photovoltaics

PV cells can be classified as either wafer-based or thin-film. Wafer-based cells are fabricated on semiconducting wafers and can be handled without additional substrate, although modules are typically covered with glass for mechanical reasons. Thin-film cells consist of layers of semiconducting material deposited onto an insulating substrate, such as glass or flexible plastic. As shown in Figure 8, wafer-based cells are much thicker than thin-film, which determines their lower power-to-weight ratio. Another important difference is that wafer-based cells are rigid, while thin-film ones are flexible.

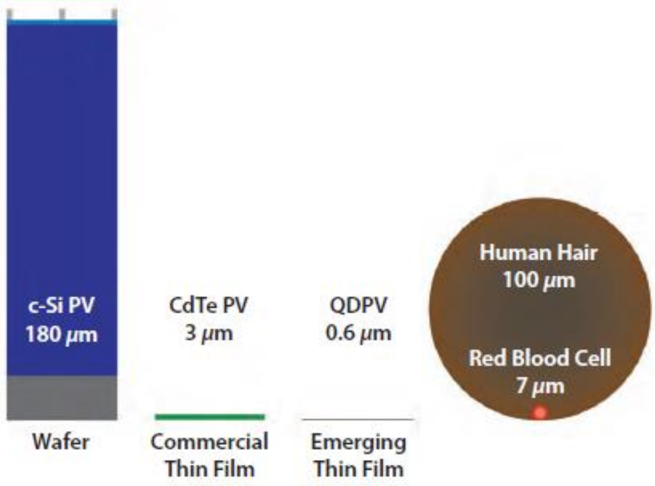


Figure 8: Solar cell thickness by technology classification

Besides the form-related classification, solar cell technologies are typically named according to their primary light-absorbing material. The vast majority of commercial PV module production has been — and remains — silicon-based, for reasons that are both technical and historical. Silicon can be manufactured into non-toxic, efficient, and extremely reliable solar cells, leveraging the cumulative learning of more than 60 years of semiconductor processing for integrated circuits. In fact, during the last decades microelectronics has developed silicon technology to a great extent. Not only has the PV community benefited from the accumulated knowledge, but also silicon feedstock and second-hand equipment have been acquired at reasonable prices. Furthermore, silicon is the second most abundant material on Earth (28%mass ca.) after oxygen and, hence, is available in almost infinite quantities.

Crystalline silicon (c-Si) solar cells constituted approximately 90% of global module production capacity in 2014 and are the most mature of all PV technologies. C-Si solar cells are divided into two categories: single-crystalline (sc-Si) and multicrystalline (mc-Si), with respective market shares of approximately 35% and 55% in 2014 [4]. The higher crystal quality in sc-Si cells improves charge extraction and power conversion efficiencies, but requires more expensive wafers (by 20% to 30%). A key disadvantage of c-Si is its relatively poor ability to absorb light, due to its indirect bandgap, which leads to weak light absorption and requires wafers with thicknesses on the order of 100 microns (μm) in the absence of advanced light-trap ping strategies. This shortcoming translates to high capital costs, low power-to-weight ratios, and constraints on module flexibility and design. Despite these limitations, c-Si will remain the leading deployed PV technology in the near future, and present c-Si technologies could achieve terawatt-scale deployment by 2050 without major technological advances [4]. Record lab-cell efficiencies stand at 25.6% for sc-Si and 20.4% for mc-Si; record efficiencies for large-area modules are 20.8% for sc-Si and 18.5% for mc-Si.

Several are the alternative materials for wafer-based technology, among them Gallium arsenide (GaAs) is almost perfectly suited for solar energy conversion. It is a compound material with strong absorption, a direct bandgap that is well matched to the solar spectrum, and very low non-radiative energy loss. GaAs has achieved the highest power conversion efficiencies of any material system — 28.8% for lab cells and 24.1% for modules.

While c-Si currently dominates the global PV market, alternative technologies may be able to achieve lower costs in the long run. Solar cells based on thin semiconducting films now constitute approximately 10% of global PV module production capacity, but they are expected to expand steadily their market share. Commercial thin-film PV technologies are represented primarily by cadmium telluride (CdTe), copper indium gallium diselenide (CIGS), and hydrogenated amorphous silicon (a-Si:H). These materials absorb light 10–100 times more efficiently than crystalline silicon, allowing the use of films just a few microns thick, as shown in Figure 8. Their low use of raw materials is thus a key advantage of these technologies. Advanced factories can produce thin-film modules in a highly streamlined and automated fashion, leading to low per-watt module costs. A key disadvantage of today's commercial thin-film modules is their comparatively low average efficiency, typically in the range of 12%–15%, compared to 15%–21% for c-Si. Reduced efficiencies increase system costs due to area-dependent BOS components. Due to their characteristics (thin, light, flexible) a particular effort has been made in recent times to improve thin-film modules' applications, such as electricity producing windows for buildings and floating systems. As it will be largely described in further chapters, Trapani et al. (2014) performed a detailed study on thin-film modules oscillating with waves while they are kept floating by some submerged floaters. Figure 9 shows the evolution in time of efficiencies in laboratory of the most PV technologies.

For floating applications, crystalline silicon will be considered for the pontoon based installations, due to its easy availability and good efficiency, while amorphous silicon will be considered for the flexible systems.

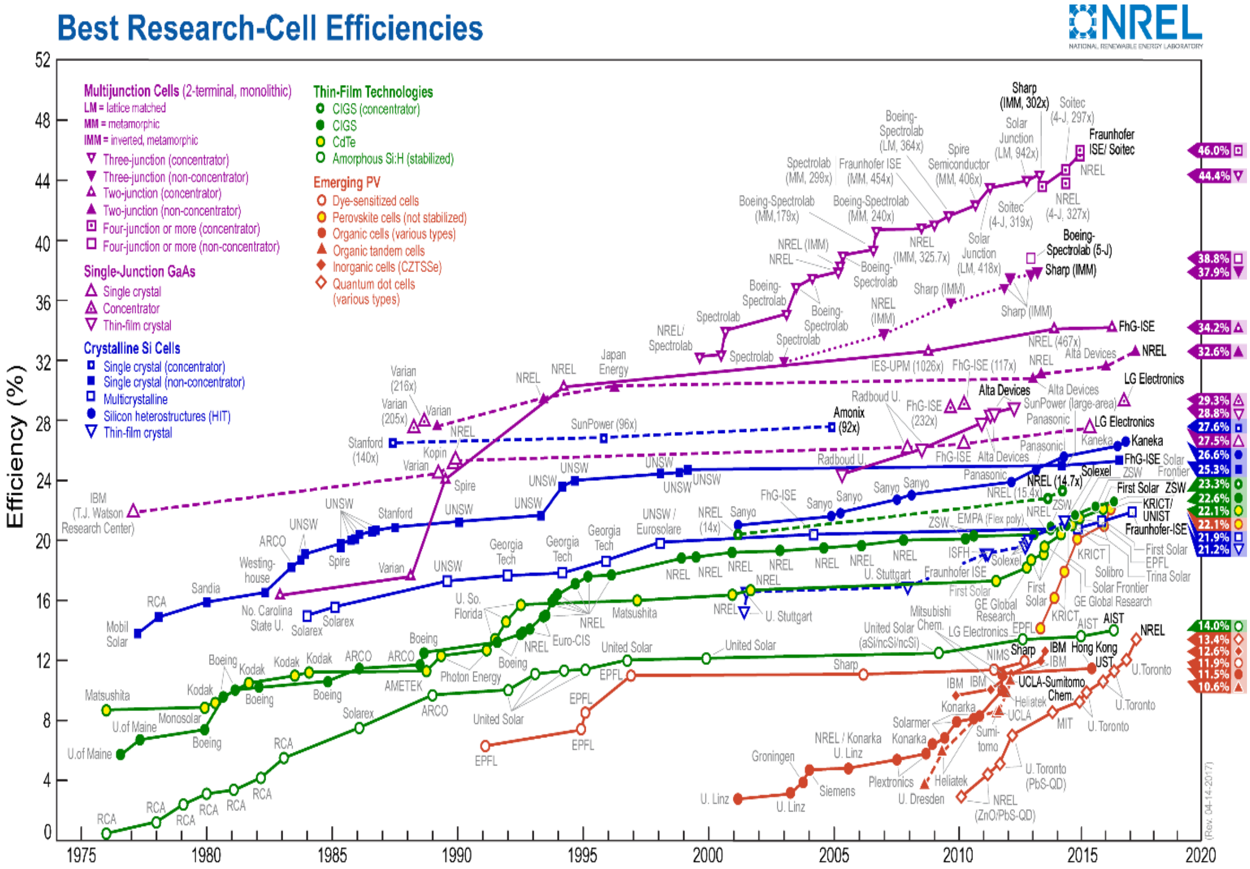


Figure 9: Evolution of efficiencies of the most performing PV technologies in time (NREL 14/04/2017)

2.6 Trends and improvements

Although solar PV technology is already mature and competitive with most energy sources, both renewable and conventional, it is plausible to expect a further innovation under various aspects:

Power conversion efficiency (% or W/m2)

Increasing sunlight-to-electricity conversion efficiency would directly benefit most of the metrics discussed in paragraph 2.2. However, gains in efficiency at the module level result from a constant investment at the R&D level, as well as from capital equipment and increasing complex manufacturing processes. Thus, it is reasonable to foresee a gradual trend toward better efficiencies over many years, rather than a sudden huge advance in performance.

Low materials usage (g/m3 or g/MW)

It is reasonable to expect a trend toward a lower usage of materials for all solar PV technologies. Thinner glass, frames and active layers can reduce material consumption and cost, while increasing specific power and cell flexibility. The growing interest in thin-film modules shows the important of low materials use.

Low manufacturing complexity and cost

For both c-Si and alternative technologies, streamline manufacturing approaches could simultaneously reduce upfront cost and enable new form factors. Both consequences should be prioritized in R&D efforts. Examples include flexible solar cells printed by low-cost methods.

No single PV technology today excels in all these three technical characteristics. Figure 10 compares the maturity, efficiency, materials use and specific power of today's PV technologies. The comparison **indicates some general observations:**

- **c-Si and conventional thin-film are the only two technologies deployed in large-scale;**
- **record efficiencies for modules are way lower than those of lab cells;**
- **thin-film technology uses between 10 and 1000 times less material than c-Si, reducing cell weight per unit area and increasing power output per unit weight;**
- **all PV technologies on the market today have been under development for at least three decades.**

Due to the increasing interest being put in solar PV by markets and investors and to the growing attention on renewable energies, today's emerging technologies are improving way faster than current **technologies improved in their early stages, but it is important to remember that the road to large-scale deployment is invariably long. Materials discovery has historically been a critical component of PV technology development. New active materials may reach cost and performance targets that are inaccessible using existing materials. But, to proceed from laboratory to production stage, any PV technology must show a substantial potential advantage over current technologies in term of at least one of the previously mentioned performance metrics, without major disadvantages. Another key consideration is that if anticipated improvements are little, any cost or performance gain can be relevant at large-scale. This barrier to entry has thus inhibited the rapid commercialization of many emerging technologies with insufficient foreseen advantages, but increased the value of technologies with a low initial capital equipment requirement.**

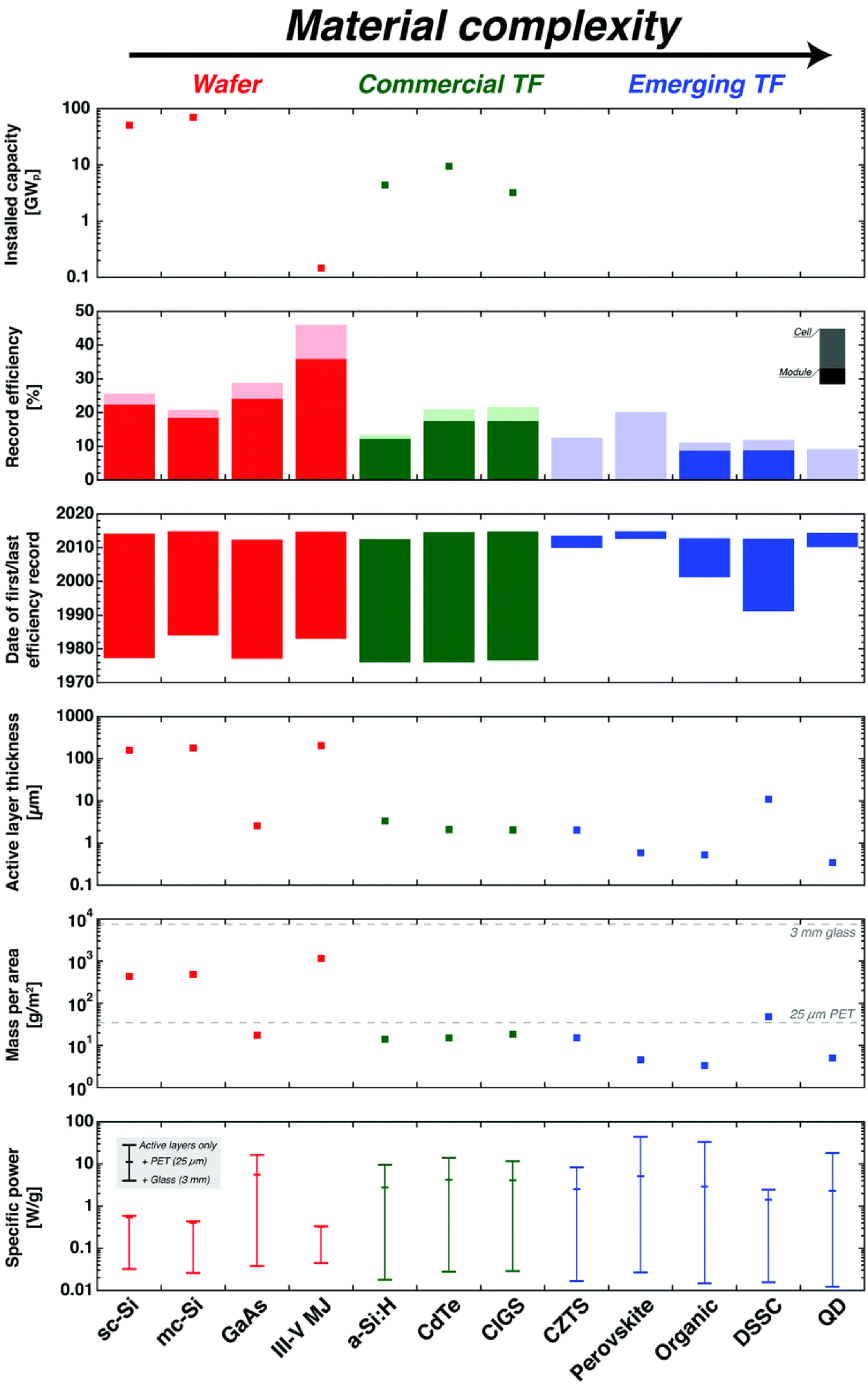


Figure 10: Comparison of PV technologies ordered by material complexity, divided in three big classes, wafer-based, commercial thin-film and emerging thin-film [4]

3. Photovoltaic Economics

The cumulative World's installed solar PV power capacity increased by 29% per year in the period 2000-2015, reaching 229 GW by the end of 2015 [8]. At the end of 2016 it was already around 320 GW, with a global PV electricity power consumption of 333 TWh (around 1.3% of the planet electricity consumption) [10]. In only 5 years, from 2010 to 2015, the total global PV capacity jumped over 450% from less than 41 GW. Looking back 10 years, solar photovoltaics' development has been even more impressive - from 5 GW of total commissioned PV capacity at the end of 2005 the market has grown 45 times in just one decade.

In this Chapter, first an overview of the solar PV global market is provided, then all the costs related to the installation of a photovoltaic power plants are analyzed, divided in capital and operational expenditures. Finally, current values of Levelized Cost of Energy (LCOE) for traditional and renewable energy sources are compared, and future economic trends for every component of PV systems are summarized.

3.1 PV Global Market

"Snapshots of global photovoltaic markets – 2016" published by the International Energy Agency Photovoltaic Power System Programme (IEA PVPS) [13] reports that China is currently the largest PV market, with over 78 GW of cumulative installed solar power, followed by Japan (42.8 GW), Germany (41.2 GW), the United States (40.3 GW), and Italy (19.3 GW).

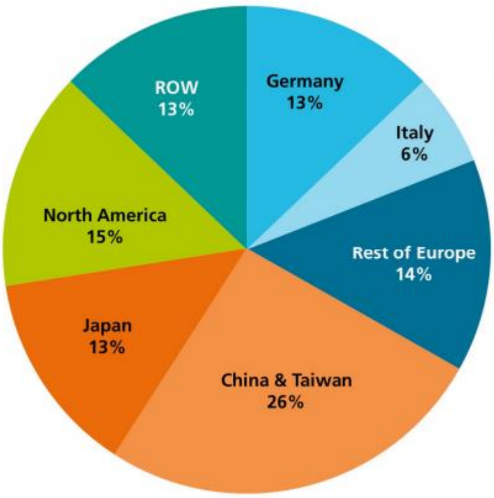


Figure 11: Global cumulative PV installation by Region at the end of 2016 (percentages related to total global installations, including off-grid systems) [13]

The largest markets in 2016 where China, United States and Japan with 34.5 GW, 14.7 GW and 8.6 GW in new additions respectively. Overall, around 75 GW of new PV systems were installed worldwide last year. Several Asian markets contributed to last year's growth, such as Korea (850 MW), Thailand (726 MW), the Philippines (756 MW) and Taiwan (368 MW). India, on the other hand, has contributed with over 4 GW. In Latin America, only Chile grew considerably, by 746 MW last year, while Mexico, Latin America's second largest market in 2016, brought online only 100 MW. In Europe, the UK was the largest market with 2 GW, followed by Germany (1.5 GW), France (0.6 GW) and Italy (373 MW).

The report notes that the United States was able to double its annual installations from 7.3 GW to 14.7 GW last year, while Japan's 8.6 GW represents a clear signal that its solar market is currently coming to a halt after several years of strong development. The report also highlights that 24 countries had more than 1 GW of solar installed at the end of 2016, while 16 countries added more than 500 MW of PV power last year.

None of last year's three major markets, however, is **among the countries with the highest share of solar in the electricity mix, which are surprisingly Honduras (12.5%), Greece (7.4%), Italy (7.3%) and Germany (7.0%).**

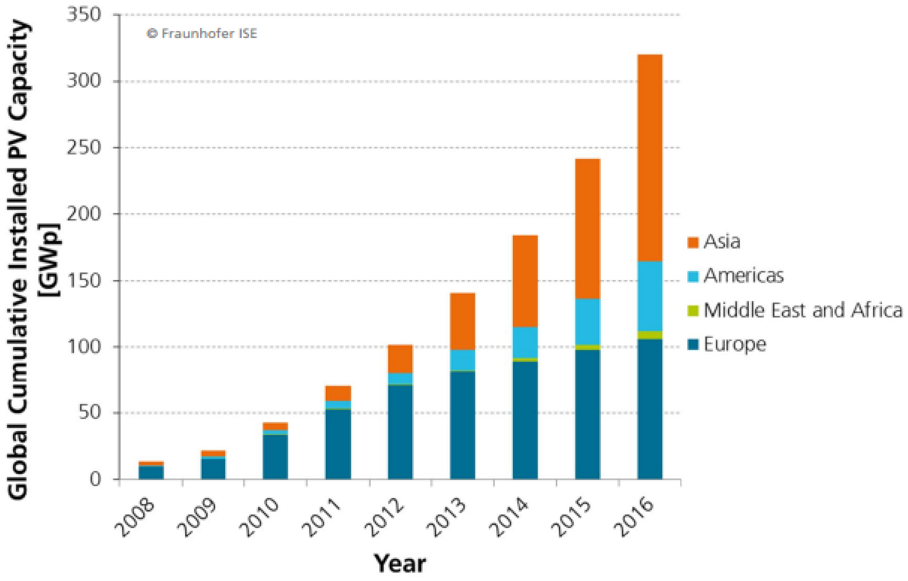


Figure 12: Evolution of global total solar PV installed capacity [11]

3.2 Capital Expenditures (CAPEX)

The costs of installation associated to a traditional photovoltaic power plant – either rooftop or ground-mounted – are generally divided in three categories: BoS (Balance of the System), modules and inverter costs.

Balance of System

Balance of System costs are the most complicated to address, as they include a wide range of different components, from hardware to management costs. Usually they are divided in three broad categories: hardware, installation costs**, and soft costs. These may be further decomposed in sub-categories. Hardware costs include cabling, racking and mounting structure, safety and security system, grid connection, and monitoring system. Installation costs are all the costs directly associated to the installation of the system, mechanical and electrical installation and supervision of the construction. Soft costs are all the costs related to design of the system, financing costs, permits, support policies. Figure 13 shows a snapshot of the utility-scale BoS costs in the main PV markets, divided by the three categories: hardware costs in blue, installation costs in yellow and soft costs in green.**

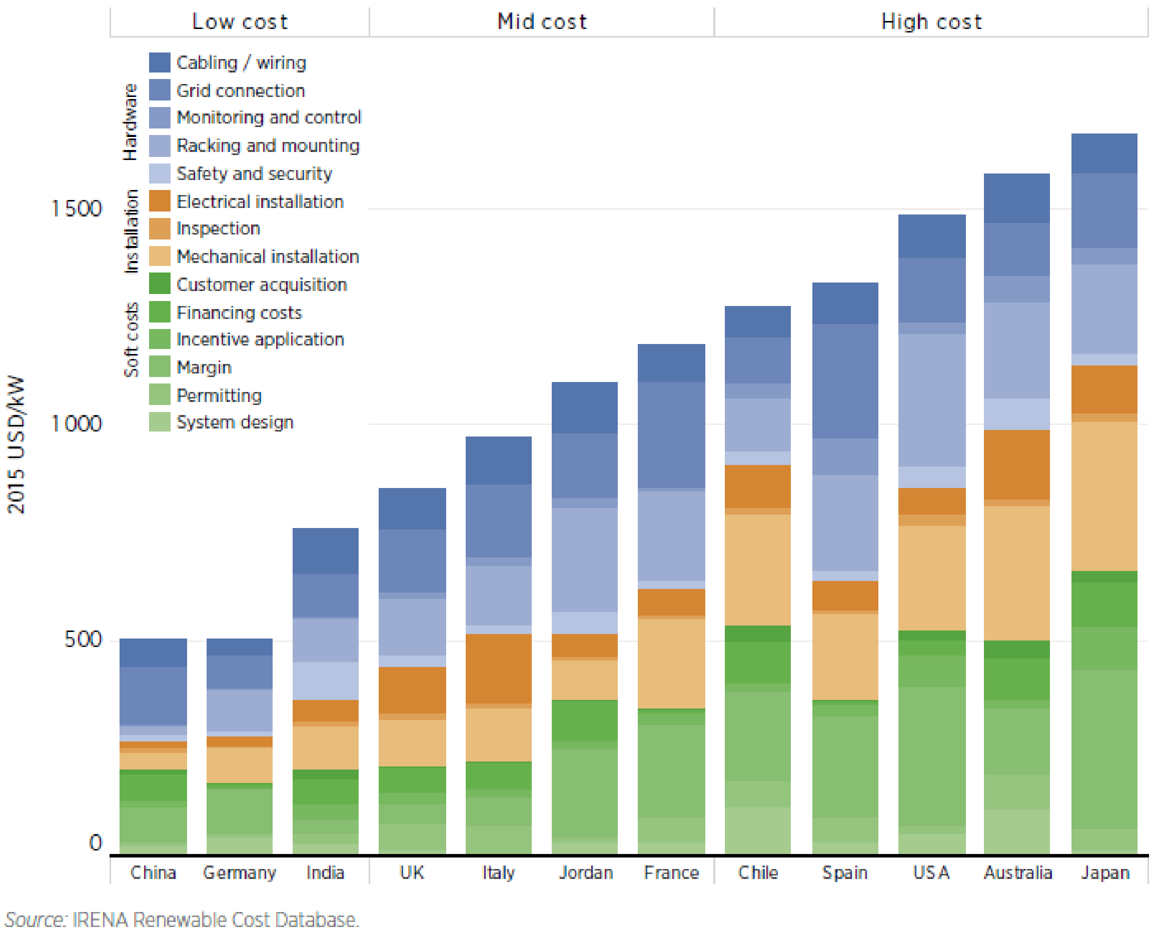
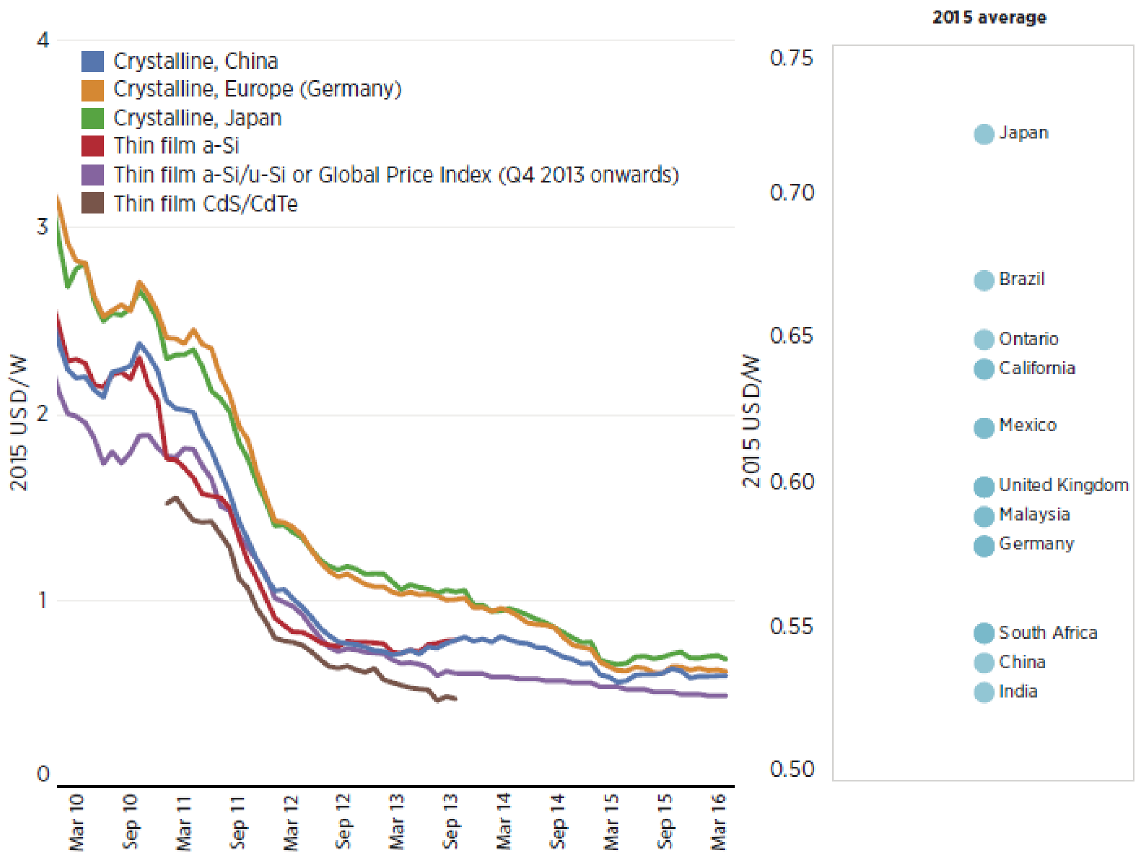


Figure 13:Detailed breakdown of PV BoS costs by country, divided by sub-categories IRENA 2016 [9]

Module costs

Solar photovoltaics modules have high learning rates (Rubin et al. [14] indicate an average learning rate for PV module between 18% and 22%) and very rapid deployment. In the last 4 years (from 2012 to 2016) there was an average 40% growth in cumulative installed capacity every year [9]. This resulted in PV module prices declining by around 80% between the end of 2009 and the end of 2015. As shown in Figure 14, in 2011 the decline in prices accelerated due to an increase in buyers' market created by **oversupply. It then slowed between 2013 and 2015 as manufacturer margins reached more sustainable levels. At the end of 2015, the weighted average country level price of a module ranged from 0.52 $/W in India and China to 0.72 $/W in Japan.**



Source: GlobalData, 2014; pvXchange, 2016; Photon Consulting, 2016.

Figure 14: Global PV modules price trends, IRENA 2016 [9]

Inverter costs

The three main inverter categories used in PV power plants are micro-inverters (capacity in the range of module's power)**, string inverters (capacity up to 100kW) and central inverters (capacity >100kW). The most used are central inverters, especially in utility-scale systems. Recently string inverters are gaining interest, but still remain much less used and only in smaller systems, like rooftop plants. Micro-inverters may find favor for some utility-scale plants in the future, as they have certain advantages, but they are likely to only make a marginal contribution in the utility-scale sector in the next years. The International Renewable Energy Agency reports average prices for the three categories of inverters (shown in Table 1), differentiating between global market and Chinese market. This is because some Chinese suppliers, such as Sungrow and Huawei, are offering prices well below global average. As these companies are increasingly entering European and American markets, they are expected to lower average costs and put significant pressure on local producers.**

Table 1: Inverter price, global average (without China) and Chinese, IRENA 2016 [9]

Characteristic	Central Inverter	String Inverter	Micro-inverter
Capacity	>100 kW	<100 kW	Module power range
Efficiency	Up to 98.5%	Up to 98.0%	90.0-95.0%
Global price (2015 $/W)	~0.14	~0.18	~0.38
Chinese price (2015 $/W)	0.03-0.05	0.06-0.08	n.a.

Micro-inverters are the most expensive inverters among the three considered, and for the foreseeable future are unlikely to be used at larger scales than residential and commercial systems.

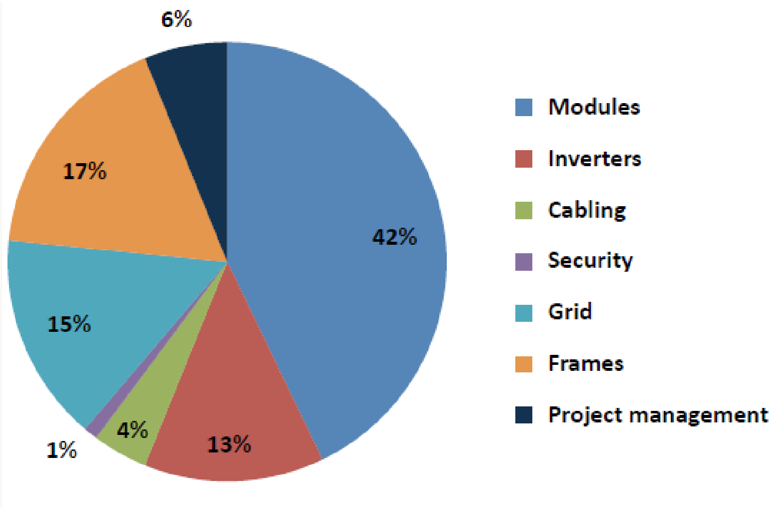


Figure 15: Average breakdown share of CAPEX costs for a ground-mounted solar PV project (dataset extracted from mature markets of Europe and North America) (from: SgurrEnergy)

Figure 15 shows average shares of capital expenditures for global more mature markets. Modules and inverters cover respectively 42% and 13% of the total CAPEX, while Balance of System is responsible for the remaining 45%.

3.3 Operation and Maintenance costs (OPEX)

The operational expenditure (OPEX) of PV systems consists mainly of operation and maintenance (O&M) costs, because there are no fuel costs related to PV electricity generation. The need for O&M can be very different depending on the system size and type. In many countries, residential PV systems need hardly any O&M because rain and snow will clean up the modules and because small inverters need usually no maintenance and are replaced at the end of their lifetime.

Solar PV O&M costs have not historically been considered as influent to its economics. Yet, with the rapid fall of modules' prices and the consequent increase of installations in the last decade, the share of O&M cost in the LCOE in some markets has climbed significantly. In the most developed markets, such as Germany and United Kingdom, O&M costs nowadays account for the 20-25% of the LCOE [9].

PV systems are designed and installed to be fully functional for a minimum of 20–30 years. The following is a list of common scheduled tasks for traditional (non-floating) PV systems:

- Module cleaning to remove soiling.
- Inspection of wires and electrical connections.
- Verification of proper inverter operation.
- Inspection of mechanical mounting system.
- Replacement of broken or damaged modules/inverters.
- Vegetation control.

Historical OPEX data from different countries vary greatly and it is difficult to find a consensus opinion. In the past, many European countries had a very high feed-in tariff (FIT) which allowed high margins in both the system CAPEX and OPEX; this is the reason why some reports have quoted very high OPEX prices. Over the years, the FITs have been reduced and even finished in many countries, which has increased the competition and reduced the price of OPEX. The need for O&M depends on the investor's willingness to carry risk, e.g., how much preventive maintenance is required. It should be analyzed case by case, whether the added O&M cost adds value.

C. Breyner et al. [12] (2015) set to 20 $/kW/year for plants from residential-scale up to 1 MW ground-mounted systems, and 15 $/kW/year for multi-watts ground-mounted systems. Similar values are reported by NREL in February 2017 [32]. After analyzing a wide range of data from U.S. plants, namely from 0 $/kW/year to 110 $/kW/year, it reports average values of 20 $/kW/year for residential plants and 16.7 $/kW/year for utility-scale plants.

Another way to express O&M costs is per unit of energy generated, A. Luque et al. [5] (2011) indicate as a common energy basis rule of thumb for large grid-tied PV systems that the O&M costs run in the range of 1-3 USD cents per kWh of energy generated. Off-grid systems are typically more expensive than grid-tied systems to operate and maintain on a relative basis due to the additional components such as batteries.

Monitoring the performance of a PV system is also important, both for recording the power output of the system and for determining the system health. Since problems can occur between scheduled maintenance intervals, it is important to minimize the period of time when the system is either down or not performing at its optimal level. Monitoring a system can be a valuable part of the O&M regimen. Monitoring is a two-fold process: the system's output and the local environmental conditions need to be recorded. This allows detection of system malfunctions as well as system under-performance. In some large systems it may make financial sense to have a regular on-site crew member to monitor the system and be able to fix problems as they arise.

Another important aspect to take into account when assessing O&M costs for a PV system is their increase during the plant lifetime. While cleaning and administration costs remain constant, replacement costs increase with time. Figure 16 shows average costs for U.S. [32].

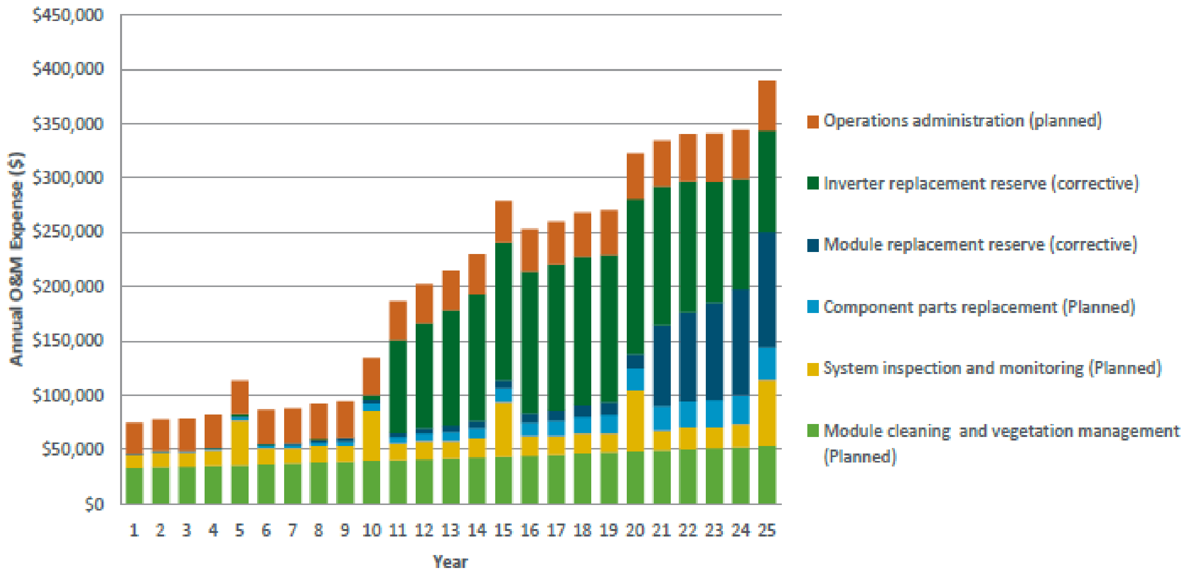


Figure 16: O&M variation during plant lifetime (NREL, 2017 [32])

For floating applications, the O&M procedures of module cleaning, mechanical support control and inspections of wires must be done by boat or under-water, which could reasonably double the cost. This would mean passing to a range of 3-6 USD cents per kWh of generated energy. More detailed estimations of O&M costs for floating installations will be made in the last chapter of this Dissertation.

Both CAPEX and OPEX are site-specific costs and can depend on various factors. In Table 2 is illustrated their variability based on actual projects observed in 2013 and 2014. The spread in Capex costs is principally explained by the different location: on the low end by the inclusion of data from projects in China, where were used low-cost, domestically installed solar PV installations, on the high end by most expensive solar plants in the U.S. solar PV market. Variations in Capex costs are also a consequence of differences in labor costs, taxes, local content rules, incentives or subsidies provided to developers.

Table 2: solar PV CAPEX and OPEX variations observed 2013/2014 based on actual projects

Value $/MW	Min	Average	Max	Percent Variation
Capex	$ 1.5 millions	$ 1.6 millions	$ 2.2 millions	47%
Opex	$ 2,200	$ 4,200	$ 7,500	241%

In countries where solar PV technology has been only recently introduced, Capex costs can vary widely due to the early process of supply chain development in the market. However, greater transparency and competition across the global supply chain, from raw materials like silicon to inverters and balance of the system, has allowed developers to make more informed assumptions about capital costs.

3.4 Recent PV LCOE Compared to Other Classic Technology

In 2015, prices of solar power supply reached record-low levels. The most **remarkable contract awarded was for a 100 MW tender in Dubai (UAE) in early 2015. A record-low 58.4 USD/MWh bid lead the Dubai Energy and Water Authority (DEWA) to double the original size of the project to 200 MW. In the meantime, several lower bids were awarded in different regions and countries, often without financial incentives. Another milestone was the 48 USD/MWh in Peru in early 2016, as well as the 36 USD/MWh in Mexico, but everything was beaten by the 29.9 USD/MWh price offered in the third round of the Dubai tender. While this lowest bid for the 800 MW project outshines everything seen in the solar and wind sector so far, even the competing bids in this DEWA tender came in at very low levels - from 36.5 to 45 USD/MWh. A good indication of how quickly solar power prices have fallen can be seen in the offer from the consortium that won the earlier 200 MW Dubai tender at 58.4 USD/MWh, and which was bidding in the latest tender at 39.5 USD/MWh** – that's a 30% price **decrease within one and a half years. Table 3 shows global average values of LCOE for conventional energy sources.**

Table 3: Averaged LCOEs of most common power production technologies (prices in USD/MWh) for plants entering service in 2022 (data from DOE 2017 Annual Energy Output [16])

Plant Type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Total System LCOE	LCOE with TAX Credits
Dispatchable Technologies						
Coal 30% with carbon sequestration	85%	94.9	9.3	34.6	140.0	140,0
Coal 90% with carbon sequestration	85%	78.0	10.8	33.1	123.2	123.2
Natural Gas-fired						
Conventional Combined Cycle	87%	13.9	1.4	40.8	57.3	57.3
Advanced Combined Cycle	87%	15.8	1.3	38.1	56.5	56.5
Advanced CC with CCS	87%	29.5	4.4	47.4	82.4	82.4
Conventional Combustion Turbine	30%	40.7	6.6	58.6	109.4	109.4
Advanced Combustion Turbine	30%	25.9	2.6	62.7	94.7	94.7
Advanced Nuclear	90%	73.6	12.6	11.7	99.1	99.1
Geothermal	91%	32.2	12.8	0.0	46.5	43.3
Biomass	83%	44.7	15.2	41.2	102.4	102.4
Non-Dispatchable Technologies						
Wind - Onshore	39%	47.2	13.7	0.0	63.7	52.2
Wind - Offshore	45%	133.0	19.6	0.0	157.4	145.9
Solar PV	24%	70.2	10.5	0.0	85.0	66.8
Solar Thermal	20%	191.9	44.0	0.0	242.0	184.4
Hydro	59%	56.2	3.4	4.8	66.2	66.2

3.5 Future trends

This section identifies the future cost reduction potential for PV systems. It analyses the same categories studied in paragraph 3.2, namely BoS, modules and inverter.

In general, total system costs for utility-scale PV are expected to decrease from around 1.8 USD/W in 2015 to 0.8 USD/W in 2025, a reduction of 57% in 10 years. The majority of the decrease in the costs is expected to come from lower BoS costs. Figure 17 shows the historical and the potential future evolution of the global weighted average total installed costs of utility-scale solar PV with a simple cost breakdown. Cost reductions from modules in the future will contribute less than in the past to total installed cost reduction potentials, even with very rapid growth in solar PV deployment. Globally, the bulk of the global average total PV system cost reduction opportunities in the next decade will therefore come from continuous BoS cost reductions. The share of BoS costs between 2009 and 2015 increased from 37% to 60%. In the same period, module costs declined more rapidly than BoS costs and contributed around 68% of the total cost reduction. For the period of 2015 to 2025, previsions see this trend being inverted, with modules contributing about a quarter of the reduction potential.

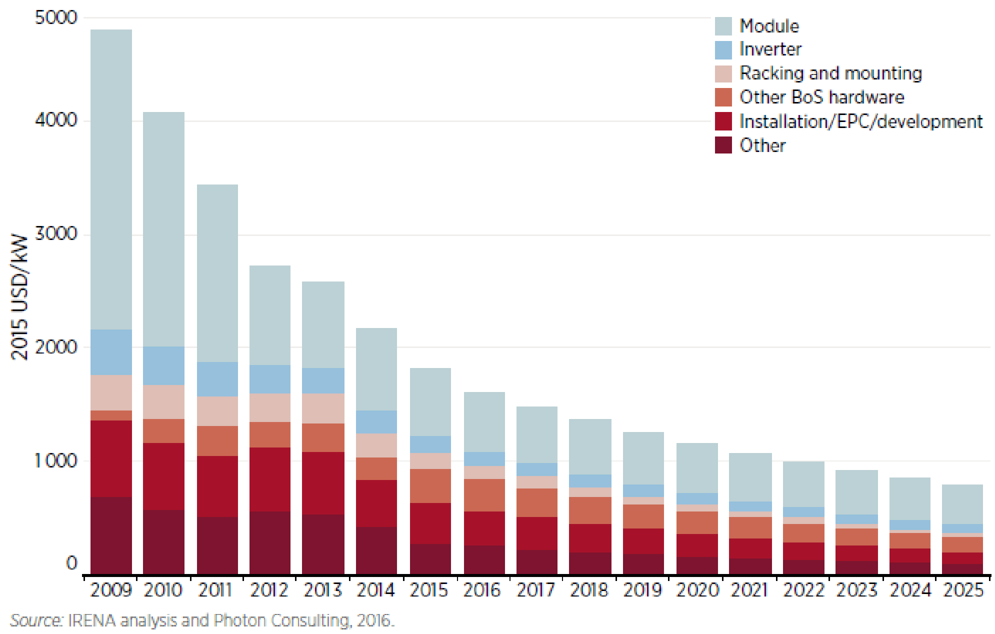
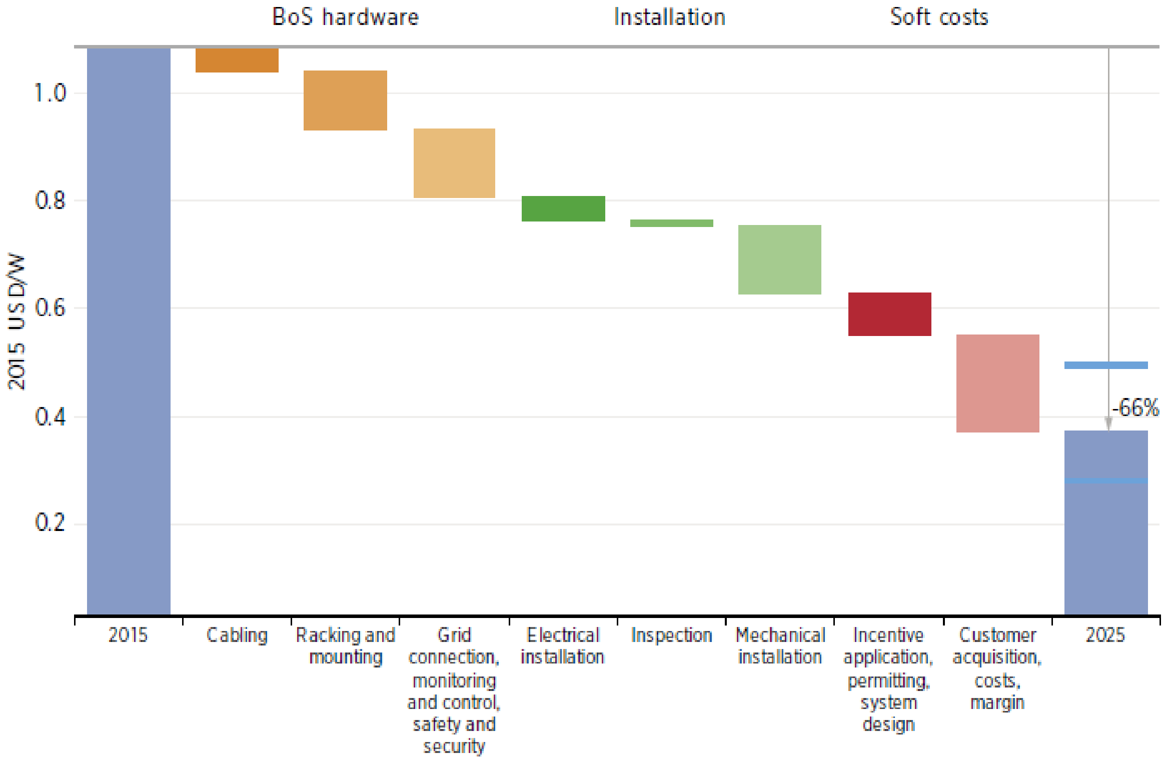


Figure 17:Global weighted average total system costs breakdown of utility-scale solar PV systems, 2009-2025 (IRENA, 2016 [9])

BoS

Balance of system costs for utility-scale PV plants are estimated to fall by between 55% and 74% in the period 2015-2025, as convergence towards best practice cost structures accelerates under increasing competitive pressures. IRENA (2016) estimated BoS costs for 2025 in the range 0.3-0.5 USD/W [9], while in 2015 they were above 1 USD/W. Given the wide range of current BoS costs and cost inefficiencies in most markets, around 90% of this reduction is expected to be driven by a convergence towards best practice. Additional costs reduction will come from racking, mounting and installation costs, due to the decrease in the surface occupied by the PV modules (consequence of the increase in efficiency). As shown in Figure 18, the total BoS costs reduction is driven by both soft cost reductions,

which contribute 36% to the total BoS reduction potential, and by hardware cost elements, contributing 39% of the total. Reduced installation costs account for around 25% of the total reduction potential.



Source: deea, 2016 and IRENA analysis.

Figure 18: Global weighted average utility-scale solar PV systems: BoS costs and cost reductions by source, 2015-2025 [9].

PV modules

In spite of significant decrease in recent years, PV module costs are expected to continue to decline. This will depend mainly on the improvement in efficiency, estimated to increase from 16% in 2015 to 19.5% in 2025 for multicrystalline modules (a 22% increase) and from 17% to 21.5% for monocrystalline modules in the same period (a 26% increase), the market scale – IRENA's REmap 2030 scenario **[36] foresees the cumulative installed capacity in 2030 within 1750 and 2500 GW (given a learning rate of 18-22%) – and a decrease in material use, already discussed in paragraph 2.6. These factors are expected to bring crystalline PV modules costs in the range of 0.28 USD/W to 0.46 USD/W.**

Inverter

With increased global PV deployment, inverters have followed a strong cost reduction path. The global average cost for inverters dropped from above 1 USD/W in 1990 to 0.14-0.18 USD/W (excluding micro-inverters) in 2015. Fraunhofer ISE (2015) [8] reported learning rates of inverters ranging between 18-20%. The potential cost reduction for solar PV inverter technologies in future decades will be driven by two main vectors, technological progress and economies of scale. The latter is expected to be the most relevant factor, and will be driven by the increased presence of Asian producers in international markets. As a result of these trends, IRENA (2016) reports an expected decrease for inverters in the range of 33-

39% between 2015 and 2025 [9]. Table 4 reports global average prices for 2015 and previsions for 2025 of most used inverters.

Table 4:Inverters cost reduction in 2015-2025 (data from [8] and [9])

	Central inverters	String inverters	Micro-inverters
Global price (2015)	0.14 USD/W	0.18 USD/W	0.38 USD/W
Reduction to 2025	-39%	-33%	-30%
Global price (2025)	0.09 USD/W	0.12 USD/W	0.27 USD/W

O&M

O&M cost assessment is a hard issue, so it is very difficult to estimate its future trend. C. Breyner et al. [12] (2015) assumed that 50% of the OPEX is area-dependent, and thus reducing with the efficiency improvement of the modules. By 2030, this will lead to a 15% reduction of the OPEX. It is also assumed that standardization, more efficient processes and competition will result in a further 15% reduction of the OPEX by 2030 compared with 2014. Therefore, the overall OPEX would reduce by 30% by 2030, which means to 14 $/kW/year for systems up to 1 MW, and to 10.5 $/ kW/year for multi-megawatts systems.

4. Floating Installations

During the last decade, a few examples of PV arrays mounted on floating structures have already been proposed and constructed all over the world. The advantages of this kind of solution are numerous.

The first is related to the increasing demand of energy in the agricultural industry as a consequence of the modernization plans carried out in the last decades. Although water efficiency has improved in the agricultural section due to the installation of more efficient irrigation systems, electrical power demand has increased substantially. The whole energetic system (and market) has drastically changed in the last years/decades. Due to many factors, such as the awareness about GHG emissions from fossil fuels, the fear of dangers related to nuclear power, the relentlessly decreasing availability of carbon, and the increasing need/wish of energetic independence, the community is looking at renewable energies as the new era energy source. Among these reasons, the run toward energetic independence, together with the land-use problem, have been the most relevant incentive for the development of floating photovoltaic systems. The possibility to install photovoltaic systems floating on irrigation tanks could mean for farmers, who wouldn't have land to dedicate to a PV system, to achieve the energy independence, or at least to cover part of their increasing power demand.

Another advantage that a floating installation on an irrigation tank would have, especially in hot and highly insulated areas, is the water evaporation rate in these agricultural reservoirs. Studies have been carried on in Spain, Turkey and Australia to estimate the water losses. Bengoechea et al. [17] estimated that in Almeria (south of Spain) water losses due to evaporation amounted to 17%. Martinez et al. [18] estimated water losses of 60 hm3 for the Segura Basin (Murcia, Spain), which means more than 8% of the available water supply for irrigation purposes. Craig et al. [19] suggested that evaporation phenomena in agricultural reservoirs in Queensland (Australia) were the cause of a total water loss of 1000 hm3, i.e. about 40 percent of its total storage capacity. Gökbulak et al. [20] made similar studies from lakes and dams in Turkey and estimated potential water savings of more than 20%. Covering all the surface of the water basin decreases temperature and sunlight, hence the water evaporation. The decrease in temperature and sunlight on the bed of the reservoir discourages also the growth of algae.

4.1 State of the Art

The project that has received the most news coverage and is usually claimed as being the first floating PV project, was that of the Far Niente wineries in California, USA by SPG Solar in 2008 [21]. The motivation of the wineries' owner to install the floating PV system on top of their water reservoir was not to displace land that was used to grow vines, which is a much more precious resource for their business. The installation was based on modular crystalline PV panels that were mounted at an optimal tilt angle on top of individual pontoons.

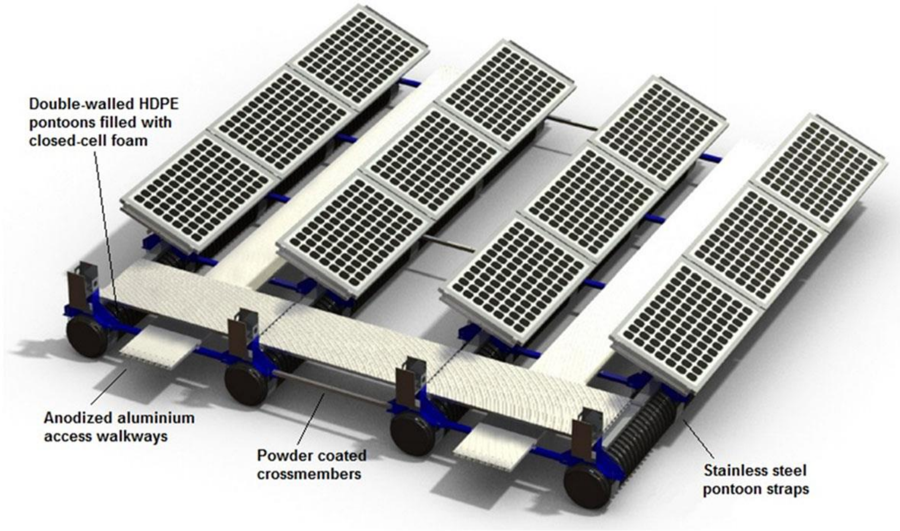


Figure 19: TTi's "Floatovoltaic" modular structure incorporated in the Far Niente floating PV system [21].

The mounting structure, called 'Floatovoltaic' **and designed by** Thompson Technology Industries (TTi's) **(illustrated in Figure 19), includes walkways between the rows of panels and along the sides to facilitate maintenance and cleaning of the panels. The biggest project among the first ones that have been developed is that of Bubano, Italy (500 kW). Here, the buoyancy for the installation is maintained with hollow polyethylene cubes at the two opposite edges of the structure which the panels are fixed to (Figure 20). An interesting feature is that this system was the first that was exposed to snow and ice. The impact was only on the surface panels, because the climate was not so cold for the water to freeze.**

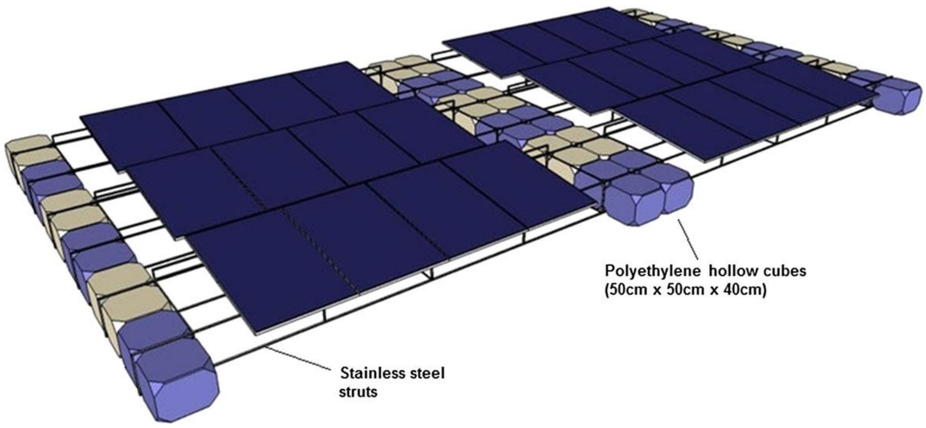


Figure 20: Schematic design of the Bubano's installation [21].

Further on the topic of evaporation of water reservoirs, a research team in Spain developed a 24kW floating PV array on a water treatment reservoir in Negret, in 2009, which was expanded to a 300kW array later the following year because of its good performance. This project is a collaboration between the Polytechnic University of Valencia and the company CELEMIN ENERGY. The array is made up of a number of modules each holding two panels, tilted at 10° (facing south) and fabricated by rotomoulding using medium density polyethylene (refer to Figure 21). The platform has inserts for the electrical cables and the metal struts from the top. Its base is smooth and rounded (designed to protect the reservoir's geomembrane), and each of the modules are connected together with metal pin links, creating a flexible elastic system able of deforming to the concave profile of the reservoir according to the changing water

levels. Recorded annual electrical yield for the Negret PV array averaged at just under 30GWh since 2009, at a capacity factor of approximately 13.5%. Economics given by Ferrer-Gisbert et al. [37] indicate that almost 45% of the costs were pontoon-associated costs. The economic analysis highlighted in the same paper indicates profitability for the array installation at the Negret site, with an internal rate of return of 12.65%, which does not include any economic savings from the reduction in water loss.

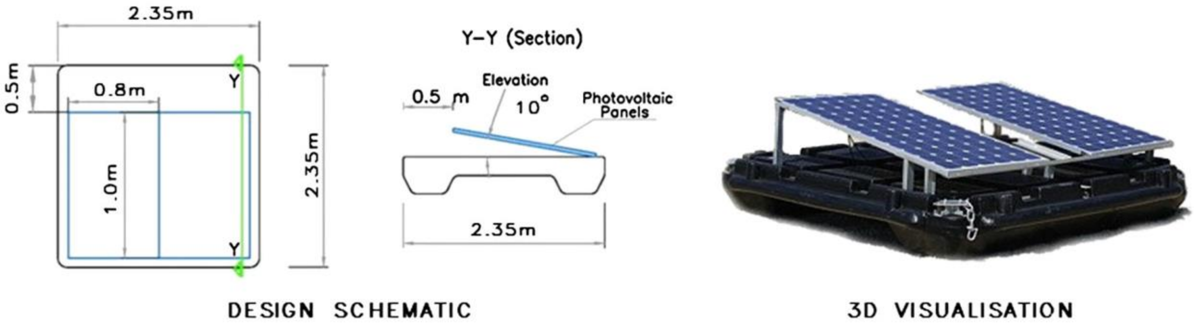


Figure 21: Polytechnic University of Valencia and CELEMIN ENERGY floating PV design [37].

In 2010, also in Italy, at Petra Winery, the first project with a tracking system that rotates the panels according to the sun's motion was realized. This was designed and constructed by Terra Moretti Holdings, while the research group Scienza Industria Tecnologia (SCINTEC) was responsible for the safety systems. The motivation of this installation is similar to that of the Far Niente winery, because it is also located in a winery. The structure of the array is made almost entirely of metal struts, with buoyancy (and integrated tracking system) underneath maintaining the system afloat. The structure is designed to hold the crystalline panels at an optimal tilt angle of 40°, while changing the orientation tracking the solar motion.

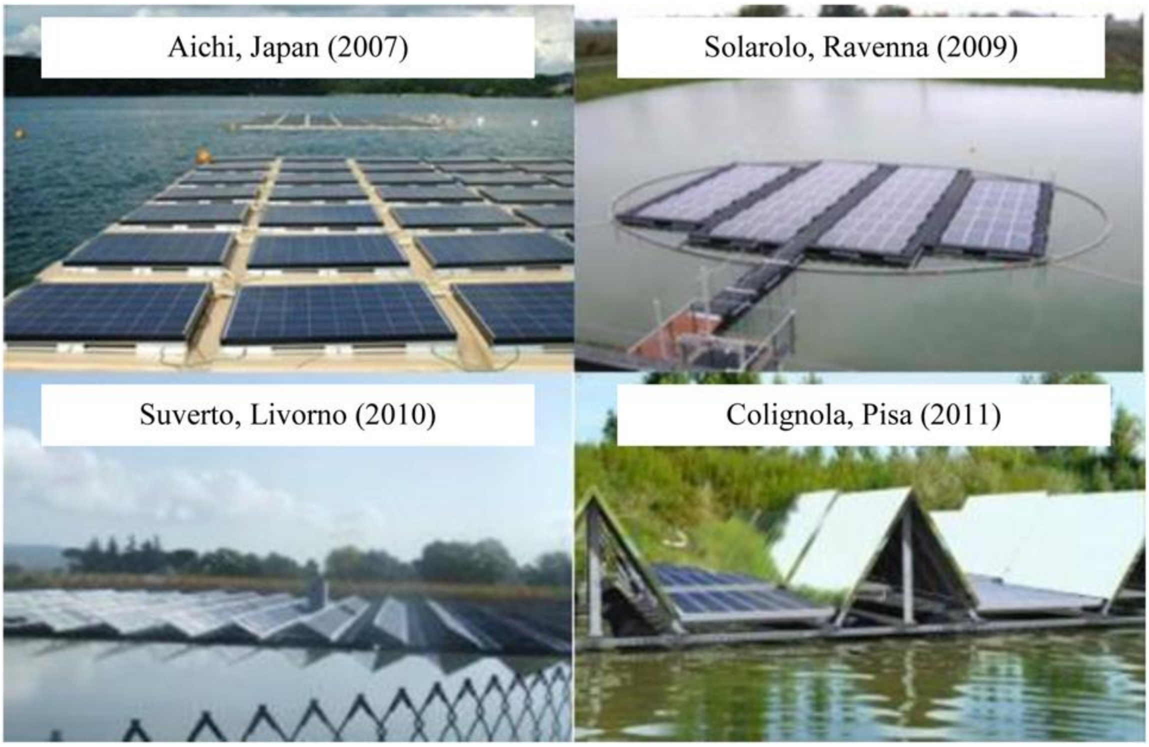


Figure 22: Some example of existing plants

The same group, SCINTEC, also developed the installation at Lake Colignola, Italy, in 2011, which has a tracking system similar to the Petra Winery one. The interesting aspect of this development was the utilization of mirrors to reflect additional solar radiation onto the PV panels (shown in Figure 22). The Lake Colignola's project was mounted horizontally rather than tilted**, with the mirrors situated on the south and north faces of each panel. The mirrors are placed at an angle 60° to the water, and this is expected to double the effective solar radiation on the panels. This also implies higher temperatures, so the proximity of the PV panels to the water surface is a key aspect in cooling the array in order to maintain decent efficiencies. Testing estimated a 60-70% increase in annual yield compared with conventional fixed-ground mounted installations.**

SCINTEC took part in other projects, among which that developed in collaboration with the French company Osesol, interesting because it was mounted on a structure that was constructed entirely from PVC. This resulted in some cost savings as compared to the installations in Italy, which required metal struts. Another very interesting project developed by SCINTEC in 2012 was that built in Cheongju, Korea, in collaboration with Techwin and Koiné Multimedia. This project was especially challenging because of the climatic conditions it was set in, with the water surrounding the installation subject to freezing temperatures during the winter months. Special considerations were taken in the choice of the individual components within the installation, so that they could withstand the seasonal freezing of the water.

Maybe the most active company in the last years is the French Ciel et Terre, which has designed 42 of the 70 biggest plants in the world. Ciel et Terre's **first installation was in Piolenc, France. Here, the PV**

panels are held tilted towards the sun with metal struts, which also links the array together, and is kept afloat with buoyancy underneath each row within the array.

Recently, several multi-megawatts plants have been installed in England, China, Japan and South Korea. The world's biggest installation has been installed in China in April 2016, and has a capacity of 20 MW.

Figure 23: Part of Kagawa's 696 kW plant, installed by Ciel et Terre [38].

4.2 Technical differences

Floating PV power plants have several differences from traditional PV systems, both roof-top and ground-mounted. These are represented by floating structure, mooring system, eventual floating sub-stations and under-water cabling, all of them depending on the nature of the water basin where the plant is installed; they are listed and analyzed in detail in the following paragraphs.

4.2.1 Floating Structures

Floating photovoltaic systems can use mounting structures for the modules with different shapes, weights and costs. The choice of the structure is crucial, as it will affect all the other components of the power plant, and relative costs. Here are listed all the existing structures, many of which have only been tested, hence are still not used in real-scale power plants.

Plane unique

This was the first solution used. It can be composed of cubic (or similar) buoys forming a floating base, on whose top one can locate the PV modules. It is an economic solution, as most of the companies producing floating structures already have this kind of basic buoys on production. This kind of cubes are typically used for docks, platforms and piers. It is economic also because it usually doesn't allow a tilt angle, which means that the cost for the metallic mounting structure is minimized. This is also the most rigid structure: it would not be suitable for e.g. an offshore marine solution because of the waves, but it is good for little lakes or for irrigation tanks. Figure 24 shows one of the structures designed by the Italian company Otto, who installed the first floating PV plants in Italy.

Figure 24: Example of floating platform built with cubic buoys [39].

Modular

This system is composed of modular floating structures, each typically supporting one PV panel, tied all together. It is the most ductile structure, as it can form plants with every shape and dimension, and also change in time. Every module is typically composed of a main float supporting the panel(s) and a secondary one for allowing maintenance. Usually the main float that support the panel has a tilt angle, which increases its performances. Figure 25 shows Hydrelio, the structure proposed by Ciel et Terre.

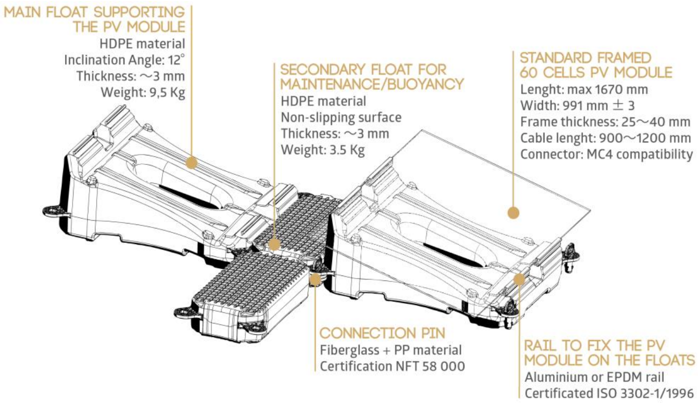


Figure 25: Ciel et Terre High-density polyethylene (HDPE) base structure [38].

Tilted resistant

This is the most resistant structure. It is composed of plastic buoys, on whose top is a metallic structure supporting the panels with a tilt angle. Young-Geun Lee et al. [22] run some mechanical tests on the structures, whose buoys are made of pultruded fiber reinforced polymeric plastic (PFRP), which has strong characteristics such as a high corrosion-resistance, concluding that they can be used for marine applications.

Figure 26: One of the structures tested for marine applications [22].

Semi-submerged

Several variants of submerged structures have already been designed and tested, but still none of them is used for a full-scale plant. The two main alternatives are: a rigid structure used with crystalline panels and a flexible solution with thin-film panels. In the rigid solution, a polyvinyl chloride (PVC) pipe is used as a buoy and a hollow square aluminum as support for the panel and as heat sink. The aluminum allows a good heat transfer between the water and the panel, maintaining lower the panel's working **temperature. Studies on this kind of structures and comparisons of performance with conventional PV modules are performed by Azmi et al. [23,24]. The flexible solution is made up of a thin-film panel directly immerged in the water, with some lateral buoys to keep it near the water level. This is the best** configuration for the module's performances. **Studies on this kind of structures are described by Trapani and Millar [25,27].**

Figure 27: Example of flexible thin-film system

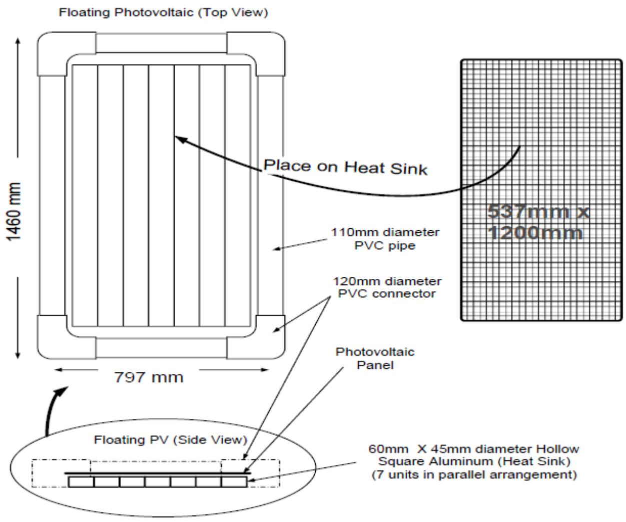


Figure 28: Scheme of the tested semi-submerged rigid structure [23,24].

Table 5: Comparison of types of mounting structures

Structure	Efficiency Gain	O&M Gain	Tilt Angle	Suitable panels	Applications
Modular	~10%	0%	Yes	mono/poly	Irrigation tanks, little lakes
Plane Unique	~10%	0%	No	mono/poly	Irrigation tanks, little lakes
Semi-submerged rigid	~10%	0%	No	mono/poly	Irrigation tanks, little lakes
Submerged panel	5-12%	~10%	No	Thin-film	All
Metallic	~10%	0%	Yes	mono/poly	All

Each structure has advantages and disadvantages, both in technical characteristics and costs. In Table 5 are summarized the different structures and relative technical pro and cons. Technical characteristics are related to the possibility to have a tilt angle and the efficiency gain due to the cooling effect from the vicinity of the water surface. The tilt angle gain strongly depends of the power plant location, and at European latitudes is estimated around 10% with optimal tilt angle. More complicated is to estimate the cooling effect of the water and its efficiency gain for the modules. Several studies have been performed on the issue, on crystalline silicon modules submerged, on thin-film submerged, and on c-Si on metallic floating structures, briefly summarized in following lines. All the studies with models installed on floating structures presented similar values, namely an efficiency gain around 10%, while thin-film submerged in the water gave lower gains, due to the lower temperature coefficient – being submerged they have

even lower temperatures than modules mounted on floating structures. Results of these studies are summarized in following paragraphs.

Panels Completely Submerged

Two main effects increase the efficiency of a commercial PV panel placed in water:

- **reduction of light reflection**
- **absence of thermal drift**

The light reflection on a commercial PV panel is related to the material used to shield the PV active material. In most panels, this is glass with a refraction index n ≈ 1.55. An intermediate layer of water, which has a refraction index n ≈ 1.33 changes the reflected fraction of an incoming perpendicular ray **approximately from 4.5% to 2.6%. This effect of course is enhanced if light is not perpendicular and increases for wide incidence angles. Thermal effects are much more important and are characterized by a set of temperature coefficients. In general, six parameters are given:**

1. **short-circuit current (**I_{sc}**)**
2. **maximum power current (**I_{mp})
3. **open-circuit voltage (**V_{oc}**)**
4. **maximum power voltage (**V_{mp}**)**
5. **maximum power** $P_{mp} = I_{mp} \cdot V_{mp}$
6. **global panel efficiency (**η**).**

Table 6 shows some of these parameters directly measured at the temperatures of 25°C and 60°C.

Table 6: Average parameters of single crystalline silicon solar cells, measured at cell temperature Tc and irradiance of 840W/m2

T_c (°C)	V_{mp}(V)	I_{mp}(A)	P_{mp} (W)	η_{PV}(%)
25	34.0	2.34	79.6	13.1
60	26.1	2.35	61.3	10.1

M. Rosa-Clot et al. [26] present a table (Table 7) that summarizes outdoor measurements of effective temperature coefficients for various commercially available silicon modules. In the table, the units for the temperature coefficients have been normalized to 1/°C by dividing the coefficient by the value for the parameter at Standard Reporting Conditions (1000 W/m2, AM=1.5, 25 °C).

Table 7: Typical effective derivatives temperature coefficients for commercial modules at 1000 W/m2 and AM=1.5 measured outdoors.

Module	dI_{sc}/dT (1/°C)	dI_{mp}/dT (1/°C)	dV_{oc}/dT (1/°C)	dV_{mp}/dT (1/°C)	$d(P_{mp}/dT$ (1/°C)
M55, c-Si	0.00032	-0.00031	-0.0041	-0.0053	-0.0056
SP75, c-Si	0.00022	-0.00057	-0.0039	-0.0049	-0.0055
SQ-90, c-Si	0.00016	-0.00052	-0.0038	-0.0048	-0.0053
ASE300, mc-Si	0.00091	0.00037	-0.0036	-0.0047	-0.0043
MSX64, mc-Si	0.00063	0.00013	-0.0042	-0.0052	-0.0051
MST56, a-Si	0.00099	0.0023	-0.0041	-0.0039	-0.0016
UPM880, a-Si	0.00082	0.0018	-0.0038	-0.0037	-0.0019
US32, a-Si	0.00076	0.0010	-0.0043	-0.0040	-0.0030

For lakes and sea, the typical range of temperature of the water in summer is between 10°C and 20°C; assuming that submerged modules reach the same temperatures of the water, these values have to be compared with the temperature of a standard panel (without forced cooling) working outside the water with good weather conditions in summer, which may even reach 80°C. For the sake of comparison, the average temperature with a weather condition of 800 W/m^2 – which is a normal solar irradiation for European latitudes – can be assumed to be 45°C. In this case it is easy to see that the temperature difference between a submerged PV panel and a standard panel exposed in air is of about 40°C with a gain in average of 20% for single crystalline silicon panels, 15% for polycrystalline panels and 10% for amorphous silicon panels, assuming temperature coefficients of -0.40%/ºC for c-Si and -0.11%/ºC for amorphous silicon [33].

The strong improvement in efficiency is contrasted by the change in solar spectrum at different water depth. As a matter of fact, clean water is a strong light absorber, but fortunately this absorption occurs mainly in the red-infrared region. Figure 29 shows what happens to the solar spectrum at different depth.

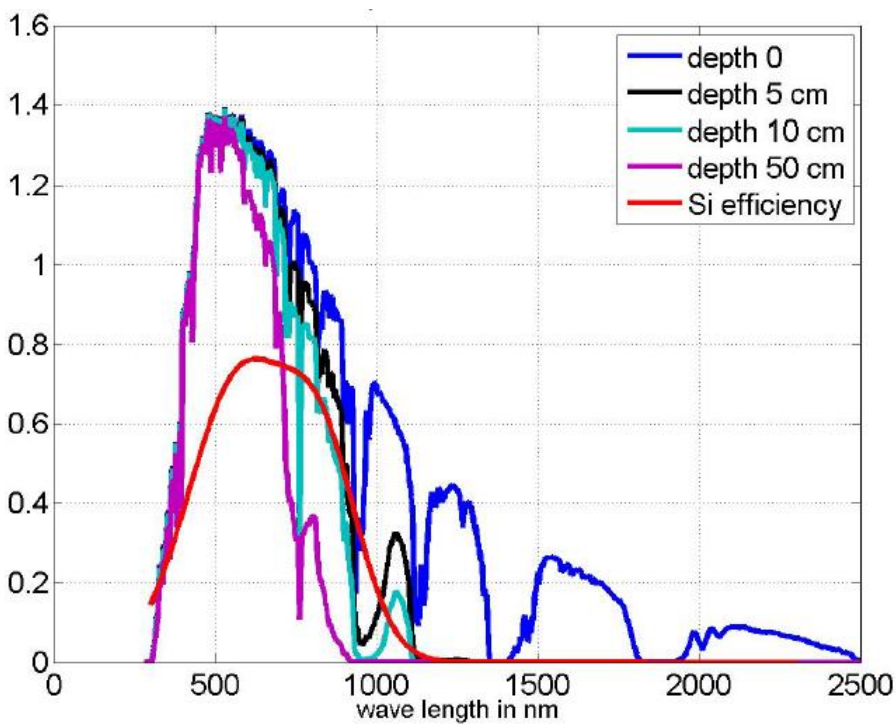


Figure 29: Variation of solar radiation with water depth with superposed silicon efficiency spectrum in arbitrary units [26]

It has been superimposed with the silicon efficiency spectrum in order to show that the hindrance of solar radiation takes place in the region where PV conversion is less effective.

In Figure 30 the behavior of mono-, poly-crystalline and amorphous silicon are given as a function of water depth. It is evident that the efficiency is increased or reduced, depending on the choice of the PV material and on the operating depths.

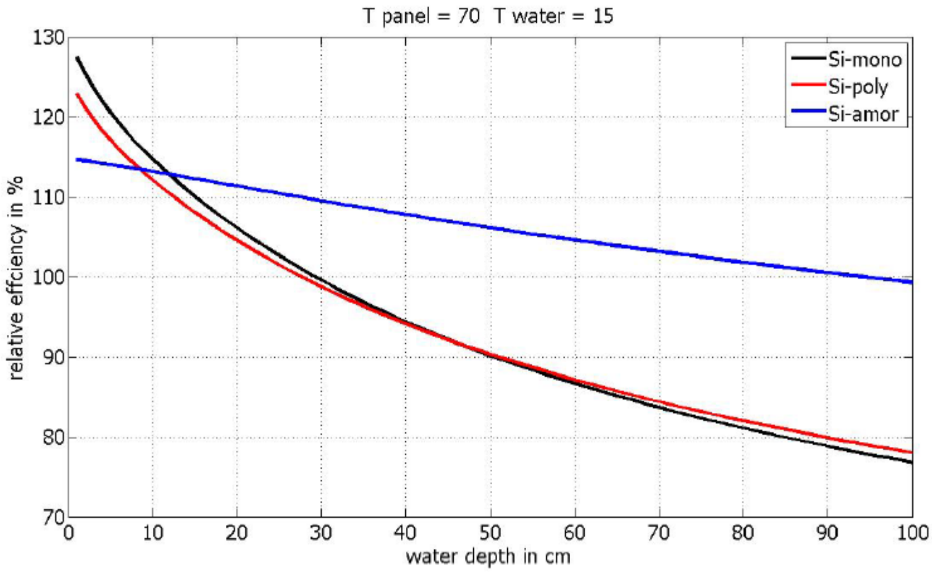


Figure 30: Efficiency of mono-crystalline, poly-crystalline and an amorphous module with the water depth [26].

In their experiment Rosa-Clot et al. measured the performances of three identical mono-crystalline silicon panels, panel P1 exposed in air, the other two (P2 and P3) submerged respectively 5 cm and 40 cm under the water level. Results confirmed what was calculated theoretically:

- P1 and P2 have almost the same output at the very beginning of the experiment but, after a few minutes, P1 begins to warm up until reaching 40°C, while the water temperature is 15°C. The calculated gain in efficiency is about 10%, which matches the expected value.
- P3 submerged 40 cm under the water surface sees its efficiency reduced of about 15%, while the authors expected value was 14%.
- Submerged panels have much less problems for cleaning than the ones exposed in air. In fact, although both have been periodically cleaned, the non-submerged panel had on long term an efficiency loss of 10% while the submerged one did not suffer any decreases of efficiency.
- When the panels P1 and P2 have the same temperature, P1 has a slightly lower efficiency by about 2%.

Another similar study has been performed by Trapani and Millar in 2013 on thin-film panels [27].

Figure 31: Thin film panels 570 W experimental floating plant (left) and the control array of 190 W (right), used by Trapani et al. [27].

Two PV systems, one ground-mounted of 190 W and the other floating of 570 W, have been installed to experience identical diurnal and environmental parameters throughout the whole experiment period. The floating system was divided in two parts, the two panels on the left-hand side in Figure 31 had normal buoyancy, while the remaining four panels had extra buoyancy in order to eliminate the layer of water between the panels and the air. A 3-days comparison of the operational performances was conducted on the three sets of PV panels. In Figure 32 are shown the different temperatures measured on the two systems.

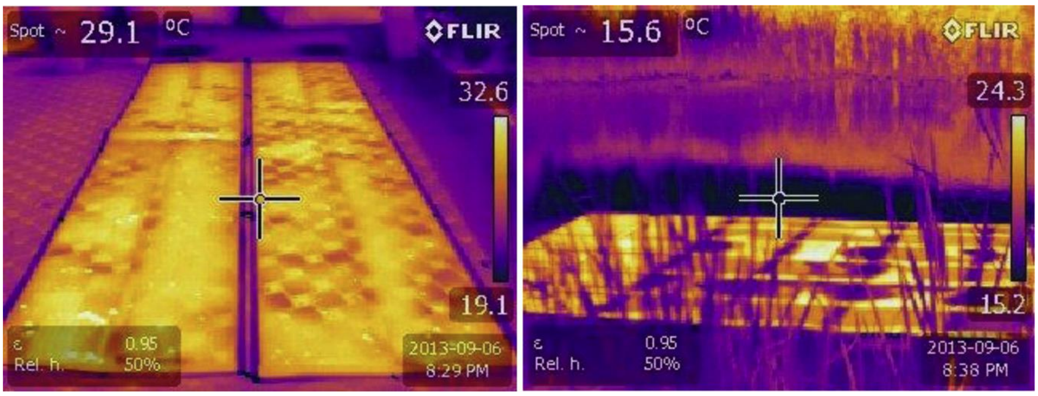


Figure 32: Thermal scans of the ground-mounted (left) and the floating system (right) [27].

The experiment results are shown in the chart in Figure 33. The better performing panels were those from the floating array that had the added buoyancy to help ensure that no water remained on top of the panels. There was an average 15% variation in output between the two sets of floating PVs, which shows how detrimental a ~10 mm layer of water can be to the electrical output. The recorded data shows a maximum improvement of 8% from onshore to offshore, and an average improvement of 5% in electrical output over the 3 days. This improvement can be attributed to the cooling effect of the water underneath the panels. It is much lower than that of crystalline PV modules because of the lower temperature coefficient, around 0.11 %/°C compared with 0.40 %/°C of c-Si modules [33]. The simplicity in manufacturing and deploying the floating PV array, combined with the added cooling benefit could be key in feasibly moving such arrays from ground mounted to offshore environments (provided favorable economics). The presence of water has though shown to have detrimental effect on the output of the panels. An initial 1% reduction in efficiency is due to accumulation of dirt on the panels, which leads to future exploration of better self-cleaning mechanisms for the array.

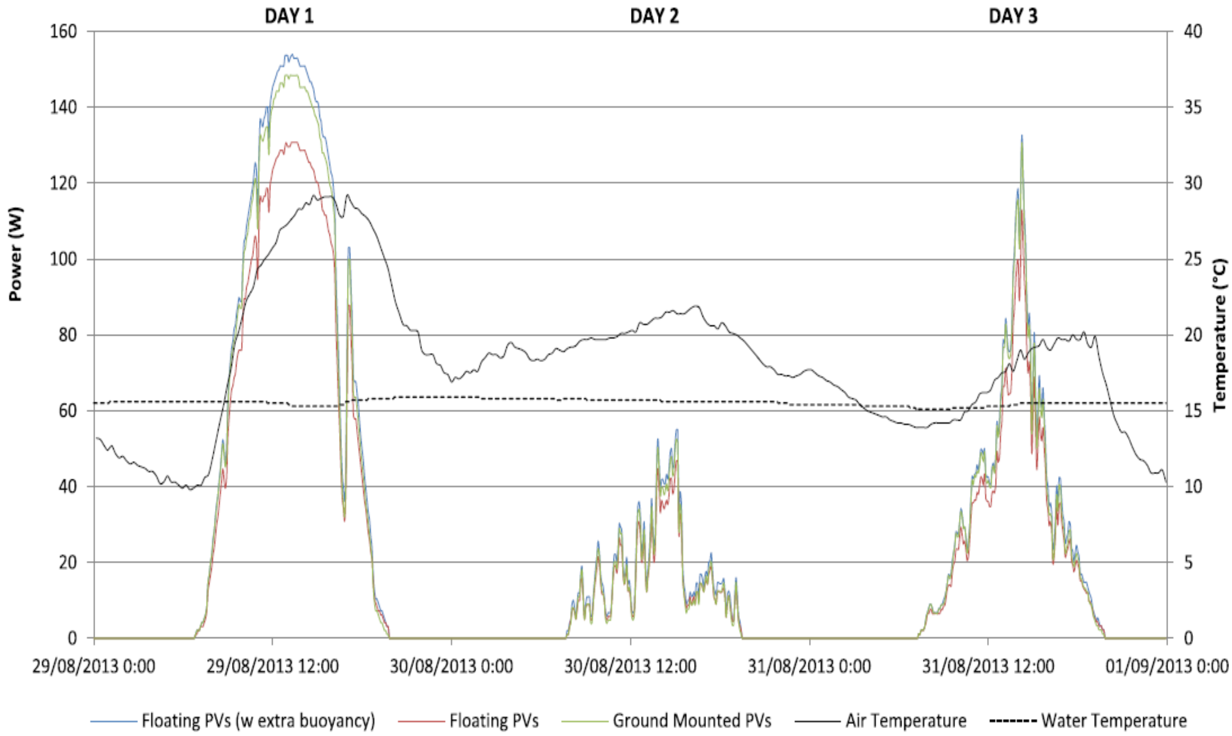


Figure 33: Electricity output from the 3 sets of PV panels, each operating differently (1 set of 2 PV panels floating with extra buoyancy to allow them to be higher than the waterline, 1 set of 2 PV panels floating just at the waterline and 1 set of 2 PV panels installed on ground).

Panels on Floating Structures

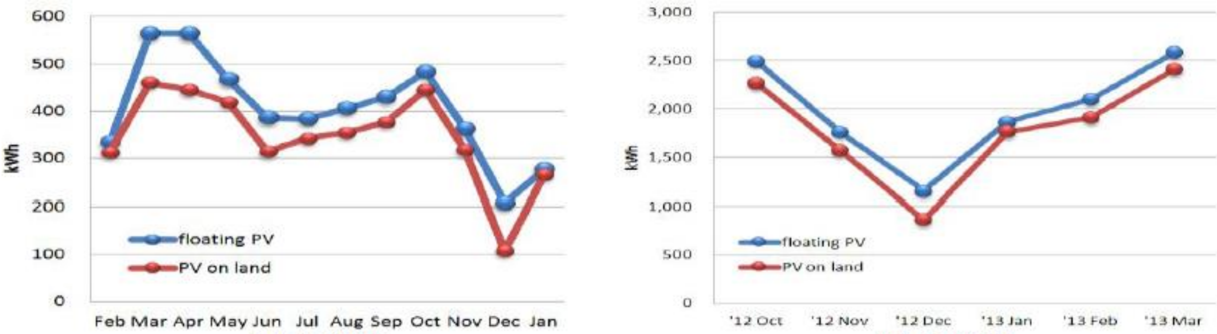
Young-Kwan Choi [28] studied the performances of two floating plants installed on the Hapcheon dam reservoir, one 100 kW and one 500kW (shown in Figure 34), comparing them to a 1MW on-land plant installed in Haman, 60 km away from the Hapcheon lake, which is a distance sufficiently low to assume equal solar irradiance and similar weather conditions. The two systems are mounted on plastic floating structures, hence, the panels are not in direct contact with the water. In both the floating plants, the panels have a tilt angle of 33°, while in the on-land plant panels are tilted of 30°.

(a) 100kW (b) 500kW

Figure 34: K-Water 100 kW (a) and 500 kW (b) plants in Hapcheon.

For an accurate comparison, analysis days with blackouts, maintenance and data errors were excluded from the comparison. The analysis period consisted of one year starting from February 2012 to January 2013 for the comparison between the 100 kW floating and the 1 MW on-land plant, and six months starting from October 2012 to March 2013 for the comparison between the 500 kW floating and the 1 MW on-land plant. To compare two plants with different capacities the 1 MW plant's daily average **energy generation has been converted into the capacity of the other plant, 100 kW or 500 kW, before being compared.**

As a result of the first comparison, the capacity factor of the 100 kW and the 1 MW were 17.6% and 15.5% respectively, which means a gain of 11.9% ca., while as a result of the second comparison, the capacity factor of the 500 kW and the 1 MW were 17.1% and 15.5% respectively, which means a gain of 9.4% ca. An average value of the two results is an efficiency gain of 10.6%.



(a) 100kW (b) 500kW

Figure 35: Comparison of daily average generated energy [28]

Regarding the floating sub-stations, they can be relatively little and composed of simple floaters with a water-resistant capsule for electrical components such as inverters and cable connectors.

4.2.2 Moorings and others

The mooring system is the component of a floating photovoltaic power plant that depends most on the nature of the water basin where it is installed. It can be just a tying system to the margins, as it is the case of irrigation tanks, which don't present any environmental disturbing comp**onent, such as waves and sensible variations of the water level. On the other extreme, it can be as complex as a mooring system for a plant in open sea, or even** more complex, due to the huge water depth variations of dam's lakes. Dams' lakes are the most c**hallenging location also for other reasons**: the lake's bed could be very steep, since dams are typically situated in mountain valleys where a river flows, so the plant must be located in the middle of the lake, in order not to touch the sides of the valley when the water level goes down. Furthermore, if the structures have a tilt angle, the orientation of the system must remain constant, namely true south for installations in Europe. The orientation of the valley/lake hardly is north-south or east-west, so the mooring lines could have very different lengths and characteristics.

Being in the middle of the lake also means longer under-water cabling. A common configuration for big installations is to use a floating sub-station (or more, depending on the dimensions of the plant) with the inverter(s) on it. The use of floating sub-stations allows all the DC umbilical cabling, i.e. connecting the PV arrays among them and to the inverters, remaining outside the water. This means that it is possible to use normal PV cables, instead of under-water cables. In case there is more than one inverter, AC cables exiting the inverters would be connected on one of the sub-stations into one big cable going to the grid. This has to be an under-water cable – it would be impossible to take it outside the water, because of the dimensions of the lake and of eventual navigation paths in the lake.

Designing both mooring system and under-water cable connection to the lake margin, several parameters must be taken into account: the distance of the system from the margin, the steepness of the valley's sides, the lake's maximum bathymetry variation, the morphology of the lake bed.

4.3 Economic differences

From an economic point of view, the passage from ground-mounted to floating plants seems to have much more disadvantages than advantages. This is because it adds some costs almost without avoiding any; in fact, its advantages are basically increases in efficiency. It is important to consider that also economics for this kind of plants strongly depends on the dimensions and characteristics of the water basin where it is installed. Namely, if the water basin is a little artificial lake/irrigation tank, the only differences from a traditional ground-mounted plant are basically the costs of the floating structures, while if it is installed on big lakes, it presents a wide range of additional costs that could turn it into non-convenient. In the following paragraphs are listed the main differences in economics between the two technologies, divided in the two categories of capital expenditures (CAPEX) and operational expenditures (OPEX).

4.3.1 CAPEX costs

CAPEX are the costs that vary the most from ground-mounted to floating PV plants. In the following paragraphs the main cost drivers and estimations of prices are explained.

Preliminary surveys

The first main difference is in the designing phase, due to the preliminary environmental impacts studies and site-related surveys. They are assumed necessary for installations on big lakes. Lakes are extremely complex environments in comparison with artificial water tanks (FPV) and land (ground-mounted PV), therefore in the initial phase of the project a range of preliminary surveys are needed, such as solar irradiation measurement, bathymetry and lake bed surveys, wind and wave survey, grid connection studies, eventual naval traffic survey and environmental impact assessments (EIA). These studies are essential for a proper optimization of the system, from the choice of the best location inside the lake – depending on solar irradiation, lake bed morphology, currents and formation of waves… – to the choice of the floating structures and the mooring lines. Their costs are completely independent from the size of the plant, reason why they could play an important role in case of little plants. Confidential sources from WavEC estimate costs for these kinds of studies can be in the range of 20-70 k$ per study.

Floating components

The second main difference is represented by the cost of floating components, namely support structures for the modules and sub-stations. Costs vary with the type of structures, Confidential sources report prices around 100 $/panel for the Ciel et Terre modular structure, 200 $/panel for rigid structure projected for hard environmental conditions (waves up to 1m high and wind up to 20 knots), while for unique structures the Italian company Otto proposes a model with prices ranging from 140 to 160 $/panel. For the semi-submerged structure cost can be estimated around 50 $/panel, while for submerged thin-film panels the only cost would be that of the floaters under the modules – in order to minimize the layer of water on the panel – and wouldn't be higher than 10-20 $/panel. Costs are expressed in $/panel because their translation to $/kW would require the choice of modules – hence a rated power – which would somehow modify the original information obtained. No literature has been found for floating sub-stations, reasonable costs vary between 200 and 700 $ each, depending on dimensions and needed resistance to environmental factors.

Mooring line system

Moorings are probably the most difficult costs to estimate, as they strongly depend on the design. A confidential source gave an average price of 60 $/panel for a rigid structure based plant, for the Alto Rabagão dam in Portugal. This is one of the biggest dams in Europe, and presents very hard conditions, such as water depth variations up to 50 m, winds up to 20 knots and waves up to 1 m height.

Cabling

The entire DC system is equal to that of a ground-mounted PV plant. On the contrary, the AC cable, in particular for plants installed on dam's lakes, must be water-resistant, which increases sensibly its costs, both because of the costs itself of the under-water cable and for the installation that requires much more time and an expensive equipment. Grid connection should not be necessary for installations on dams, as it is available that of the turbines – which would represent a saving compared with a classic ground-mounted plant – while for installations on private lakes/tanks costs for grid connection must be incurred as in ground-mounted systems.

Installation

In general, installation of a floating PV plant is more expensive than that of a ground-mounted system. Installation is expected to last 2-5 days. Usually the system is mounted on the lake's shore and gradually put into the water. Once the structure ensemble is completed it can be located in its working site and fixed to the mooring lines by boat. For installations in dams, cables location typically needs a ROV, as they must be positioned under the lake bed, while in little lakes can just lay on the lake bed, or even be taken out of the water in case the floating structure cover almost the great majority of the basin's surface.

Eventual purchase of boats/ROV (remotely operated vehicle) would take part of CAPEX costs, but, especially in case of installations on dams, they could already be available. If not, a typical price for a ROV is around 120 k$.

Table 8: Comparison between typical CAPEX costs of ground-mounted utility-scale PV systems and estimations of CAPEX costs of floating PV power plants on little lakes

Item	Ground-mounted	Little lakes	Details
	$/MW		
Land	8,300	0	assumed 2 acres/MW varying with technology and land cost.
PV modules	620,000	620,000	c-Si prices in the range of 0.52-0.72 $/W.
Mounting structure	306,000	400,000	cost assumed for the structure irrespective of the type of technology. For floating it is the cost of the floating mounting structures (modular structure, 100$/panel).
Power conditioning units/inverters	200,000	250,000	including the required controls and instrumentation. In floating systems it is assumed a slightly higher value due to eventual floating substations/supports and higher protection for electrical components.
Grid connection	255,000	255,000	this cost includes supply, erection, and commissioning of all cabling, transformers, and evacuation infrastructure up to the grid connection point. This is a highly variable cost depending on the distance to the point of connection.
Preliminary and operating expenses	11,000	11,000	services related to design, project management, insurance, and interest during construction, among others.
Civil and general works	120,000	50,000	infrastructure development, application for permits and approvals and presentation of project reports. Lower for floating because irrigation tanks usually already have roads…
Developer fees	100,000	100,000	average figure for the EU and dependent on market conditions.
Mooring lines	0	0	
TOTAL	1,620,300	1,686,000	
% Increase	-	4%	

Table 8 compares average values of CAPEX costs for ground-mounted utility-scale power plants and estimations for floating systems on small size water reservoirs. It is interesting to notice that the PV mounting floating structures are responsible for great part of the gap between the two technologies. The resulting percentage increase in CAPEX would be only 4% ca. In small size lake case grid connection costs have been considered, because there is not possibility to take advantage of the presence of the turbine, but preliminary surveys are not necessary. The same comparison will be done also for floating installations on dams in Chapter 5, with the values resulting from the plant simulation.

4.3.2 OPEX

Maintenance procedures required by photovoltaic systems in small lakes are the same as for traditional ground-mounted plants, with the difference that here they must be done by boat. However, costs could not differ so much, since typically in large-scale ground-mounted this kind of operations are made with the use of machines designed for this scope. The cost of these machines could be even higher than that of a boat, with the advantage of having onsite water to clean the modules. So, for installations in small lakes OPEX costs can be considered almost equal to those of ground-mounted systems.

What makes the OPEX rise in floating installations on dams are the mooring line system and the under-water cables, whose operational maintenance requires a control with a ROV with a frequency of about twice per year, as well as monitoring of power output in case of coupling with the turbine. Plausible values for OPEX costs for floating installation on dams are double of the ground-mounted OPEX costs.

5. Feasibility Analysis of installations on dams

As previously seen, most of the floating PV have been installed on water reservoirs of small dimensions. If we move our attention to installations on dam's lakes, we need to take into account several more variables during the design of the system, among which the most relevant are the bathymetry variation, the incident waves and the wind. Dam's lakes are usually considerably larger than irrigation reservoirs: they can have non-negligible fetch, hence, high wind can generate waves capable of damaging the floaters. In addition, the highly inconstant turbine's water flow contributes to make the variations of the lake's water depth unforeseeable, making harder (and more expensive) the mooring lines design. Another big disadvantage is the shadowing effect of the mountains surrounding the lake, or of the dam itself, which could represent a relevant production loss. This is one of the main reasons why the floating structure should be located in the middle of the lake, instead of close to the shore, which would significantly facilitate the mooring system of the plant. Another reason is related to the water depth variations: if the structure was moored close to a shore, it could touch the side of the valley and be damaged when the water level reaches its minimum levels. Furthermore, as dams are usually situated in mountainous areas, there could be complications related to the wind blowing on the structure. All these are key factors that increase the cost of the system and could represent the difference between a convenient project and a non-convenient one.

On the other hand, PV on a dam's lake has several unique benefits, in particular a large and unused space and the presence of a grid transmission line already in place, as well as environmental and other kind of surveys probably already assessed for the previous construction of the dam and easy licensing due to the existing power plant. Depending on many variables, there is also the possibility to couple the photovoltaic and hydropower technologies in order for the PV to work as a 'virtual storage system'. For the total system's economics, these benefits could represent a fundamental saving, contributing to reduce its cost of energy, which is inevitably higher than that of large-scale ground-mounted PV plants, as it is further explained.

In this chapter the economic viability analysis of PV installations on dams is analyzed, starting with a brief breakdown of the Portuguese hydropower situation, and an analysis of the main challenges related to the installation of a floating structure on a dam lake. In the central part of the chapter an example of how a coupled hydro-photovoltaic system could work is given, and finally the model that has been designed for FPV plants simulations, the base-case simulation developed in Portugal results and sensitivity analyses performed on it are described.

5.1 Portuguese Hydropower Statistics

With no fossil fuel resources or reserves of its own, Portugal has had to depend on imports to meet its domestic demand for oil, gas and energy at large. This situation, coupled with European Union targets to cut carbon emissions, has led to substantially increased interest and investment in renewable sources of energy over the last decades. In 2014, renewables accounted for 62% of the country's energy mix in terms of electricity generated. Hydropower amounted to 31% of the mix, occupying half of the total share of renewables. With its 5902 MW installed (with the pumped storage systems), Portugal is the 11th country in Europe in hydropower electricity generation.

Table 9:Portuguese hydropower situation in 2014 [34]

Area	92’200 sq km
Population	10’460’000
Installed hydropower capacity	4’455 MW + 1’343 MW pumped storage
Hydropower generation	**16.16 TWh**
Hydropower share of total en. generation	**31%**

At the same time, Portugal is the country in Europe (after Malta and Cyprus) with higher solar irradiation, since it has annual average values around 1900 MWh/m² (Figure 36). The high share of hydropower energy, together with the high solar irradiation, makes of Portugal the perfect country in Europe to develop floating photovoltaics in dam’s lakes and to study the opportunity of coupling it with hydropower.

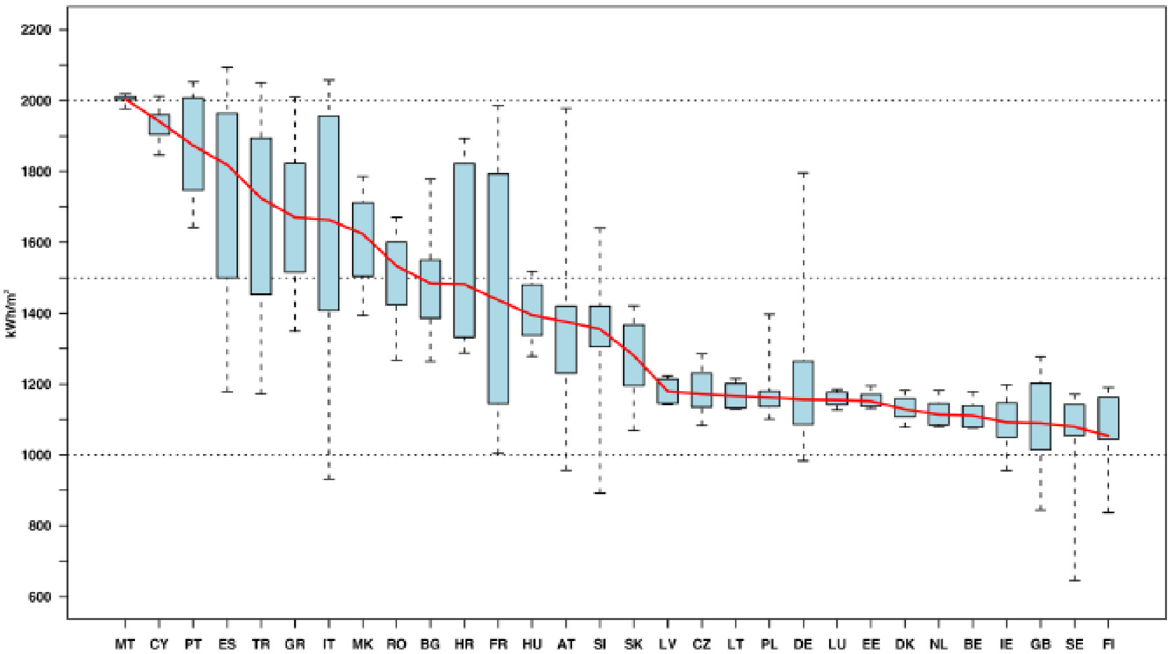


Figure 36: Comparison of yearly global irradiation on optimally-tilted surface of 25 European countries and 5 candidate countries. The country averages are connected with the red line, minima/maxima are shown as dashed lines, while the boxes show the range in which 90% of built-up areas in the countries fit [31].

5.2 Environmental Challenges

Dams can present hard environmental conditions for floating structures. Since dams can be located in very different environments, their conditions are strongly site-related, reason why environmental surveys are fundamental in the project development phase of a floating photovoltaic system. The main challenges that a project developer must take into account are listed below:

- Wind in Portuguese lakes can reach 20 knots of velocity. It could damage the system in two different ways, directly with its pressure on the system, especially if the modules are tilted, and creating big waves. The wind blowing on the structure requires stronger supporting structures for the panels and tougher mooring lines due to its continuous force applied in one direction.

- Waves generated by the wind can reach 1 meter height, depending on the length of the lake and the direction of the wind related to that of the lake (fetch). When wind is blowing in the lake's longitudinal direction and the lake itself is some kilometers long – as most of the dam's lakes are, particularly in Portugal – it could generate high waves. The incident waves, in the long-term, could seriously damage the junctures between structures, due to the relative movements of one structure to the other.
- Current is another relevant factor, especially in long lakes. When the turbine is generating, it could reach up to 5 m/s of velocity, and could represents a danger for mooring lines, pushing the structure out of its proper position. Currents in lakes also depend on the characteristics of the lake itself, such as its shape, length and steepness of the shores and vary considerably with the measuring spot. Higher currents are measured in the very proximity of the dam.
- Water depth variations are probably the most critical factors for mooring lines costs. Dams lakes can have up to 5 meters daily and to 50 meters yearly variations in the water depth. The daily variations are due to the turbine's flow and cannot be precisely foreseen, since water flow in the turbine depends on several variables, mainly on energy demand. Yearly variations are usually gradual and easily foreseeable.

All these factors strongly rest on the lake characteristics, mainly its shape, its dimensions, the steepness and morphology of its shores and of the lake bed, as well as on the hydropower plant characteristics, such as height of the dam, number and section of the turbines, which determine their average water flows. Preliminary surveys are essential to properly design the floating system in order to optimize costs and performance and minimize operations and maintenance interventions during the plants' lifetime. In fact, for example, a badly-designed mooring system may require further greater maintenance operations than an optimized one.

5.3 The Opportunity of Coupling PV and Hydropower

The beneficial effect of locally coupling photovoltaics and hydropower energies has potential to be the most important aspect related to the installation of photovoltaic systems on dams.

The large-scale integration of renewable energy sources such as wind and solar power is advancing rapidly in numerous power systems in Europe and the United States. But it is facing huge problems, because utilizing renewable resources at a bulk scale is hindered by the fact that these resources are highly variable. Though the integration of renewable energy is increasing, an integration level beyond 20-30% is currently hardly perceived as economical. Assuming capital costs for renewable power will continue to decline in the future, one of the major challenges for the large-scale integration of renewable energy will be its variability. Currently renewable generators operate under favorable regulations in many markets. A number of system operators in China, Europe (Denmark, Germany, Greece) and the United States accept renewable generation on a priority basis. But it is clear that this preferential treatment has its limitations. A solution could be a local coupling, where the contemporaneous (or alternate) energy generated by two or more technologies, with different energy sources and characteristics (dispatchability, predictability, capacity) gives a constant and predictable energy output, even capable of energy storage with the hydroelectric pump.

For example, power production from a photovoltaic plant can allow a corresponding reduction in the water flow through the hydropower turbines. This would preserve that water for later use, potentially during more valuable hours in a day (such as the early evening peak load that is typical in many locations). Most hydropower plants cannot generate electricity at full capacity 24 hours per day because there is not sufficient annual water flow through the dam catchment to maintain the average flow rate that is required at full power. Hence, both the turbine and its transmission line are not used at their full potential. So, since the annual water flow availability through a hydro system is the main limit to the hydropower energy resource, a co-located solar component of generation can allow increased dispatchable energy production, making more full usage of the grid connection line.

Hydropower is typically used as a supplement to fossil fuels as it is limited by the amount of water it has available to use on a daily and seasonal basis. The chart in Figure 37, provided by an Australian company that is promoting this kind of solution [30], shows a perfect combination of coal and hydro to provide base and peak loads. The fossil power plant is typically used to provide the base power load until its rated power, while the hydro plant starts working when the demand exceeds this value.

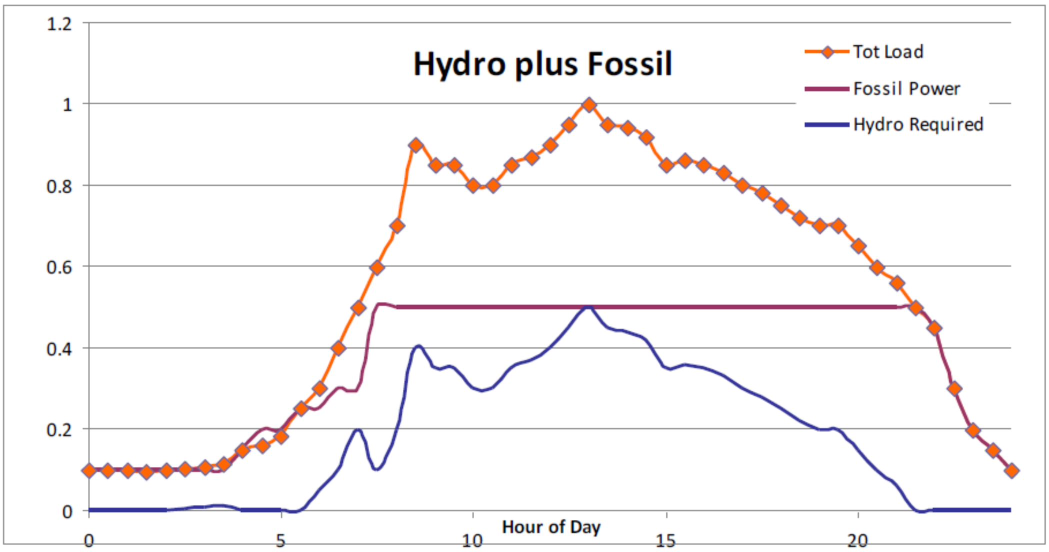


Figure 37: Typical coupling hydro-coal [30]

Chart in Figure 38 shows how a hydropower turbine and a solar PV plant could be combined, with the PV producing during the central hours of the day, when there is sun irradiation, and the hydro working the remaining time and being available to fill in through cloudy periods. If the solar generation capacity equals or exceeds the maximum hydroelectric output, almost no water needs to be consumed from 8am to 4pm on most days, as the power could be supplied by the PV system.

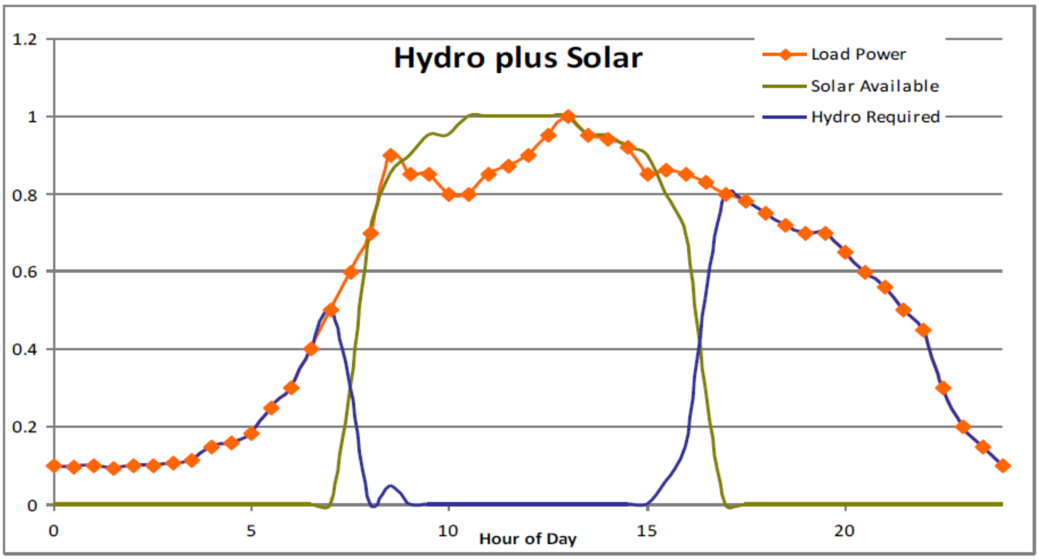


Figure 38: Example of coupling hydro-solar PV [30]

This kind of benefit can be achieved with the installation of big PV systems, and their success anyways depends on the daily load and solar irradiation profiles. However, if well matched, such a combined plant would be a much more reliable power producer than hydropower alone, as the system would be far less dependent on water supply; in drought conditions it would be possible to continue daytime solar power generation from the PV with no consumption of water at all.

5.4 Simulation model: LCOE

LCOE represents the per-kilowatthour cost (in discounted real euros) of building and operating a generating plant over an assumed financial life. Key inputs for calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed capacity factor for each plant type. The importance of the different factors varies among the technologies: for technologies that have no fuel costs and relatively small variable O&M costs, such as wind or solar, LCOE changes in rough proportion to the capital costs, while for technologies with a high dependence on fuels, the fuel costs affect much more the LCOE. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all these factors and their values can vary both regionally and across time as technologies evolve and fuel prices change. It is important to note that this method is an abstraction from reality with the goal of making different sorts of generation plants comparable. For example, the method is not suitable for determining the cost efficiency of a specific power plant. For that, a financing calculation must be completed taking into account all revenues and expenditures on the basis of a cash-flow model. The LCOE can be computed as

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A^t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{t,el}}{(1+i)^t}} \tag{3}$$

where:

LCOE: Levelized cost of electricity in $/MWh

I_0: Investment expenditures in $

A_t Annual total costs in $ in year t

$M_{t,el}$: Produced quantity of electricity in the respective year in MWh

i: Real interest rate in %

n: Economic operational lifetime in years

t: Year of lifetime (1, 2, ...n)

Although LCOE is widely recognized as the most effective metric for comparing energy sources, it presents some important limitations, mainly related to its dependency on the assumptions, financing terms and technological deployment analyzed. In particular, assumption of capacity factor has significant impact on the calculation of LCOE. Other relevant limits of LCOE are related to the fact that it ignores time effects associated with matching energy production to demand. This happens at two levels: dispatchability, the ability of a generating system to come online, go offline, or ramp up or down, quickly as demand swings, and the matching between availability profile and market demand profile.

Thermally lethargic technologies like coal and nuclear are physically incapable of fast ramping, as they could need hours or even days to reach the optimal working point. Capital intensive technologies such as wind, solar, and nuclear are economically disadvantaged unless generating at maximum availability since the LCOE is nearly all sunk-cost capital investment. At the same time, intermittent sources can be competitive if they are available to produce when demand and prices are highest, such as solar during summertime mid-day peaks seen in hot countries where air conditioning is a major consumer. Despite these time limitations, leveling costs is often a necessary prerequisite for making comparisons on an equal footing before demand profiles are considered.

In the present study, a simulation of a floating PV power plant installed in Portugal has been carried out with a simulation model designed to estimate the LCOE.

5.5 Simulation model: construction of the model

The model is organized in various sheets, each assessing a structural/economic/financial aspect of the plant. In the following lines it is explained how the model has been structured and the main assumptions made during it design.

Key elements of the model:

- Regarding the power plant location and relative energy resource, the Portuguese territory has been divided in nine main areas, each associated to the solar irradiation of the main city in the area.
- Values of irradiation are from RETScreen's database [33], which for Portugal is based on NASA's values. The project developer can choose the tilt angle, which impacts the total solar irradiation on the surface. The azimuth angle is assumed to be constant and equal to the optimum value, which is 0° (true south), because it is assumed that a floating structure in the middle of a lake can be freely oriented. Also, as mentioned in paragraph 2.4, the influence of little variations of module's orientation on the annual energy output is negligible.

- For the design of the photovoltaic system, it has been chosen to use as support a software, PVsyst, which optimizes the whole system to work at the maximum power point, giving as an output all the operating parameters necessary for the dimensioning of the rest of the power plant. These are, for example, the optimal number of modules connected in series per string, which determines the DC voltage, and of strings connected in parallel, determining the DC current, the panel's efficiency and surface area among the others. PVsyst also allows to choose the inverters and the cabling system, computing electrical losses. Finally, it provides the Maximum Power point working conditions, namely current and voltage, which are used for the cabling optimization.
- System's losses are addressed in a specific sheet, and include cabling losses, in both DC and AC circuits, shading and weak irradiation losses, inverter losses, temperature losses and losses due to external factors covering the modules (snow, dust…).
- The project developer can choose between two types of floating mounting structures, the modular and the rigid structure (both well described in paragraph 3.2), because these are the only two that have already been tested in lacustrine environments, with waves and currents. In case there are no structures available, the model includes a tool to estimate the cost of construction of floating structures, based on simple shapes and raw material costs. The PV panels disposition on the rigid structures is arbitrary, and doesn't really affect neither the energy production nor the costs of installation. While for module structures, the disposition is completely arbitrary and depends on the electrical connection among modules.
- CAPEX and OPEX sheets list all the costs divided in categories.
    - For Capex, categories are:
        - project development, which includes project management costs, preliminary surveys and legal and financial expenses;
        - system manufacturing, including all the main components of the system, from PV modules to mooring lines;
        - electrical connection equipment, including all cabling (DC and AC) and sub-stations;
        - assembly, installation and commissioning;
        - monitoring and miscellaneous equipment.
    - For OPEX are:
        - management and administrative costs;
        - annual monitoring and maintenance;
        - onsite replacement and works;
        - major replacement and works onshore;
        - contingencies.

Once determined all the costs and the technical characteristics of the plant, the model is able to predict the annual energy generation, hence to compute the expected cost of energy, with the formula previously described.

5.6 Simulation model: base-case

The simulation was thought as a base-case system, on which several sensitivity analyses have been performed. The result of the model is a value of cost of energy, but it is not the main reason why the simulation has been performed. The main objective of the simulation is to identify and study through sensitivity analyses which are the parameters that affect more the cost of energy and how. Sensitivity analysis, also referred to as what-if or simulation analysis, is a way to predict the outcome of a decision given a certain range of variables. By creating the set of variables, it determines how changes in one variable impact the output. The chosen location for the simulation is Alqueva dam, near Évora, a city in central-south Portugal. This is one of the most highly insolated areas of Europe, having an average annual solar irradiation on horizontal plane of 1.84 MWh/m^2 [33]. The lake has a large part in front of the dam where the plant can be located and a dockside where boats are parked. It is assumed that the administration of the hydropower plant already owns a boat for dam maintenance and monitoring, which could be used for installing and monitoring the FPV plant. The base-case is a 262 kW, similar to the first floating PV system that EDP (Energia de Portugal) installed in the Alto Rabagão dam in November 2016. Panels are mounted on rigid structures, because the lake is long and tight, hence significant waves can be generated. The system is designed to have a tilt angle of 20°, which is a good compromise between the optimum tilt angle (higher than 30°) and a good price for the mounting structure. In fact, with growing tilt angles, also the inter-row spacing sensibly increases, hence the cost of the structures. Inter-row spacing is the minimum distance between two rows of modules that avoids shadowing effects. Table 10 shows how solar irradiation on tilted surface, inter-row spacing and energy production vary with the tilt angle. Values of energy production and irradiation are related to this specific case (in Évora with a 262kW PV system). The optimum tilt angle for Portuguese latitude is around 35°, but between the two configurations (20° and 35°) there is a reduction of less than 3% in irradiation and energy production (directly proportional to irradiation) and a reduction of around 40% in inter-row spacing. Since the floating structures are one of the system components that affect most the LCOE, it is preferable to reduce their costs, even if it means slightly reducing the energy production.

Table 10: Inter-row spacing, irradiation and energy production varying with tilt angle. Optimum tilt angle is in green, chosen tilt angle in yellow.

Tilt Angle (°)	Inter-row spacing (mm)	Irradiation on tilted surface (MWh/m^2)	Energy production (MWh/y)
10	491.5	2.028	429
15	732.5	2.099	444
20	968.0	2.154	456
25	1196.1	2.193	464
30	1415.2	2.215	469
35	1623.4	2.220	470
40	1819.3	2.208	467
45	2001.3	2.180	461
50	2168.2	2.135	452

The simulation plant is composed of 1008 260W poly-crystalline Yingli modules. They are installed on 36 rigid structures, which means 28 modules per structure. The photovoltaic circuit is organized in 72 strings, each composed of 14 modules in series. Every structure has 2 strings installed on it, organized in 3 rows, two rows of nine modules and one of ten modules. The total surface of each structure is approximately 93 m^2. Transformers from energy generation voltage to 15 kV are assumed to be necessary, while from 15 kV to grid voltage the hydropower system transformers can be used. The system uses 8 string inverters with 30kW of capacity, each connected to 9 strings. The system is designed to have a floating sub-station per inverter. Only one sub-station has the connection to the under-water cable that connects the floating plant to the shore. It is a sort of star configuration, where all the strings are connected through their inverters to a central sub-station, from which a unique under-water cable links the system to the grid. For simplicity it has been avoided the presence of a transformer, it is assumed that the transformer of the hydropower turbine can be used.

The mooring system is composed of 8 lines and associated anchors. No information has been found on the lake bed nor on water depth variations of the lake. The lake bed has been assumed composed of 70% rock and 30% mud, with water level variations of around 30 m. From cartography valuations the steepness of the lake bed has been assumed low (<10 degs), so deadweight anchors, i.e. the cheapest and easiest to install, can be used. The space in front of the dam is 800 m long and 700 m ca., so the system is thought to be placed at a distance of around 200 m from the dam. The under-water cable doesn't go directly to the dam, but to an on-shore substation at a distance of 100 m from the dam. From this sub-station to the electrical central of the hydropower plant, a distance of 150 m have been estimated.

Finally, an interest rate of 8% and a project lifetime of 25 years have been assumed.

5.7 Simulation Model: results and sensitivity analyses

The simulation results in an energy production of 455.7 MWh/year and a capacity factor of 19.8%. The value of LCOE is 23.88 c$/kWh, i.e. 238.8 $/MWh, which is relevantly higher than both land-based renewable and conventional energies. It is composed of 82% of CAPEX costs and of 18% of OPEX costs.

CAPEX

As expected CAPEX costs represent the major part of the LCOE, and are divided as follows:

- 28% Project development
- 50% System manufacturing
- 8% Electrical connection equipment
- 11% Assembly, installation and commissioning
- 3% Monitoring equipment

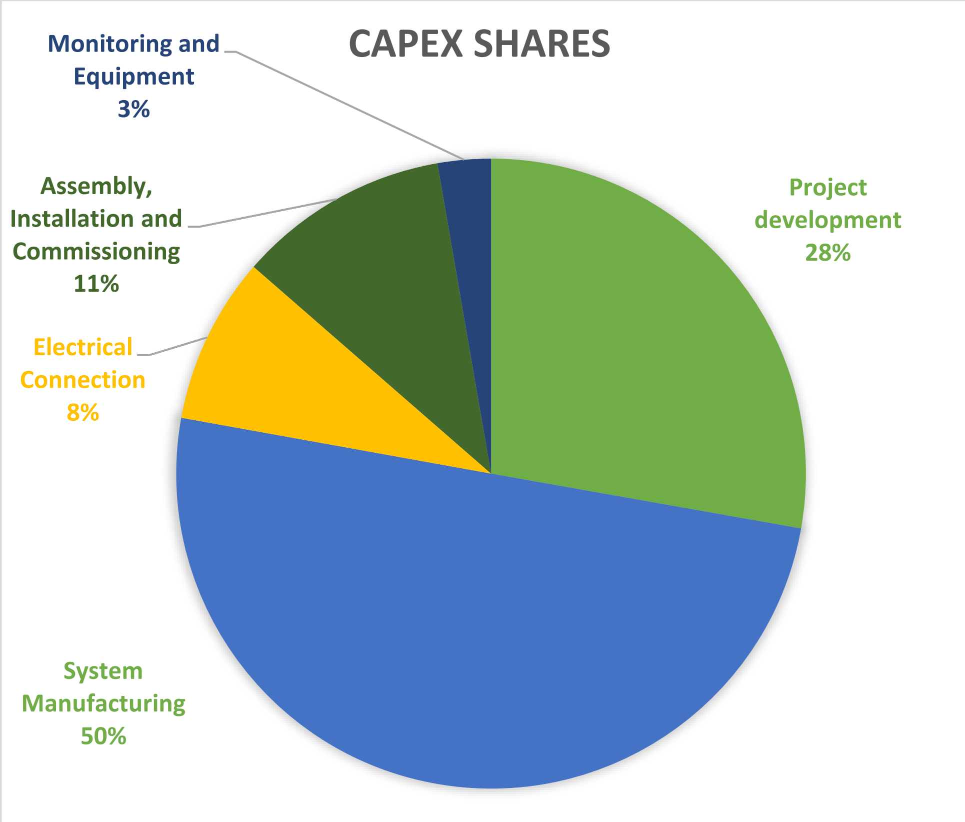


Figure 39: CAPEX shares of the simulation

Project development has a high cost due to the preliminary surveys that have been considered necessary for an installation on a dam. Namely it has been assumed a cost of 20 k$ for a lake bed survey, 50 k$ for environmental and climate (wind and wave) surveys, 50 k$ for a real resource data assessment, 100 k$ for EIA (environmental impact assessment) and grid connection studies. In case all these preliminary studies had already been available – e.g. previously done for the construction of the dam – the value of project development costs would drastically go down. Other development costs are for insurance, project management and construction supervision costs, which together are assumed to have a cost around 5% of the construction costs (40 k$ ca.). Avoiding preliminary surveys, project development costs would reduce from 28% to 5% of the total CAPEX.

System manufacturing has the most important share of CAPEX costs, and includes PV modules, inverters, floating structures, mooring lines and anchors.

Electrical connection equipment includes AC and DC cabling from the plant to the grid connection, including the under-water cable and off-shore floating sub-stations for the inverters. As can be seen in Figure 40, it has a lower share of the total CAPEX costs than in ground-mounted plants, because it is assumed that there is no need to build a transmission line nor to buy a transformer, as those of the hydropower plant can be used. The simulation plant location is approximately 300 m distant from the dam, so also the cost of under-water cabling is quite low (at least compared with other off-shore technologies such as wind off-shore or wave energy).

Assembly and installation costs depend on the availability of machines from the dam management equipment, namely for boat and ROV utilization. For the simulation it is assumed that both are available for installation and for further maintenance uses.

Finally, monitoring equipment includes power conditioning control system, marker buoys, logistics and dockside facilities.

Table 11 lists typical CAPEX costs of ground-mounted conventional utility-scale PV systems compared with the results of the simulation with the model, with and without the preliminary surveys. For the sake of comparison, model's CAPEX categories have been adapted to those of the previous studies. Namely, project development costs have been divided in preliminary and operating costs (surveys, legal and financial costs) and Developer fees (project management), electrical connection went to Grid connection, assembly and installation costs are considered as civil and general works, monitoring equipment entered in Preliminary and operating expenses. In Figure 40 are plotted these costs' shares of total CAPEX expenses, for the three plant examples.

Table 11: Comparison between average values of CAPEX components of ground-mounted plants and simulations with the model, in $/MW

Item	Ground-mounted	1 (base-case)	2 (no surveys)
PV modules	620,000	600,000	600,000
Land	8,300	0	0
Mounting structure	306,000	769,231	769,231
Power conditioning units/inverter	200,000	109,890	109,890
Grid connection	255,000	236,570	236,570
Preliminary & operating expenses	11,000	1,046,001	274,000
Civil & general works	120,000	446,543	446,543
Developer fees	100,000	59,943	59,943
Mooring lines	-	244,200	244,200
TOTAL	**1,620,300**	**3,512,379**	**2,740,378**
% Increase from ground-mounted	**-**	**117%**	**69%**

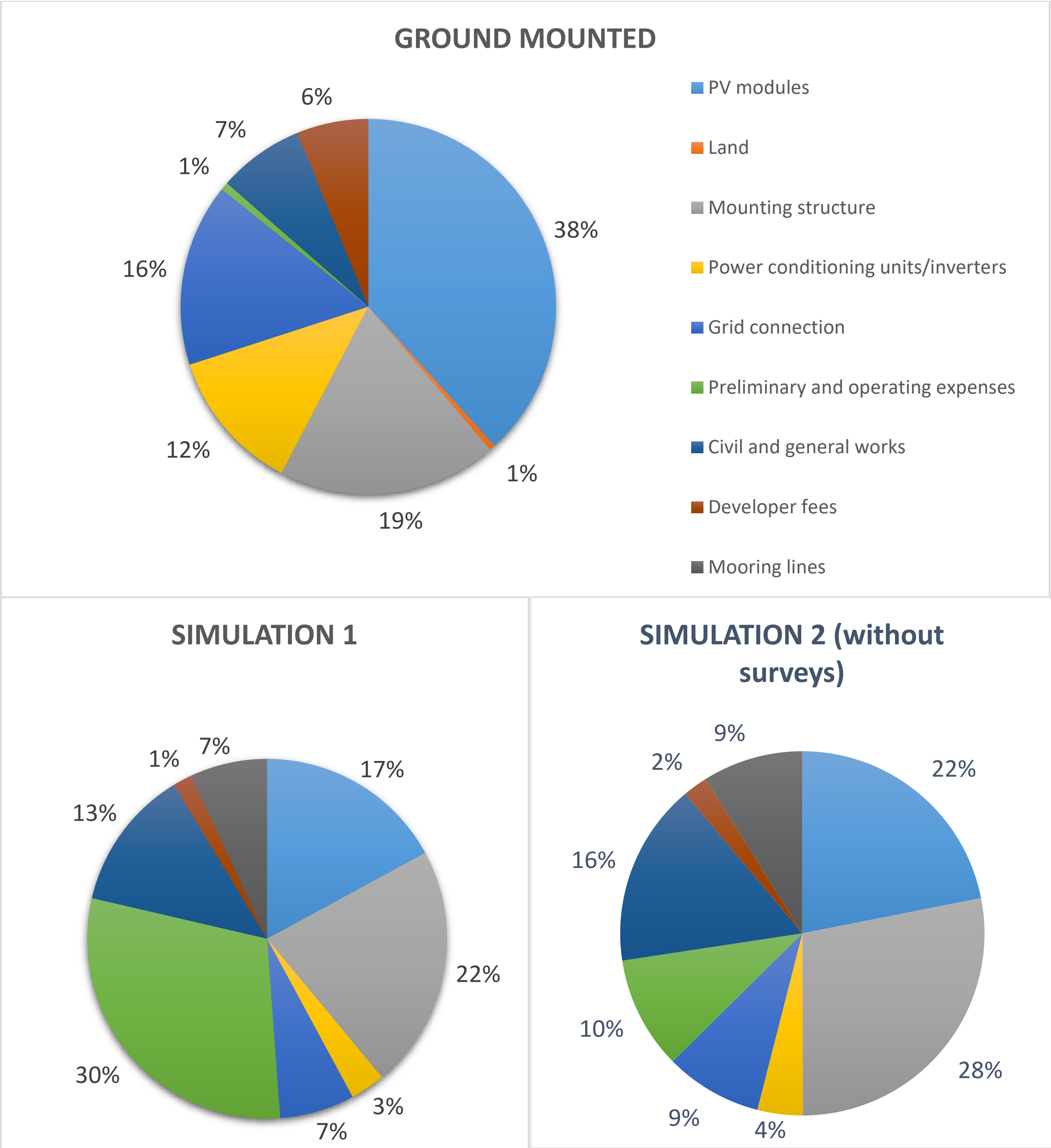


Figure 40: CAPEX shares comparison of ground-mounted, simulation with model and simulation with model without preliminary surveys.

The two simulations show the important role that preliminary studies play in such little plants. In simulation 1, their costs have been reported to MW-scale, this meant almost multiplying their value by 4 (262 kW is almost a quarter of 1 MW). Since their cost doesn't depend on the farm capacity, the influence on total CAPEX sensibly decreases passing from kW to MW plant scale.

Mounting structures have sensibly higher values (more than double) because, as already explained, the use of rigid structures has been assumed necessary. Grid connection costs have a similar value to that of ground-mounted, which means that the advantage of having a transmission line is balanced by the higher cost of the electrical grid in lacustrine locations (floating sub-stations for the inverters, under-water cables…). **Also Civil and general works have much higher values than for ground-mounted, because of the higher difficulties of installations on water.**

OPEX

OPEX costs are divided as follows:

- **69% Management and administrative costs**
- **12% Annual monitoring and maintenance**
- **17% Onsite replacement and works**
- **3% Major replacements and works on-shore.**

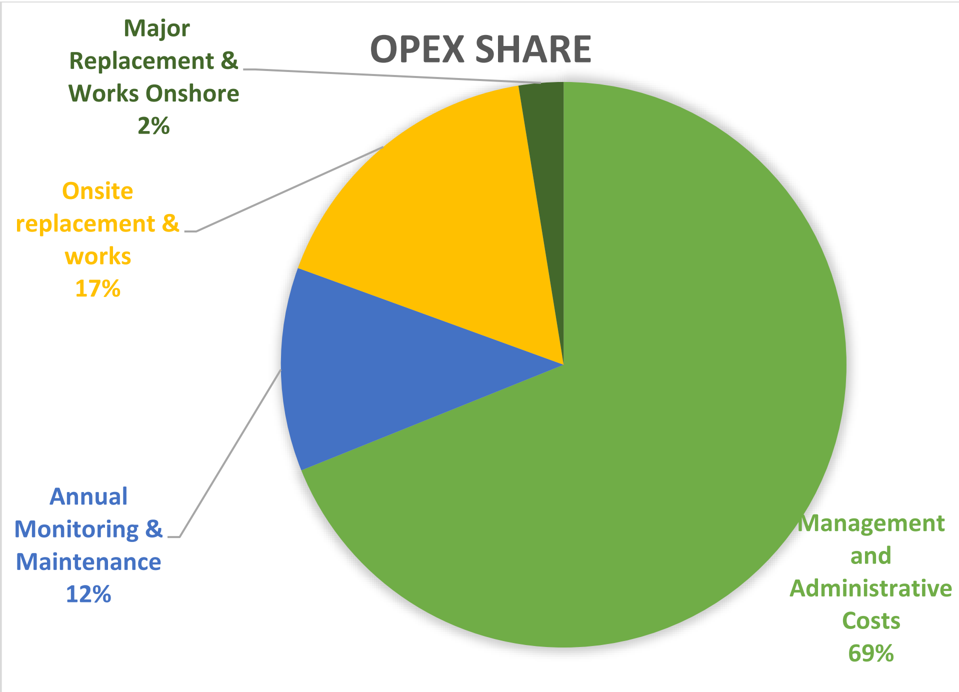


Figure 41: OPEX shares of the simulation

It is assumed a frequency of 6 onsite visual inspection and module cleaning per year, 4 technical periodic maintenance (mainly for structures and inverters) per year and 2 under-water visual inspections with ROV per year.

OPEX total costs are 4.26 c$/kWh, almost double of estimations for ground-mounted, while CAPEX total costs are 19.15 c$/kWh, which is much higher than average values for ground-mounted.

Sensitivity Analyses have been performed on the parameters with higher influence on the LCOE value: the system total capacity, the cost of the floating mounting structures, the plant location.

Table 12 and Figure 42 show the influence of the system capacity on LCOE. As largely expected, growing system installed capacity results in a decrease of cost of energy. For utility-scale (multi-megawatts) plants, LCOE almost reaches values comparable with those of conventional energy sources, such as conventional combustion turbines (10.9 c$/kWh) and biomass (10.2 c$/kWh). It is interesting to notice that variations in LCOE are much higher for little plants than for big ones: an

increase of 300 modules between 200 and 500 results in halving the cost of energy, while an increase of 5000 modules between 15000 and 20000 results in a 2% variation of cost of energy. The plant CAPEX costs include various fixed costs whose influence on the total cost of energy decrease with economy of scale, such as the already cited preliminary surveys, the under-water electrical connection, as well as the installation costs and the mooring lines costs.

Table 12: Sensitivity analysis on total installed capacity

Capacity (kW)	52	130	262	390	520	780	1300	2600	3900	5200
n. Modules	200	500	1008	1500	2000	3000	5000	10000	15000	20000
LCOE (c$/kWh)	77.26	37.35	23.88	19.71	17.46	15.26	13.44	12.10	11.66	11.43

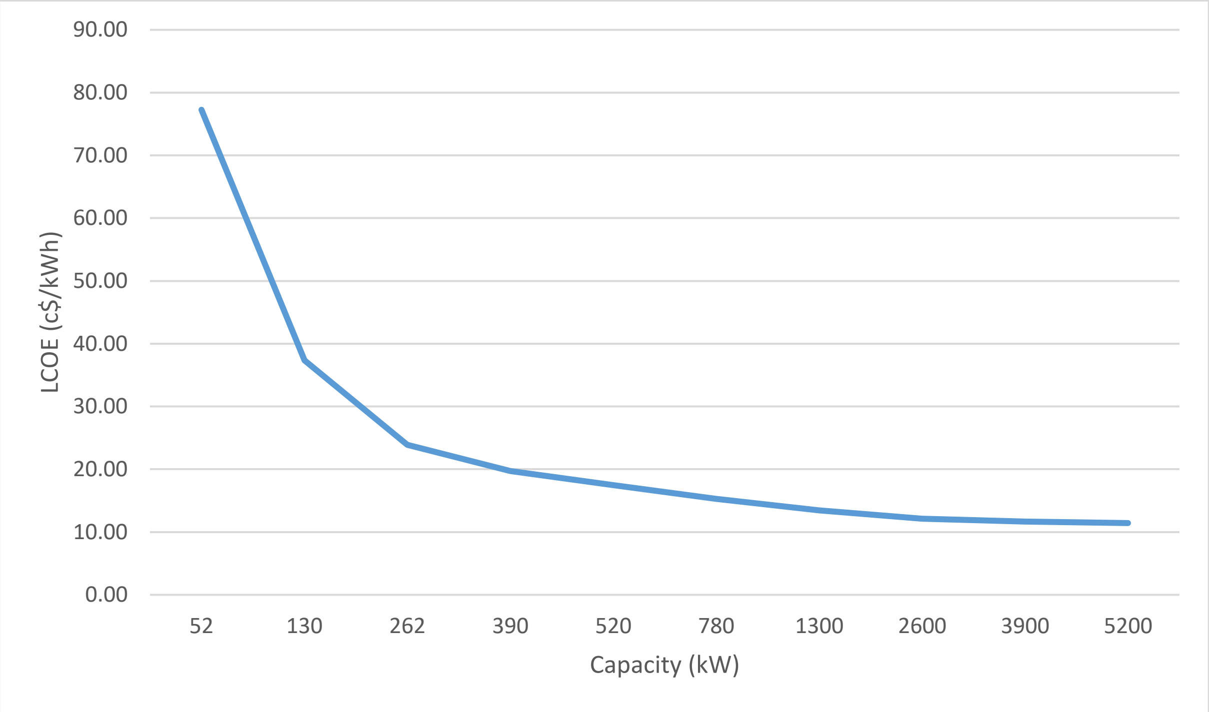


Figure 42: System capacity influence on LCOE

Another parameter that strongly influences the LCOE is the floating structures cost. Tables 13 and 14 show how the choice of the structure – between modular and rigid, the two considered in the model – affects the cost of energy. With a fixed number of modules (1008), it gives a difference of 11% on the value of LCOE. Since the number of floating structures directly depends on the system capacity, i.e. grows with the number of modules, the cost of the structure gains greater influence on the cost of energy with growing total installed capacity. As shown in Table 14, in a 5.2 MW system, which would have 20'000 modules, the choice of modular instead of rigid structures would reduce the cost of energy of about 20%.

Table 13: Influence on LCOE of the choice of the structure for the 262 kW base-case plant.

Structure type	Modular	Rigid
LCOE (c$/kWh)	21.46	23.88

Table 14: Sensitivity analysis on the cost of the floating mounting structures

Capacity (kW)	52	130	262	390	520	780	1300	2600	3900	5200
n. Modules	200	500	1008	1500	2000	3000	5000	10000	15000	20000
LCOE w. rigid structure (c$/kWh)	77.26	37.35	23.88	19.71	17.46	15.26	13.44	12.10	11.66	11.43
LCOE w. modular structure (c$/kWh)	74.26	34.89	21.46	17.25	15.00	12.80	11.01	9.67	9.23	9.00

Location is also a fundamental parameter when designing a PV system, both for ground-mounted and for floating systems. In Table 15 are listed the LCOEs for the 9 different zones in which Portugal has been divided. It confirms that Évora (location of the simulation) is in one of the zones with higher solar irradiation in Portugal. The only cities with a higher irradiation are Faro and Sines, both on the ocean side and situated in southern latitudes. In case of installations on dams, solar irradiation is not the only parameter influencing the choice of the location. In fact, also the choice of the dam is very important: the lake's characteristics, such as shores' steepness, lake bed composition, shape and dimensions of the lake itself, as well as the hydropower system's characteristics, such as grid connection and transformer capacity, water flux in the turbine, presence of a meteorological station, could considerably affect the viability of the FPV system.

Table 15: Influence of plant location on LCOE

Location	Bragança	Porto	Guarda	Coimbra	Beja	Lisboa	Évora	Sines	Faro
LCOE (c$/kW)	26.72	26.05	27.33	26.46	25.64	25.67	23.88	23.77	23.79

5.8 Validation of the model

The last step of the work is the validation of the model's cost of energy prediction efficacy through the integration of data related to a real case. This was (only partially) possible thanks to a collaboration with the Portuguese energy company EDP (Energia de Portugal), which in November 2016 installed a 218 kW FPV system on a Portuguese dam, Alto Rabagão. EDP provided some cost estimations made by Ciel et Terre for a 10 MW floating system to be installed in Portugal, relating in particular some system components:

- Cost of the mounting structures
- Modules working temperature measuring equipment
- Grid connection

- **Mooring system**
- **O&M costs**

The simulation run with these values results in an LCOE of 7.53 c$/kWh, to be compared with the value of 6 c$/kWh provided by Ciel et Terre. It represents a difference of around 25% of the cost of energy, which is acceptable if considered that provided data had to be integrated with previous estimations. Although it still needs a thorough validation with data from a real case, this first simulation confirms the good performances of the model designed for the thesis.

6. Conclusions

In the next years solar photovoltaic is expected to keep on its path toward higher competitiveness, due to lower components' prices, lower installation costs and economies of scale. For many reasons, such as conventional ground-mounted PV's high land-use and water-related efficiency gains, in the last few years both privates and public entities have been looking at floating photovoltaics (FPV) as an interesting solution. Floating photovoltaics is already a reality for small size water tanks and artificial lakes, where environmental conditions are favorable, which means that there is no need of mooring lines to the bottom of the basin and cheap mounting structures can be used. Installations on dams, on the other side, present important cost reducing potential related to the possibility of coupling of the two energy sources (PV and hydropower), and numerous avoided costs, such as the preliminary environmental and engineering surveys, and the construction of infrastructures. However, capital costs considerably raise due to the costs of mooring system, the mounting structures, the under-water cabling. Yet, it is not clear whether floating photovoltaics on dams would represent a feasible solution. In this research, a deep viability assessment of installations on dams has been performed.

In the installations on small lakes, the slightly higher capital costs (4% higher ca.), mainly due to the floating mounting structures, and operational and maintenance costs, which have to be done by boat, are balanced by the efficiency gain principally resulting from the lower working temperature. In fact, it has been demonstrated that PV models installed on floating structure work at much lower temperatures, resulting in higher efficiencies. Efficiency gains are around 10% for modules installed on plastic floating structures or pontoons, and may be even higher if the modules are submerged. Floating photovoltaic installations on little lakes/reservoirs have average LCOE comparable with ground-mounted PV plants of the same size.

Different is the case of installations on dams, where capital costs raise considerably due to the tougher environmental conditions, requiring more resistant structures and mooring lines, preliminary environmental surveys (compulsory when installing a power plant in a delicate natural environment such a lake and essential for the optimization of the system), and the higher distance among the components of the system (namely between the floating plant and the electrical plant), which increases cabling capital costs as well as losses during operation. On the other hand, installations on dams could take advantage of some savings related to the presence of the hydropower plant, e.g. by using its transmission line, offices, boat/ROV for O&M procedures, measurement and monitoring system. Another potentiall advantage of installations on dams, still to be exhaustively investigated, is the possibility of coupling PV and hydroelectric energy sources. This could represent a good local solution for the renewable energy integration issue, creating a multi-energy-sources plant, much more reliable and predictable than renewables on their own. LCOE estimations performed with the simulation model are around 240 $/MWh for medium size PV plants floating on dams (~260kWp), which is still a very high value, if compared to both conventional energy sources and renewable energies. Many factors are expected to reduce the cost of energy, among them economy of scale is the most important. Some of the capital costs considered in the simulation are fixed costs, which means that they don't increase with the system capacity. This is the case of the preliminary surveys, which for the 262 kW plant of the simulation account for the 30% of the system's capital costs, while for a 1 MW plant would drop to 14%, and to 8% for a 5 MW plant. Other potential cost-reducing factors are the aforementioned coupling with the existing hydropower system and the system's components' general cost reduction (analyzed in Chapter 3).

The sensitivity analyses carried on with the model highlighted the important role played by the system capacity on the total cost of energy, which showed an almost-exponential decreasing trend for growing capacities, reaching values similar to those of conventional technologies for multi-Watts scale plants. In fact, for capacities higher than 2 MW LCOE stabilizes around 12 c$/kWh for systems mounted on rigid structures, and under 10 c$/kWh for systems installed on modular structures. These values are comparable to LCOEs of conventional combustion turbines (10.9 c$/kWh) and biomass (10.2 c$/kWh) plants. Sensitivity analyses have been carried on also on the choice of the mounting structures, showing a variation between modular and rigid structures growing up to 20% of the LCOE for a 5 MW plant. Finally, the location has shown a considerable weight on the cost of energy, confirming the choice of Alqueva dam as a good location for the installation of a floating PV plant.

Summarizing, even if today's LCOE estimations are still prohibitive, there are several promising aspects about this technology that justify the growing interest and expectative around it. Some of these aspects are still to be exhaustively investigated.

Recommendations for future work

The research undertaken within this dissertation is only the basic backbone and there are other considerations that will need to be deeply analyzed in future works. Firstly, the simulation model reliability is to be verified with experimental values from a real floating system. In fact, it is based on numerous assumptions, due to lack of material available on the issue. Secondly, a thorough investigation should be conducted on all the electrical connection possibilities, including the opportunity of coupling solar PV with hydropower energy productions.

The path to commercialization is highly dependent not only on the technical aspects of the project, but also on social acceptance. Social aspects should thus not be overlooked; experience from many renewable energy projects have shown that this could be what makes or breaks the concept.

References

[1] United Nations, Department of Economic and Social Affairs, Population Division (2017); World Population Prospects: The 2017 Revision, Key Findings and Advance.

[2] U.S. Energy Information Administration (2017); International Energy Outlook 2017.

[3] Turney, D., Fthenakis, V. (2011). Environmental impacts from the installation and operation of large-scale solar power plants; Renewable and Sustainable Energy Reviews 15, 3261–3270.

[4] Schmalensee, R., Bulovic, V. (2015). The Future of Solar Energy**.**

[5] Luque, A., Hegedus, S. (2011). Handbook of Photovoltaic Science and Engineering**, 2nd Edition, 1-165.**

[6] Duffie, J. A., Beckman, W. A., (2013). Solar Engineering of Thermal Processes**, 4th Edition, 3-199.**

[7] Pandey, A. K., Tyagi, V. V. (2016). Recent advances in solar photovoltaic systems for emerging trends and advanced applications. Renewable and Sustainable Energy Reviews, 53, 859–884,

[8] Fraunhofer ISE (2015): Current and Future Cost of Photovoltaics. Long-term Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems. **Study on behalf of Agora Energiewende.**

[9] IRENA (2016), The Power to Change: Solar and Wind Cost Reduction Potential to 2025**.**

[10] Fraunhofer ISE (2017): Photovoltaics Report, updated: 12 July 2017.

[11] Solar Power Europe (2016). Global Market Outlook for Solar Power/ 2016-2020**, 13-23.**

[12] Breyner, C., Vartiainen, E., Masson, G. (2015). PV LCOE in Europe 2014-30, Final Report**.**

[13] IEA PVPS (2017). Snapshot of global photovoltaic market – 2016**.**

[14] Rubin, E. S., Azevedo, I.M.L., Jaramillo, P., Yeh, S. (2015). A review of learning rates for electricity supply technologies. Energy Policies, 86, 198-218.

[15] Jäger-Waldau, A. (2017). Snapshot of Photovoltaics – March 2017. Sustainability, 9, 783.

[16] EIA (2017), Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017.

[17] Bengoechea, J.M., Pérez Cobos, J., Pérez Parra, J., López Segura, J.G. (1991). Evaluación de las pérdidas de agua de riego en el Campo de Dalías. Symposium sobre el agua en Andalucía. Cordoba, Spain.

[18] Martinez-Granados, D., Maestre-Valero, J.F., Calatrava J., Martínez-Álvarez, V. (2011). The economic impact of water evaporation losses from water reservoirs in the Segura basin, Spain. Water Resour Manag, 25, 3153-75.

[19] Craig, I., Green, A., Scobie, M., Schmidt, E. (2005). Controlling evaporation loss from water storages. NCEA Publication No. 1000580/1. Queensland, Australia.

[20] **Gökbulak, F., Özhan, S. (2006). Water loss through evaporation from water surfaces of lakes and reservoirs in Turkey. European Water Association.**

[21] **Trapani, K., Redon Santafé, M. (2013). A review of floating photovoltaic installations: 2007- 2013.**

[22] **Young-Geun Lee, Soon Jong Yoon (2014). Design and installation of floating type photovoltaic energy generation system using FRP members. Solar Energy, 108, 13–27.**

[23] **Othman, M.Y., Sopian, K., (2013). Study on Electrical Power Output of Photovoltaic and Conventional Photovoltaic. AIP Conference Proceedings, 1571, 95.**

[24] **Majid, Z.A.A., Ruslan, M., Sopian, K., Othman, M.Y., Azmi, M.S.M., (2014). Study on Performance of 80 Watt Floating Photovoltaic Panel. Journal of Mechanical Engineering and Sciences (JMES), 7, 1150-1156.**

[25] **Trapani, K., Millar, D.L. (2016). Floating photovoltaic arrays to power the mining industry: a case study for the McFaulds Lake (Ring of Fire). Environmental Progress & Sustainable Energy, 35, 898-905.**

[26] **Rosa-Clot, M., Rosa-Clot, P. (2008). Submerged Photovoltaic Solar Panel: SP2.**

[27] **Trapani, K., Millar, D.L. (2014). The thin film flexible floating PV (T3F-PV) array: The concept and development of the prototype. Renewable Energy, 71, 43-50.**

[28] **Young-Kwan Choi (2014). A study on power generation analysis of floating PV system considering environmental impact. International Journal of Software Engineering and Its Applications, 8, 75-84.**

[29] **Texeira, L.E., Caux, J., Beluco, A., Bertoldo, I., Louzada, J.A.S., Eifler, R.C. (2015). Feasibility study of a Hydro-PV hybrid system operating at a dam for water supply in Southern Brazil. Journal of Power and Energy Engineering, 3, 70-83.**

[30] **Connor, P. (2011). Liquid Solar Array Synergy with Hydropower.**

[31] **European Commission – DG Joint Research Centre (2006).** Photovoltaic Solar Electricity Potential in European Countries**.**

[32] **Walker, A. (2017). PV O&M cost model and cost reduction.**

[33] **RETScreen software, http://www.nrcan.gc.ca/energy/software-tools/7465.**

[34] **EDP (2014),** Declaração Ambiental 2014, Aproveitamentos Hidroelétricos da Direção de Produção Hidráulica.

[35] **Randolph, J., Masters, G.M. (2008),** Energy for Sustainability. **Island Press, Washington.**

[36] **IRENA (2016).** Letting in the Light: How solar PV will revolutionize the electricity system**. Abu Dhabi.**

[37] **Ferrer-Gisbert, C., Ferrán-Gozálvez, J.J., Redón-Santafé, M. et al. (2013). A new photovoltaic floating cover system for water reservoirs. Renewable Energy, 60, 63-70.**

[38] Ciel et Terre (2016), Available at: http://www.floatingsolarpanels.co.uk/hydrelio-floating-solar-system/. Accessed July 2016.
[39] Otto (2016), Available at: http://www.gmiotto.it/impianto_fotovoltaico_galleggiante.php?lang=en. Accessed July 2016.