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Optimization of All-Renewable Generation Mix According to Different Demand Response Scenarios to Cover All the Electricity Demand Forecast by 2040: The Case of the Grand Canary Island

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Abstract: The decarbonization of the electric generation system is fundamental to reaching the desired scenario of zero greenhouse gas emissions. For this purpose, this study describes the combined utilization of renewable sources (PV and wind), which are mature and cost-effective renewable technologies. Storage technologies are also considered (pumping storage and mega-batteries) to manage the variability in the generation inherent to renewable sources. This work also analyzes the combined use of renewable energies with storage systems for a total electrification scenario of Grand Canary Island (Spain). After analyzing the natural site's resource constraints and focusing on having a techno-economically feasible, zero-emission, and low-waste renewable generation mix, six scenarios for 2040 are considered combining demand response and business as usual. The most optimal solution is the scenario with the maximum demand response, consisting of 3700 MW of PV, around 700 MW of off-shore wind system, 607 MW of pump storage, and 2300 MW of EV batteries capacity. The initial investment would be EUR 8065 million, and the LCOE close to EUR 0.11/kWh, making the total NPC EUR 13,655 million. The payback is 12.4 years, and the internal rate of return is 6.39%.

Keywords: renewable energy; storage technologies; pumping storage; mega-batteries; stand-alone electricity generation; electrification final energy consumption; statistical analysis of high variable energy sources; demand management; self-consumption; vehicle-to-grid

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1. Introduction

The increasing concern over the Earth's global warming and greenhouse gases could lead to important technological changes. The world energy demand has been growing in the last few centuries. Most of this energy comes from fossil fuels [1,2]. Regarding electricity generation, approximately 2/3 is generated through fossil fuels [3], and this percentage is even worse in the case of isolated regions, particularly for most islands [4]. This situation poses a double problem: on the one hand, a foreseeable depletion of fossil fuels in the medium term if the current rate of consumption is maintained, which would compromise the continuity of electricity supply in the coming decades [5,6], and a second problem, even more serious and in the nearer term, is the unacceptable growth of emissions of different polluting gases due to the use of these fossil fuels [7,8].

Focusing on electricity generation, the inclusion of renewable energies is mandatory, aggravated by the fact that electricity has a growing share in the final energy consumption of all countries [9,10], and even more so in the scenarios simulated in this paper, where a total electrification of the different energy uses is envisaged. In the case of Grand Canary Island, more than 90% of electricity comes from fossil fuels, and it is not connected to a large grid [11]. This isolated operation favors fossil fuels such as diesel, coal, and gas because of their high reliability. However, what could be an advantage a priori poses the aforementioned problem of high emissions and a high external dependence on fossil fuels. Additionally, since there is a strong dependence on a vast supply chain of fossil fuels, which could break under certain circumstances, the system's reliability could be reduced [4]. This situation can be aggravated in many cases, since most of the countries producing these fuels are very unstable, with the consequent risk of shortages.

Therefore, electricity generation using cleaner technologies could contribute to achieving sustainable energy systems [12,13], so they should be constituted as much as possible by renewable sources [14,15]. However, the use of this type of energy poses significant challenges in its management, mainly due to its wide and/or unpredictable variability, a situation that is particularly applicable in the case of wind and photovoltaics [16–18]. Thus, to make large-scale use of these energies, it is essential to store the inevitable excess of electricity produced under certain conditions due to the decoupling between demand and production and feed it into the grid in situations where it becomes necessary [9,19]. Therefore, to design a reliable system only with renewable energies, the existence of a storage system, which must have a large capacity, is essential. This system, at present, can only be of two types: storage through mega-batteries and/or pumping stations. This large-scale storage use could also pose an additional problem in islands since many surfaces would be required, which may not be available [20].

This study analyzes an optimized system of isolated zero-emission electric power generation based on renewable energy and storage technologies (reversal pumping and mega-battery systems) for the electrification of the whole final energy demand, all applied to the Grand Canary Island in Spain. The criteria used to reach the optimum generation MIX is based on economic aspects, zero emissions, and reduced energy wastages. The use of pumping as a storage system is motivated by the maturity of this technology, coupled with its suitability in Grand Canary Island [21,22], given its orography. In fact, there is currently a first project that focuses on installing a pumping storage plant to manage the growing surpluses of solar photovoltaic and wind generation installed on the island. Meanwhile, mega-batteries have been used to complement the contribution of the pumping stations to optimize the size of the system. Given the expected high electricity demand due to the total electrification of energy end uses, the renewable sources considered in the current research are solar and wind because other renewable resources such as biomass, geothermal, tidal, etc., are not so good options for Grand Canary Island. For instance, biomass resources are limited, geothermal is not economically competitive and tidal is neither economically competitive nor a sufficiently mature technology to be used on a large scale.

Thus, wind and solar photovoltaics are the only renewable energy generation technologies mature enough today to allow the substitution of conventional fossil technologies [23,24]. However, as is widely known, they currently pose two fundamental problems, mainly associated with economic and reliability issues. A large part of the solution to these problems probably involves the use of energy storage systems [25,26]. Among the possible candidates, two are currently viable: pumped storage and mega-battery storage. Thus, a system based on renewable energy supported by the storage system(s) will satisfy the energy demand more efficiently than a single renewable energy installation, given the inherent variability of wind speed and solar irradiation [27].

The decarbonization of the different energy consumptions must be a reality by 2050 in the countries of the European Union, according to the recent agreements reached between the different countries. In fact, it is planned that the non-peninsular Spanish territories will be the vanguard and their economy will be decarbonized 10 years in advance. Thus, the Canary Islands are currently working on their strategy to reduce their dependence on fossil fuels, so that they can take advantage of their abundant natural resources, such as sun and wind. The Canary Islands Technological Institute (ITC) has considered up to ten scenarios to achieve 100% clean energy generation. In all ten scenarios, large-scale storage technologies would be necessary to achieve the targets. In particular, a reversible pumped-storage hydroelectric power plant, the Chira-Soria project, is projected for the Grand Canary Island [28]. This plant would have a storage capacity of between 3.2 and 3.6 GWh, with a total power of 200 MW. Additionally, it is expected to at least double this capacity in the not-too-distant future, for which the connection of the Soria reservoir with the Las Niñas reservoir is being studied. In addition, given the suitable orography of the island, there are other appropriate sites for this technology, reaching a total storage capacity of around 10 GWh with a total power slightly above 600 MW [29]. However, in all likelihood, in order to achieve total electrification of energy consumption, this storage will not be enough, but will have to resort to the use of mega-batteries. The use of both technologies will be analyzed throughout this document.

Consequently, it becomes essential to explore the existing possibilities to cover the electricity needs only with totally renewable generation sources and with the assistance of the mentioned storage technologies. Different models are currently used to simulate microgrid and energy demand responses [30–32]. The Hybrid Optimization Model for Multiple Energy Resources (HOMER) has been used to carry out this comparative analysis of the different systems. This software was developed by the National Renewable Energy Laboratory (NREL) [33]. The criteria used by the software is economical so that the program estimates the optimal size of a system based on the investment to be made, the Levelized Cost of Energy (LCOE), and the payback time based on the energy sources to be installed [34]. In addition, HOMER has the advantage of being able to integrate storage systems [35–37]. Moreover, much scientific work uses HOMER to simulate renewable energy systems [38–42]. It is used to solve rural electrification problems where grid power is expensive or insufficient, in scenarios where the software calculates the most cost-effective and techno-economically renewable energy alternative [43]. Additionally, demand response is studied for a better integration of renewable energy resources against conventional technologies by performing an economic evaluation with HOMER's microgrid optimization [44]. Moreover, algorithms have been used to validate the performance of HOMER's results, showing both substantially equal optimal solutions regarding energy produced, excess of electricity, and cost of energy [45]. Therefore, this study uses HOMER to carry out the optimization assessment [46].

On the other hand, another possible option to transmit electricity to islands is through a submarine electricity interconnection. There is currently an electricity interconnection between two islands of the Canary archipelago, Lanzarote and Fuerteventura, with an AC submarine link of 66 kV and 14.5 km length [47]. A new interconnection of 132 kVm 15 km and 120 MVA between both islands is planned to be finished this year. Additionally, an electric interconnection between La Gomera (a small island) and Tenerife is under investigation, in which the main objective is that Tenerife supplies energy to La Gomera [48]. The power of these connections is small compared to the Grand Canary demand, and it is used to supply energy to the minor islands in the Canary archipelago. This is not the case for Grand Canary, being the second most populous of the Canary Islands, after Tenerife.

According to recent reports [9,16,27,48], the roadmap of the Spanish governments for the Canary Islands goes toward a self-sufficient island from an energetic point of view, through a renewable energy system, taking profit from the large available solar and wind resource and the potential storage system due to the natural rafts located in the Canary Islands. Since the nearest continent to Grand Canary Island is Africa at 210 km away, there is no generation system for this type of infrastructure on the closest African coast, and Gran Canarias has enough renewable resources; a submarine interconnection to Africa has not been considered in this study. The second nearest continent to Grand Canary Island is Europe (as the island is part of Spain), around 2000 km away. Currently, the longest submarine electrical interconnection in the world is the North Sea Link; it has 720 km and goes from Kvilldal, Suldal, in Norway, to Cambois near Blyth in England. A distance of 2000 km would imply higher losses. In either case, the energy must be generated from renewable sources, the cost of the submarine interconnection would have to be added to the installation cost, obtaining and exorbitant installation costs. The Canary Islands have a much higher renewable resource (solar and wind) per area than the Iberian Peninsula; therefore, it would not make sense to produce energy in the peninsula to transmit it to Canary Islands. That would exclude the possibility of an economically viable renewable system through an electric submarine interconnection.

To conclude this introductory section, it should be noted that this work addresses the challenge of a zero-emission generation system based entirely on renewable energies for a scenario of total electrification of energy consumptions, but which also meets economic, technological and land use criteria. Since it is an autonomous system, it is also required to have a 100% coverage of the demand precisely because of the need for very high system reliability since it is an isolated network. The main novelty of this work is the analysis of the exclusive use of renewable energies, in particular solar PV and wind, together with storage technologies to achieve a reliable generation mix with zero emissions and being economically competitive, all for a system with a degree of total penetration of electric energy in final energy consumption. As another novel aspect, the HOMER software is also used to simulate reversible pumping stations, which must be conducted by implementing a hydrogen storage system in the code, so that the technical characteristics of the pumping stations are introduced once translated in terms of the input variables required by the hydrogen storage system. Other novel issues addressed in the paper are the implementation of demand management measures and self-consumption with/without distributed storage, aspects that are very important to reduce the huge need to install energy generation and storage sources for scenarios with total penetration of electricity in energy consumption. Such large installed power would be associated with gigantic surpluses of electric energy.

Then, with these objectives in mind, the paper is organized as follows: Section 2 gives the information of a future generation system of the island; Section 3 describes the methodology; while in Section 4 the scenarios are described; Section 5 describes the generation and storage technologies used in the current study; Section 6 is devoted to analyzing the main results of the performed simulations; and finally, Section 7 is dedicated to the discussion and conclusions of the present study concerning the needs of the proposed generation systems.

2. Future Power Demand

The historical data of Grand Canary Island show that there have been no significant variations in the demand curves during the last years. However, if the full decarbonization of the whole energy system is faced, this would mean a big change, and current figures of generation and demand will change. Under this scenario, electricity generation should be decarbonized, but transport, households, and services should be decarbonized. Hence, this implies a very significant increase in the demand for energy generation needed to meet the requirements of these sectors, but not only that, but the hourly profile of this demand will change significantly from today's one. Additionally, if renewable energies are used as the main sources, there will be a decoupling between generation and demand, so management of this problem becomes complicated and requires the installation of large storage capacities. However, it also requires the development of a series of measures that lead to the implementation of a series of profound changes in different aspects related to the management of generation and demand.

2.1. Clean and Total Electrification of the Final Energy Consumptions

It has been considered that this transition to a fully renewable generation system and the total electrification of energy consumption should be carried out progressively. This transition must be carried out through a clear commitment to this model and transition periods implemented in various stages. To achieve these ambitious objectives, a series of measures must be taken, the first of which would be to create a general legal framework for energy transition planning, with the definition of an energy transition plan and a climate change law. Then, among others, the following measures should be implemented [49]:

- A transport planning plan should be defined, favoring electricity penetration in passenger transport, modal shift to public transport and non-motorized means.
- Taxation should be modified or other incentives should be created to favor the penetration of electric vehicles, both in the private and business sectors (cabs, VTCs, buses, rental channels, etc.); in the latter case, it could even become compulsory to use electric vehicles.
- Provide the necessary charging infrastructures for these transports.
- Establish specific plans for the renovation of thermal equipment for Domestic Hot Water (DHW) and air conditioning to heat pump in the hotel sector.
- The penetration of renewable generation should be encouraged (eliminating administrative barriers and/or streamlining administrative processes, providing legal and juridical guarantees to accelerate investments, etc.).
- Define a remuneration mechanism that allows the development of storage and demand management systems.
- Adapt electricity tariffs to give the appropriate signals for electrification and that demand shifts its consumption to the most appropriate hours in each system (demand management).

2.2. Decarbonization of the Electricity Generation System

As the full electrification of final energy consumption by the year 2040 is a must, then implementing all these listed actions will lead to a total growth in the electricity demand of around 3.5% per year [49]. This increase would be mainly due to the electrification of light passenger transport. Additionally, the residential and services sectors will contribute to replacing less-efficient electrical equipment (electric water heaters and radiators) with heat pumps. Finally, the last contribution will come from using hydrogen as an energy vector for non-electrifiable consumptions, mainly in the industrial sector and heavy transport. A detailed view of the different contributions is seen in Figure 1. A summary of the major assumptions considered for the Monitor Deloitte and Endesa model [49] estimations are:

- ~2% of average real GDP (Gross Domestic Product) evolution.
- 100% electric fleet of passenger cars and light goods vehicles.
- 100% electrified energy consumption. Increased penetration of heat pump (more efficient than current equipment) in residential (50%) and services (70%).
- ~10% electrification of industrial consumption (electrifiable industrial processes).
- 100% electrification of energy consumption.
- Increased efficiency of electrical equipment in residential (household appliances, lighting), in industry and other sectors.
- Demand for heavy transport, maritime and non-electrifiable industry.

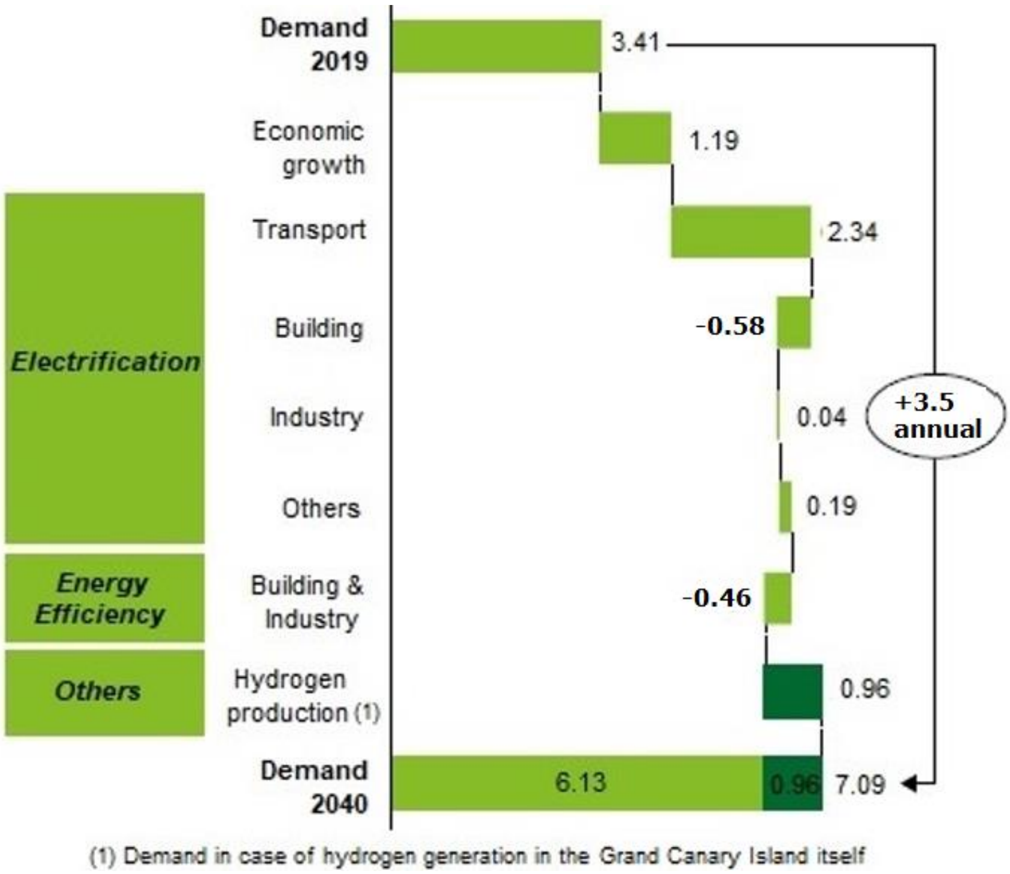


Figure 1. Forecast of the energy demand in the Canary Archipelago, from 2019 to 2040, energy demand in TWh. Adapted from [49].

Then, assuming that the current ratio of Grand Canary Island/Canary Archipelago consumption is maintained (approximately 40%), it would mean that of the 16.1 TWh/year of the total Canary Islands consumption (not counting the hydrogen production to cover the approximately 5% of "non-electrifiable" final energy consumptions), 6.4 TWh/year would correspond to Grand Canary Island. Similar values have been reached by a Canary Islands government study [50]. For these calculations, the starting point was the current stabilized consumption, to which the expected consumptions of electric vehicles and other minor contributions were added. Consequently, values of approximately 6.4 TWh by 2040 are considered appropriate figures to reach the total electrification of the energy consumption in the island.

2.3. Changes in the Demand Curve

Transport is responsible between 60–80% of the final energy consumption in the Spanish non-peninsular territories. The consumption of petroleum products predominates in this sector, almost 100%. The residential and services sectors account for a smaller share of consumption, between 20–30% of the consumption, and also a high degree of electrification, between 70–80%. The industrial sector has a much lower consumption of around 5%.

Consequently, the major contribution by far is the passenger transport; its complete decarbonization requires the renewal of the vehicle fleet, mainly the promotion of electric vehicles, and a modal shift to public transport and non-motorized means of transport. The key aspect is the change to electric transport in all sectors, both passengers and goods. According to the study Estrategia del vehículo eléctrico de Canarias of the Canary Islands government [50], only with the full implementation of electric vehicles in Grand Canary

Island, an increase of about 2.2 TWh of annual electricity consumption will be produced. In this consumption, the vehicle fleet forecast for the year 2040 has been considered.

In order to determine the impact of electric vehicles on the electricity system, it is important to estimate the increase in annual consumption and evaluate user behaviour and, consequently, to predict the hourly demand profile foreseen to supply the electric vehicle. Regarding hourly demand forecasting, there will be not only a standard behaviour, but different behaviours depending on the type of recharging point used. For example, there will be different charging profiles in parking lots linked to private homes, public roads, workplaces, hotels, shopping centres, regulated parking lots and service stations [50]. The aggregation of these charging profiles, according to the unique characteristics of each identified recharging point, provides a characteristic demand curve of the electric vehicle for each of the islands. Figure 2 shows the hourly demand forecast profile of Grand Canary Island by 2040 (forecasts carried out by the Canary Government [50]). As can be seen in the figure, there is an increase in demand during night hours compared to the current demand profiles. This increase has flattened the demand curve (valley filling). Therefore, the difference between peaks and valleys of demand will be reduced, which, in principle, would be favourable for the management of the electricity system. However, if the solar PV has an important contribution, then the generation curve becomes very peaky in the central day hours and, consequently, there is an important difference between generation and demand profiles. This should be reduced as much as possible, and in later sections the way to solve this drawback will be analysed.

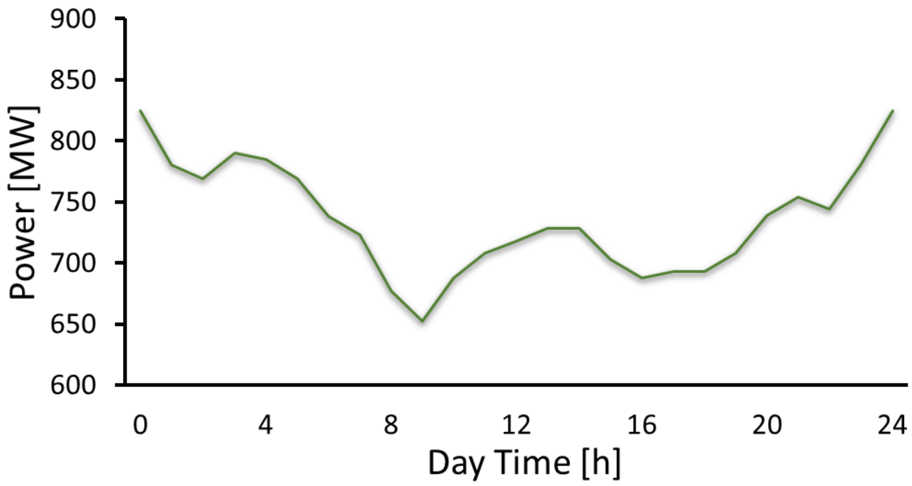


Figure 2. Forecast of hourly profile of demand by 2040. Adapted from [50].

The decarbonization of residential and services sectors requires the deployment of electric heat pumps for air conditioning and DHW, as it is the most efficient technology. The replacement of natural gas/LPG thermal equipment and low-efficiency electric water heaters with heat pumps should be the main solution to achieve the complete decarbonization of service and residential sectors. All these changes contribute to the demand curve shape, but major contribution is the one described above, the influence of the electric vehicle.

2.4. Demand Management

Demand management is a powerful way to improve the performance of electric system, particularly in the current transitioning electric systems. The management of domestic demand is the most widely used strategy to move demand towards generation [51,52].

So far, generation and demand estimates had been analysed separately, but it is also important to know the daily distribution of generation and demand in order to try to match them as much as possible, so as to optimize the storage capacity needed to manage this decoupling. To do this, generation patterns of the renewable sources that will make up our generation mix will be analysed, i.e., wind and solar photovoltaic sources. Solar PV generation has a very good fit with storage technologies, as it has a more predictable output, which allows for more accurate sizing of the storage capacity needed. Solar PV production is concentrated at specific day times, which facilitates the daily day–night charge–discharge cycles. In addition, irradiation in Grand Canary Island is very high, while days with a shortage of sunshine are few and usually do not occur for consecutive days. Wind generation, generally speaking, can have periods of several days with low production, which requires a greater storage capacity, along with periods of several days producing at high capacity, which saturates the storage system and generates wastages. However, in the case of Grand Canary Island, the winds in the areas described in Section 5.2 present high and very stable wind values. Therefore, the optimal generation mix will probably be close to the equality power installed for both technologies.

Consequently, mainly when the weight of solar generation is large, an adequate demand management becomes necessary. This demand management allows aligning the electricity consumption with the generation profile, thus reducing the need for storage. In general, in all the Canary Archipelago and in particular in Grand Canary Island, there could be a potential for demand management towards central day hours of approximately 20–30% of the daily consumption [49]. In Figure 3, as an example, the hourly estimations for the Tenerife Island by 2040 for the renewable generation and demand curves (without and with demand management strategies) are shown.

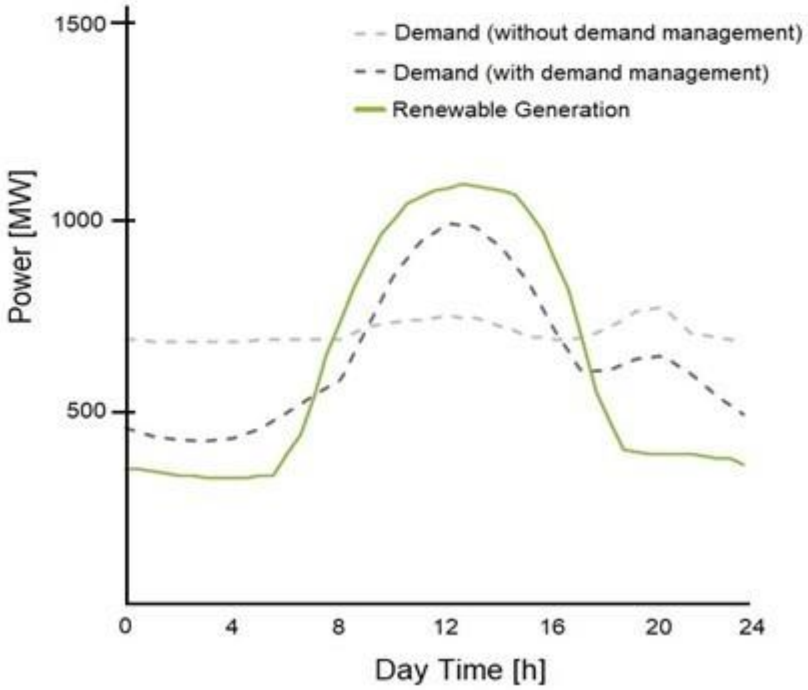


Figure 3. Hourly profile of the renewable generation and demand by 2040 (estimations for the Tenerife Island). Adapted from [49].

This example comes from the Deloitte report [49], where the optimal generation mix is composed of 25% wind and 75% solar PV, a situation which leads to a much-appointed generation curve near the central day hours. As previously explained, the demand curve of fully electrified final energy consumption tends to be quite flat; thus, demand management is important to bring the demand curve closer to the production curve. Then, through demand management, the demand curve passes from an almost flat shape to a curved shape that fairly well follows the estimated calculations of a forecast energy demand curve by 2040. This demand curve shape change could be achieved by favouring the recharging of electric vehicles and consumptions in the building sector (DHW and household appliances such as washing machines and dishwashers) towards the desired schedule time. To this end, an electricity tariff and an hourly price signal should be introduced to encourage consumption during the hours with the highest renewable production, the central day hours in the case of a mix with a significant solar weight. Mechanisms should be developed to allow the System Operator to manage demand at necessary times (in parallel and in coordination with how the System Operator would manage storage). These mechanisms will be different for each type of consumer, and could include demand aggregators, systems for the management of connected electric vehicles or an evolution of interruptibility tariff for large consumers. An appropriate regulatory scheme would need to be developed for this service, as well as an operating procedure that would allow the System Operator to manage it in a clear and transparent manner.

2.5. Vehicle-to-Grid (V2G) Strategies

The electric vehicle fleet itself is another potential distributed storage technology [53], so the electric vehicle itself is not only an electricity consumption from the grid in off-peak hours of the electricity demand curve, but is manageable so that it can act as a storage system that can provide energy to meet demand at peak hours. This strategy can help to optimize the generation system (flattening the demand curve) and reduce the probability of surpluses from non-manageable renewable sources. The success of these policies will depend on the search for an efficient solution that reduces as far as possible the need to reinforce the electricity grids due to the entry of electric vehicles. To minimize these investments, optimal communication and coordination between recharging systems and smart grids will be necessary, which will lead to an adequate integration that avoids these unnecessary investments and, on the other hand, will provide the opportunity for new customer-oriented services, such as the vehicle-to-grid (V2G) energy transaction.

To implement the V2G strategies as efficiently as possible, VE should be integrated into future smart cities' renewable energy grid management procedures. To integrate the V2G system, optimization studies associated with the number, typology, and route followed by the vehicles must be carried out [49,54]. In this procedure of integration of the different subsystems in a smart grid, it is necessary to know the customer value of the use of the smart grid in smart cities so that it is known how customers use smart grid applications to control their consumption of electricity, water, and central heating [55]. With this knowledge, the necessary measures can be implemented to optimize the system, matching the demand curve with the generation curve as far as possible. Finally, it is essential to emphasize that this electric power management system must be unaffected to different adverse incidents, both physical and cyber risks, while supporting the integration of renewable sources will drive a transformative development approach for future smart cities [56].

Throughout the exhaustive forecast analysis of the Canary Islands government for the implementation of electric vehicles in the coming decades [50], a detailed projection of the growth of the Canary Islands car fleet broken down by islands has been carried out. These estimates have been carried out using multivariate regression methods, specifically through the Machine Learning Random Forest technique. The models use the socioeconomic variables of population and GDP as the starting data. Additionally, another variable has been introduced, which tries to compute the effectiveness of the collective mobility policies that are expected to be implemented over the next few years in the Canary Islands. Thus, the final result estimates the evolution of the car fleet broken down by islands and year by year from the present to 2050. In the case of the Grand Canary Island, considering the electrification of the economy, forecasts indicate that there will be around 600,000 electric vehicles in operation by 2040, of which 461,421 would be cars and vans. The latter are those that in principle would be suitable for use as distributed storage, since, for example buses, tractors and trucks are not taken into account in the storage capacity because they are not considered adequate, given that they must provide a prolonged service and their storage capacity must necessarily be associated with their activities. Therefore, it cannot be subject to the management needs of the grid. Additionally, this report [50] describes the phases in which the progressive penetration of the electric vehicle should be made, along with the infrastructures needed to provide the demanded services. For instance, in Grand Canary Island, it is planned to have approximately 670,000 recharge points disseminated through the whole island. Most of them will be placed in private and public garages, on public roads, workplaces, hotels, shopping centres, etc., added to the ones of service stations, which will be used as emergency recharge points. This would mean a total investment in recharging points and the rest of the infrastructures to supply the electric vehicle fleet of around EUR 1250 million for Grand Canary Island.

Consequently, if all cars and vans were used as possible storage systems, then it would have a storage management capacity of 12,311 MWh. (Only private cars and vans have been considered, since other vehicles as public, farm and heavy transport must provide extended service and their storage capacity must necessarily be associated with their own mobility.) In this context, it would be impossible that the total capacity would be available just when needed. Even if it would be available, there must be a balance between the needs of the power system and the user's requirements. Thus, according to the aforementioned Canary Islands Government report, a more realistic scenario would be one in which only half power and storage capacity would be available since vehicles are not connected to the grid all the time. Capacity considerations can be appropriate, as the significant increase in total storage capacity of electric vehicle models that occur year by year would be compensated by a reduction in the number of grid connections (greater spacing between recharges). However, concerning the estimations of the total power of this vehicles fleet, which has been carried out in the most conservative current solution, cars would charge/discharge through slow recharging (3.7 kW), although the existing Spanish electricity tariff "Tarifa 2.0 TD" offers a 10 kW of charge/discharge power [57], which supposes an increase of the total power to approximately 2300 MW. According to [50], the current Electric Vehicle (EV) average capacity is close to 27 kWh (average of 57 current EV models) [42]. However, such capacity has significantly increased during the last years. Nowadays, the capacity of the electric vehicle storage system reaches up to 200 kWh [58–60], while this study considers double capacity (54 kWh) per vehicle. This is a conservative value given that the movements needed on the relatively small Grand Canary Island do not require a big storage capacity.

2.6. Specific Constraints of Islands for Near-Total Decarbonization

Only the technical aspects have been studied up to this point, but islands usually have additional constraints. Most of them are mainly due to their limited space availability, and it is essential to minimize land occupation. Consequently, there are a series of possible measures that must be taken into account to comply not only with the technical and economic restrictions, but also with those of land occupation: i) install less renewable capacity than would be economically optimal, ii) promote the use of self-consumption, with or without distributed storage, iii) explore the option of off-shore generation technologies [61] (more expensive but reduces land occupation, which is critical on an island, and, in the case of wind turbines, at sea there are higher and more stable average wind speeds), and iv) promote demand management and encourage the displacement of consumption towards peak hours of energy production.

The demand values with total electrification usually will lead to very high values of installed power. Therefore, it is essential to consider the above-explained premises that must be followed when determining the most appropriate generation mix.

Combining renewable generation with storage to store surpluses of renewable energy and use it later in periods of lower production is a must when implementing highly variable generation sources. However, installing more renewable power than necessary could be more economically efficient since the cost of renewable generation will be lower than the cost of storage, but other considerations possibly have to be considered.

Batteries as a form of short-term storage have advantages over pumping storage in terms of modularity, land occupation, efficiency, and in many cases, cost, especially if the technological evolution which has occurred in recent years continues as it has done so far. All this is assuming that batteries will be able to provide the technical requirements of voltage and frequency regulation. Although the orography of the terrain is favourable, most of the infrastructures for installing pumping stations are already available in Grand Canary Island. Consequently, the best option would probably be a combined system of both technologies.

3. Methodology

The methodology developed in this paper consists of obtaining the different input data needed to perform the simulations. Through such data, it is possible to analyse the scenarios under study. A schematic summary of the implemented method is shown in Figure 4. The main required inputs are annual hourly energy demand, technical information of the renewable systems to be used, and cost of the generation system to be considered (in this case, photovoltaic and wind power plants); technical information and price of the storage system (reversible pumping and the EV batteries have been analysed); the energy resource of each generation system (solar and wind resource available in Grand Canary Island); and other economic data (such as the annual interest rate and the lifetime of the project). In addition, the cost of generation and storage system has taken into account the unexpected expenditure (6%); this value includes the decommissioning installation cost (3%) when the plants reach the end of their life.

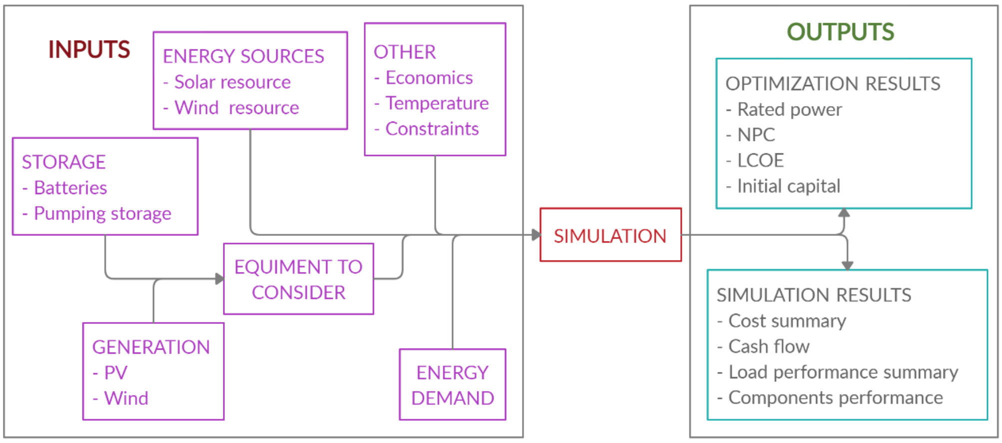


Figure 4. Schematic overview of inputs and outputs of HOMER software.

The software used to carry out the simulations is HOMER (Hybrid Optimization of Multiple Electric Renewables). It is used for optimizing renewable grid design in both island utilities and grid-tied scenarios. Among the inputs introduced in the models, components' characteristics, components' cost, and resource availability can be mentioned. The simulation is carried out by making energy balance calculations at each time step of the year, comparing electric demand to the energy supplied by the power generation system, estimating how to operate the generators and whether it is necessary to charge or discharge the batteries. Then, it is determined if the configuration is feasible regarding the energy flow and calculates the installation and operation cost of the system over the lifetime of the project. According to [30], HOMER uses a novel algorithm without derivatives to search for the cheapest system, showing a list of feasible configurations sorted by net present cost. Thus, the global optimum is chosen as the best solution in this study. [33].

The technical inputs and technical information of the renewable systems to be used (Figure 4) due to their techno-economic viability are included:

1. For the PV system, the PV panel characteristics are described in Section 5.1.

2. For the off-shore wind systems, the wind turbine characteristics are described in Section 5.2.
3. The characteristics of the pump storage hydropower system are described in Section 5.3
4. The battery system's characteristics are described in Section 5.4. Additionally, in the battery modelling, general information on lithium batteries and car batteries has been considered when choosing the most suitable equipment.

Moreover, the best options for the combination of generation and storage systems to supply all the necessary power can be estimated for every scenario. Economic information, such as LCOE, initial capital, Net Present Cost (NPC), payback, and Internal Rate of Return (IRR), is also obtained. Figure 5 shows a schematic overview of the inputs and outputs of HOMER software.

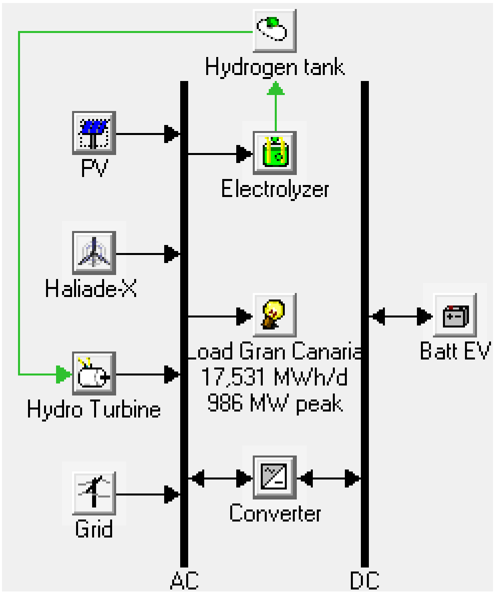


Figure 5. Scheme of the energy system design in HOMER.

Demand management strategies have been analysed for the scenarios under study to test their capacity and enhance the energy demand balance. For example, the solar and wind resources available in Grand Canary Island have been simulated to estimate the optimized generation system.

4. Scenarios

The full decarbonization of energy consumption must become a reality by 2050 in the countries of the European Union. In the particular case of its non-peninsular territories, Spain wants to bring a step forward in this process; therefore, these territories would lead the ecological transition and implement a decarbonized energy system 10 years in advance [49]. Within this development, three strategies are also being elaborated on relevant aspects of the Canary Islands system: self-consumption, batteries, and electric vehicles. Consequently, the Canary Archipelago is currently working to reduce its dependence on fossil fuels. Specifically, Grand Canary Island now has around 85% of the total installed power and around 95% of their power generation as non-renewable [11]. The Canary Islands have an advantage due to their abundant natural resources, namely the sun and wind. To reach this decarbonized scenario, the Instituto Tecnológico de Canarias (ITC) has considered several different scenarios to reach 100% clean energy generation in all its islands. The enormous natural resources must be harnessed for all of them, but these are not enough, since the ability to manage these highly variable resources must be available, which entails using storage systems to support them.

The total electrification of the island's energy consumption would be the desired scenario for the nearest possible future, of course, avoiding the use of fossil fuels in its power generation. The transition from an almost entirely fossil-fuel power generation system to total decarbonization, but in addition, with the entire generation system based on renewable energies and with total electrification of the final energy consumption, is a large leap. This scenario leads to a huge increase in electricity demand in Grand Canary Island, approximately 6.4 TWh per year (estimations of the Canary Government [50]).

The forecast of the electric demand by 2040, shown in Figure 2, has been used as input for the base scenario (Line 0 DR Figure 6), i.e., a scenario without applying demand response. Next, the effect of the implementation of the demand management strategies has been analysed; in particular, four fitting degrees of demand response curves have been simulated (Lines 0.25, 0.5, 0.75, and 1 DR of Figure 6), where the number means the demand response degree analysed, 0 DR being the scenario without demand response management and 1 DR the scenario with the maximum possible demand response management. Additionally, a Business As Usual (BAU) scenario has also been considered; this scenario reproduces the shape of today's demand curve but scaling the energy demand forecast for 2040 (Line BAU of Figure 6). The system is designed to cover 100% of the energy demand of Grand Canary Island in all the scenarios analysed.

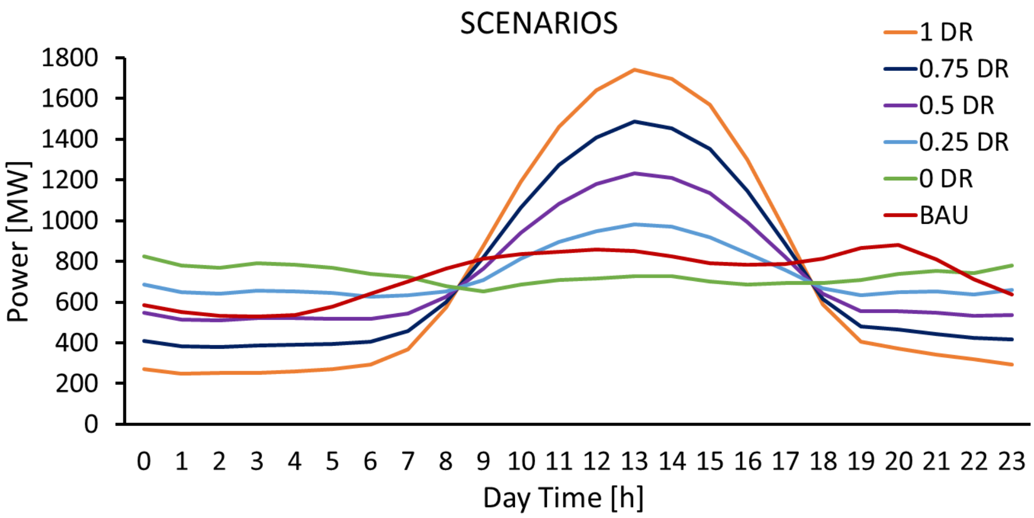


Figure 6. Scenarios with different degrees of demand-side management penetration.

The next step is, taking the baseline scenario as a reference to analyse the effect of demand management strategies on the generation–demand balance, estimating the impact on energy wastages, installed power, energy prices, etc. The cost used is the real hourly cost for the Canary Archipelago for the year 2019 (prepandemic period obtained from the web page of the Spanish electric system operator-ESIOS [61] (Figure 7)). However, since an increasing cost is expected in the coming years, it could be considered a conservative scenario.

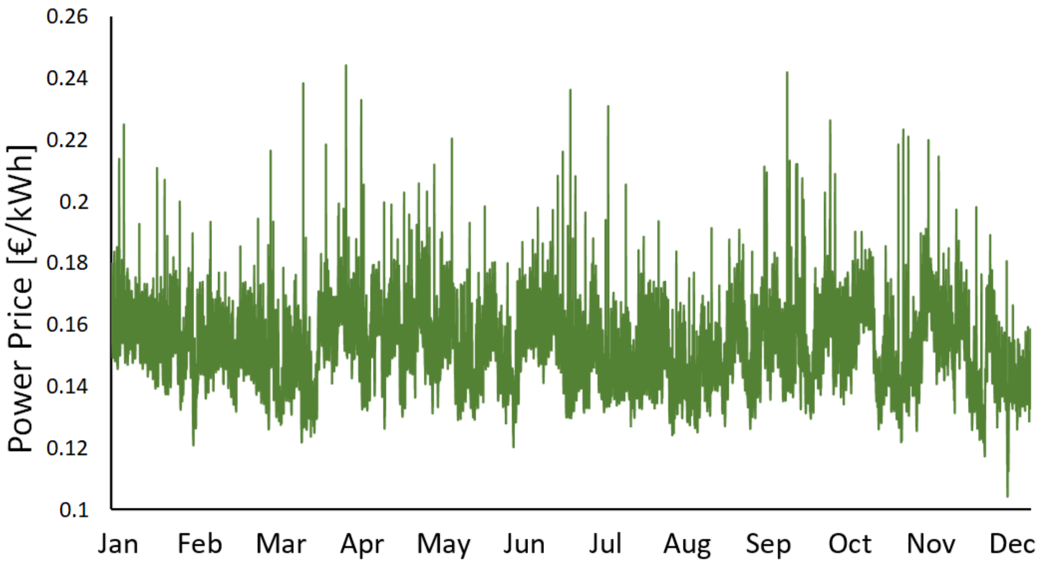


Figure 7. Cost of energy in Grand Canary Island. Adapted from [62].

According to [50], the base scenario reaches a compromise solution between costs, minimization of excess energy, and affordable land occupation. It covers the yearly demand of 6.4 TWh, implemented through the hourly forecast by 2040, as shown in Figure 2 [50]. The daily variation of the energy demand, a day-to-day random variability with a standard deviation of 5% over the daily average has been implemented, and an intra-daily variation from time-step to time-step has also been implemented, with a standard deviation of 3.65% in the difference between the hourly data and the average daily profile.

5. Power Generation System

5.1. PV System

The Canary Archipelago has one of the highest natural resources in Europe due to both sources: solar and wind. The available solar energy can be estimated using the European Photovoltaic Geographical Information System (PVGIS) [63]. This energy supposes a potential global horizontal irradiance of 1800 ESH/year (Equivalent Sun Hours), which can increase up to 2250 ESH/year by locating the PV panels at a fixed slope angle of 25°, as shown in Figure 8. These data have been used to provide the HOMER software with the hourly available solar resource on the island, although, probably considering the possible global warming suffered by the planet, these values could slightly be different.

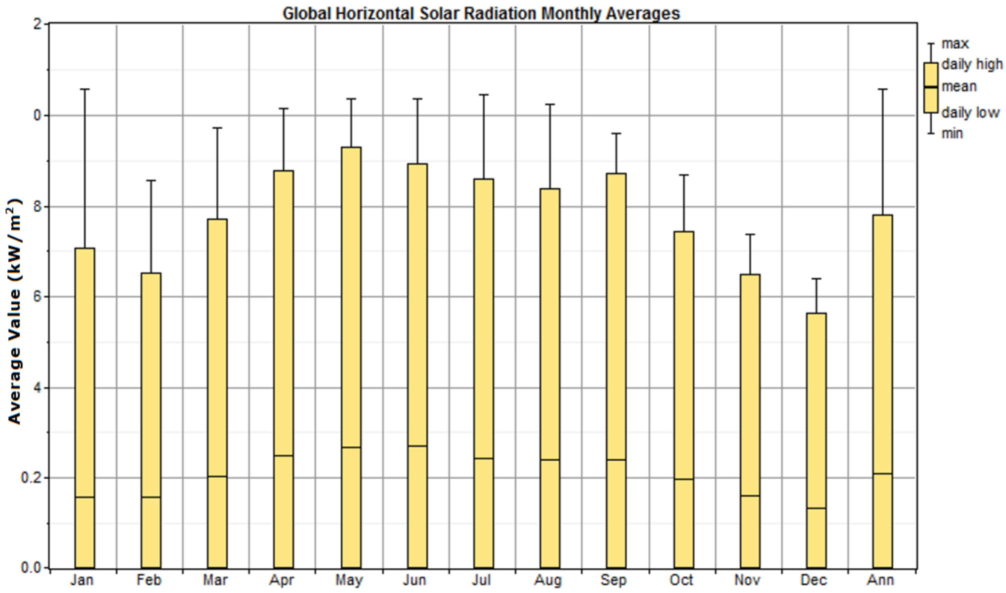


Figure 8. Monthly solar energy resource in Grand Canary. Adapted from [63].

Additional information regarding solar PV system inputs used is shown in Table 1, while the information of the selected photovoltaic panel is shown in Table 2. The photovoltaic power to install is obtained from the optimal estimations of the self-consumption analysis of the latest Canary Islands report [50]. The document analyses the total roof area available in the Canary Archipelago broken down by islands. According to this report, the solar PV generation potential through self-consumption of the Grand Canary Island is 3700 MW, a value in which the maximum occupancy rate is considered to be 70% of the total available roof area on the island.

Table 1. Inputs used for the PV system.

Lifetime (Years)	25
Derating factor (%)	82
PV power potential (MW)	3700

Table 2. Inputs used for the PV system. Adaptede from[64,65].

Used Panel	**Trina Solar TSM-DE19**
Temperature coefficient of power (%/°C)	−0.36
Peak Power (W)	550
Nominal operating cell temperature (°C)	42.6
Efficiency of the panel at standard conditions (%)	20.5
Cost (EUR/kW)	800
O&M cost (per 1 MW peak power) (EUR/year)	3500

Other information regarding the PV panel required as an input (peak, power, temperature coefficient of power, nominal operating cell temperature, etc.) was taken from the PV panel datasheet (Table 2). For estimating the derating factor, the mismatch (1%), the inverter losses (4%), wiring losses (1%), module quality loss (1%), soiling (1%), and shading (15%) were taken into account [31]. Temperature losses are estimated hour by hour in HOMER through the coefficient of power, the Nominal Operating Cell Temperature (NOTC), and ambient temperature. The PV panel has been chosen for its efficiency, being a recognized brand, and its cost per kW_P (200 EUR/kW_P) (VAT not included).

5.2. Wind System

Due to the high wind power generation potential, installing floating off-shore wind systems in Grand Canary Island is planned [61]. For instance, Greenalia, a renewable energy company, has planned to install 250 MW in the coming year in Grand Canary [66].

For this study, the wind resource can be estimated using the global wind data of the second Modern-Era Retrospective analysis for Research and Applications (MERRA-2), developed by NASA [67]. As for the case of solar resources, these hourly wind data have been used as an input. However, the temperature variation due to the global warning must be taken into account as it could slightly modify the values.

In Grand Canary, there are many suitable locations for installing wind generators, both on-shore and off-shore. The installation of off-shore wind turbines has been the most suitable option considering land occupation and energy production criteria, even though the installation, operation, and maintenance costs are higher than those of the on-shore technology. In addition, the vast ocean expanses available in the east and southeast of the island are considered the best place due to their location. According to the global wind atlas, Figure 9 shows monthly wind energy resources in Grand Canary [68].

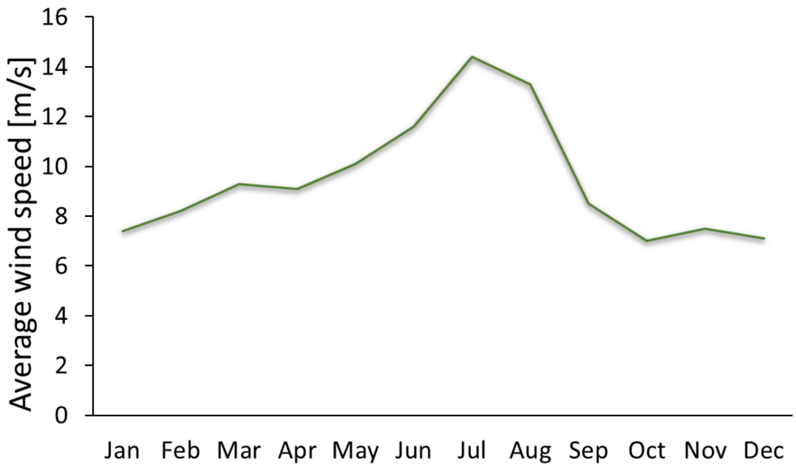


Figure 9. Monthly wind energy resource in Grand Canary. Adapted from [67].

Other required information for wind resources simulations is taken from MERRA-2 [67]. The data are summarized in Table 3, while the datasheet of the selected wind generator is shown in Table 4.

Table 3. Inputs used for the wind system simulation. Data taking from [67].

Weibull k	1.7151
Weibull c	9.9695
Measurement reliability (%)	80
Altitude m asl	0
Anemometer height (m)	50
Wind shear profile	Logarithmic
Surface roughness length (m)	0.02 m

Table 4. Datasheet of the wind turbine. Data taking from [69–71].

Wind generator	**Haliade-X General Electric**
Rated power (MW)	12
Rotor diameter (m)	220
Height to the axe (m)	140 m

Total height (m)	220 m
Lifetime (years)	25
Cost of the system (MEUR/turbine)	28.6
MEUR/MW	2.38
O&M cost (MEUR/year)	3.5

5.3. Pumped Storage Hydropower

A reversible pumped-storage hydroelectric power plant is planned to be built, the Chira-Soria project [28]; in fact, the facility is expected to be operational by 2027. This Chira-Soria plant would have around 3.2–3.6 GWh storage capacity, with a total generation capacity of 200 MW, which means 16 h of power generation at full load. The project includes the construction of a seawater desalination plant, all the associated marine works, and the necessary facilities for its connection to the transmission grid. Reverse pumped storage stations are the most widely used form of electrical energy storage, accounting for about 95% of all storage facilities worldwide. The whole cycle's total round trip energy efficiency (turbine and pumping) ranges from 70% to 85% [72,73]. In addition to this plant, it is planned to install at least another twin facility: the Las Niñas-Soria pumping storage system. There are many other alternatives to place pumping stations [22], El Parralillo-Siberio and the El Parralillo-El Caidero de las Niñas pumping stations, with powers around 40 MW and storage capacity of 700 and 625 MWh, respectively. A total number of at least 10 plants are considered to be viable, with a total power of more than 600 MW and a total energy stored of around 10 GWh [29].

Based on the viability of this kind of system in the Grand Canary Island, part of the required storage capacity needed to manage the variability of the renewable sources has been covered by employing a reversible pumping storage system (maximum size according to the island orography). Since pumping storage stations cannot be directly simulated in the HOMER software, this technology has been analysed through the hydrogen storage system module (electrolyser, hydrogen tank, and generator). The maximum storage capacity of the pumping stations is simulated by the maximum capacity of a hydrogen reservoir; the pumping power (flow rate that the water pump is able to drive from the downstream to the upstream dams) is simulated by the amount of hydrogen that the electrolyser can produce. In contrast, the pumping efficiency is simulated in the electrolyser. The capacity of the hydrogen reservoir would be equal to that stored in the upper reservoir (equivalence between the total potential energy stored by the difference in elevation between the reservoirs when the upper reservoir is full and the amount of hydrogen that must be stored to contain that same energy). At the same time, hydrogen power generation simulates turbine power by transferring water from the upper reservoirs to the lower reservoirs, taking into account the efficiency. In the current case, the design data have a total turbining power of 607 MW, able to operate at a full load for 16 h if the upper dams are filled and supposing the same time to fill them once [29]. The assumed efficiency of the round-trip process has been 80% (typical values between range from 0.7 to 0.85) [72,73]. The required data to implement the equivalence between pumping and hydrogen storage are displayed in Table 5. The maximum reverse pumping storage capacity considered is 607 MW of total power with a storage energy capacity of 10.8 GWh (9.73 GWh after turbining losses). The installation cost is EUR 2000/kW and the O&M cost is EUR 2810/h [27]

Table 5. Summary of correspondence data between pumping and hydrogen storage.

Reverse Pumping Storage	Hydrogen Storage
DATA	
P_T = 607 MW	P_G = 607 MW
$t_T = t_P$ = 16 h	$t_G = t_E$ = 16 h

$\eta_P = \eta_T = \sqrt{\eta_{tot}} = \sqrt{0.8} = 0.894$	$\eta_E = \eta_G = \sqrt{\eta_{tot}} = \sqrt{0.8} = 0.894$
CALCULATIONS	
$E_{P,max} = \frac{P_T t_T}{\eta_T} = \frac{607 \cdot 16}{0.894} = 10{,}800 \text{ MWh}$ $P_P = \frac{E_{P,max}}{\eta_P \cdot t_P} = \frac{10{,}800}{0.894 \cdot 16} = 760 \text{ MW}$	$E_{E,max} = \frac{P_G t_G}{\eta_G} = \frac{607 \cdot 16}{0.894} = 10{,}800 \text{ MWh}$ $M_{max} = \frac{E_{E,max}}{LCV_{H_2}} = \frac{10{,}800(\text{MWh}) \cdot 3600(\frac{s}{h})}{120 \text{ (MJ/kg)}} = 324{,}000 \text{ kg}$ $\dot{M}_{max} = \frac{M_{max}}{t_E} = \frac{324{,}000}{16} = 20{,}250 \text{ kg/h}$ $P_E = \frac{E_{E,max}}{\eta_E \cdot t_E} = \frac{10{,}800}{0.894 \cdot 16} = 760 \text{ MW}$

5.4. EV Batteries

Additionally, if extra storage capacity is needed, part of the storage capacity of EV is considered by implementing V2G strategies [50], while for the other storage technology considered, the V2G strategy, the maximum figures for the Grand Canary Island considering a huge electric vehicle penetration would be 2300 MW of total power and 6.15 GWh of storage capacity. Information about the battery used is included in Table 6.

Table 6. Standard system specifications of the selected battery system. Data taking from [74–77].

Energy Available per battery (kWh)	**50**
Round-Trip System Efficiency	87%
Cost (EUR/kWh)	300
O&M cost (EUR/year)	216

6. Results

A summary of the six scenarios' simulations is shown in Table 7. The significant aspects to highlight are:

- The scenario with the best results is 1 DR. From the economic point of view, the best option is to install 58 wind generators (12 MW each, around 700 MW in total). The initial investment would be EUR 8065 million; the O&M costs are around 286 MEUR /year, and the LCOE is EUR 0.11/kWh, with the total NPC cost equal to EUR 13,655 million. In this scenario, 2347 GWh (26% of the energy produced by the whole system) is not stored since the storage systems are fully charged.
- The worst scenario is 0 DR. In this scenario, the best option from the economic point of view is to install 103 wind generators (1236 MW in total). The initial investment would be equal to EUR 9362 million; the O&M costs are around EUR 462/year and the LCOE is EUR 0.14/kWh, the total NPC cost being EUR 18,371 million. In this scenario, 8892 GWh (41% of the energy produced by the whole system) is not stored since the storage systems are fully charged.
- The BAU and 0.25 DR scenarios are very similar. In the BAU scenario, the best option from an economic point of view is to install around 85 wind generators (12 MW each, around 1 GW in total). The initial investment is EUR 8800 million; the O&M costs are around EUR 3800 million/year and the LCOE is EUR 0.13/kWh, the total NPC cost being equal to EUR 16,200 million. In these scenarios, around 3800 GWh (35% of the energy produced by the whole system) is not stored since the storage systems are fully charged.

Table 7. Summary of the analysed scenarios.

		PV	Wind Turbines	Hydro Turbines	Batteries	Initial Capital	O&M	NPC	COE
S	Units	(MW)	(MW)	(MW)	(MWh)	(MEUR)	(MEUR /yr)	(MEUR)	(cEUR /kWh)
1	BAU	3700	1020	607	6196	8837	381	16,284	13.0
2	0 DR	3700	1236	607	6196	9352	462	18,371	14.7
3	0.25 DR	3700	1008	607	6196	8808	377	16,175	13.0
4	0.5 DR	3700	888	607	6196	8522	342	15,206	12.2
5	0.75 DR	3700	792	607	6196	8294	314	14,431	11.6
6	1 DR	3700	696	607	6196	8065	286	13,655	11.0

According to the results, all the scenarios require the maximum possible capacity of the PV system on residential buildings rooftop (3700 MW); in all the scenarios such capacity has been considered. Similar occurred with the pumped storage system (607 MW, 10.8 GWh [28]). In the case of the EV batteries, the capacity analysed (2300 MW, 6.15 GWh) was estimated by [50] for the year 2040.

Reduction when the demand response is applied, comparing the different scenarios to 1 DR, is shown in Table 8. In the case of the opposite scenarios (0 DR respect to 1 DR), the LCOE is reduced a 25%. The initial investment is reduced by 14%, mainly because wind turbine cost is reduced by 44% (from EUR 1236 to 696 million).

Table 8. Cost reduction of the different scenarios compared to the best one (1 DR).

1 DR respect to	BAU	0 DR	0.25 DR	0.5 DR	0.75 DR
Wind Turbines	32%	44%	31%	22%	12%
Initial capital	9%	14%	8%	5%	3%
O&M	25%	38%	24%	16%	9%
NPC	16%	26%	16%	10%	5%
COE	15%	25%	15%	10%	5%

6.1. Energy Analysis

The first aspect of being analysed is energy generation. Table 9 shows the energy demand and production per component for every scenario, and Table 10 shows the additional energy required to cover the energy demand in the different scenarios compared to the 1 DR scenario. The energy to be covered is 6.4 TWh. Since the PV system capacity is the same in all the scenarios, the energy produced by this system will also be the same. Comparing the opposite scenarios 0 DR and 1 DR, scenario 1 DR requires 58 wind turbines (696 MW), while scenario 0 DR requires 103 wind turbines (1236 MW). Consequently, in the 1 DR scenario, the energy required to cover the entire demand is reduced by 24%, and the energy required by the wind system is reduced by 44%. Additionally, the excess of electricity (energy able to be produced by the system but not stored due to the storage system being fully charged) is reduced by 52% (from 4.9 to 2.3 TWh).

Table 9. Energy demand and energy production per component for every scenario.

	1. BAU		2. 0 DR		3. 0.25 DR		4. 0.5 DR		5. 0.75 DR		6. 1 DR	
Yearly Generation	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%
PV array	5.3	49	5.3	44	5.3	49	5.3	52	5.3	55	5.3	58
Wind turb.	5.5	51	6.7	56	5.4	51	4.8	48	4.3	45	3.8	42
Total	10.8	100	12.0	100	11	100	10.1	100	9.6	100	9.0	100

AC load	6.4		6.4		6.4		6.4		6.4		6.4	
Excess elect.	3.8	35	4.9	41	3.7	35	3.2	32	2.8	29	2.3	26

Table 10. Additional energy required to cover the energy demand in the different scenarios compared to the best one (1 DR).

1 DM respect to	BAU	0 DR	0.25 DR	0.5 DR	0.75 DR
Wind turb.	32%	44%	31%	22%	12%
Total	16%	24%	16%	10%	5%
Excess elect.	38%	52%	37%	27%	15%

On the other hand, the BAU scenario requires less energy production compared to 0 DR (10.8 vs. 12 TWh), the BAU scenario being more efficient than the base case. It happens because, in the BAU scenario, the peak demand occurs during the day, when the energy production from the PV system is highest, favouring a demand response scenario. Comparing the BAU scenario and 1 DR scenario, the BAU scenario requires 103 wind turbines (1236 MW), reducing 16% of the required energy to cover the entire demand and reducing 32% energy required by the wind system. In this case, the excess of electricity is reduced a 38% (from 3.8 to 2.3 TWh).

Analysing system by system, some significant aspects could be highlighted. For example, the generation map of the solar PV system (Figure 10) shows a fairly constant generation rate throughout the year, although it is higher during the summer months and has a considerable generation capacity even in winter. As shown in Table 11, around 3700 operation hours with a capacity factor of 16.3% and an LCOE lower than EUR 0.04/kWh are the major figures of the solar PV generation.

Table 11. PV system summary for all scenarios.

	Value	Units
Rated capacity	3700	MW
Mean power output	603	MW
Mean energy output	14,470	MWh/d
Capacity factor	16.3%	%
Total production	5281	GWh/yr
PV penetration	82.5%	%
Hours of operation	4121	hr/yr
LCOE	3.93	cEUR/kWh

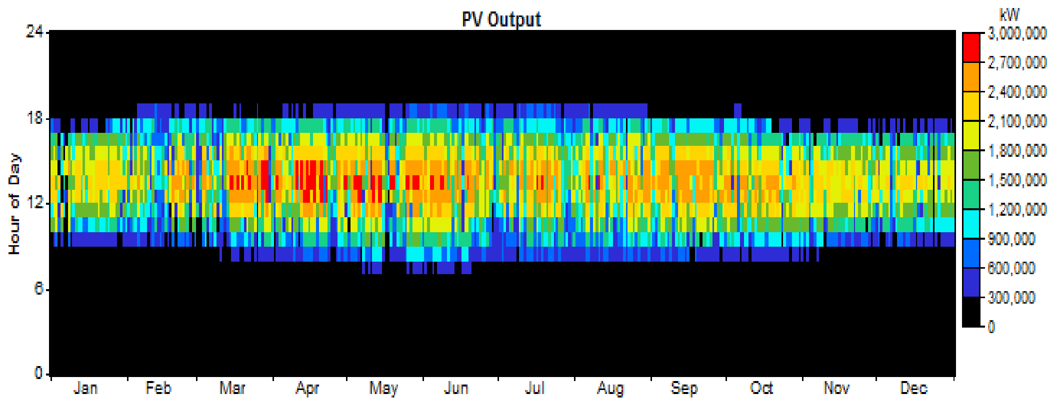


Figure 10. Generation map of the solar PV system for all the scenarios.

Regarding to the off-shore wind power system, as shown in the generation maps of the 0 DR and 1 DR scenarios (Figure 11), the wind system takes better advantage in scenario 1 DR compared to 0 DR. This is because in the 0 DR scenario, the wind system capacity needs to be bigger to cover the energy demand, mainly the critical days with peak demand and not enough solar or wind resources. Consequently, in the 1 DR scenario the wind system works more efficiently and closer to its rated operation point.

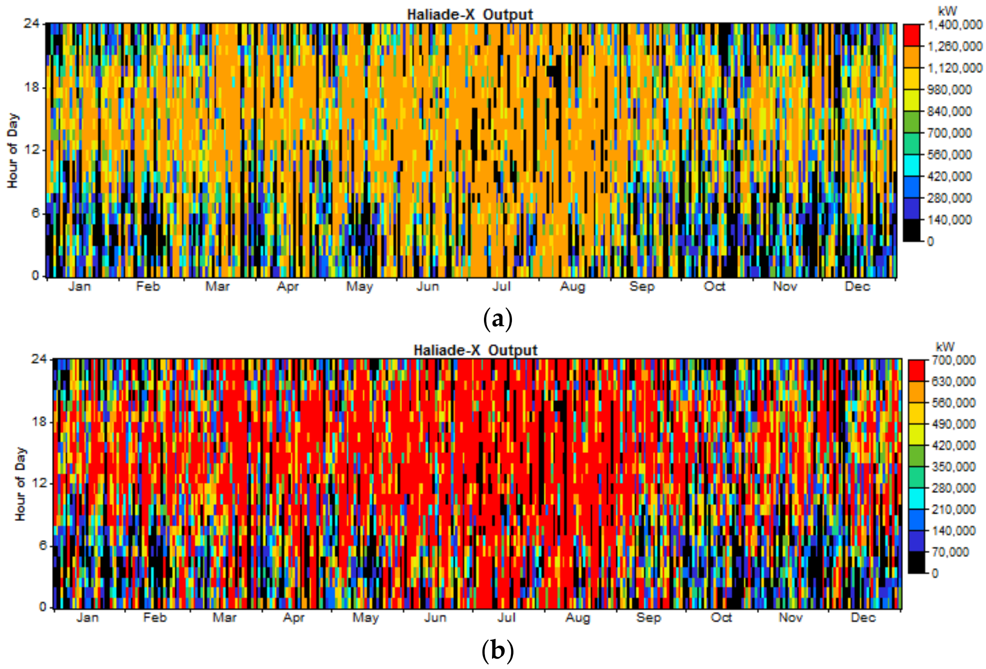


Figure 11. Wind system power production during one entire year: (**a**) 0 DR scenario (**b**) 1 DR scenario.

Table 12 shows that the capacity factor of the wind system is more than 83% in all the cases, which is because of the privileged location of the island, with one of the biggest wind resources in Europe, added to the fact that wind turbines are placed in the sea, which means that the wind resource is even higher. However, despite these figures, the cost of the off-shore wind generation is higher than the solar system, due mainly to the high cost of the off-shore wind system. The LCOE is slightly over EUR 0.0767/kWh.

Table 12. Wind system summary.

Quantity	1. BAU	2. 0 DR	3. 0.25 DR	4. 0.5 DR	5. 0.75 DR	6. 1 DR	Units
Total rated capacity	1020	1236	1008	888	792	696	MW
Mean output	628	762	621	547	488	429	MW
Total production	5505	6671	5441	4793	4275	3757	GWh/yr
Levelized cost	7.67	7.67	7.67	7.67	7.67	7.67	cEUR /kWh

The reversible pumping storage system has been simulated through a hydrogen storage system which is composed of an electrolyser (water pump), a hydrogen tank (dam), and a hydrogen turbine (water turbine). Concerning the pumping storage system, as shown in Figure 12, this system practically never delivers energy to the grid during the mid-day hours. This situation is because solar PV generation occurs mainly during the mid-day hours, except for cloudy days. Nevertheless, although more energy is delivered to the grid in the 0 DR scenario with respect to the 1 DR scenario (1077 vs. 583 GWh/year), the total installed capacity (PV + Wind system) is smaller in the 1 DR scenario, while the energy required during mid-day hours is bigger in 1 DR scenario. From Table 13, the capacity factors could be highlighted, going from 11 to 22.6 depending on the scenario. In this sense, it would seem the storage system is oversized, but it is not the case since the storage systems must cover the entire demand, even when solar irradiation and wind velocity are not enough for meeting the energy necessities. A few days per year with unfavourable weather conditions cause the necessity of a large storage system.

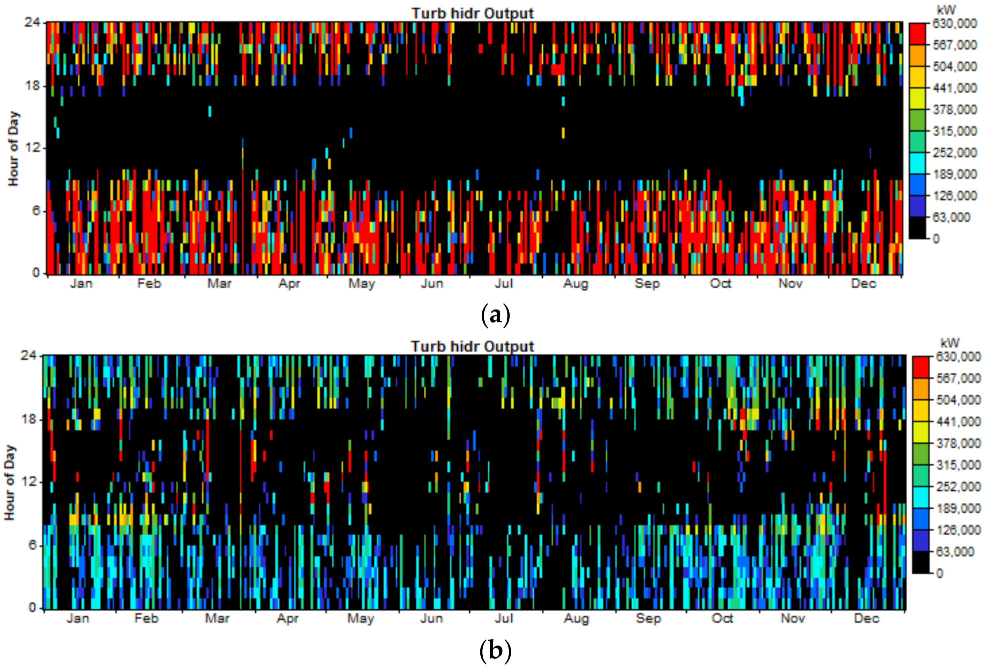
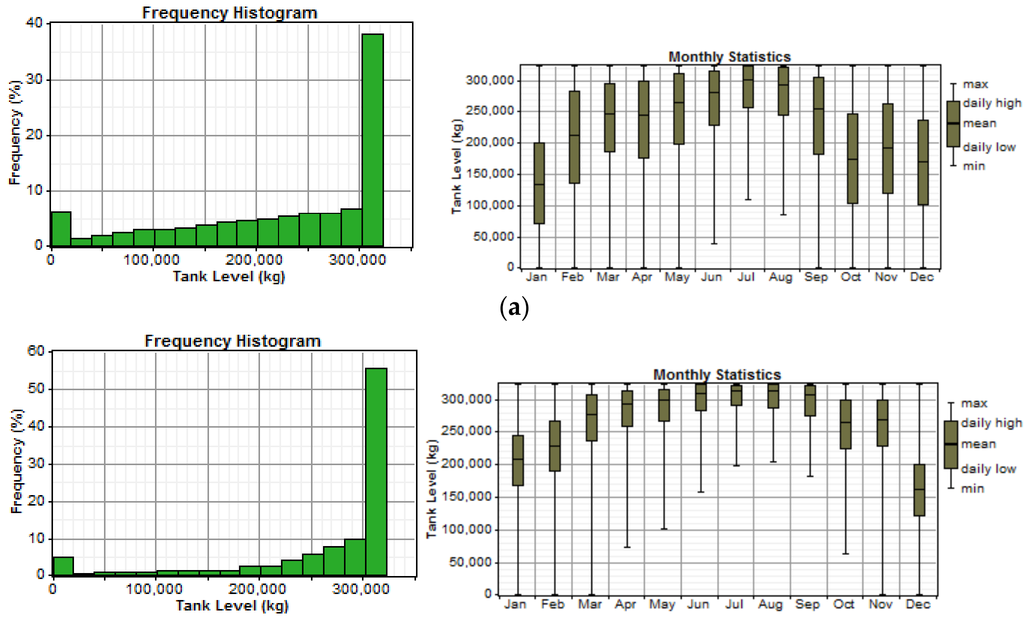


Figure 12. Power discharge to the grid by the "pumping storage" for one year: (**a**) 0 DR scenario; (**b**) 1 DR scenario.

Table 13. Pumped-storage hydropower system summary.

	1. BAU	2. 0 DR	3. 0.25 DR	4. 0.5 DR	5. 0.75 DR	6. 1 DR	Units
Capacity factor	20.3	22.6	20.5	17.4	14	11	
Electrical production	1077	1202	1092	919	746	583	GWh/yr
Mean electrical output	122.9	137.2	124.6	104.9	85.2	66.5	MW
Max. electrical output	607	607	607	607	607	607	MW

Figure 13 shows the yearly dam level frequency and monthly dam level data for the 0 DR and 1 DR scenarios. Most of the time, the dam's level is full (37 to 55% of the time for all six scenarios), but there are even periods when it is almost completely empty (about 5–7% of the time for the six scenarios). Analysing the evolution of the dam level through Figure 14, in all the scenarios this storage technology is partially required in summer, while in winter, the dam is empty on some critical days. Nevertheless, the 1 DR scenario is more favourable, and the dam is empty at some times between November and February, while in the 0 DR scenario, it happens from September to May.



(**a**) (**b**)

Figure 13. Dam level frequency (yearly) and monthly data of the dam level: (**a**) 0 DR scenario, (**b**) 1 DR scenario.

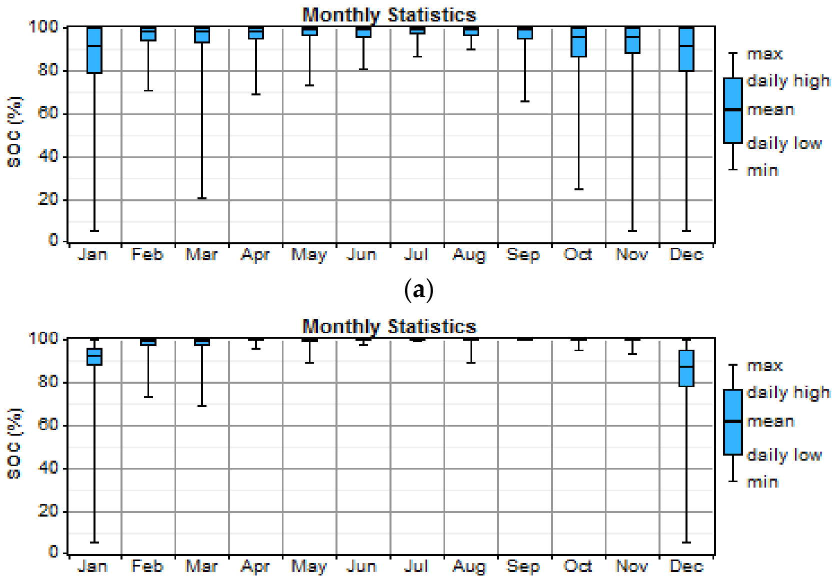
Finally, the EV battery storage system summary is presented; this system has a total storage capacity of almost 25 TWh, but only 25% has been considered to deliver energy to the utility grid. Table 14 summarizes the major data of the batteries, such as number of EV, battery wear cost, etc.

Table 14. VE battery storage system summary.

Quantity	1. BAU	2. 0 DR	3. 0.25 DR	4. 0.5 DR	5. 0.75 DR	6. 1 DR	Units
Number of EV (2040 Scenario)	461,421						
Capacity per vehicle	54						kWh
Power capacity	2300						MW
Total capacity	24.9						GWh
Considered capacity	25%						%
Considered capacity	6.2						GWh
Lifetime throughput	5598	5501	5606	5614	5604	5604	GWh
Energy in	242.2	301.3	179.2	102.5	72.2	81.9	GWh/yr
Energy out	210.7	262.1	155.9	89.2	62.8	71.2	GWh/yr
Battery wear cost	28.2	29.0	28.5	28.1	28.1	28.1	cEUR /kWh

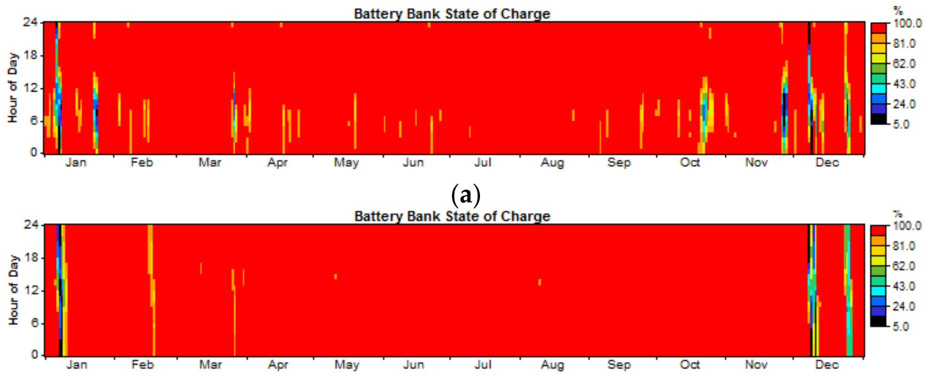
Regarding the frequency histogram of the batteries' state-of-charge mapping, as the analysed pumping storage system, the battery system is not significantly used; nevertheless, it is a key piece to keep the system's reliability. Figure 14 shows that on average it used less than 10% of its capacity during one entire year in all the scenarios. Additionally, this aspect can be shown in Figure 15, where SoC equal to 100% (red colour) vastly predominates, with the assumptions analysed, which means that during long periods the energy would not be stored. On the other hand, without the storage system, an unaffordable installed power (Wind and PV) would have been required to meet the demand and, in addition, a huge amount of energy would have been wasted for many periods. For example, comparing scenarios 0 DR and 1 DR (Figures 14 and 15), in the 0 DR scenario, the battery provided energy in critical moments in January, March, October, November, and December. In the case of the DR1 scenario, it just occurs in December and January.

Moreover, considering the battery wear cost, the table above shows a higher value for the 0 DR scenario compared to the others. This value shows the cost of cycling energy through the storage system, which is directly limited by the battery's lifetime throughput (0 DR scenario has the smallest value). Therefore, when the total throughput of the storage system equals its lifetime throughput, the storage system requires replacement, with 0.5 DR, 0.75 DR, and 1 DR being the most favourable scenarios regarding the battery wear cost.



(**a**) (**b**)

Figure 14. Monthly data of the dam level: (**a**) 0 DR scenario; (**b**) 1 DR scenario.



(**a**) (**b**)

Figure 15. Battery bank state of charge: (**a**) 0 DR scenario, (**b**) 1 DR scenario.

As is well known, a critical point in renewable systems is the impossibility of producing energy when it is required; for that reason, this kind of facility requires a storage system which significantly increases the investment and the O&M costs, and at the same time a lot of energy is wasted when the storage system is full of energy, becoming a challenge to obtain the best configuration. In this study, even optimizing every scenario, the excess of produced energy goes from 26 to 41% in 0 DR and 1 DR, respectively, values on average for renewable energy systems. So, this means an important quantity of energy is wasted. Looking to the future, one way to profit from part of this energy is through hydrogen storage. In the second phase of this study, information about the analysis storing the excess of electricity into hydrogen will be given. The hydrogen will be used for not electrifiable purposes.

6.2. Economic Analysis

Table 15 shows initial capital, O&M cost, and salvage, both total and per source. The initial capital required to implement the systems required goes from EUR 8000 to 9350 million in scenarios 1 DR and 0 DR, respectively. In the same way, the operation cost goes from EUR 5683 to 7527 million during the project's entire life. Table 16 shows the payback goes from 14.4 (1 DR scenario) to 24.3 (0 DR scenario). Therefore, it is important to remark that the cost of the battery system increases the cost of the entire system significantly. According to Table 14, the battery wear cost is close to EUR 0.28.

Table 15. Initial capital, O&M cost, and Salvage. Total and per source.

	MEUR	Capital	O&M	Total NPC
1. BAU	PV	3330.0	722.4	4052
	Wind turbine	2431.0	5808.2	8239
	Pumped-storage	1214.0	480.6	1602
	Batteries	1862.0	516.6	2390
	System	8837.0	7527.8	16,284.1
2. 0 DR	PV	3330.0	722.4	4052
	Wind turbine	2945.8	7038.2	9984
	Pumped-storage	1214.0	480.6	1602
	Batteries	1862.0	516.6	2390
	System	9352	8758	18,029
3. 0.25 DR	PV	3330.0	722.4	4052
	Wind turbine	2402.4	5739.9	8142
	Pumped-storage	1214.0	480.6	1602
	Batteries	1862.0	516.6	2379
	System	8808.4	7459.4	16,175.3
4. 0.5 DR	PV	3330.0	722.4	4052
	Wind turbine	2116.4	5056.6	7173
	Pumped-storage	1214.0	480.6	1602
	Batteries	1862.0	516.6	2379
	System	8522	6776	15,206
5. 0.75 DR	PV	3330.0	722.4	4052
	Wind turbine	1887.6	4509.9	6398
	Pumped-storage	1214.0	480.6	1685
	Batteries	1862.0	516.6	2379
	System	8293.6	6229.5	14,513.8
6. 1 DR	PV	3330.0	722.4	4052
	Wind turbine	1658.8	3963.3	5622
	Pumped-storage	1214.0	480.6	1602
	Batteries	1862.0	516.6	2379
	System	8065	5683	13,655

Table 16. Economic analysis summary.

	1. BAU	2. 0 DR	3. 0.25 DR	4. 0.5 DR	5. 0.75 DR	6. 1 DR
Present worth (MEUR)	2694.9	749.1	2767.2	3558.5	4155.9	4753.3
Annual worth (MEUR /yr)	138.0	38.4	141.7	182.3	212.9	243.5
Return on investment (%)	6.70	5.56	6.75	7.28	7.70	8.16
Internal rate of return (%)	4.39	2.66	4.46	5.20	5.79	6.39
Payback (years)	15.1	17.6	15.0	13.9	13.1	12.4

7. Conclusions and Discussion

Both the European Union and Spain are increasing their commitment to the decarbonization of the economy, and to this end, they are accelerating their plans to promote the energy transition. The non-peninsular Spanish territories are promoting legislative and energy planning developments in this direction. Specifically, in the Canary Islands, an Energy Transition Plan (PTECan) is currently being drawn up with the "objective of achieving the decarbonization of the Canary Islands economy by 2040 and even, if possible, before 2035". Under this context, it would be interesting to consider policies that subsidize the installation of renewable technologies. In the same sense, carbon taxes can be established to penalize whoever does not comply with them—taking all these actions would favour the penetration and speed of installing renewable energy sources within all areas.

However, decarbonization presents a series of very important challenges, which are even greater in the case of the islands due to their special characteristics, such as the problems associated with their isolation, although, on the other hand, they also present a series of opportunities, such as possibilities offered by their natural resources. Therefore, this paper analyses six different scenarios to reach a completely decarbonized energy system by 2040 and shows that it is feasible and beneficial for, in this case, Grand Canary Island, but what is presented here is easily extrapolated to the rest of the islands of the Canary Archipelago, as well as to a multitude of territories with similar characteristics. To achieve economy decarbonization, not only is the elimination of greenhouse gases from the electricity generations systems important, but so too is electrifying all the energy consumptions as much as possible.

The analysed scenarios modified the energy demand curve according to the degree of demand response application. Concerning the model's assumptions, the selection criteria have been the economic ones, keeping the greenhouse gas emissions at zero and considering engineering and land occupation criteria. The economic criterion has implicitly associated a compromise between the sizing of the generation and storage facilities to meet the demand at all times, reaching the optimal point between oversizing the generation and the storage systems and wasting energy.

According to the simulations, in all the scenarios, the maximum potential PV power has been considered. The maximum possible capacity of the PV system on the house's rooftop is 3700 MW. Similar occurs with the pumped storage system (around 600 MW and 10 GWh of power and storage energy, respectively). In the case of the EV batteries, it was used as input the estimated capacity by 2040; it is 2300 MW and 6.15 GWh.

The scenario with the best results is 1 DR. According to this scenario, from the economic point of view, the best option is to install 58 wind generators (12 MW each, around 700 MW in total). The initial investment is EUR 8065 million; the O&M costs are around EUR 286 million/year and the LCOE is EUR 0.11/kWh, with the total NPC cost being EUR 13,655 million. In this scenario, 2347 GWh (26% of the energy produced by the whole system) is not stored since the storage systems are fully charged. The payback for this scenario is 12.4 years, and the internal rate of return is 6.39%.

The worst scenario is 0 DR. In this scenario, the best option from the economic point of view is to install 103 wind generators (1236 MW in total). The initial investment is EUR 9362 million; the O&M costs are around EUR 462 million/year and the LCOE is EUR

0.14/kWh, with the total NPC cost being EUR 18,371 million. In this scenario, 8892 GWh (41% of the energy produced by the whole system) is not stored since the storage systems are fully charged. The payback for this scenario is 17.6 years, and the internal rate of return is 2.66%.

The BAU and 0.25 DR scenarios are very similar; in both scenarios, the best option from an economic point of view is to install around 85 wind generators (12 MW each, around 1 GW in total). The initial investment is EUR 8800 million; the O&M costs are around EUR 3800 million/year and the LCOE is EUR 0.13/kWh, with the total NPC cost being EUR 16,200 million. In these scenarios, around 3800 GWh (35% of the energy produced by the whole system) is not stored since the storage systems are fully charged. The payback for this scenario is 15.1 years, and the internal rate of return is 4.39%

In the case of the opposite scenarios (0 DR with respect to 1 DR), the LCOE is reduced by 25%. On the other hand, the initial investment is reduced by 14%, mainly because wind turbine power capacity is reduced by 44% (from EUR 1236 to 696 million).

If all consumers responded to the DR scenario as much as possible, without additional cost, the costly wind power capacity would be reduced, and an optimal result would be achieved. The benefit obtained compared to the BAU scenario would be EUR 2629 million. This value could be divided by the number of consumers and the project's lifetime, obtaining a fee that could be paid as an incentive for DR. Considering a lifetime of 25 years of the project and 286,408 buildings, on average, an annual fee of EUR 367.17 /building could be paid yearly to every consumer.

Regarding the ways for applying the demand response scenario, Red Eléctrica de España, the entity in charge of operating the national electricity grid in Spain, mentions it is an option to increase the energy cost when energy is more expensive; in this aspect, it deepens on the user. Nevertheless, a trusty and automatic option could be carried out through a control system, taking profit from the technological devices. From 2018 in Spain, all Power meters are smart meters (Real decree 1110/2007 and ICR 3860 2007). The smart meters have inputs and outputs able to give orders and receive information from the switch; the smart meters can send and receive data from the central management system through data concentrators. In this aspect, only one important part of the system required to control the demand response is available. The part not yet available are the switches and systems to connect, disconnect, or modify the loads' settings according to the user's agreement. The government must regulate this part, and predictably, as it happens to smar tmeters, the system could be installed by the electrical company, and the user pays a monthly fee for using the devices. Nowadays, the fee to pay the company for the smart meter is regulated by the government, and it is EUR 9.7/year in the case of households. A similar scheme will probably be used for the demanded response.

On the other hand, Directive (EU) 2019/944 of the European Parliament has included the figure of aggregator. The customer has the right to generate, consume, store, and sell electricity individually or through an aggregator. One of the possibilities is, using the control system, the aggregator could connect, disconnect or modify the setting of the load when convenient, according to an agreement with the client. In any case, the cost of implementing demand response will be negligible compared to the numbers of the entire project.

We conclude highlighting that the methodology used could apply to any place, preferably to isolated systems with geographically suitable sites and energy problems similar to those on the Canary Islands. It would simply be necessary to make the corresponding modifications of the isolation conditions and natural resources map and introduce the detailed demand data.

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