Does the Electricity Sector in 2050 Belong to Solar Power?

A Case Study on Portugal

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ABSTRACT

Southern European countries, such as Portugal, can successfully use solar power to meet their climate targets given their favorable exposure to insolation. Considering the year 2050 and Portugal as basis of its assumptions, this thesis uses a green-field investment model to outline which uncertainties are associated with solar becoming the major source of energy in the electricity sector. An extensive sensitivity analysis, by performing a Monte Carlo analysis, evaluates different technologies' development - investment and fuel costs. Additionally, different scenarios, including expensive battery storage, carbon capture and storage (CCS) technologies, and an addition of hydrogen (H_2) demand, are studied. The results show that solar power, despite of being primarily influenced by the solar power investment cost, is also impacted by the investment cost of battery storage. When battery storage investment costs is, on average, lower than 91 €/KWh, solar power becomes the major electricity generation source of the electricity sector when the solar power investment cost is lower than 650 k€/MW. Still, at times when the demand cannot be met by only solar power and the excess energy stored in batteries, wind power, CCS technologies, and biogas power plants become important. Nuclear power becomes extremely important at times when solar power is frequently complemented. The system Levelized Cost of Electricity (LCOE), from decreasing the solar power investment cost from 800 k€/MW to 200 k€/MW is reduced by 24%, reaching a lowest of 48 €/MWh. CCS technologies promote an increase in system LCOE by 4 €/MWh, while adding a demand for H_2 lowers system LCOE by 2 €/MWh.

Keywords: Carbon Capture and Storage (CCS), Expensive Battery Storage, Hydrogen (H_2) Demand, Monte Carlo Analysis, System Levelized Cost of Electricity (LCOE).

1. INTRODUCTION

Ever since the mid-20th century, an acceleration in global warming has been observed, caused by the increase in global atmospheric carbon dioxide (CO_2). This acceleration has made renewable energy production, such as solar and wind power, gain significant importance due to the characteristics they share as carbon-neutral power sources [1]. Solar and wind power are also referred to as intermittent electricity sources because the power output cannot be controlled, due to their dependence on weather and geographical conditions [2]. Nevertheless, it is necessary to maintain the load balance, that the generation output (supply) equals the load (demand), at all times. Due to this, an increased share of variable energy renewable sources (VRESs) in the electricity sector can be a challenge during the times when renewable production is low [3].

Since the output of the VRESs fluctuates at the same time that the load balance needs to be fulfilled, both solar and wind power should be used in connection with a more dispatchable source of energy to ensure that the power supply equates the demand. Consequently, the strategies and technologies that manage the mismatch in supply and demand are important for an electricity system composed of high shares of VRESs.

Southern European countries, such as Portugal, can use solar power to meet their climate target given their favorable exposure to insolation [4]. However, as a renewable source, solar power has an inherent challenge to meet the demand for electricity during hours of low production. For this reason, variation management strategies (VMSs)[1], such as other electricity generation sources, flex-

[1] VMSs are solutions that can control VRESs' intermittent production, without compromising the cost efficiency of the whole system.

ible demand, and storage, become important to ensure a resilient electricity system with electricity generation meeting the demand.

2. BACKGROUND

Climate neutrality implies a net-zero global carbon footprint and given the current society's oil-dependency, shifting towards low carbon energy sources, like VRESs, is essential. Transitioning to a carbon-neutral society becomes increasingly financial and technologically possible, as the cost and technology of solar and wind power advances and can compete with traditional technologies [5].

2.1. Portuguese Goals

In 2016, in accordance with the Paris Agreement, the Portuguese government targeted carbon neutrality by the end of 2050, enforced by the decarbonization of the national economy. The 2050 Carbon Neutrality Roadmap (RNC) describes how all societal sectors can, and must, contribute to meet the goal. The statistical data shows that the electricity and the transport sector were responsible for 50% of the total emissions between 2007-2017. Therefore, the RNC 2050 supports the reduction of carbon intensity in the electricity produced in Portugal by relying on renewable sources of energy for electricity generation. The RNC 2050 outlines the importance of both VRESs and energy storage technologies to the expected increased demand for electricity in the future Portuguese society, which is expected to be characterized by a 100% carbon neutrality [6].

2.2. Variable Renewable Energy Sources & Battery Storage Systems

The market of renewable energy, especially the market for solar power, has grown rapidly over the last decade. Stern [7] explains the reason why solar PV system cost has fallen by nearly 80% in the last ten years. The main reason for the cost decline is the fact that the installed renewable capacity has seen a sharp increase, as a consequence of the solar PV cells being composed of silica (silicon dioxide). These conclusions adhere to the data extracted from the International Renewable Energy Agency (IRENA) [8]. Figure 1 illustrates the learning curve of both VRESs between the years 2010 to 2018, which suggests a solar power's learning rate[2] of 34%. At the same time, it also indicates that wind power has a learning rate of 20%. Moreover, Figure 1 highlights that wind power is already a maturated technology since 2010, while solar experienced the growth phase until approximately 2017. Nowadays, solar power is already assumed as a maturated electricity generation source.

[2]Learning rate measures the pace of technology development, e.g. a learning rate of x% means that a cost of a given technology drops by x% when a technology's cumulative installed capacity is doubled.

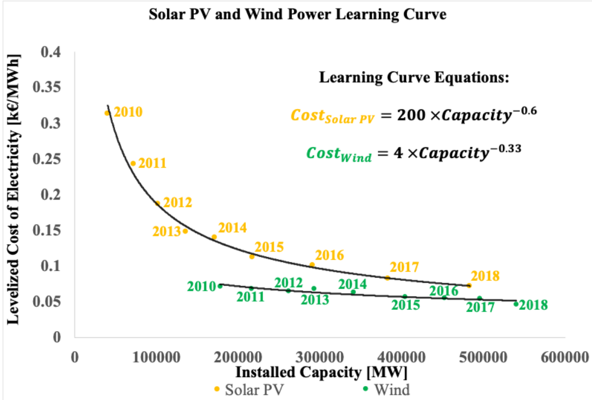

Figure 1: VRESs' learning curve over time - 2010 to 2018. Empirical data obtained from IRENA [8], converted from dollar to euro (with 2018's average conversion rate of 1.18).

As the renewable share does increase, the electricity sector requires extra flexibility. Since batteries store the excess of the energy produced and then deliver it at times of electricity deficit, these energy storage technologies can decrease the short-time demand and supply discrepancies [9]. Due to the batteries' storage nature and the drop of their cost in the last years, batteries hold immense possibilities to make solar power able to transform the power systems into 100% carbon-neutral.

2.3. Previous Studies

There are already several studies [10]–[14]. that look particularly at how the synergy between solar power and battery storage can promote the transition of the electricity sector to 100% carbon-neutral.

Frew *et al.* [10] simulate an electricity sector in 2050 composed of a high share of solar PV. The authors use a dispatch model to link capacity expansion and production cost to study the feasibility of the simulated electricity system. In the case of high share of solar power, the electricity system would efficiently replace a huge part of the hours of dispatch power generation by storage, and at extremely sunny hours curtailment would become the best solution to maintain the load balance and the system frequency. Consequently, the increase in solar capacity in the electricity system leads to a drastic decrease in the energy price and even hours with zero price (which are strongly correlated with curtailment hours).

Victoria *et al.* [11] explore the impact of energy storage technologies on achieving the CO_2 emission targets and sector-coupling scenarios. This study proposes that different types of energy storage technologies are better suitable for certain situations, i.e., electrical batteries are preferable for an electricity sector composed of a high solar share. In this very example, the reason is the need for short-term storage, while H_2 storage is better suited for smooth power fluctuations, such as electricity typically generated by wind.

Schlachtberger *et al.* [12] vary the solar power and battery storage cost separately and evaluate the impact that this has on the total system cost. This research paper suggests that with the decrease in solar power cost, the capacity installed, the energy generated, and the curtailment for wind power decreases. Also, the system cost decreases linearly with both lower solar PV systems and battery storage costs. This linearity is identified by the authors for solar power cost greater than 300 k€/MW and battery storage cost greater than 232.5 k€/MWh. For costs below the previous values, the decline in total system cost is even steeper.

Atsmon and Ek Fälth [13] explore the changes in system LCOE[3] by varying both solar PV systems and battery storage costs. The authors found that decreasing the cost for solar power by 50% and battery storage by 62%, reduces the system cost by about 27% to 34%, depending on the geographical area, which results in a lower system LCOE.

Villar *et al.* [14] emphasize, by using a techno-economic performance analysis, the importance of solar power self-consumption. The authors suggest that to encourage the self-consumption for solar power, it is important to combine solar PV production and other technologies. These technologies, such as energy storage technologies and demand-side management (DSM)[4], are considered to be a solution to the mismatch of demand profiles and PV generation. Also, this study reveals that the existence of these synergies would promote the increase of the overall efficiency, by reducing the costs associated with distributed energy grid integration.

According to the aforementioned papers, due to the wide range of parameters where no consensus is found, it is not clear at which extent varying generation mixes and cost parameters influence the cost-efficiency of solar power and thus the system LCOE. Additionally, none of the previous research studies model CCS technologies or explores the industry sector for an addition of H_2 demand, which is investigated in this master's thesis.

3. METHODOLOGY & INPUT DATA

3.1. Model

The regional model, eNODE, which applies the General Algebraic Modeling System (GAMS)[5] was firstly presented by Göransson *et al.* [15]. This bottom-up regional model defines the electricity sector as a single region. Thus, eNODE does not consider the possibility of inter-regional transmission of electricity. The model only uses real-world data for each of the different geographic locations. Hence different correlations for each location are used in the modeling such as energy and heat demand but also different real-world context restrictions, such as VRESs production curves and area limitations for investmenting in VRESs. As a green-field investment model, eNODE is applicable for electricity systems where high shares of renewables are under consideration. This means that it does not consider any pre-established capacity but instead invests in a new optimal mix of technologies [15]. The model accounts for a wide set of technologies and thus a more precise and realistic electricity system is modeled. Each technology is characterized by proprieties such as investment, running[6], and cycling[7] costs.

Additionally, eNODE, which uses linear programming (LP) to minimize the total system cost, meets the electricity demand while respecting different constraints in terms of CO_2 emissions and weather resources. The LP-model was run with a three-hour resolution for a full year, which represents Portugal in the year 2050 in terms of electricity demand, technologies costs and assumptions on CO_2 emissions.

3.1.1 Model Formulation

The model accounts for a range of sets (upper-case), parameter (italic upper-case), and variables (italic lower-case).

The objective function of the model is to minimize the total system cost (c_{tot} [€/year]) for one year (T). The total system cost includes investment cost (C_{inv} [€/kW]) with respective investment (i [kW]) and annuity factor (A), as a function of lifetime and discount rate, fixed operation and maintenance cost (OM_f [€/kW]), running (C_{run} [€/MWh]), and cycling cost (C_{cycl} [€]) of each electricity generation technology (P)[8] which composes the electricity system. The total system cost is implemented as:

$$c_{\text{tot}} = \sum_{p \in P} i(p)(C_{inv}(p)A(p) + OM_f) + \sum_{p \in P}\sum_{t \in T}(C_{run}(p,t) + C_{cycl}(p,t)) \quad (1)$$

[3] Average electricity cost

[4] Shift of consumer demand for electricity, by encouraging the consumer to use less electricity during peak hours, or to move the time of electricity use to off-peak times.

[5] GAMS is a high-level modeling software suitable for mathematical optimization.

[6] Running costs include fuel costs and operation and maintenance costs.

[7] Cycling costs are both start-up and part-load costs.

[8] Combination of dispatch energy sources and VRESs. VRESs are composed of 12 different types of wind onshore power, wind offshore, and solar PV.

The running costs for fueled technologies are defined by the fuel cost (C_{fuel} [€/MWh]), efficiency (η), and variable operation and maintenance cost (OM_v [€/MWh]). For the cases which allow the CCS technologies, the CCS technologies cost (C_{CCS} [€/MWh]) is also part of the running cost as:

$$\sum_{p \in P} \sum_{t \in T} C_{run}(p,t) = \frac{C_{\text{fuel}}}{\eta} + \frac{C_{\text{CCS}}}{\eta} + OM_v \qquad (2)$$

As previous stated, the model implemented accounts for several constraints, such as constraints in terms of electricity generation, emissions, and storage. Firstly, the model requires that the demand be met at all times, and thus the load balance is guaranteed. The total electricity generated (g [MWh/h]) needs to be greater than, or equal to, the electricity demand (D^{el} [MWh/h]). The load balance is defined as:

$$\sum_{p \in P} g(p,t) \geq D^{el}(t), t \in T \qquad (3)$$

When electrification of the industrial sector is considered, the industrial demand is solely supplied by energy generated from electrolysers by electrolysis processes. Consequently, the H_2 storage is modeled as a function of energy stored (sto_{H_2} [MWh/h]), energy generated from electrolysers (x_{elec} [MWh/h]) and respective efficiency (η), and industrial demand (D^{H_2} [MWh/h]):

$$sto_{H_2}(t+1) = sto_{H_2}(t) + x_{elec}\eta(t) + D^{H_2}(t), t \in T \qquad (4)$$

The model used in this thesis also set a cap on carbon emission (E_{cap} [$GtCO_2$]) as zero to obtain a system with high share of renewable energy. This means that the carbon emission (E [$GtCO_2$]) from the electricity generation must be zero:

$$\sum_{p \in P} \sum_{t \in T} E(p,t)g(p,t) \leq E_{cap} \wedge E_{cap} = 0 \qquad (5)$$

eNODE also accounts for the intermittency of VRESs and for thermal cycling. As the regional model accounts for a high temporal resolution, it can easily capture the variability originated from a high VRESs share. Thus, the model implements energy storage technologies in order to solve the need for flexibility that an electricity system composed of a high share of VRESs requires. Mathematical descriptions concerning these constraints including investment of VRESs, thermal cycling, and energy balances for energy storage are thoroughly described in [16].

3.2. Monte Carlo Analysis

It is important to note that this master's thesis does not attempt to forecast the future, but rather aims to understand which uncertainties promote, or prevent, the optimal share of solar power. As a result, this thesis evaluated the cost-effectiveness of different technologies and thus an extensive sensitivity approach was adopted for the whole range of parameters. Consequently, as all the parameters ran with a Monte Carlo analysis with a uniform distribution, different scenarios regarding an electricity sector composed of a high share of solar were obtained. The diversity of possible scenario was extremely important when it came to understand the factors that influence the increase in solar power share in the electricity sector. Thus, this master's study identified different trends, which can shape the composition of a future electricity sector.

3.2.1 Sensitivity Analysis

An extensive sensitivity analysis of all the parameters studied was conducted in this paper. Sensitivity analysis is described by Saltelli *et al.* [17] as "the study of how uncertainty in the output of a model (model or otherwise) can be apportioned to different sources of uncertainty in the model input". Thus, conducting a sensitivity analysis suited the purpose of this study considering that it allowed the evaluation of how different uncertainties - investment and fuel costs - affect the solar power share while minimizing the total system cost.

3.3. Input Data

This thesis added financial data to the pre-existing data in the model. The financial added data was included in two different forms, investment, and fuel cost. The data was rearranged in gaps of values varying between lower and upper limits, originally from different sources. The main input data used in this this can be seen in Tables 1 and 2.

Table 1: Main input data of this master's thesis - Technology investment cost added to the model.

Technology	Investment Cost		Reference
	Lower Limit	Upper Limit	
Solar PV [k€/MW]	200	800	[18]-[13], [19]
Wind Onshore [k€/MW]	800	1500	[18]
Wind Offshore [k€/MW]	1420	2140	[18]
Battery Storage [k€/MWh]	46	225	[18]
Battery Capacity [k€/MW]	40	250	[18]
H_2 Storage [k€/MWh]	1	11	[18]-[16]
Fuel Cell [k€/MW]	500	1100	[18]
Electrolyser [k€/MW]	350	700	[18]
Nuclear Power [k€/MW]	4000	6000	[20]-[21]

Table 2: Main input data of this master's thesis - Updated fuel cost. Data originally from different sources.

Fueled Technology	Fuel Cost [€/MWh]		Reference
	Lower Limit	Upper Limit	
Hard Coal	4.8	14.7	[22], [23]
Natural Gas	17.1	51.4	[22], [23]
Biomass	30	100	[22] -[24]
Biogas	63	163	[25]
Nuclear	6		[26]

This master's thesis re-utilized most data, which was already implemented in the model. The pre-existing data used in the analysis, in terms of annual electricity demand and demand profile for each technology, is taken from the projections made by ENTSO-E and their assumptions. The Portuguese electricity demand for 2050 is assumed to be 55.68 TWh, as proposed by ENTSO-E [27]. Additionally, most of the pre-existing economic data are retrieved from the World Energy Outlook by International Energy Agency IEA in 2014. The pre-existing data also considered weather profiles [28]–[33].

3.4. Model Scenarios

This paper evaluates the possibility for the existence of both expensive batteries storage investment cost and the CCS technologies, as well as, an industry demand characterized by an increase in H_2 demand from electrolysis. Consequently, this thesis brings together four different scenarios, which are described in detail in Table 3.

Table 3: The four different case scenarios implemented in this thesis.

Scenario	Battery Storage Investment Cost [k€/MWh]	CCS	H_2 Demand	Runs
Base Case	46-135	x		533
Expensive Battery	135-225			467
No CCS Technology	46-135			500
Industrial Demand		x	x	

For all the scenarios, the financial data remained constant and the total emission of CO_2 was set to zero. All the scenarios have the possibility to utilize nuclear power and VMSs, such as battery storage and H_2 storage.

3.4.1 Base Case

The base case scenario only includes batteries with investment cost ranging from 46 k€/MWh to 135 k€/MWh. This scenario also includes thermal power plants with the possibility of CCS technologies. There are two possibilities for dispatch power plants associated with CCS, which are associated with both coal and natural gas: bio-coal CCS[9] and bio-natural gas CCS[10].

3.4.2 Expensive Battery

This scenario was initially included in the base scenario, which ran 1000 times. Nevertheless, it was found that battery storage investment cost had a strong impact on the solar power share. Owing to this, this master's study, split the base scenario in two scenarios, varying according to the battery storage investment cost. One ranging from the lowest value (46 k€/MWh) suggested from DEA to the medium value (135 k€/MWh) - base scenario 3.4.1 - and other one covering values higher than the medium value and the highest value (225 k€/MWh) also suggested by DEA - expensive battery scenario.

3.4.3 No CCS Technology

This scenario excludes the possibility of CCS technologies. Thus, this scenario investigates how the role of not allowing CCS technologies can impact the carbon neutrality of the electricity sector, in comparison with the system composition of the base scenario. Additionally, as in the base scenario, in this scenario battery storage investment cost is set in an interval varying between 46 k€/MWh and 135 k€/MWh.

3.4.4 Industrial Demand

Lastly, this scenario considers an addition of the H_2 demand of 15% of the total demand. The addition of H_2 demand is solely ensured by the energy generated from electrolyzer technologies. Furthermore, this scenario emphasizes how including an increase of H_2 production in the industrial sector will impact the electricity sector, by comparing it with the base scenario. In terms of battery storage investment cost, the same approach as adopted in the base and no CCS scenarios is used in this scenario, with battery storage investment cost higher than 46 k€/MWh but lower than 135 k€/MWh.

4. RESULTS & DISCUSSION

4.1. Solar Power Generation

The results presented in Figure 2 depicts the differences in regards of solar share between the base and expensive battery scenarios. In the base scenario, the average battery storage investment cost was 91 k€/MWh, while the cost, in the expensive battery scenario, was approximately 182 k€/MWh.

By looking at the base scenario (yellow boxes), it is possible to conclude that when solar power investment cost decreases from 800 k€/MW to 200 k€/MW, the solar power share increases by a minimum of 14% to a maximum of 88%. Regarding the different solar power investment costs, it is also possible to see that larger uncertainties - higher length of the probability boxes - are associated with cost varying between 400 k€/MW and 700 k€/MW. Thus, at low (200 k€/MW to 400 k€/MW) and high (700 k€/MW to 800 k€/MW) solar power investment costs, it is easier to predict what is happening in the system. When the solar power investment cost is higher than 700 k€/MW, the cost-optimal solar power share can not surpass 50% of the total electricity generation. On the other hand, when solar power investment cost goes bellow 400 k€/MW, the solar power share covers at least 50% of the whole electricity generation. When solar power investment cost is varying between 400 k€/MW and

[9] Bio-coal CCS is a combination of hard coal and biomass associated with CCS technologies. It is composed of 90% coal and 10% of biomass

[10] Bio-natural gas CCS is a combination of natural gas and biogas with CCS technologies. It is composed of 88% natural gas and 12% biogas.

700 k€/MW, there is huge uncertainty about what is happening regarding other technologies in the electricity sector.

In the expensive battery scenario (orange boxes), the solar power share is expected to increase from a minimum of 11% to a maximum of 77%, when the solar power investment cost is lowered from 800 k€/MW to 200 k€/MW. If comparing this scenario to what is happening in the base scenario, it is possible to conclude that for solar power investment costs higher than 400 k€/MW, the electricity system does not have the capacity of reaching solar power shares higher than 50%.

Finally, Figure 2 conveys that solar power investment cost was found as being the major uncertainty of solar becoming the major electricity supplier in the electricity system. Nevertheless, battery storage investment cost is also identified as having a prominent role in determining the solar power share. More precisely, this master's thesis found that doubling the battery storage investment cost from 91 k€/MWh to 182 k€/MWh promotes a reduction in solar power share by an average of 18%. Consequently, high solar power share also benefits from lower investment cost of battery storage systems, which emphasizes a synergy between these two technologies. In essence, lower solar PV investment costs promote an increase in solar power generation. Higher solar power shares require short-term flexibility solutions to guarantee a functional electricity system, such as battery storage systems. Battery storage technology is primarily stimulated by electrical vehicles (EVs). Nevertheless, and if the solar power market continues to grow, which is strongly correlated to low solar power investment costs, the battery storage technology development is also likely to be promoted by higher solar shares.

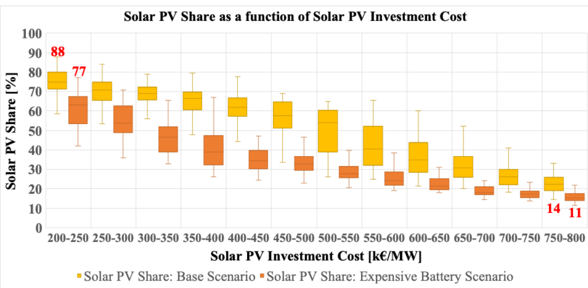

Figure 2: Probability of solar PV share according to different solar power investment costs for both base case and expensive battery scenarios. The boxes represent the 25% and 75% percentiles, while the middle line defines the median. The whiskers represent both the minimum and maximum shares.

4.2. Generation Mix

The results here presented assume battery storage investments costs varying between 46 k€/MWh to 135 k€/MWh, considering that it is of importance to evaluate how battery storage devices becoming cheaper impacts the cost-optimal share of solar power.

From the electricity generation perspective, solar power share differs between an electricity sector that allows CCS technologies and one which prohibits them. As it is possible to see in Figure 3, when solar power investment costs are higher than 400 k€/MW, the solar PV share is lower in the no CCS scenario (middle columns) than in the base scenario (left columns). At these investment costs of solar power, the balance between nuclear power and VRESs is changed in favour of nuclear and thus it is more cost-efficient to invest in dispatchable electricity generation sources, such as nuclear and biogas power plants, than in VRESs. The main reason is the lack of options for the system to invest in. With no option for CCS technologies, for solar power investment costs higher than 400 k€/MW, the system finds it more cost-optimal to increase the share of electricity generated from firm sources, which require less complement. However, when solar power investment costs are lower than 400 k€/MW, the solar power share in the no CCS scenario is, in fact, higher than in the base scenario. At these reduced solar power investment costs, together with the few options of electricity generation sources - solar, wind, nuclear, and biogas power -, it is more cost-efficient to invest in higher capacities of solar power rather than in other sources.

Generally, in the no CCS scenario, as previously mentioned, dispatchable power plants have major importance in the generation mix of the electricity system. Nuclear power plants co-exist in the system at solar power investment costs ranging from 250 k€/MW to 800 k€/MW. For solar power investment costs higher than 550 k€/MW, nuclear power plants account for at least 50% of the total electricity generation share and therefore becoming the major source of the whole system. Biogas, which is typically a peak-load power plant[11], increases its total share to 5% and hence acts, to some degree, more like an intermediate-load power plant[12]. Owing to the evident importance of dispatchable technologies, wind power in the no CCS scenario, remain quite constant at all the solar power investment cost. For solar power investment costs higher than 700 k€/MW wind power is outcompeted by nuclear power. Additionally, when solar power investment costs are lower (<500 k€/MW), wind power is outcompeted by solar power.

The industrial demand scenario (right columns) accounts for similar shares of solar power as the

[11] Peak-load power plants operate when the demand reaches exceptional peaks

[12] Intermediate-load power plants address the variation of load throughout the day.

base scenario. The main reason being is both scenarios having similar constraints. The only difference is that the industrial demand scenario accounts for the addition of the H_2 carrier demand, which does not result in major changes in the generation mix. Contrary to what happens in both base and no CCS scenarios, wind power has more importance in the system for higher solar power investment costs. More precisely, the added H_2 demand for electricity to power the electrolyzers can be successfully supplied by electricity from wind power, as a consequence of the suiting cost structure of a H_2 system with low cost of storage. When the solar power investment is higher than 700 k€/MW, wind power becomes the major electricity generation source of the whole system. This is the result of H_2 being relatively cheap in comparison to other technologies. H_2 storage at these low costs is able to provide important services in the system, which brings flexibility. Thus, as H_2 storage manages well the slower variations of wind power (relatively to solar power), cheap H_2 storage promotes the increase of wind power share in the system.

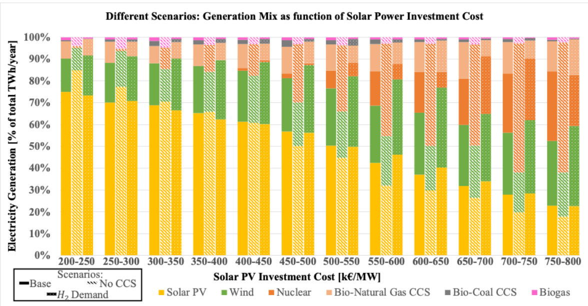

Figure 3: Generation mix of three scenarios: base, no CCS, and industrial demand scenario; which represent the average of the runs within the same solar power investment cost span.

4.3. System LCOE

Figure 4 shows that the no CCS scenarios account for the highest values of the system LCOE. The main reason being is that in the no CCS scenario the system is limited in the types of plants that can be invested in and thus less options results in higher system LCOE. As a result of less alternative for complement, nuclear and dispatchable power plants, like biogas, become the cheapest option. Nevertheless, even the cheaper option, nuclear power plants, as a baseload power plant[13], are expensive to install and to start to run, while biogas power plants in this scenario are responsible for a higher share of electricity generated, which make these plants more costly when they operate at longer duration in the year than what characterizes typical peak-load power plants. Thus, even thought not as a principal cause for the increase of the system LCOE, the extensive use of these plants also increases the system LCOE.

In regards to the industrial demand scenario, the system LCOE is lower than in the other scenarios. In this scenario, the lower system LCOE results from the added H_2 demand, which is more flexible than the base case scenario demand from an economic view, considering that H_2 can be stored for longer periods than electricity.

The difference between the system LCOE in the three scenarios is constant for all solar power investment costs. This means that CCS technologies and industrial demand is important for the system LCOE, regardless the investment cost of solar power. Higher capacity undoubtedly results in lower system LCOE. Furthermore, it is possible to see that the value of CCS technologies is approximately 4 €/MWh, at any solar power investment cost. On the other hand, the value of an addition of H_2 demand is around 2 €/MWh, which could be higher if electrolyzers, which are needed to convert electricity in H_2, would become cheaper.

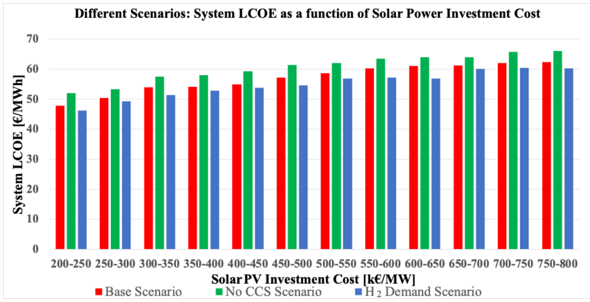

Figure 4: System LCOE of three scenarios: base, no CCS, and industrial demand scenario; which represent the average of the runs within the same solar power investment cost.

4.4. Three Electricity System Cases

For the base scenario, seasonal differences for three different cases were studied in detail. These three cases are examples of different electricity systems, which aim to show large differences between the parameters studied in this study:

- A case with the highest solar power share;
- A case with high solar and wind power share - composed of 40% solar and 40% wind power;
- A case with the highest nuclear power share.

For each case, both the first three weeks of January and August were considered when exploring the differences between winter and summer, respectively. The differences in the generation mix between winter and summer result in differences regarding the marginal electricity cost [14].

Figures 5, 6, and 7 depict that the total daily demand is clearly higher during winter than during summer, which can be explained by the fact

[13]Baseload plants fulfill the minimal load by constantly operating throughout the year.

[14]Cost of producing 1GWh extra of electricity.

that in the summer there is not the same need for heat technologies and light to compensate for the dark and cold days prevalent during winter. Also, the daily demand is higher during the day than the night, with peaks both on weekdays and also between the work hours. Winter seasons are characterized by higher peaks in solar power generation, considering that this type of solar panels (PV) decrease their efficiency when exposed to high temperatures (summer).

Figures 5 and 6 illustrate that for electricity composed of a high share of VRESs, regardless of the season, a big part of the electricity generation is powered by solar power. The functionality of the system is also strongly dependent on battery storage systems, as they store the surplus of electricity generated to later use. In the highest solar power share, during winter - Figure 5 (graph a) - , the system also includes complements such as wind power and biogas power, which well fit situations when the need for the complement is only occasional. In the high solar and wind power share case - Figure 6 -, the wind goes from being only a complement to being the major electricity source of the system. Additionally, due to the existence of long periods of high wind, the excess can be stored in fuel cells for later use. To compensate the times when both solar and wind are operating at low power, the complement, despite of including biogas power plants, also includes CCS technologies.

In the summer, CCS technologies and biogas are partly replaced by higher generation of solar power. More precisely, in an electricity system composed of 88% of solar power share, in the summer - Figure 5 (graph b) - the synergy composed of solar power and batteries solely guarantees the functionality of the electricity sector. The same synergy also plays an important role during the summer in an electricity system composed of high solar and wind power share - Figure 6 (graph b). However, this synergy only replaces the peak power generated, during the winter, by biogas power plants. This is explained by the fact, that there is an inherent complementary provided by CCS technologies, that compensate periods when both solar and wind power are not being generated at required levels to meet the demand.

When the electricity system composed of a high share of nuclear is considered - Figure 7 -, 69% of the total electricity generation originates from nuclear power. Consequently, the generation mix of this case differs from the previous two, which is explained by the fact that nuclear power as a base load power plants, is better complemented by other thermal power plans than VRESs. In both seasons the scarce power generated from VRESs is instantaneously used, considering that the high importance of thermal power plants in this type of electricity system limits the role of VRESs due to their inherent intermittency.

The marginal electricity cost is lower during the summer than during the winter. Owing to this, higher marginal electricity cost is associated with cold months - winter -, considering the inherent need of the system being complemented by dispatchable technologies - fossil-fueled power plants with CCS and biogas power plants -, which have a considerable high start and running costs. However, as there is a constant need for bio-natural gas CCS to complement an electricity system composed of 40% of solar power share and 40% of wind power share - Figure 6 -, the seasonal differences regarding the marginal electricity cost are not accentuated as depicted in Figure 5.

During the summer, as possible to see in Figures 5 and 6, due to peaks in solar power generation, the systems extensively use battery facilities which reduces the marginal electricity cost. Still, at times of excess of solar power generation, the system is very likely to curtail some solar power and the marginal electricity cost gets absolutely low, close to zero.

In an electricity system composed of high share of nuclear power - Figure 7 -, despite the marginal electricity cost being also lower during the summer than during the winter, the summer does not experience such low marginal electricity costs as electricity systems composed of high share of VRESs. This is a consequence of the system being composed of 69% of nuclear power, which as a baseload power cannot easily change its output, considering different economical, technical, and security constraints. Additionally, nuclear power puts aside the need for high levels of electricity generated from VRESs. During times of extra need of power generated, the system prefers to invest in bio-coal CCS instead of in more VRESs' capacity, which undoubtedly is associate with higher marginal electricity cost than the marginal electricity cost associated with VRESs.

5. CONCLUSION

This master's thesis has outlined which uncertainties are associated with solar becoming the major electricity generation source in the electricity system in 2050 in a country with favorable conditions for solar power generation, such as Portugal. This study found that:

- Solar power becomes the major electricity generation source of the electricity sector when **1)** the battery storage investments cost is, on average, lower than 91 k€/MWh; **2)** the solar power investment cost is lower than 650

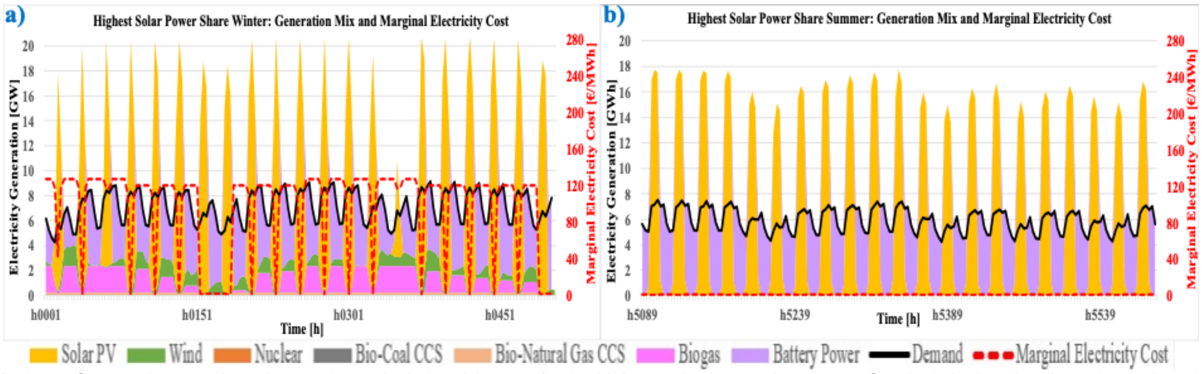

Figure 5: Seasonal generation mixes and marginal electricity cost for the highest solar power share case. Graph a) depicts the dispatch graph and marginal electricity cost of the first three weeks of January; Graph b) illustrated the dispatch and marginal electricity cost of the three first weeks of August.

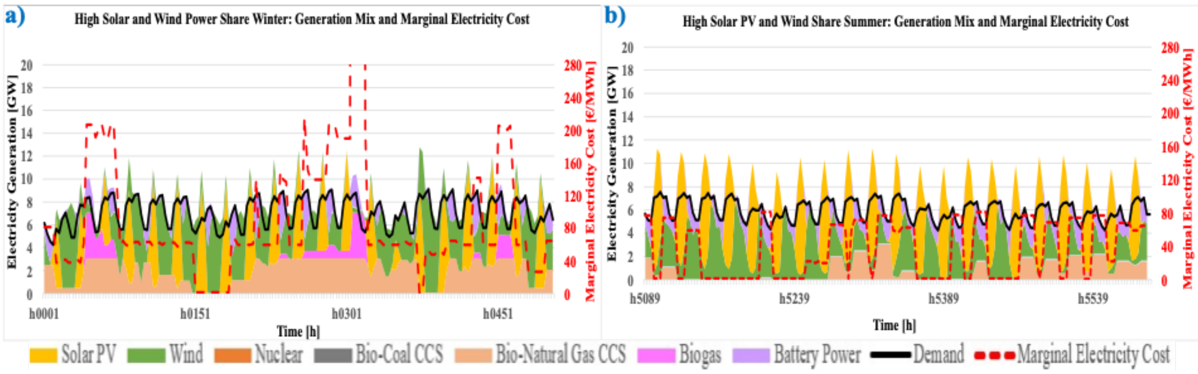

Figure 6: Seasonal generation mixes and marginal electricity cost for the high solar and wind power share case. Graph a) depicts the dispatch graph and marginal electricity cost of the first three weeks of January; Graph b) illustrated the dispatch and marginal electricity cost of the three first weeks of August.

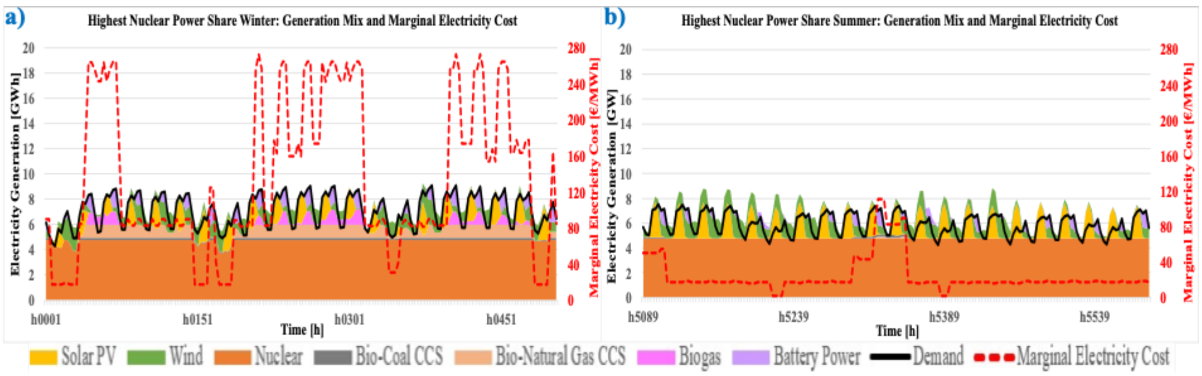

Figure 7: Seasonal generation mixes and marginal electricity cost for the highest nuclear power share case. Graph a) depicts the dispatch graph and marginal electricity cost of the first three weeks of January; Graph b) illustrated the dispatch and marginal electricity cost of the three first weeks of August.

k€/MW.

- Solar power investment cost was found to be the major uncertainty for increased dependence on solar power in the electricity sector. Still, low battery storage investment costs stimulate an increase in solar power generation.

- The system LCOE is lowered as a result of the increase in solar power share. When solar power investment cost is reduced from 800 k€/MW to 200 k€/MW, the system LCOE is reduced by 2% per every 50 k€/MW, to a minimum of 48 €/MWh.

- The increasing dependence on solar power in the electricity sector is promoted by, and also promotes, the use of battery storage to ensure the load balance. At times when the demand cannot be ensured by only solar PV and the excess of energy stored in the batteries, CCS technologies and biogas power plants become important, due to their intermediate and peak-load power plant nature. Nuclear power plants become important at solar power investment cost higher than 400 k€/MW, due to the intrinsic need for more constant output generation provided by these baseload power plants.

- For solar power investment costs higher than 700 k€/MW, wind power starts to account for a higher share in the electricity sector than solar. At solar power investment costs ranging between 700 k€/MW and 500 k€/MW, wind power is complementing solar power generation. Wind power is partially outcompeted by solar PV, at solar power investment costs varying between 500 k€/MW and 200 k€/MW, and thus at high solar PV share.

Doubling the battery storage investment cost from 91 k€/MWh to 182 k€/MWh decreases the solar power share by 18% on average. Forbidding CCS technologies stimulates the solar power generation, as long as the solar power investment costs are lower than 400 k€/MW. Nevertheless, the system LCOE is higher in the absence of these technologies, increased by a total of 4 €/MWh. An exogenous demand for H_2 encourages an increase in wind power generation by providing greater flexibility to the electricity system. Due to the relatively low cost of H_2 storage, an addition of H_2 demand was found to lower the system LCOE by 2 €/MWh, to a minimum of 46 €/MWh.

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