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Development of a modelling and planning tool for renewable microgrids: The case study of Terceira Island

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Abstract

Due to security reasons in isolated microgrids, when assessing long-term dispatch and capacity investments, it is crucial to consider in sufficient detail the system's short-term variability. The objective of this study is to develop a modelling and planning decision-aid tool for the optimal integration of renewable energy (RE) generation in isolated microgrids that combines the short variability with the medium/long-term planning.

The present work proposes the evolution of a short-term economic dispatch model to an integrated operation modelling tool, with several new modelling and planning features. The modelling features developed consist of: the implementation and sizing of different energy storage systems; the development of future demand scenarios with the introduction of electric vehicles, the implementation of demand response strategies, or the replacement of inefficient residential equipment (heating, cooling and domestic hot water systems). The main planning feature is the calculation of the levelized cost of electricity (LCOE) for renewable technologies and storage systems that the user would like to test in the energy system, while operation costs, CO_2 emissions and renewable energy shares are also assessed.

The Terceira Island case study was adopted to validate and shape the integrated economic dispatch model, and results demonstrated that this preliminary tool has a great potential for supporting planning decisions, allowing users and grid managers to test several scenarios and obtain valuable parameters to analyze the proposed strategies. The integrated features allow, in fact, to understand whether a new technology, besides being technically feasible, is economically viable with respect to the already existing technologies in the system under study.

Keywords: Economic Dispatch – Microgrids – Renewable Energy – Energy Storage – LCOE

Resumo

Com vista a garantir a segurança de abastecimento, quando se analisa a longo prazo a operação e investimento em microredes isoladas, é crucial que se considere igualmente a variabilidade da operação do sistema a curto prazo. O objetivo desta tese é o desenvolvimento de uma ferramenta de decisão que se apoia na modelação e planeamento energético de microredes isoladas, que pretende maximizar a penetração de energia renovável, combinando a modelação a curto e médio/longo prazo.

O estudo aqui presente propõe o desenvolvimento de um modelo de operação de despacho económico das centrais, para uma ferramenta integrada de modelação da operação e planeamento, recorrendo a diversos parâmetros de caracterização e modelação. Estas consistem em: implementar e dimensionar diferentes sistemas de armazenamento de energia; desenvolver cenários futuros de consumo, como, por exemplo, a introdução de veículos elétricos, implementação de estratégias de consumo adaptativo, ou de conversão dos sistemas existentes de aquecimento/arrefecimento/AQS ao nível do sector residencial, para tecnologias mais eficientes. Os principais outputs do modelo são os custos de operação, percentagem de energia renovável e de emissões de CO_2, enquanto para o planeamento calcula-se o custo normalizado da eletricidade (LCOE) das tecnologias a serem testadas no sistema.

Como caso de estudo considerou-se a ilha Terceira, Açores, para a validação e aperfeiçoamento da ferramenta. Os resultados demonstram que esta ferramenta tem um grande potencial para ajudar nas decisões estratégicas de planeamento, permitindo aos utilizadores testar múltiplos cenários tanto do lado do abastecimento como da procura, percebendo a viabilidade técnica e económica das mesmas.

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1 Introduction

1.1 Energy security & supply (Islands & Remote areas)

While transport and industries worldwide still rely on fossil fuels as primary energy vector, the power generation sector has been facing considerable changes, especially in developed countries, where dramatic cost reductions for solar photovoltaic, but also for wind power, are driving high levels of investments in renewables and a consequent shift from fossil fuels to renewable resources. At the same time, where untapped economic hydropower, geothermal and biomass resources exist, these technologies are becoming able to provide endogenous low-cost electricity [1].

In recent years, the increasing awareness of GHG emissions due to fossil fuel combustion, and the competitive energy cost of renewables is driving the development of hybrid renewable energy systems integrated with energy storage systems, searching for more reliability in renewable energy production. As the penetration of these variable renewable energy sources increases, maintaining system reliability may, in fact, become more challenging and costly. Having a portfolio of complementary renewable energy (RE) technologies is one solution to reduce the risks and costs of RE integration. Other solutions include the development of complementary flexible generation and the more flexible operation on existing schemes, improved short-term forecasting, system operation and planning tools, electricity demand that can respond in relation to supply availability, energy storage technologies, and modified institutional arrangements [2].

However, isolated power systems, like islands and remote areas, still rely mainly on imported fossil fuels for electricity production [3]. Fossil fuel based power generation is able to ensure grid stability and power supply flexibility, which are essential for a safe and correct functioning of the electrical grid, in particular in isolated systems. Moreover, in addition to the commonly associated environmental issues, given that fossil fuel combustion accounts for 90% of CO_2 emissions worldwide (primary contributor to GHG emissions), this dependence from fossil fuels is cause of many other issues [4]. Between these issues, the most concerning ones are energy security and cost of energy supply. This is due to the fact that fossil fuels are not endogenous resources, thus usually have to be imported, making the energy resource expensive. The majority of islands, European in particular, suffer in fact from large dependence of imported energy [5].

Despite the fact that islands face severe energy security, renewable energy resources such as wind, solar, hydropower, biomass and geothermal, are frequently abundant opportunities to explore for power conversion. Island systems are being the test bed of innovative technologies that can potentially lead the future of large interconnected grids [6]. The European Island Union, for example, has established island demonstration projects to prove that energy supply systems could rely on endogenous renewable energy sources [4]. However, many challenges are hindering the integration of renewable resources on isolated systems. These challenges range from long-term planning to short-term operations and require island system operators to meld all existing technologies and further explore innovative technology options. Political backup is needed as well, in order to promote a variety of issues, such as smart grids, distributed generation, climate policy, system resilience and storage technologies. Moreover, due to the lack of interconnection between isolated and main grids, technical constraints often hinder the penetration of renewable energy production. In particular, fluctuations in intermittent renewable energy production threaten grid stability and reliability.

The right equilibrium between conventional thermoelectric and renewable power production, together with the minimization of fossil fuel consumption, can bring to more independent and sustainable isolated power supply systems.

1.2 Objective of study and scope

In light of the energy security and supply problems in isolated systems presented above, the need of a decision-aid modelling tool for isolated hybrid energy systems was identified. A tool where technical constraints of generation units have a significant impact on both the short-term optimization of production costs and long-term planning. A “beta version” of this tool was firstly developed by Abeysekera [7]. The objective of this work is to improve this previously developed economic dispatch (ED) model and integrate a variety of features in order to create a universal tool that can be implemented for any microgrid under study, either an island or isolated municipality.

1.3 Structure

The structure of the present work follows the chronological development of the integrated model in order to clearly demonstrate the contribution of the author to the initial dynamic programming algorithm. First of all, a literature review on the existing energy system modelling tools, economic dispatch and unit commitment problem is conducted. The research hypothesis and need of the presented modelling tool is then identified within the designated frame. Subsequently, the initial ED model is presented, adapted to a real case study and validated. In particular, the case study focuses on the Portuguese island of Terceira in the Azores Archipelago. The opportunity of using Terceira as case study was made available thanks to *Project Vulcano*, a collaboration between Instituto Superior Técnico of the University of Lisbon and the Luso-American Development Foundation, whose main goal is to identify solutions and strategies to promote the development of a sustainable energy system in “islanded” energy systems. Following this preliminary validation, the ED model is further developed with the integration of a wider range of renewable energy production sources. Moreover, the complexity of the model is increased by including energy storage systems (ESS), demand side management programs such as Demand Response (DR) strategies, the possibility of simulating future scenarios such as the implementation of Electric Vehicles (EVs) in vehicle-to-grid (V2G) applications, and efficiency measures consisting in the replacement of older and less efficient domestic technologies with more recent and efficient ones. The investment planning aspect is then integrated through specific economic parameters in order to provide a more complete overview of the scenarios developed. Finally, an example of the complete integrated model working with a combination of its features is provided and analyzed both in the short-term and long-term time horizons.

2 Literature review

2.1 Energy systems models

In recent years, several energy system modelling tools have been developed in order to aid the integration of renewable energy production in fossil fuel based power systems and analyze its reliability and cost efficiency. These modelling tools meet different goals and can be classified in different ways, according to their scope. The main purposes are: simulate the behavior of an energy system and optimize its operation costs, search for market equilibrium, and identify and evaluate investment options [8]. Modelling tools with the first two goals are mainly used for grid operation planning, where the time horizon is classified as short-term, while investment evaluations are more related to long-term analyses of energy system planning.

The minimization of operation costs of an energy system mainly relying on fossil fuel consumption, can lead to significant economic benefits [9]. In particular, in small isolated micro-grids, there is a need of a better planning of the long-term investment, and at the same time the need of an economic dispatch tool able to schedule the unit commitment of the thermal generators in order to minimize fossil fuel consumption and foster the integration of renewable power production, assuring grid reliability.

A variety of tools able to partially satisfy the request were found in the literature [8], and the two more widely used are reported below, together with a brief description.

EnergyPLAN (developed by Aalborg University, Denmark)

- EnergyPLAN is a user-friendly tool to assist the design of national or regional energy planning strategies by simulating the entire energy system. This tool can model thermal and renewable power production, energy storage and conversion, transports and all the associated costs. The model is an input/output model. The analysis is carried out in hourly steps for one year. General inputs are demands, renewable energy sources, power plant capacities, costs, regulations for import/export and excess electricity production. The model is able to develop several kinds of energy systems analyses, such as technical, market exchange and feasibility studies. Each analysis is measured through a particular set of outputs. In technical analyses, outputs consist of annual energy balances, fuel consumptions and CO_2 emissions. Concerning market exchange analyses, the economic simulation strategy is based on a short-term marginal price market, therefore focusing on bids to the electricity market while minimizing short-term electricity consumer and district heating costs. The calculation of feasibility occurs in terms of total annual costs of the system under different designs and simulation strategies. The model determines the socio-economic consequences of the production [10].

HOMER (developed by the National Renewable Energy Lab, division of U.S. Department of Energy)

- HOMER (Hybrid Optimization of Multiple Energy Resources) is a micro-power design tool that simulates and optimizes stand-alone and grid connected power systems with multiple pre-determined choices between different types of energy generators, batteries and hydrogen storage, serving both electric and thermal loads and which can be specified in detail [11]. The time resolution of the model can go from one day to one year, based on a default time step of one hour (which can be modified from minutes to several hours). The objective of the optimization is to evaluate the economic and technical feasibility for a large number of technology options, considering variations in technology costs and energy resource availability [8]. The final output used to indicate economic and technical feasibility is a list of all the feasible configurations with increasing Net Present Cost (NPC).

Despite the capability of these tools to simulate, with hourly time step resolutions, the dispatch of an energy system, they do not contemplate the input of detailed technical constraints regarding the generation units (i.e. startup/shut down times and costs), therefore they are not able to develop a reliable and realistic unit commitment schedule.

The importance of considering such short-term balancing in long-term energy models in order to derive reliable power system configurations is demonstrated in [12]. Dispatch and capacity investments derived from long-term models may be significantly different if the system's short-term variability is not accounted in sufficient details. For this reason, cases were found in the literature where the authors felt the necessity of combining a short-term and a medium/long-term tool to simulate the desired scenarios, rather than using an already existing modelling tool. For example, in order to assess the energy reduction potential from the shift to electric vehicles in the Flores island, Pina et al. [13] used a two-step modelling approach. Firstly, TIMES, a medium-term model, was used to optimize the investment in new generation capacity from RES by taking into account the evolution of electricity demand and fuel prices over a time horizon of 20 years. The outputs of this model, consisting in the quantification of the annual installed capacity, were then used as input for a short-term self-built electricity dispatch model with a one-year time horizon and an hourly temporal resolution. The short-term model was used individually for each year in order to optimize the balance between electricity production from the different energy sources and electricity demand.

2.2 Economic Dispatch

Economic dispatch can be defined as the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities [14]. The main idea is that in order to satisfy a load at the minimum total cost, the set of generators with the lowest marginal cost must be committed first. The system's marginal cost is set by the marginal cost of the final generator needed to meet the load.

The historic methodology for economic dispatch was developed to manage fossil fuel burning power plants, whose commitment availability is constrained from technical characteristics. For this reason, a unit commitment (UC) schedule allowing the economic dispatch of the fossil fuel burning generators at every instant has to be identified. This optimization of operating costs of thermoelectric power plants can be done through the resolution of the UC problem. The UC problem consists in defining the order in which generating units are to be turned on and shut down over a period of time, so that the total operating cost, in this period, is minimum [15]. The formulation of the UC problem occurs through an hourly economic dispatch model, which matches the load demand at a particular hour using the committed generators by producing power at the minimum operating cost. This process should always respect operating and transmission constraints [16]. The UC problem can therefore be defined as economic dispatch over a sum of time steps (i.e. day, week, month or year). This often results highly dimensional and combinatorial due to the restriction, by certain constraints, of the freedom of choice in starting up and shutting down generating units. Since the development of a rigorous mathematical model capable of solving the whole problem is extremely complex, many methods using approximations and simplifications have been proposed in the literature.

The available approaches for solving the unit commitment problem can usually be classified into heuristic methods and mathematical programming methods. Following, is reported a brief description of the main approaches found in the literature [17][18], using heuristics or mathematical programming solution methods such as mixed integer programming, Benders decomposition, dynamic programming and Lagrangian relaxation.

1. Heuristic methods

Heuristic methods are non-rigorous computer aided empirical methods, which make the unit commitment decisions according to a pre-calculated priority list and incorporate all the operating constraints heuristically. The priority list is set on the basis of the average full load cost of each unit. Heuristic methods are flexible, usually obtain feasible solutions (if they exist) and their computational requirements in terms of memory and running time are modest. On the other hand, they cannot guarantee the optimal solutions or furnish an estimate of the magnitude of their sub-optimality due to their non-deterministic nature.

2. Mixed integer programming

Mixed integer programming (MIP) is a modification of standard integer programming that allows non-integer functions. MIP treats objective and constraint functions as continuous and variables as integers.

The main shortcoming is that the formulation of unit commitment through MIP is a very complex problem and takes a long computational time.

3. Benders decomposition

This method consists in decomposing the unit commitment problem into two main blocks: a master problem involving only the discrete commitment variables and a sub-problem involving the continuous generation variables (economic dispatch problem). The marginal costs, for each hour, resulting from the economic dispatch, constrain the allowed commitments in the master problem. The master problem supplies commitments back to the economic dispatch sub-problem. These two are solved iteratively until the solution converges. The master problem is still considered as a large scale integer optimization problem, and constitutes the major difficulty in Benders decomposition approach.

4. Dynamic programming

The principle of dynamic programming as an optimization technique is to break down a complex problem into simpler sub-problems, solving each sub-problem just once, and storing the solution. The optimal solution is developed from the sub-problems recursively. In the literature, dynamic programming has been used extensively to develop unit commitment programs. In its fundamental form, the dynamic programming algorithm for unit commitment problem examines every possible state in every time interval. Even though some of the states are rejected instantaneously due to infeasibility, a large number of feasible states will exist and the requirement time of execution will be problematic. Therefore, simplifications and approximations, such as truncation and fixed priority ordering, are adapted to the fundamental dynamic programming algorithm. These simplification techniques make dynamic programming, together with Lagrangian relaxation, the main mathematical approach to UC problems given its reasonable computational time.

5. Lagrangian relaxation

The use of this method in unit commitment problems is much more recent than dynamic programming methods. Lagrangian relaxation approximates a complex problem of constrained optimization by a simpler problem. The formulation of the unit commitment problem through this method consists in decomposing the total problem in single generator sub-problems. Each of the sub-problems may be solved by a simple dynamic programming recursion. This method has the advantage of being easily modified to model characteristics of specific utilities and it is more flexible than dynamic programming because no priority ordering is imposed. Since the amount of computations varies linearly with the number of units, this method is computationally much more unattractive for large systems.

Moreover, in the literature, several studies present a variety of methodologies for economic dispatch (ED) of island grids with distributed energy resources. Su and Chuang [19] use genetic algorithms to optimize the integration of a Battery Energy Storage System (BESS) in a given power system. Daily time varying loads, wind power generation and diesel generators operation scheduling are considered together with BESS characteristics such as capacity, installation location and charging/discharging schedules. The problem is formulated as a non-differential combinational optimization problem to solve the ED of the BESS and power units, where the total system cost to be minimized is subject to capacity and system operation constraints. A practical island power system is then selected for computer simulations to ensure and demonstrate the performance of the proposed method and explore the benefits of the BESS to system operations. Neves and Silva [20] study the use of Domestic Hot Water (DHW) electric backup from solar thermal systems to optimize the total electricity dispatch of an isolated mini-grid. The proposed approach estimates the hourly DHW load, and proposes and simulates different Demand Response (DR) strategies from the supply side, to minimize the dispatch costs of the energy system. This study considers the use of an economic dispatch model that combines the unit commitment problem and the quadratic dispatch method, taking into account the operational restrictions of generation technologies.

3 Economic Dispatch model

Economic dispatch consists in the optimization of operating costs of power generators while respecting their technical constraints. However, different generation technologies have different constraints and associated operating costs. In particular, cost structures of different power plants depend on several factors: the access to the energy resource that these convert, the technology they use, the location in which they are situated, among others. Nevertheless, it is possible to distinguish between fixed and variable costs, separation which can be considered valid for all different types of power plants. The first can be identified in installation and decommissioning of the plant (capital costs), while the latter are the plant's fuel, operating and maintenance costs. The ratio between capital and operating costs strongly depends on the plant's technology. In nuclear generation, fixed costs of building and decommissioning the plant are extremely higher than fuel, operating and maintenance costs. For fossil fuel technologies, fixed costs of building the plant are lower than for nuclear, but fuel costs (coal, gas and oil) are higher. Hydropower has high fixed costs, such as nuclear, but, once installed, tends to require less maintenance costs and last longer, while fuel costs only consists in water usage fees that may be set by the region where the plant is situated. Concerning renewable technologies (e.g. wind and solar), their cost structure is mainly fixed, being their fuel cost inexistent [21]. These examples show that, in several cases, increasing the operational efficiency of the plant, mainly by reducing fuel consumption, may lead to extremely relevant cost savings. This is the case of thermoelectric power plants that use fossil fuels as energy vectors. With this in mind, the main goal of the developed tool is to decrease operating costs, thus fuel costs.

The original self-built model is a daily economic dispatch model that combines the unit commitment problem with a linear dispatch method, taking into account operational constraints of various generating technologies [11]. The model was developed using a MATLAB simulation platform. The UC problem was handled using a dynamic programming approach, while each time step economic dispatch was optimized by an optimization solver available in MATLAB (*fmincon*).

The dynamic programming algorithm operates through a fixed priority list, based on the generators' full load average production cost (FLAPC). This list establishes in which order generators should be committed, giving priority to units with lower generating costs per kilowatt-hour produced.

Generally, the constraint equation to be met in a solution of this type of problem, is the following:

$$P_{load} + P_{loss} - \sum_{1}^{N} P_i = 0 \tag{1}$$

Where P_{load} is the load of the energy system, P_i are the power outputs of the *N* generators in the system, and P_{loss} are the transmission losses. This equation has to be met at every instance. However, for sake of simplicity and because of their relatively small influence on the solution in the small systems analyzed, grid losses are assumed to be zero.

The economic dispatch algorithm advances as follows:

- In the first time step the algorithm considers all possible unit combinations for the dispatch and the resulting production costs are saved with each configuration;
- As the time step advances to the next time interval, all possible combinations are considered again. However, in this time step the cost of transition from each previous feasible state is accounted for. The minimum cost considering the sum of transition, start up (if required) and production at that time step, from different possible previous feasible states, is saved for the progression of the algorithm; this procedure is carried out for every feasible combination in the considered time step;
- As the time step advances, the minimum cost transition paths are saved within the program. Finally, at the end of the program (last time step), the minimum cost path is chosen.

Figure 1 reports a scheme of the forward programming algorithm adopted.

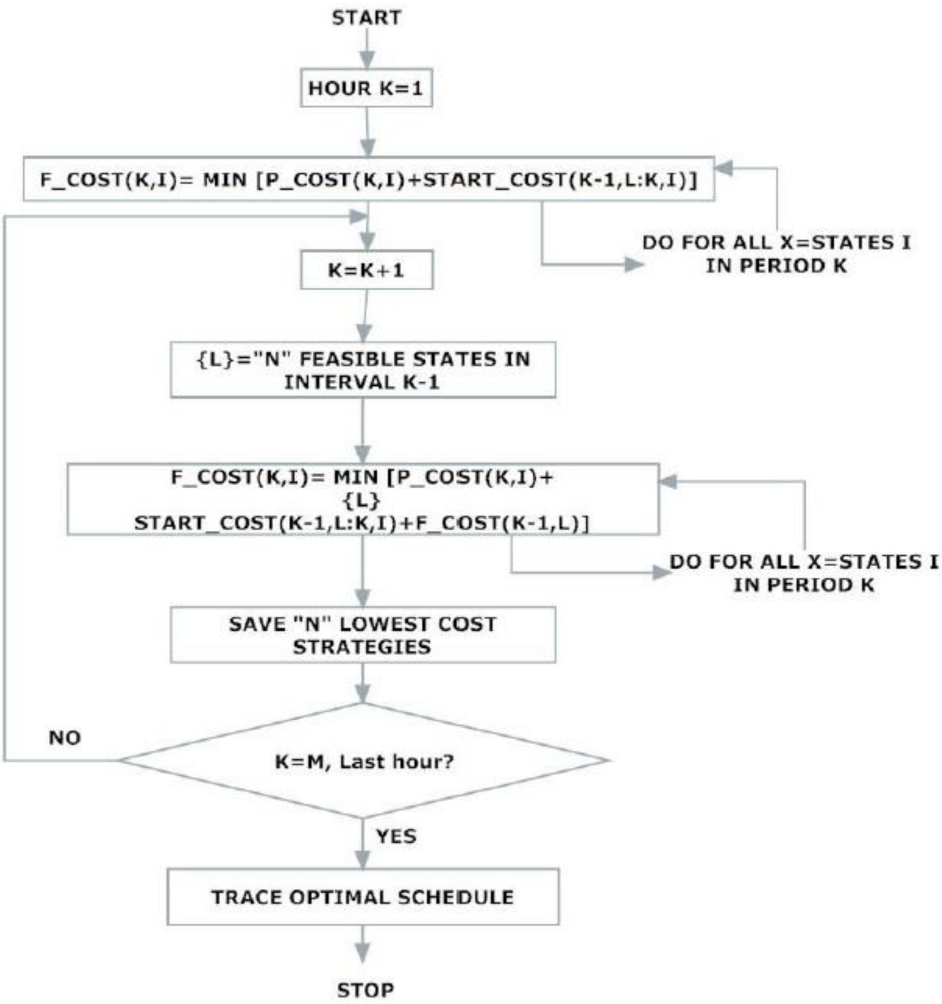

Figure 1: Unit Commitment via forward programming [22].

The recursive algorithm to compute the minimum cost in hour K with combination I is:

$$\mathrm{F_{cost}}(K,I) = \min[P_{cost}(K,I) + S_{cost}(K-1,L:K,I) + F_{cost}(K-1,L)] \quad (2)$$

Where:

- State (K,I) = I[th] combination in hour K.
- $\mathrm{F_{cost}}(K,I)$ = Minimum total cost to arrive at state (K,I).
- $P_{cost}(K,I)$ = Production cost for state (K,I).
- $S_{cost}(K-1,L:K,I)$ = Transition cost form state $(K-1,L\,)$ to state (K,I).

The production cost calculated for every feasible state at every hour is:

$$\mathrm{P_{cost}}(K,I) = \sum_{i=1}^{N}[(G_{inc_i} \times P_i(K,I) + G_{NLC_i}) \times CS_i(K,I) \times G_{FC_i}] \quad (3)$$

Where:

- N = Number of generators with an associated fuel cost.
- G_{inc_i} = Incremental heat rate in L/kWh of generator i.
- P_i = Power output of generator i (vector subject to optimization).
- G_{NLC_i} = No Load Cost of generator i in L/h.
- CS_i = Current state of generator i (1 if on-line, 0 if off-line).
- G_{FC_i} = Specific fuel cost of generator i in €/L.

Following are presented the main inputs to the model, namely technical operating constraints of the generators, specific fuel costs and renewable resources availability.

3.1 Model Inputs

3.1.1 Operating constraints

The model takes into account generators' technical characteristics by transforming them into constraints of the unit commitment problem. These constraints are mainly associated to thermal generators, and allow the model to develop more realistic simulations. Below a description of the technical constraints considered in the model together with the mathematical formulation of the constraint is reported [7].

- **Minimum and maximum power outputs**

Minimum and maximum active power outputs set the range between which each generator is able to produce electricity. They usually refer to generation limits under normal operating conditions. At every hour K, for every generator, the power output P_i has to be:

$$P_{min} < P_i(K) < P_{max} \quad (4)$$

- **Spinning reserve**

The spinning reserve is the difference, at a certain time step, between the total amount of nominal capacity available from all the units committed to the system, and the power currently supplied. The spinning reserve is necessary in order to meet the demand in case there is a disruption in supply or an unexpected event on the demand side. This constraint is taken into consideration by the model when initially checking for all feasible states. A state is considered feasible for a particular hour K if:

$$\begin{cases} P_{tot_{min}} \leq Demand(K) - R_{down} \\ P_{tot_{max}} \geq Demand(K) + R_{up} \end{cases} \tag{5}$$

Where R_{up} and R_{down} are the upward and downward spinning reserves respectively. These can either be input as a vector of values for each hour or as a fraction of the demand.

- **Ramp up and ramp down rates**

Ramp up and down rates are defined respectively, as maximum increase and decrease rates, in power output, that a generator can provide between two time steps K and K-1.

$$\begin{cases} P_i(K-1) - P_i(K) \leq DR_i \\ P_i(K) - P_i(K-1) \leq UR_i \end{cases} \tag{6}$$

Where UR_i and DR_i are ramp up and down (respectively) limits of generation unit I per hour K.

- **Minimum up and down times**

Minimum up time is the minimum amount of time a generator should run, once it is synchronized to the system. Minimum down time is the minimum amount of time a unit should rest once it is de-committed before recommitting it again. These constraints have a relevant impact on the resolution of the unit commitment problem. In fact, the model has to verify that the combination of units committed is feasible with regard to these constraints for every step.

3.1.2 Operating costs

Operating costs considered in the model are all the costs directly related to fuel consumption. In particular, operating costs are divided into generation and transition costs. The first ones consist in all costs attributed directly to fuel consumption for power generation, while the second derive from fuel burnt during startup, shutdown and ramp up/down phases. Startup costs are due to the fact that, depending on their current status, generation units burn a certain amount of fuel in order to be brought on-line. This energy spent does not produce any power generation, but has to be considered as a cost. Moreover, these can be divided in hot and cold startup costs, depending on how much time the generator has been off before the time step in consideration. The introduction of startup costs provides the solution with a more realistic value for the system operation, as it avoids turning on and off the generation units arbitrarily.

While for thermal generators the calculation of fuel consumption costs is a straight forward process, concerning RE operating costs it often results complicated to identify indirectly associated fuel consumption costs. For this reason, it is possible to consider levelized costs of electricity (LCOE) as RE operating costs [23]. The LCOE parameter will be further explained in the following sections.

The thermal generator cost model adopted describes the generator's cost function as a linear equation, seen in Figure 2, that relates power output to fuel consumption rate. Technical sheets of thermal generators provide specific fuel consumption per kilowatt-hour at different load factors. Combining this information with the specific fuel cost, the hourly fuel consumption cost per power output equation is obtained.

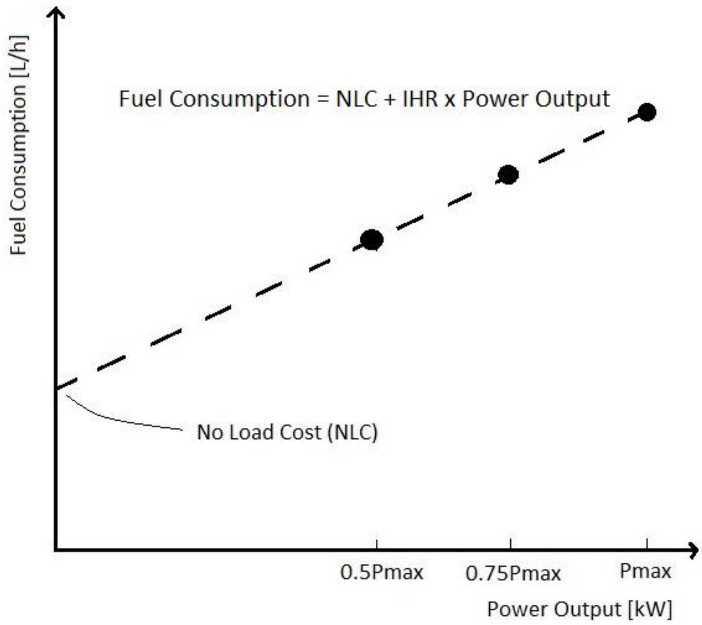

Figure 2: Linear fuel consumption curve of thermal generators [24].

No load cost (NLC) is considered as the theoretical cost for a unit to remain connected to the system while not supplying electrical power. Such a mode of operation is not possible for most thermal generating units [24].

Where NLC is in L/hour, IHR in L/kWh and fuel cost in €/L.

The no load cost is the constant term in the cost curve and does not have any physical meaning. The Incremental Heat Rate (IHR) is the amount of extra fuel necessary in order to increase the generator's power output.

When the fuel consumption cost is calculated for the generator's maximum power output, the full load average production cost (FLAPC), on which the previously mentioned priority list is based, is obtained (Equation 7).

$$FLAPC = (NLC + P_{max} \times IHR) \times \frac{FuelCost}{P_{max}} \quad (7)$$

3.1.3 Renewable energy integration in the model

Since operating constraints are defined only for thermal generators, power production from renewable resources is modeled through independent functions that convert the available resource at a certain instance, into available electrical power output. Renewable energy technologies can be divided into dispatchable (their output can be varied to follow the demand) and non-dispatchable (less flexible technologies whose operation is tied to the availability of an intermittent resource) [23].

3.1.3.1 Dispatchable renewable technologies

Renewable technologies classified as dispatchable are biomass/solid waste (which will be considered as one type of resource [23]), geothermal and hydroelectric. Hydroelectric technology could be classified as well as non-dispatchable as its overall operation is limited by resources available by site and season. However, it is assumed that hydroelectric has seasonal storage so that it can be dispatched within a season. Since dispatchable RE production availability depends on biomass/solid waste reserve stocks, earth’s heat content and reservoir level in biomass, geothermal and hydroelectric power plants respectively, these are not subject to stochastic variations. The only parameter indicating the availability of dispatchable renewable technologies is their capacity factor, intended as the maximum number of hours the power plant is able to work at nominal capacity over one year. However, as the ED model produces annual values from the extrapolation of daily/weekly simulations, the capacity factor cannot be taken into consideration as it does not reflect on average short-term dispatch behaviors. Therefore, despite being average capacity factors 83% for municipal solid waste, 92% for geothermal and 54% for hydropower [23], no fix capacity factor constrains the dispatchable generators’ production, which are therefore free to range between 0-100%.

3.1.3.2 Non-dispatchable renewable technologies

Non-dispatchable renewable technologies are wind, solar PV and solar thermal. The models of non-dispatchable renewable generation depend on the resource exploited, therefore they will be described separately. In particular, the proposed economic dispatch model integrates solar PV and wind technologies.

- **Solar PV**

The idea was to develop an auxiliary function that would take as input the mean solar irradiation of a certain month for the selected location, together with geometry and technical characteristics of the PV arrays, and model the hourly production for the time horizon considered. This vector of values is then considered as the hourly availability of the renewable generators in the economic dispatch model. The function takes the mean irradiation on a horizontal surface, value available for any location (i.e. from NASA [25] or WRDC [26]) and transforms it into hourly irradiation over the entire day. The following equation represents the relation between hourly and daily irradiations:

$$r_t = \frac{I}{H} \tag{8}$$

Where H is the daily and I the hourly irradiation (both in energy over area unit, i.e. kWh/m² or J/cm²). The ratio r_t is calculated according to [27] and it determines how the daily irradiation is distributed over the day. If the user already has hourly irradiation data, these can be directly input into the model in order to have more accurate results, bypassing the day-to-hour modelling.

An example of the implementation of the proposed methodology can be seen in Figure 3. The example reports values acquired on the 28th of July 2015 in the from the Wien/Hohe Warte Station, recorded by the *World Radiation Data Center* [26]. This particular station was chosen as an example as it provided both daily and hourly values.

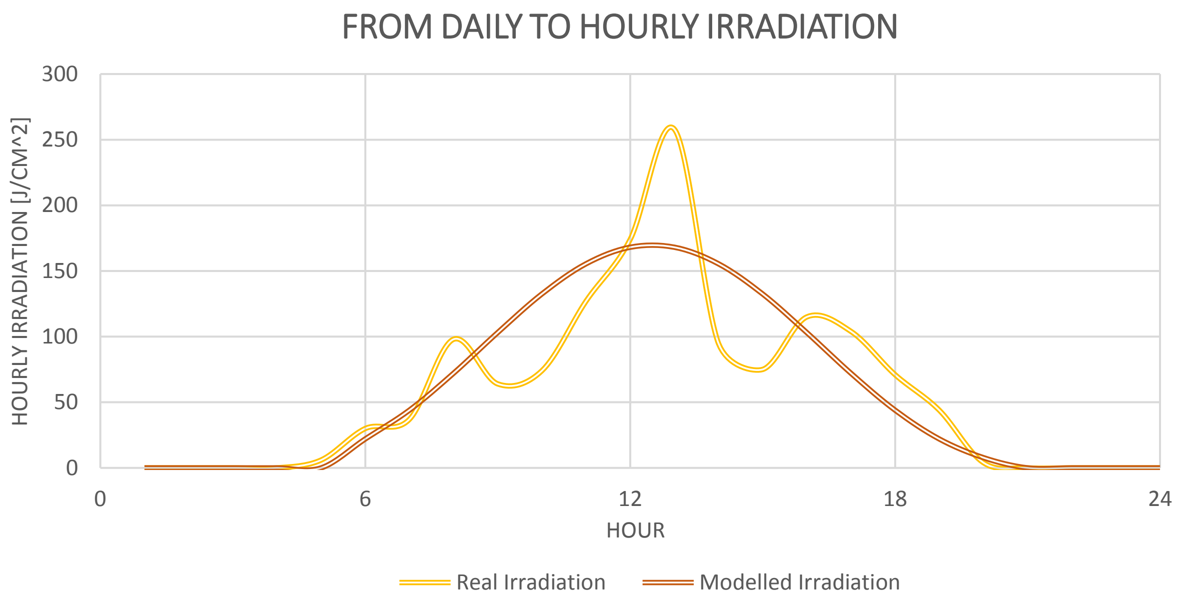

Figure 3: Comparison between real hourly irradiation data and modelled hourly irradiation from daily values with the proposed methodology. Example for Wien, Austria on the 28th of July 2015 [26].

It can be seen that the forecasting model respects sunrise and sunset hours, but is not able to accurately reproduce the hourly irradiation. Therefore, when available, it is recommended to use directly hourly values.

Once the hourly irradiation is calculated, there are two options for obtaining the hourly power output of the PV system. The first is through an electrical model that simulates the PV generator behavior under real operating conditions, requiring more detailed inputs, but resulting more accurate as it takes into consideration the operating temperature of the PV modules [27]. Inputs to this electrical model are:

- Operating ambient temperature
- Effective Irradiance incident on the PV panels (calculated by the first part of the model)
- Nominal Operating Cell Temperature (NOCT)
- Number of PV modules (series X parallel)
- Characteristics under Standard Operating Conditions (STC)
  - Operating ambient temperature
  - Irradiance

- Short circuit current (I_{sc})
- Open circuit voltage (V_{oc})
- Maximum module power (P_M)

The model is then able to calculate the characteristic curve of the generator, and determine the maximum power point as:

$$P_M = I_M \times V_M \tag{9}$$

Where I_M and V_M are, respectively, the maximum current and voltage. Inverter efficiency is assumed to be constant at 95% [27].

The other approach is more generic, and it requires as inputs only the total area covered by the PV system and the system's overall efficiency η:

$$P_M = G_{eff} \times \eta \times Area \tag{10}$$

Where G_{eff} is the hourly irradiance on the PV in kW/m^2.

- **Wind**

Concerning wind energy, the integration of this auxiliary function in the economic dispatch model is similar to the solar PV case. However, since wind resource is more variable than solar irradiation, and therefore more complex to model, the function takes as input directly a vector of hourly wind speed. Technical data sheets of wind turbine manufacturers provide the power curves of the generators. Standard power curves for several sizes of wind turbines were selected and integrated in the function, which is therefore able to calculate an available power output for each hour depending on the wind speed forecasted. This vector becomes then an input to the economic dispatch model.

3.2 Model outputs

3.2.1 Operating costs

The main objective of economic dispatch is to minimize operating costs in power systems. Usually, these operating costs consist in fuel consumption costs, especially in power systems mainly relying on thermal generators. In this case, operating costs are calculated as the sum of dispatch costs related to power production and transition costs of starting up/shutting down thermal generator. However, as mentioned previously, operating costs can be associated to renewable energy production and storage systems as well through levelized costs of electricity (LCOE). LCOE of RE technologies are, in fact, used to spread the investment and O&M costs of RE power plants over their nominal life time, allowing to economically compare RE and non-RE technologies. Therefore, the model outputs the total operating cost for the time interval of the optimized production.

3.2.2 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions are calculated by the model in order to quantify the environmental impact of power generation in the studied system. In particular, carbon dioxide emissions, as they are the most relevant concerning diesel generators. The model takes into account all CO_2 emissions related to the operational phase of the power plants: therefore, released while generating power and during transition phases of the generating units such as startup and shutdown. Moreover, operational CO_2 emissions are directly related to fuel consumption and are therefore associated to thermal generators only, and not to renewable energy generation.

CO_2 emissions are calculated, at every time step, according to the following formula [28]:

$$Emissions CO_2 = \frac{44}{12} \times Q \times NCV \times EF \times (1 - s_f) \times f \tag{11}$$

Where Q is the amount of fuel consumed, NCV is the net calorific value of fuel, EF the emission factor (carbon content per unit of energy), s_f is the carbon storage factor and f the oxidation factor. The 44/12 factor is the ratio between the molar masses of CO_2 and C, necessary to pass from carbon to CO_2 emitted.

3.2.3 Renewable shares

The model provides shares of the different production sources in the electricity production mix for the analyzed time period. One of the main objectives of the model is, in fact, to quantify the penetration of renewable energy production in the supply system. This output is extremely valuable for comparing the results of simulations done to assess the impact of storage systems or demand response strategies on the penetration of renewable energy production. Moreover, capacity factors of renewable energy generators can be output, which represent valuable indicators of how much different technologies are exploited, and allow the comparison with standard values found in the literature.

4 Case Study: Terceira Island

The main reason Terceira Island was adopted as a case study is because of the exceptional amount of data made available by Electricidade dos Açores (EDA). These data were fundamental for a correct validation of the model and for the development of new integrated features such as Energy storage systems (ESS), Demand Response (DR) and efficiency measures.

This section is divided into three parts: first, an introduction on the island is presented, then Terceira's energy supply system is characterized and finally the model is validated with the presented data.

4.1 Introduction on Azores & Terceira: From primary energy to electricity

The Azorean archipelago is composed of nine volcanic islands located in the middle of the North Atlantic Ocean, about 1,360 km west of continental Portugal and 1,925 km southeast of Canada. The archipelago forms the Autonomous Region of Azores, one of the two autonomous regions of Portugal. Azores' main industries are tourism, cattle raising for milk and meat, and fishing [29].

In Figure 4, the shares of primary energy consumption in Terceira in 2014 divided by sector, can be seen. Despite being Agriculture the main industry, it can be seen that the largest share of primary energy consumption is attributed to transportation. The total amount of primary energy consumption in 2014 was of 2,334 TJ [30].

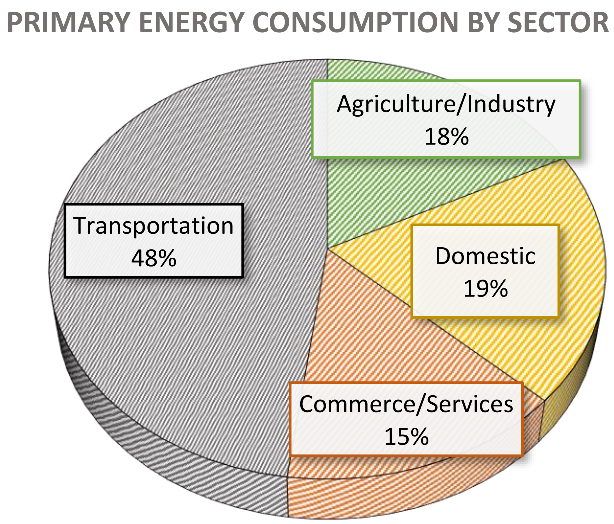

Figure 4: Primary energy consumption in Terceira, divided by sector, in 2014 [30].

Regarding final energy consumption, Figure 5 shows its evolution between 2001 and 2014 [30]. Diesel and gasoline are mainly used for transportation, while a large share of the fuel oil consumption is used for electricity production, and is therefore contained in the electricity share.

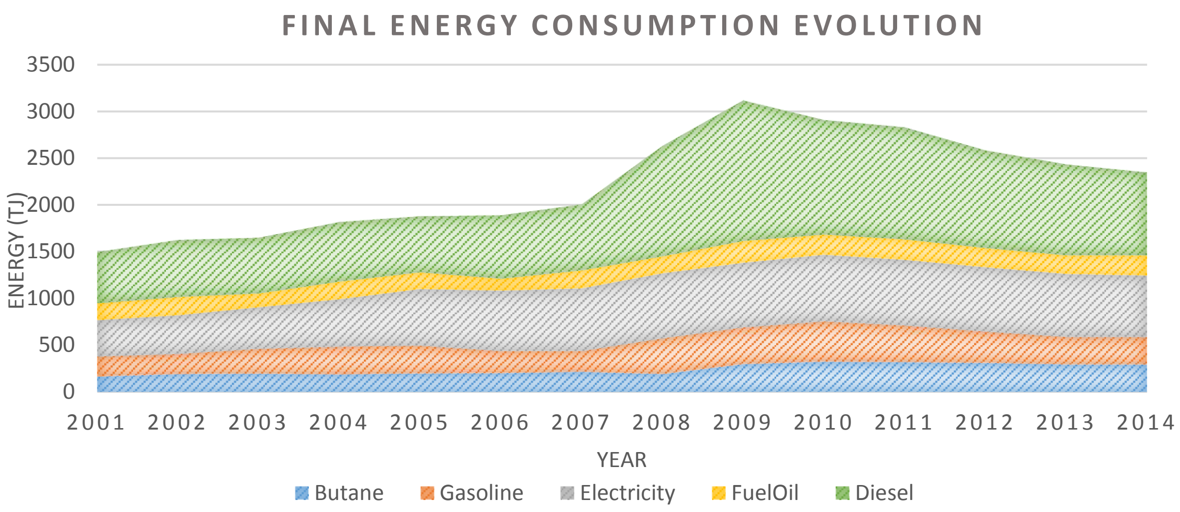

Figure 5: Evolution of the final energy consumption in Terceira between 2001 and 2014 divided by energy vector [30].

An important characteristic of Azores is that EDA is the only electric utility existing and operating in the Archipelago, which made it feasible, in the present work, to focus on the economic dispatch, ignoring the influence of electricity market prices.

4.2 Characterization of Terceira's energy supply system

According to the local utility Electricity of Azores (EDA), on December 31st 2014 the electric system of Terceira was composed by five active power plants and five substations. The Transport & Distribution system comprised a medium voltage transmission network (MV) of 30 kV and a medium voltage distribution network of 15 kV. In the Military Detachment of the U.S Air Base at Lajes, the electricity distribution was realized with a voltage level of 6.9 kV [31].

Table 1 reports a picture of Terceira's power production system at December 31st 2014, concerning EDA's power plants. The installed capacity on the island by the end of 2014 was of 71.548 MW [31].

Table 1: Terceira's power production system owned by EDA at December 31st 2014.

Acronym	Power Plant	Energy Source	Generation units	
			N° of units	Installed Capacity [kW]
CTBJ	Belo Jardim	Thermic – Fuel	2	3,128
			1	3,000
			1	2,860
			4	6,100
			2	12,300
CHNA	Nasce D'Água	Hydric	1	720
CHSI	São João de Deus	Hydric	1	448
CHCD	Cidade	Hydric	1	264
PESC	Serra do Cume	Wind	10	9,000
Total	**-**	**-**	**23**	**71,548**

However, an additional power plant on the island, that is not included in Table 1, has to be taken into consideration. This is a private windfarm belonging to "Companhia Açoriana de Energia Renováveis (CAEN Lda.)" that started producing in September 2013 with a total install capacity of 3.6 MW and has been fully operational since then.

Figure 6 reports the evolution of Terceira's installed capacity between 2006 and 2014, and annual maximum and minimum peak and off-peak values for the same period. It can be observed that peak and off peak values do not present increasing or decreasing trends over this 9-year timespan, but they rather remain constant. However, concerning the installed capacity, three evident "steps up" can be identified in Figure 6. They are all due to the installation of wind farms.

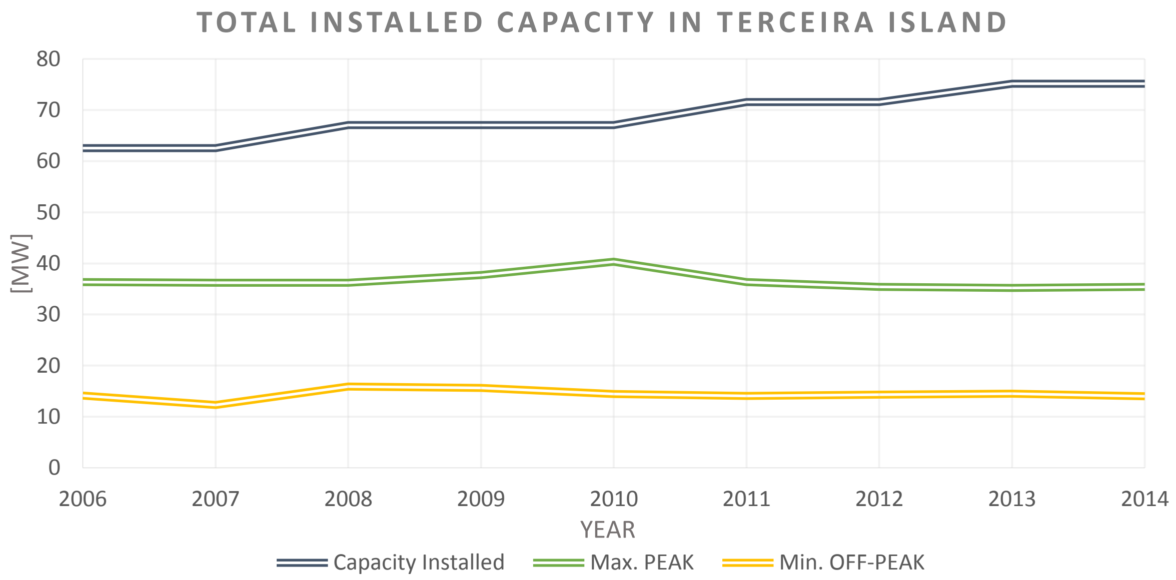

Figure 6: Evolution of Terceira's total installed capacity between 2006 and 2014 [32].

The first took place in 2008, when the first half of EDA's Serra do Cume wind farm started operating, bringing 4.5 additional MW_e to Terceira's energy supply system. Three years later, in 2011, the wind park was expanded with the integration of other 4.5 MW_e. Finally, in 2013 CAEN installed the first private power plant on the island, consisting of 3.6 MW_e always situated in Serra do Cume, adjacent to the already existing wind farm [32].

Moreover, as seen in Figure 7, the progressive expansion of wind power installations on the island brought to a significant penetration of wind energy production in Terceira's electricity mix. From 3.4% in 2008, with the first 4.5 MW_e of EDA's wind farm in Serra do Cume, to the 17% in 2014 exploiting all 12.6 MW_e of wind power installed [32].

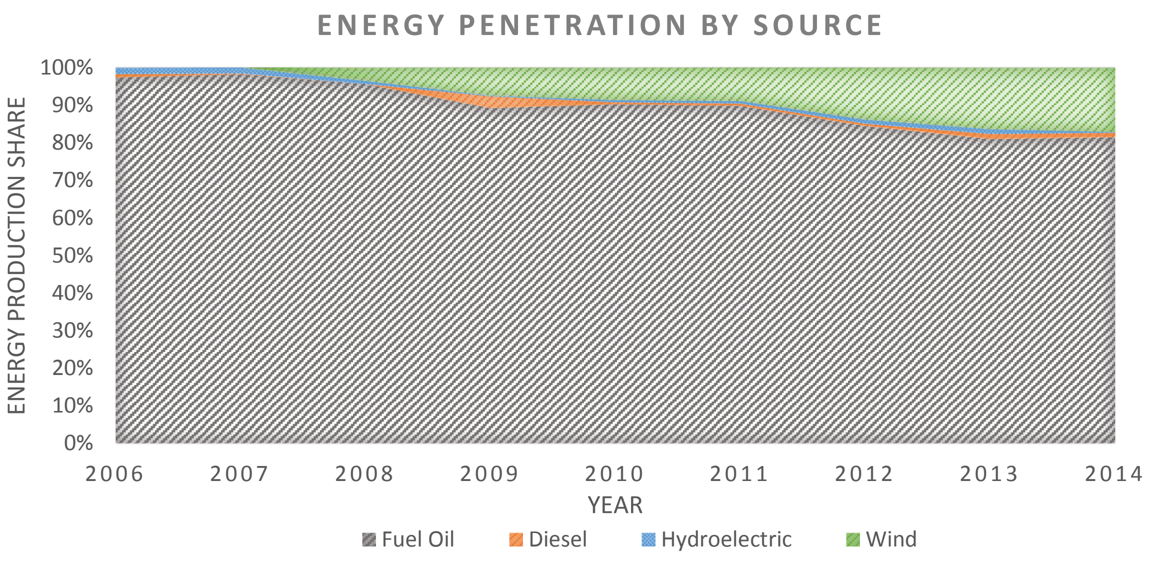

Figure 7: Energy penetration by source in Terceira between 2006 and 2014 [32].

In 2010, some electricity production deriving from microgeneration appeared on the island. However, it is not reported in the graph due to the really small share it has in the total electricity production mix (maximum of 0.4% reached in 2014).

Concerning the Transmission & Distribution System above mentioned, Terceira's power generation system has five substations that reduce the transmission's voltage from 30 kV to 15 kV. The only exception is made for the installations of the U.S. military detachment of Lajes, where there is a private line with 6.9 kV. The substations are reported in Table 2.

Table 2: Substations present in Terceira at December 2014 [31].

Acronym	Substation	Transformation ratio	Number of Transformers	Power Installed [MVA]
SEBJ	Belo Jardim	30/15	2	20
SEVB	Vinha Brava	30/15	2	20
SEAH	Angra do Heroismo	30/15	2	10
SEQR	Quatro RIbeiras	30/15	1	10
SELJ	Lajes	30/6.9 30/15	2 1	12.5 1
Total	**-**	**-**	**10**	**73.5**

The Belo Jardim substation is directly connected to the thermoelectric power plant, while the other four power plants are connected to the MV transmission line. Figure 8 shows the locations of the power plants generating at 30 kV and of the MV transmission lines.

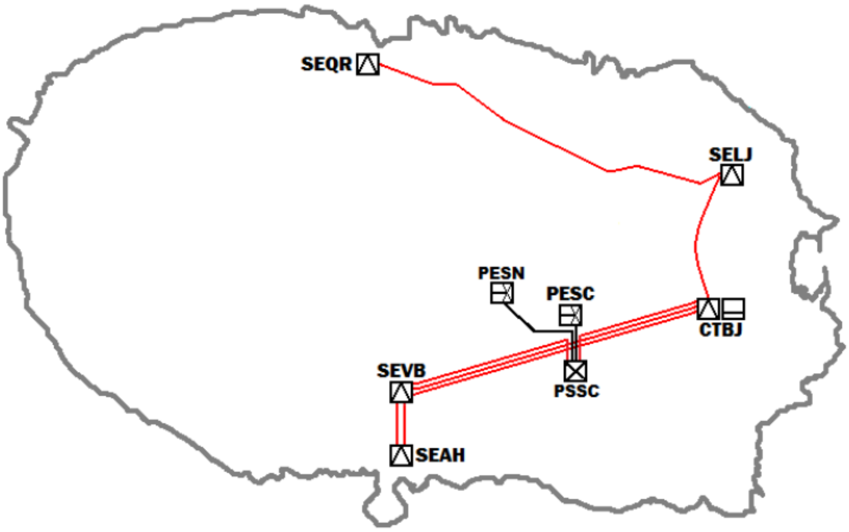

Figure 8: Power plants generating at Medium Voltage and respective transmission lines [31].

The hydroelectric power plants are all located near Angra do Heroismo, and are not shown in Figure 8 because they generate power directly at the distribution voltage of 15 kV.

4.2.1 Thermoelectric

Belo Jardim Power Plant

The Belo Jardim thermoelectric power plant is located in Belo Jardim, Canada dos Pastos, in the Santa Cruz municipality – Praia da Vitória district. It is located at an altitude of 25 m AMSL and framed between two “Serras”: Serra do Cume on the south-east side and Serra de Santiago on the north-east side. This is an industrial zone, close to Terceira’s international airport and near the highway that connects Angra do Heroísmo to Praia da Vitória [33].

The plant is composed by ten independent diesel motors, which develop a total installed capacity of 61.17 MW_e (158.81 MW_{th}). Of these ten generators, the two largest ones have a nominal capacity of 12.3 MW_e each, the four medium 6.1 MW_e and the four smallest ones around 3 MW_e each. The exact thermal and nominal electric power of the thermal generators are reported in Annex A.

All of these generators are powered by fuel oil (HFO), except for starting-up and shutting-down phases of the electro generators where diesel oil is used [34]. Only the four smaller generators (together with two emergency generators present in BJ) always run on diesel oil [35].

The Belo Jardim power plant has been operational since 1984, when the first unit was installed. The other generators were installed in sequential form between 1984 and 2004. This plant can be considered Terceira’s energy supply backbone. In fact, until the introduction of the first wind farm in 2008, the thermoelectric plant owned more than 98% of the island’s electricity production mix. Since then, its share started decreasing, still maintaining the absolute lead, but reaching 82% in 2014 [32]. In fact, due to environmental reasons and regulation policies, thermal generators are used the least possible; however, enough to meet base load and guarantee security of supply.

In particular, the dispatch occurs as follows [34]:

- Largest generators (Gen. 9 and 10) have priority on the others due to their lower specific consumption, thus being the most efficient ones.
- Medium size generators (Gen. 5, 6, 7 and 8) are the following ones to be turned on. They are used to replace one of the large generators when this is off for any reason (maintenance, rest, etc.) or meet daily load peaks when it is not possible with other power sources.
- The smallest generators (Gen. 1, 2, 3 and 4) present the highest specific fuel consumption, as they run on diesel oil and not HFO. Moreover, for legal requirements, they are not allowed to run more than 500 hours per year.

The main pollutants emitted by the power plant are the characteristic ones associated to fossil fuel combustion, namely: particulates, sulphur dioxide (SO_2), nitrous oxides (NO_x) and carbon dioxide (CO_2). In 2007, NO_x concentrations registered in close proximity to the plant resulted higher than legal values. Therefore, several measures were taken by EDA in order to minimize pollutant emissions [35], [36]:

- Develop a plan to constantly monitor atmospheric pollutant emissions.
- Install denitrification reactors in order to reduce NO_x emissions.
- Use fuels with lower sulphur content.
- If in the next monitoring campaign, the values of registered emissions exceeded the legal values, the hypothesis of installing a bag filter has to be taken into consideration.

4.2.2 Hydroelectric

There are three hydroelectric power plants operating in Terceira, that form a micro cascade-functioning chain. The three plants all became operational in 1954, and have been working since then. With a total hydroelectric installed capacity of 1,432 kW_e, the power plants have been able to provide around 1% of the total electricity annually produced in Terceira [33]. Not much information about the management of the hydroelectric power plants was accessible. However, according to the limited information provided by EDA, the three plants are dispatched for a total production of around 60% of their nominal capacity when the hydric resource is available [34]. More technical information about the individual power plants is reported in Annex A.

4.2.3 Wind Energy

Wind power production in Terceira is concentrated in two adjacent wind farms, both located in Serra do Cume. Due to its extremely low operational costs (if compared with the Belo Jardim Power Plant) and because of environmental and grid reliability reasons, wind power production dispatch has priority over thermal generators.

Serra do Cume - EDA

The largest wind park is owned by EDA RENOVÁVEIS; it was opened in 2008 and it consisted of 5 ENERCON E 44/900 (900 kW_e each) that added to 4.5 MW_e of installed capacity. Considering the immense wind resource present on the island, in 2011 the park was extended by installing other 5 identical aero generators, resulting in a total installed capacity of 9 MW_e. The wind park is able to function in “abandoned regime” being monitored from the Belo Jardim thermoelectric plant [37].

Serra do Cume - CAEN

The second wind park is located in the northern part of Serra do Cume and it is owned by CAEN, a private company. The park is made of 4 ENERCON E44/900, for a total installed capacity of 3.6 MWe, that were connected to the grid and started operating in September 2013.

4.2.4 Potential Endogenous Energy Sources

4.2.4.1 Geothermal

The Azores Archipelago is located at the triple junction of the North American, Eurasian and African plates. This geo-structural framework provides the islands with an intensive volcanic activity and large endogenous energy resources in the underground. This resource is currently being exploited in Azores, by two geothermal power plants, both in São Miguel island, which have a total generation installed capacity of 23 MW_e. Thus, geothermal power production in Azores presently meets 42% of the electrical consumption in São Miguel and 22% of the total demand of the archipelago [38].

Many field studies have been conducted in Terceira in the past years in order to evaluate the feasibility and eventual dimensions of a geothermal power plant. In particular, deep exploratory drilling was conducted at the Pico Alto Geothermal Field between 2003 and 2010. Tests conducted on 5 geothermal wells between 2013 and 2014 confirmed the presence of a reservoir with the capacity to support a 2.5-3 MW_e pilot power plant [39].There is the additional objective of expanding the power plant to a total installed capacity of 10 MW_e, if it is proven that there are enough energy resources [40]. According to EDA [40], the Pico Alto Geothermal Power Plant should become operative in 2016.

The main advantage of geothermal power plants is that, unlike wind parks, these are able to provide a more stable and constant production due to the nature of its resource. This technology can be therefore considered as a possible substitute of thermal diesel generators, allowing a higher penetration of renewables with no threat to grid stability.

4.2.4.2 Residual Solid Waste

TERAMB is the local entity in charge of managing, processing and valorising urban solid waste of Angra do Heroísmo and Praia da Vitória municipalities. The company started a project in 2012 for the construction of a power plant that would use the solid waste to produce energy (electric and thermal) [41]. The plant is designed to receive and digest solid wastes from 7 of the 9 Azores islands; Terceira is currently receiving waste from Graciosa, Flores and Corvo islands [42].

The power plant will be divided into 4 sections:

- Pre-treatment and storage unit
- Treatment unit
- Energy recover and conversion unit
- Gas treatment unit

Moreover, the plant will adopt a continuous functioning regime, divided in 3 shifts per day of 8 hours each, 7 days a week. The solid waste incineration process will have a maximum capacity of 40,000 tons/year, for a lower heating value of 8.0 MJ/kg [43]. This will bring to a total nominal output of around 1.8 MW_e [42]. The power plant will start operating by the end of July 2016.

4.3 Validation of the ED model

As mentioned in the previous section, a preliminary validation of the model with the last available production data (2013) was done before further developing the tool. This real production data was made available by EDA thanks to a collaboration with the Instituto Superior Técnico (IST) in Lisbon. The validation consisted in running several simulations for different days and then comparing the results with the real production data. This section is divided in the following way: first the inputs will be presented, then results of several simulations will be analyzed.

4.3.2 Inputs

Table 3 reports the technical characteristics of all Terceira's generation units.

Table 3: Technical characteristics and constraints of Terceira's power generation units [34].

Unit	Energy Source	Generator	P_max [kW]	P_min [kW]	Ramp_up [kW/h]	Ramp_down [kW/h]	Min_up_time [h]	Min_down_time [h]
1	Diesel	MIRLESS K8	3,128	1,500	Inf	Inf	2	1
2	Diesel	MIRLESS K9	3,128	1,500	Inf	Inf	2	1
3	Diesel	MIRLESS K10	3,000	1,500	Inf	Inf	2	1
4	Diesel	MIRLESS K11	2,860	1,500	Inf	Inf	2	1
5	Fuel Oil	MAN 9L 40/54	6,100	3,000	Inf	Inf	3	2
6	Fuel Oil	MAN 9L 40/55	6,100	3,000	Inf	Inf	3	2
7	Fuel Oil	MAN 9L 40/56	6,100	3,000	Inf	Inf	3	2
8	Fuel Oil	MAN 9L 40/57	6,100	3,000	Inf	Inf	3	2
9	Fuel Oil	MAN 12 V 46/60B	12,300	6,000	Inf	Inf	7	5
10	Fuel Oil	MAN 12 V 46/60B	12,300	6,000	Inf	Inf	7	5
11	Wind	ENERCON E44/900	9,000	0	Inf	Inf	1	1
12	Wind	ENERCON E44/901	3,600	0	Inf	Inf	1	1
13	Hydro	Pelton	1,432	0	Inf	Inf	1	1

Thermal Generators

Fuel used, generator model, minimum and maximum power outputs of each unit were obtained from the technical sheets in [33] and [34]. Spinning reserves were simplified and calculated as $\pm 20\%$ of the forecasted demand. No ramp up or down limits were considered as all thermal generators are able to reach their nominal power in less than the modelling time step (1 hour). Since no minimum up and down time were specified by the system manager, standard values for thermal generators of similar dimensions were considered in order to avoid arbitrary turn on and shut down of the units.

Wind and Hydro Power Plants

As reported previously in the system characterization section, both wind and hydroelectric power plants are formed by several independent generators. In particular, 14 aero generators and 3 hydro generators. However, for the validation of the model it was decided to aggregate the generators per renewable source and consider them as a whole. The only distinction made was between the two windfarms present on the island, EDA's and CAEN's respectively. It can be seen in Table 3 that these generators are subject to blander constraints: there is no minimum power output and ramps and up/down times coincide with the modelling time step for logical reasons.

The data accessed consisted in the hourly production of all generators (thermal and renewable) on the island for the year 2013. Since there were no data concerning the renewable resources available, for the validation of the model, the renewable functions were bypassed and the RE production was considered to be directly the one in the recorded data.

Specific operating costs of all generation units introduced in the model are reported in Table 4.

As mentioned in the description of the dispatch model, operating costs for variable renewable energy production are considered to be zero.

Cold startup costs, together with average fuel costs for diesel and fuel oil between January and November 2013, were provided by EDA [34]. Incremental heat rate and no load cost are calculated with the methodology presented in 3.1.2.

Table 4: Operating costs of Terceira's generating units [34].

Unit	Startup cost_cold [€]	Startup cost_hot [€]	Shutdown cost [€]	Fuel cost [€/L]	Incremental heat rate [L/kWh]	No load cost [L/h]
1	60.1	0	0	0.7518	0.2366	55.12
2	60.1	0	0	0.7518	0.2366	55.12
3	60.1	0	0	0.7518	0.2366	52.87
4	60.1	0	0	0.7518	0.2366	50.40
5	76.7	0	0	0.5481	0.2172	61.77
6	76.7	0	0	0.5481	0.2172	61.77
7	76.7	0	0	0.5481	0.2172	61.77
8	76.7	0	0	0.5481	0.2172	61.77
9	290.5	0	0	0.5481	0.1723	671.82
10	290.5	0	0	0.5481	0.1723	671.82
11	0	0	0	0	0	0
12	0	0	0	0	0	0
13	0	0	0	0	0	0

Demand

Regarding the load profiles, no data directly reporting the hourly demand was provided. However, by assuming that no grid losses between production and distribution occurred, it was possible to consider the total hourly production as equivalent to the demand.

4.3.3 Outputs & Analysis

Due to the evolution of Terceira's energy supply system during 2013, two significant periods were taken into consideration: spring and autumn. In particular, the CAEN private windfarm was completed in summer and started operating in September [34], while the hydroelectric power plants were not operating between July and December due to low resource availability. For each period considered, three days were simulated in order to analyze different load profiles that occur on week and weekend days. Moreover, since demand profiles vary consistently throughout the year, two more simulations were done (one in winter and one in summer) in order to have more complete overview on the correct behavior of the model. Thus, eight different load days were simulated, which are reported below Table 5.

Table 5: Days in 2013 simulated by the ED model.

Season	Month	Days		
Winter	January	Wednesday 9th		
Spring	March	Wednesday 27th	Saturday 30th	Sunday 31st
Summer	August	Wednesday 28th		
Autumn	October	Wednesday 23rd	Saturday 26th	Sunday 27th

The main outputs of the simulations were:

- Unit commitment of the generators
- Daily penetration of renewable energy production
- Operational daily costs
- CO_2 Emissions

A more profound analysis of the unit commitment scheduling and the daily renewable penetration was made for **Wednesday 27th of March** and **Sunday 29th of October**, while for the rest of the simulated days, operational costs and emissions are reported.

The priority list established by the model for the solution of the unit commitment problem resulted in accordance with the one presented in the system characterization section.

Renewable production is always committed first, together with one or two large generators (9, 10), followed by medium-size generators (5, 6, 7, 8) and finally smaller diesel generators (1, 2, 3, 4).

Wednesday 27th March 2013

It can be seen from Figure 9 and Figure 10 that simulation results are very similar to the real behavior of the generation units. However, some slight differences in the commitment occur.

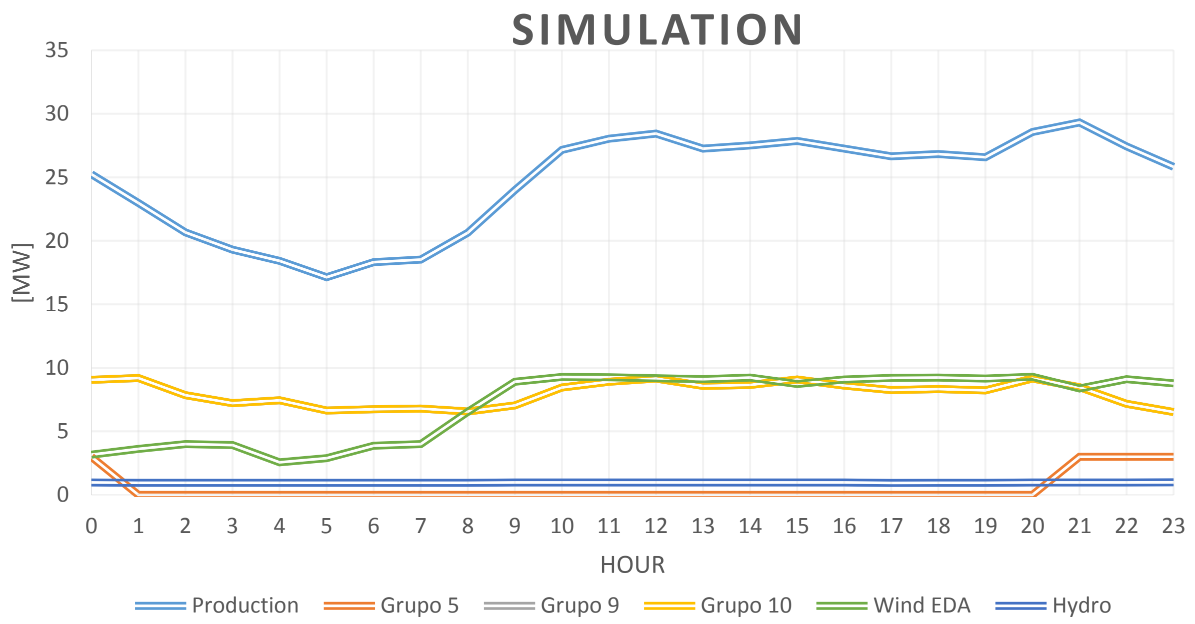

Figure 9: Unit commitment scheduling simulated for Wednesday 27th of March, 2013.

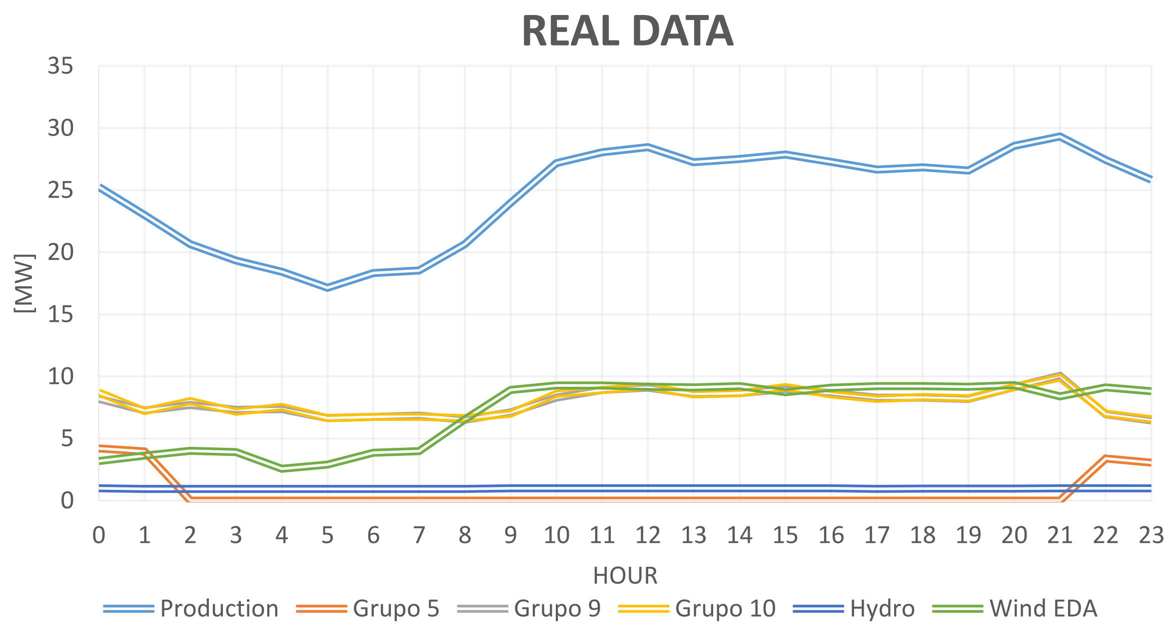

Figure 10: Real unit commitment scheduling for Wednesday 27th of March, 2013 according to EDA [34].

For example, the evening peak between 20:00 and 22:00 is handled in a different way. The model commits one of the medium size generators (6,100 kW) right when the peak occurs (21:00), while in the real situation the demand in the first peak hour was matched by increasing the large generators' outputs and the medium size unit was turned on only at 22:00. Nevertheless, for the day considered, the model faithfully reproduces the unit commitment patterns, making slight changes in the scheduling in order to optimize operating costs.

Regarding renewable energy penetration, giving the assumptions made, it was known a priori that daily shares would have been the same for real data and simulations. However, values obtained are compared below, in Figure 11, with monthly values provided by EDA in order to further validate the correctness of the model.

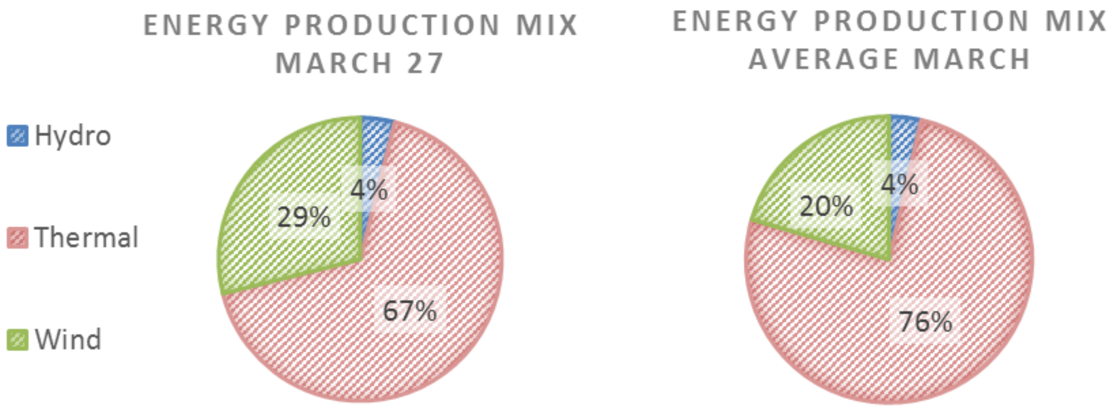

Figure 11: Energy production mix for March 27th and average values for all March 2013 [44].

The electricity mix shares in March 2013 for Terceira were obtained from EDA [44]. While hydroelectric production on Wednesday 27th was in line with the month average around 4%, there is a 9% shift of electricity production form thermal to wind. Monthly values reported 76% of electricity from the thermal power plant and 20% from the Serra do Cume windfarm.

Sunday 27th October 2013

While in the previous case the model faithfully represented the real behavior, in this case some discrepancies emerge. However, they can be justified by sensible considerations and therefore reinforce the model's validation. The commitment schedule of the generators can be seen in Figure 12 and Figure 13.

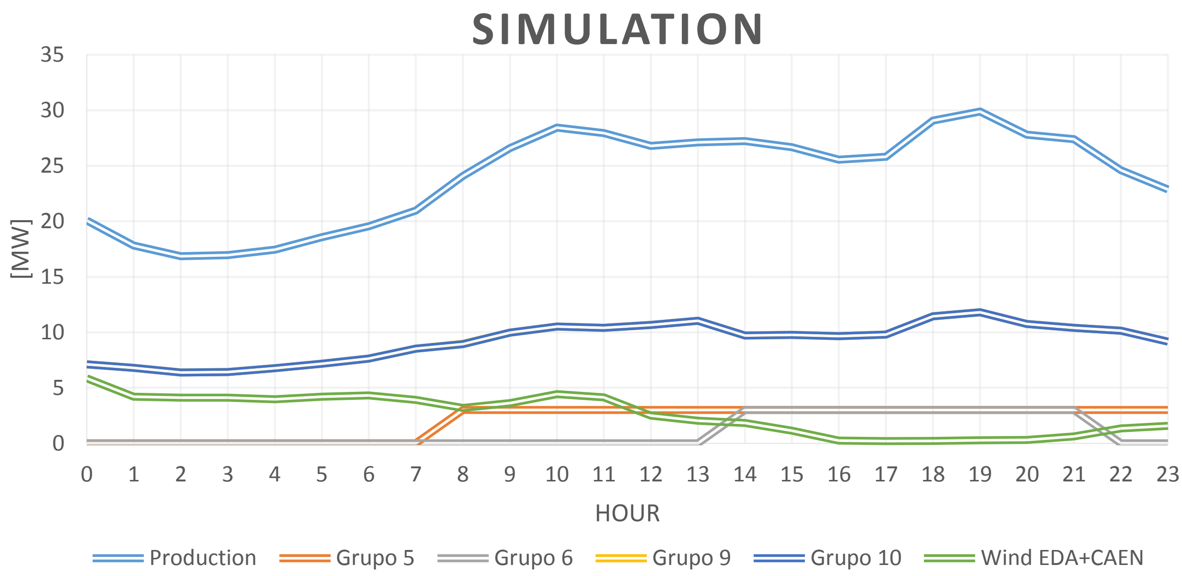

Figure 12: Unit commitment scheduling simulated for Sunday 27th of October, 2013.

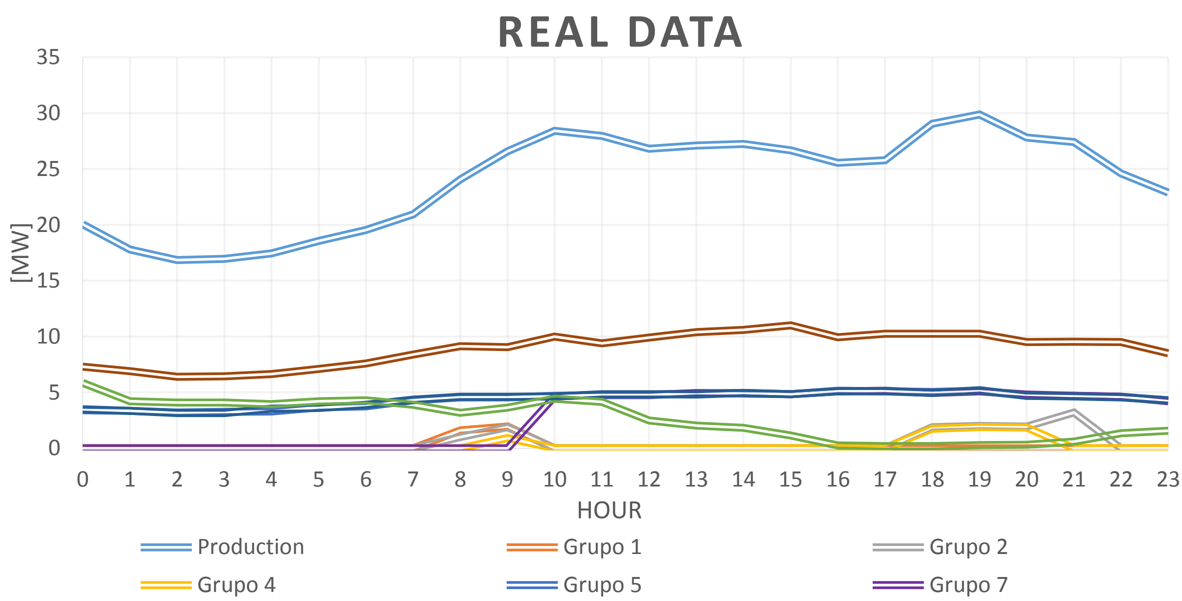

Figure 13: Real unit commitment scheduling for Sunday 27th of October, 2013 according to EDA [34].

Regarding the simulation, the model acts as predicted, following a straightforward strategy: two largest generators are on-line following the demand, together with the available wind power. The morning peak requires a medium-size generator to be turned on, while another medium-size generator is put on-line in the afternoon due to a decrease in wind power generation. Comparing simulated results with real data, the first observation to be made is that only one of the two large generators is committed. This is probably due to maintenance or simply resting reasons. In fact, as mentioned above, the two large generators are always committed first because of their lower operating costs [34]. The non-operative large generator is therefore replaced by two medium size generators, which combined develop the same nominal power as the large one. A third medium-size generator is committed in correspondence to the first morning peak and is kept online throughout the whole day. To avoid committing all the larger generators available, further peaks are met by committing the smaller generators running on diesel rather than the last medium-size unit available.

This simulation brought to the conclusion that a "maximum operating hours" constraint should be introduced in the model. This constraint should take into account the number of hours that the generator has been working before the first time step of the simulation, and decide if it should be committed or not.

Figure 14 below shows the renewable penetration October 27th and it is compared with monthly average values provided by EDA.

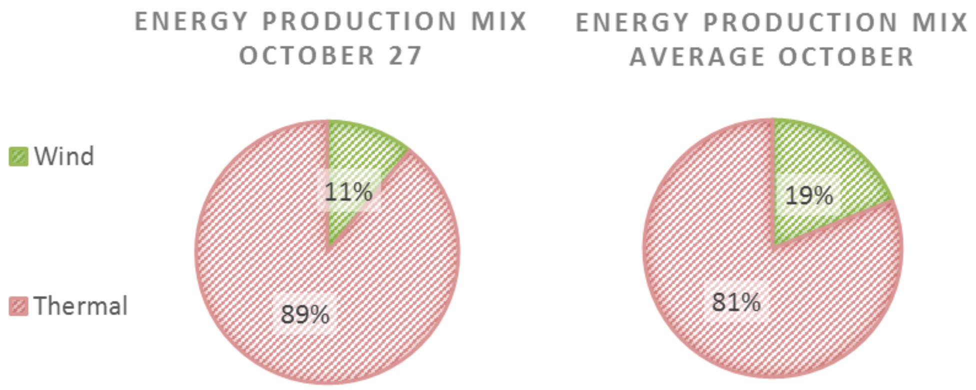

Figure 14: Energy production mix for October 27th and average values for all October 2013 [44].

Not being hydroelectric plants operational, there were only wind and thermoelectric power production during October 2013. Monthly average values (19%) are higher than in the day considered, where wind power production is 11% and thermoelectric is 89%.

Operational Daily Costs

The operational costs considered and compared to average real values will be dispatch costs, which are calculated as the sum of generating costs and startup/shutdown costs. The reference value of 0.1356 €/kWh was obtained from the local utility [34].

Table 6 reports both simulated production costs and annual average values for the year considered. Real average daily production cost was calculated by multiplying the energy produced by the average specific cost previously mentioned. The daily specific cost was obtained entirely from the simulation results, dividing the total production costs by the energy produced.

Table 6: Simulated and real average operational costs for 8 sample days.

		Winter	Spring			Summer	Autumn		
		wk day	wk day	Sat	Sun	wk day	wk day	Sat	Sun
Simulation costs	En. prod. [MWh]	606	590	483	562	625	574	524	576
	Daily prod. cost [€]	71,062	55,603	49,160	54,332	78,386	58,701	51,963	68,925
	Daily specific cost [€/kWh]	0.1172	0.0942	0.1017	0.0967	0.1254	0.1024	0.0992	0.1197
Real average costs	Avg. daily prod cost [€]	82,225	79,997	65,517	76,186	84,746	77,760	71,047	78,092
	Avg. specific cost [€/kWh]	0.1356	0.1356	0.1356	0.1356	0.1356	0.1356	0.1356	0.1356

It can be observed that, for all the cases considered, specific production costs are lower in simulations results than in real data. This is most likely due to the fact that generators' efficiencies used in the simulations are taken from the products factsheet, while in real operation, the age of the generators affects the efficiencies making them lower. Summer presents the closest value to the average specific cost, since production costs tend to be higher due to lack of wind resource and larger shares of more expensive thermoelectric power generation.

CO_2 Emissions

Emissions are directly related to fossil fuel consumption and therefore, depend on the amount of energy produced by thermal generators over the period under consideration. Specific CO_2 emissions (kg_{CO2}/L_{fuel}) are calculated as in 3.2.2, where methodology and standard values adopted were found in [28]. Table 7 reports the main parameters used and specific CO_2 emissions calculated for each fuel.

Table 7: Specific CO_2 emissions for diesel and heavy fuel oils [28].

Fuel	Density [kg/m^3]	Net Calorific Value [GJ/t_{fuel}]	Emission Factor [t_C/TJ]	Oxidation factor	Specific emissions [kg_{CO2}/L_{fuel}]
Diesel Oil	837	43.33	20.2	0.99	2.659
Heavy Fuel Oil	930	40.19	21.1	0.99	2.863

Figure 15 compares the daily emissions for the eight days considered, presenting also the reference emissions reported by EDA.

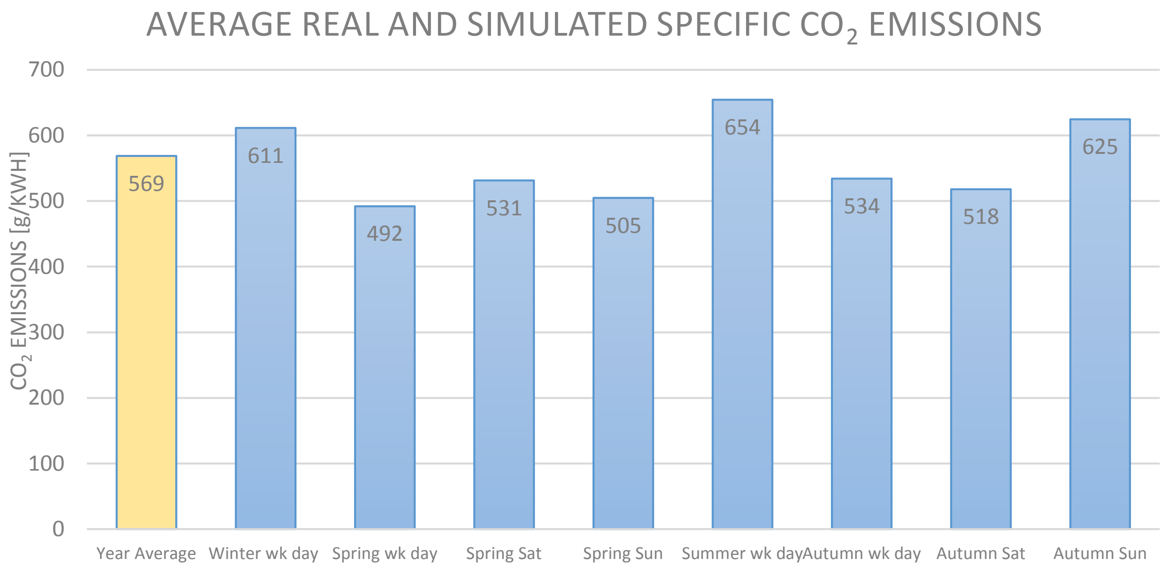

Figure 15: Comparison between CO_2 emissions in simulated days and year average provided by EDA [45].

Results show that the average value of the 8 days simulated is in accordance with the one provided by EDA. The three days where specific CO_2 emissions are higher than average are also the ones where wind penetration is lower and production costs are higher. This correlation further validates the correct functioning of the model. Moreover, it highlights the several benefits that economic dispatch brings to a power system strongly dependent on fossil fuel resources.

5 Development of the Integrated Operation Modelling Tool

As previously mentioned, the purpose of this integrated dispatch model is to fill in the gaps between short-term and medium/long-term energy planning. Starting from an already existing short-term economic dispatch (ED) model, which would remain the core of the new model, several integrated features were developed in order to provide valuable outputs for the assessment of medium/long-term planning strategies. The architecture of the integrated operation modelling tool can be seen in Figure 16.

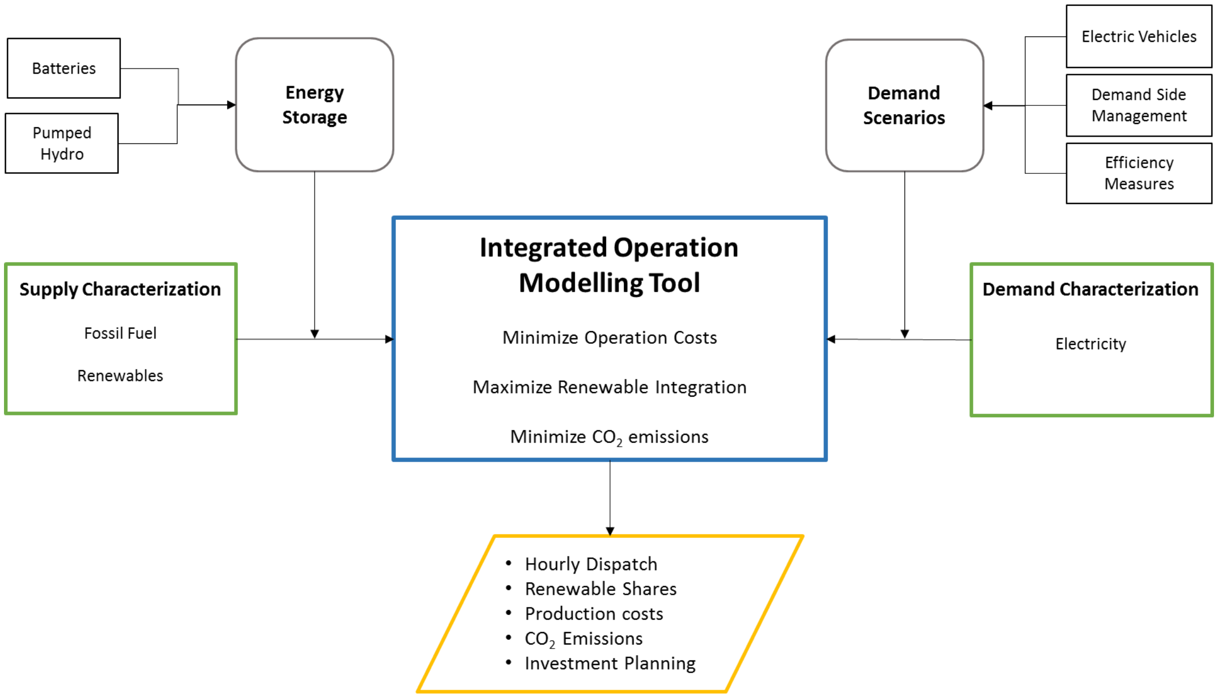

Figure 16: Architecture of the integrated operation modelling tool developed.

The modelling tool is defined as in “integrated” as it outputs valuable parameters for the analysis of investment planning scenarios. These parameters will be presented in detail in the final part of this work, and they will all be expressed as levelized costs in order to equate and compare both technical and economic impact of the strategies adopted on the energy system under study.

This section in particular focusses on the energy modelling part of the tool, describing the integration of energy storage systems, demand response strategies, efficiency measures and future scenarios mainly from a technical point of view. The integration of the investment planning part will be described in the next section.

5.1 Renewable Resources

In 3.1.3 the integration of RE technologies in the model is described and then, in 4.3, the model is validated under the assumption that these RE technologies do not have any operational costs. This simplification was done under the assumption that both dispatchable and non-dispatchable RE technologies would not have associated operating costs in order to always have priority on all the other production technologies in the power system. As mentioned previously in 3.1.2, it is possible to associate a LCOE to both types of RE technologies by combining the RE power plant's capital costs, fuel costs, fixed and variable operations and maintenance costs, and financing costs [23]. The purpose of this parameter is to associate a cost per kilowatt-hour produced by each technology so that these can be compared at the same level. Nevertheless, in islands, endogenous energy resources are valorized according to many criteria, and not only economic ones. For this reason, priority has to be granted, in respective order, to VRE, dispatchable RE and non-renewable energy generation, independently from their associated operating cost.

Figure 17 reports typical LCOE ranges and regional weighed averages by technology according to IRENA [1]. To be noticed that values in the figure are expressed in USD/kWh, therefore need to be converted to €/kWh if used in the model. However, the model itself, being an operational planning tool, is able to provide specific LCOE for each technology and ESS introduced into the system. This feature will be further explained in the following section. Nevertheless, based on the location and characteristics of the energy system analyzed, pre-defined LCOE can be input into the model in order to establish a realistic priority list of the RE power plants when modelling the economic dispatch. Moreover, while all technologies presented in Figure 17 are considered as renewables, in the present case study, energy produced from municipal solid waste is considered as 50% renewable and 50% non-renewable [30].

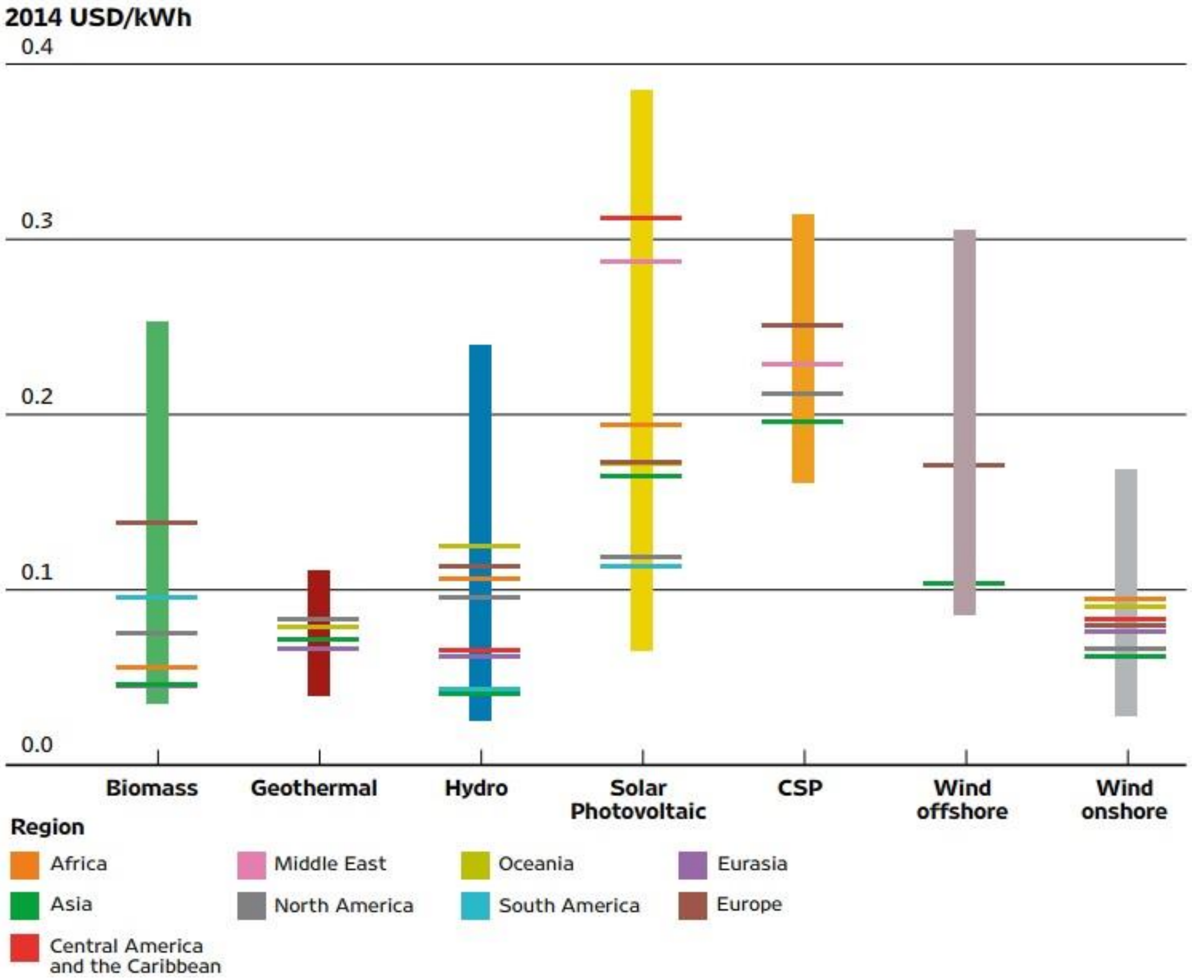

Figure 17: Typical Levelized Cost of Electricity (LCOE) ranges and regional weighed averages by technology [1].

5.2 Energy Storage Systems (ESS)

Energy storage systems (EES) take a central role on isolated systems, especially when dealing with increasing renewable integration [46] . According to IRENA [47] some critical issues on the deployment of an energy storage system in isolated grids relate to its sizing, integration in the system and financial sustainability.

When a hybrid isolated system has a larger share of dispatchable generation (usually thermal power plants), the uncertainty on generation is mitigated. However, for increasing shares of non-dispatchable renewable generation, this uncertainty rises, leading to the curtailment of renewable energy generation in order to assure grid stability [48]. Nevertheless, integrating forecast of demand and renewable generation with energy storage facilities can help to best manage the grid, storing the surplus of renewable generation and using it to replace fossil fuel generation (mainly during peak load). In this scenario, the overall efficiency of the system increases, and the operation costs decrease.

The following section focusses on the integration of ESS in the economic dispatch model, describing which are the main parameters considered, the methodologies adopted and the main challenges faced. Then, examples of the model's behavior are presented with the integration of two different ESS technologies: Li-ion batteries and a pumped hydro storage system. These two technologies were chosen due to their vast perform on multiple applications, as seen in Table 8, which make them the more suitable technologies to be tested on the case study of Terceira, addressing different storage purposes.

Table 8: Applications of Energy Storage Technologies [49].

Application	Time scales	Example of EES
Energy arbitrage, load leveling	Hours to days	PHS, NaS, CAES, VRB
Frequency regulation	Seconds to minutes	Li-ion, NaS, FES, VRB
Inertia emulation, oscillation damping, voltage support LVRT	<1 s	LA, NAS, FES, VRB
Primary reserves	10 min	PHS, FES, BES
Secondary reserves	Minutes to hours	PHS
Efficiency use of transmission network	Minutes to hours	Li-ion
Emergency power supply, black start	Minutes to hours	LA

Moreover, different ESS technologies have different power system applications, as observed in Figure 18. While pumped hydro energy storage systems, which are considered as large scale systems, are usually used for larger storage needs, batteries (small scale) are more commonly used for voltage and frequency regulation due to their high energy and power density.

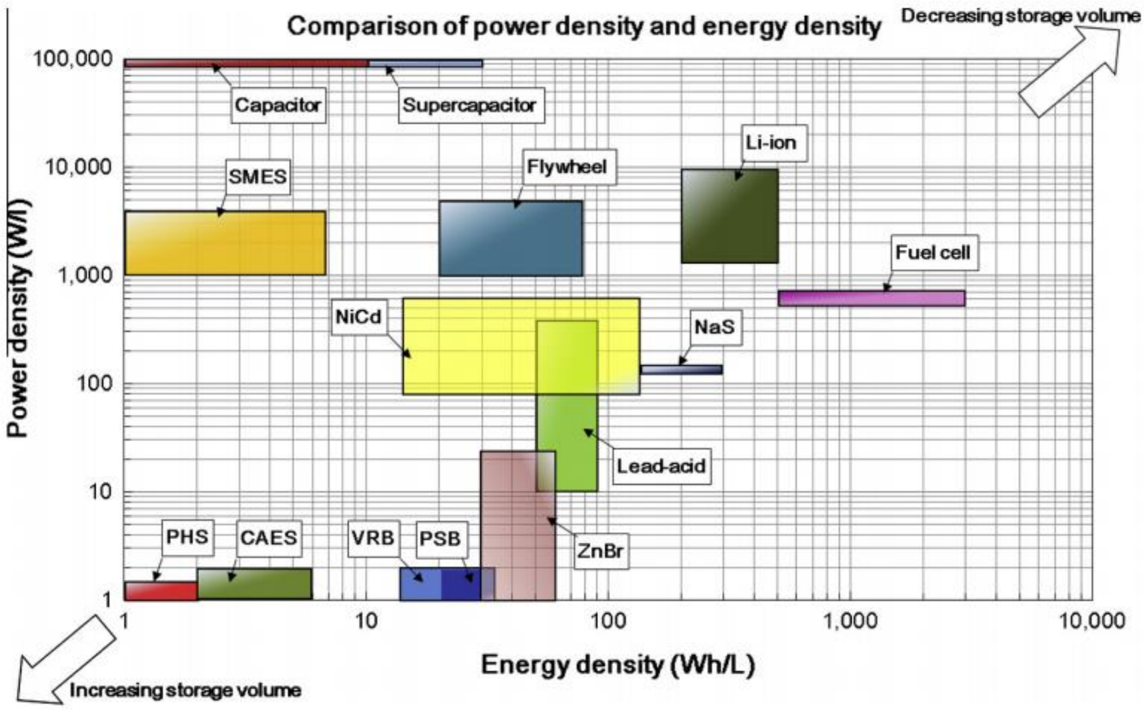

Figure 18: Comparison of power and energy density among different storage technologies [50].

These two ESS technologies are complementary, and their combination in the power system would allow to store large quantities of excess VRE while ensuring a stable voltage and frequency regulation of the electricity grid at the same time.

A fundamental parameter in establishing the necessity of a ESS is the maximum limit of intermittent VRE generation allowed by the system at every time step in order to preserve grid stability. From now on, this parameter will be referred as Variable Renewable Energy (VRE) penetration factor and indicated with β [51]. According to IRENA [47], there is a thumb rule based on this parameter that indicates the need of an ESS in isolated systems:

- When variable renewable penetrations are under 20% of the load, storage is usually not necessary;
- Between 20% and 50% VRE penetration, it is likely that some actions will be necessary to maintain reliability, which will probably include storage, but could also include demand response, use of emergency-only generators or other solutions;
- For variable renewable penetrations over 50%, storage or one of the other options listed above will almost certainly be required.

The main parameters that characterize the ESS are storage capacity, storage charge/discharge rate and efficiencies.

5.2.1 Modelling the integration of Energy Storage Systems

The different technical parameters for each storage technology are the actual inputs to the model, which allows to set these parameters in two different ways:

- One consists in allowing the user to choose the value of these parameters based on his considerations, or in case he would like to model a specific/already existing ESS;
- In the second case, an ESS sizing function is provided, which calculates optimal parameters given as inputs a certain storage technology, the power supply system characterization and demand profiles.

In case ESS sizing is required by the user, the program calculates, for every time interval, the difference between the VRE availability and the maximum VRE allowed. This vector containing the curtailed renewable energy is then used by a function (different depending on the chosen storage technology) that calculates the ESS design parameters and saves them in the model. The definitions of these functions are reported in the following respective sections.

Concerning the ESS dispatch behavior, the model considers the Energy Storage System as a generation unit with additional constraints concerning charging/discharging phases. The ESS is modeled as "unidirectional", meaning that during one time step it is not possible to charge and discharge the ESS simultaneously. Moreover, since the model works with 1-hour time steps, the simplification of assuming no distinction between power and energy is made.

Inspiration for the initial approach was taken from [52], which consisted in introducing the ESS in the program as a "sub optimization" problem. Firstly, the model searched for the best path of the economic dispatch without considering the ESS. Once this was identified, the model ran the dispatch a second time, only for the best path selected, and allowing the ESS to actively participate in the unit commitment.

In order to do so, heuristically established parameters would determine the thresholds under which the ESS would charge or discharge. In particular, in order to allow ESS dispatch in the model, two conditions had to be satisfied:

- The load of the current time steps *i* had to be higher than a fixed percentage of the system's total installed capacity.

$$P_{load_i} > x\%\ Capacity \tag{12}$$

  where the $x\%$ of the installed capacity was calculated as the sum of the base load thermal generators over the total power installed. This was to ensure that the ESS would substitute the more expensive/peak load generators rather than the base load ones.

- The State of Charge (SoC) of the ESS at the current time step *i* had to be higher than a minimum threshold:

$$SoC_i > SoC_{min} \tag{13}$$

This condition represents the operating constraints that had to be constantly respected by the ESS. (i.e. batteries' SoC should never go under a certain level, hydro reservoir should not be completely empty, etc.). The SoC in Li-ion batteries is limited to an operating range of 20-80% of its total capacity in which the battery is neither fully depleted nor fully charged [53].

Since the main objective of the implementation of an ESS is to increase the total share of RE generation, the assumption that only these would charge the storage system was made. Moreover, priority of charging is given to non-dispatchable RE such as wind and solar PV.

Furthermore, three noteworthy considerations made are:

- The total production of thermal generators is constrained at every time step by a lower bound equal to 25 % of the current load;
- Charging and discharging efficiencies are accounted depending on the ESS technology; standard values are reported in the respective sections;
- The introduction of an ESS does not affect the formulation of the spinning reserve that has to be constantly guaranteed by the supply system.

However, in order to make the model more stable, realistic and adaptable to any power supply system, an improvement in the storage dispatch method was considered necessary. In particular, this was integrated in the initial best path searching phase and the discharging conditions were replaced by associating a cost to the energy dispatched by the ESS. Figure 19 shows the final approach adopted for ESS integration in the economic dispatch model.

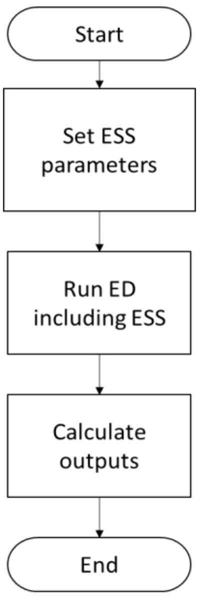

Figure 19: Final approach for the ESS integration in the economic dispatch model.

The ESS parameters (dispatch costs, capacity and charge/discharge rates) are all calculated based on the initial inputs. This way, the model can run the economic dispatch while considering the ESS as an active generator and updating its availability at every time step. Finally, the best path is identified and the main outputs, such as production costs, RE penetration and CO_2 emissions, are printed by the program.

Reference values of levelized costs of storage for Li-ion BESS and PHES are, respectively, 0.27-0.35 €/kWh and 0.04-0.13 €/kWh[1] [47].

5.2.2 Design and integration of Battery Energy Storage Systems (BESS)

As mentioned previously, the generic ESS model was applied to specific technologies. In this section, the design and integration of a BESS is assessed in the following way. First, the sizing methodology is presented and supported by a sensitivity analysis. Then, the contribution of batteries for power system operation and reserve purposes is studied. In particular, Lithium-ion batteries are tested on the case study of Terceira, assuming a round trip efficiency of 95% [47]. Lithium-ion batteries were chosen mainly for two reasons. The first is because of their high energy and power density, which is leading to a promising potential in transportation and small-scale ESS applications [50]. The second is because of their recent and successful implementation as EV batteries: the development of Vehicle-to-Grid scenarios where EV batteries are used as storage devices could be interesting to model.

Nevertheless, any BESS technology can be simulated by the model, since the definition of the technology is considered as a set of specific technology inputs that may be varied by the user.

BESS sizing procedure

An iterative technique is adopted for the design of a BESS which is based on energy balance [54]. The idea is to define an energy curve that represents the excess/deficit of the storable renewable energy with respect to the maximum allowed variable renewable penetration to the grid. Assuming that the maximum RE penetration is set as a certain percentage of the total demand, it is possible to calculate, for every time step, if the RE production available is below or above this fixed threshold.

On an average day, batteries are required to cycle between the positive and negative peaks of the energy curve. Therefore, the BESS should at least have a capacity equal to the difference between these two peaks. Figure 20 shows, as an example, the variable renewable energy surplus and deficit

[1] Converted from USD with a conversion rate of 1 EUR = 1.13 USD [62].

regarding 30% of the load (the VRE Penetration factor defined in 5.2) regarding Terceira Island, in an autumn day with average wind production, in October.

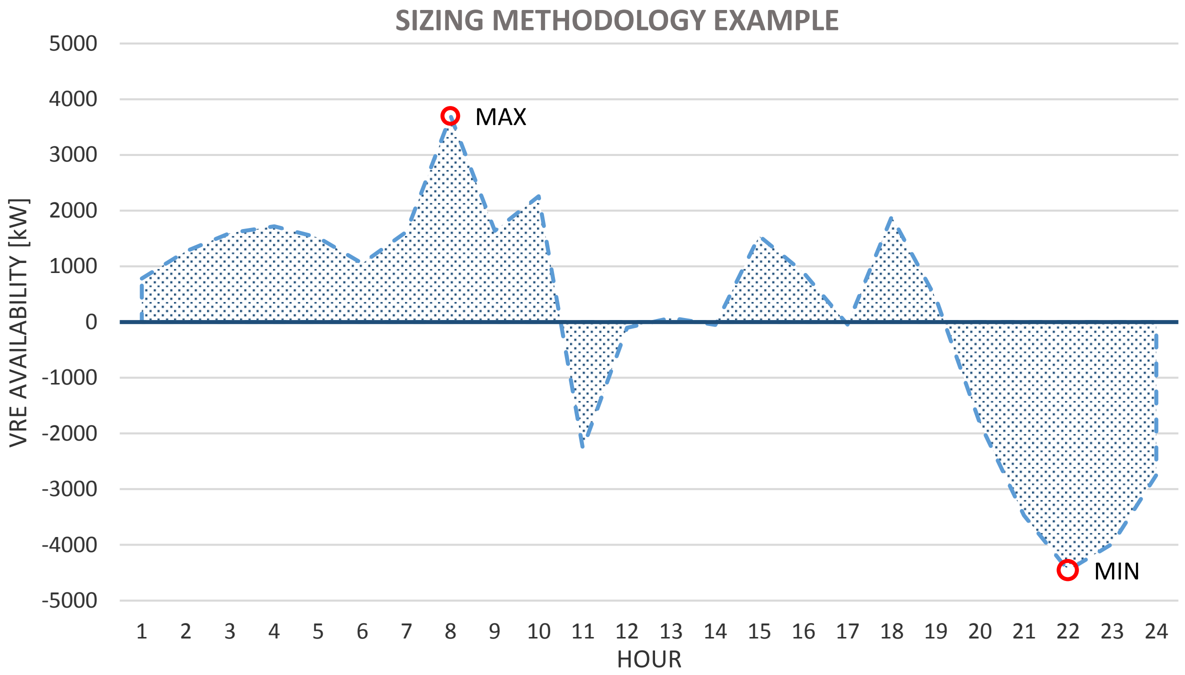

Figure 20: Excess/deficit of RE production on an average day during October in Terceira [34]. VRE production limit set to 30% of load.

Despite not being in line with the thumb rule mentioned above, the VRE penetration factor was set to 30% of the load. This decision was induced by fact that the VRE currently installed capacity in the system (EDA and CAEN wind parks) barely reaches 50% of the average daily demand. Therefore, in order to obtain a vector of curtailed energy that could be stored and dispatched by the BESS, the VRE penetration threshold had to be lower than standard values. Alternatively, another solution could have been the development of a scenario where the VRE installed capacity would have been increased in order to have more VRE availability.

The optimal sizing of the BESS in the example reported, where the maximum variable renewable energy production is set to 30% of the demand and both the geothermal and residual waste power plant are considered fully operational, results in 8,155 kWh of battery capacity. However, since Li-ion batteries' SoC has to vary between 20-80% of the total storage capacity (as mentioned in 5.2.1), the 8,155 kWh are considered as the effective storage capacity. To obtain the nominal BESS capacity, in fact, the extra 40 % has to be taken into consideration. Another constraint is the rate at which the battery is able to discharge to accomplish the energy deficit. This value was set to C/3, where C is the storage capacity [55].

In order to assess the effectiveness of the sizing methodology, a sensitivity analysis on BESS capacities for a fixed VRE penetration limit of 30% was developed and is reported in Figure 21.

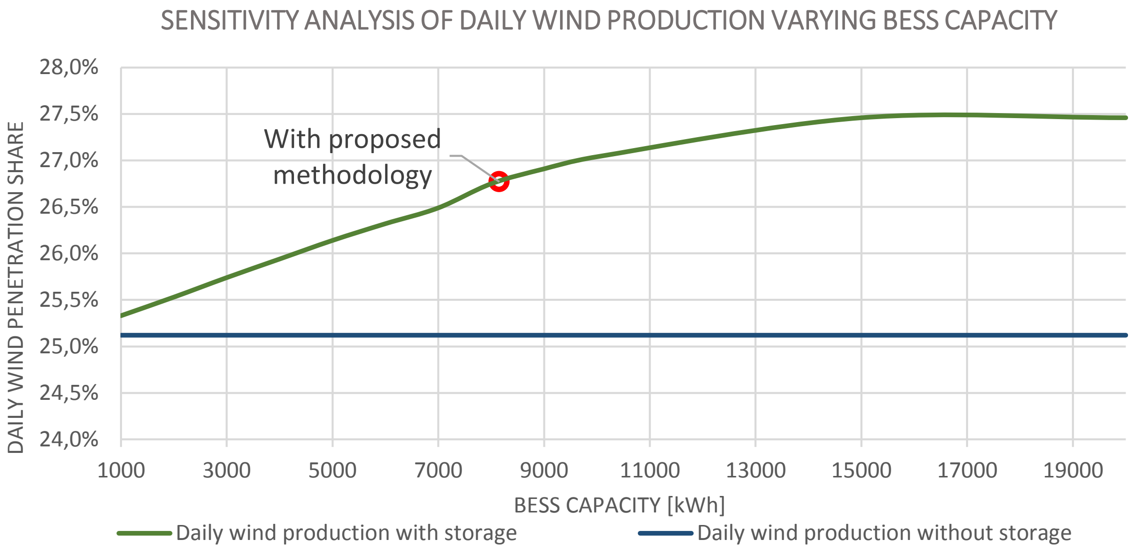

Figure 21: Sensitivity analysis of BESS capacity with VRE penetration limit set at 30% of load.

Given that storage costs found in the literature were relatively high with respect to diesel generators' operational costs, and since the scope of the analysis was to assess the technical influence of the BESS, the storage costs introduced in the model were considered to be between the baseload and peak generators' operational costs. In this way, it was possible to assess the active contribution of batteries in power system operation and reserve management. The remaining system configuration is the same as in the sizing procedure.

The maximum daily penetration is reached with a BESS capacity of approximately 15,000 kWh. The methodology adopted sizes the system to 8,155 kWh. Given that variations in wind penetration shares are in the order of decimals of percentage and in BESS investment costs of millions of euros, a trade-off between RE penetration increase and BESS investment cost should be identified. The sizing function tends to undersize the BESS, which results in a slightly lower exploitation of the RE availability, but at the same time in significant economic savings. An interesting aspect that could be deepened in future work is the integration of a variable which directly considers investment costs in order to identify a BESS optimal trade-off size. This approach would replace the default under sizing procedure here adopted with a more accurate and optimal one.

The optimal BESS characteristics for Terceira according to the methodology adopted and considering that it is a small scale storage system, are shown in Table 9. The storage capacity is calculated from the effective capacity, as mentioned previously, and rounded for practical and commercial reasons.

Table 9: Li-ion BESS optimal sizing considering an average day of October and a VRE penetration factor of 50%.

Capacity [MWh]	13.5
Charge & Discharge rate [MW]	4.5
Charging efficiency	95%
Discharging efficiency	100%

The BESS is a small and short-term scale ESS, and sizing it for a time horizon of several days may result in an oversized system. Since the BESS sizing methodology relies exclusively on the RE availability and load profile input by the user, when the time horizon of the simulation is more than one day, the model selects the day with the average demand and sizes the BESS according to that profile. This is a basic approach that can be deepened and improved in future work.

Integration of BESS in the power system

Finally, a sensitivity analysis varying the storage dispatch costs for fixed VRE penetration factors was done in order to assess and illustrate the hourly behavior of the ESS dispatch. Table 10 reports the values of the mentioned parameters for the analysis of the ESS dispatch behavior.

Table 10: Parameters for the sensitivity analysis on the ESS dispatch behavior.

VRE Penetration Factors (β)	BESS dispatch costs [€/kWh]
	0
	0.05
20%, 30%, 40%, 100%	0.1245
	0.13
	0.30

Arbitrary dispatch costs were chosen in order to reproduce the most significant scenarios. Specific costs of baseload and medium-sized generators in the case study adopted are respectively 0.1244 and 0.1246 €/kWh. For this reason, an intermediate value of 0.1245 €/kWh was chosen as one case. Other cases are realistic values for BESS found in the literature, while 0 €/kWh is the only extreme value used to assess the reaction of the model to no BESS dispatch cost. Regarding the VRE penetration factor, due to installed capacity reasons, for $\beta > 40\%$ it was noticed that no curtailment occurred (only in particular day with extremely high wind availability). Therefore, in cases where $\beta > 40\%$, all the VRE available was already committed and there was no difference for β between 50% and 100%.

The BESS resulted capable of completely replacing the medium size thermal generators during restrained peaks and partially replacing these during longer demand peaks. The BESS “dispatchable” capacity is in fact comparable to that of the thermal generators (8.2 MWh against the 6 MW of nominal capacity of the thermal generators), and its discharge rate is slightly higher than the minimum power output that constraints the thermal generator (4.5 MW and 3 MW respectively). However, due to SoC constraints, the BESS can dispatch at full discharging rate only for a couple of hours. The implementation of a BESS is therefore capable, depending on the situation, of partially or completely replacing thermal generators and therefore decrease the total operating costs and CO_2 emissions.

One of the interesting scenario results found is reported in Figure 22, and it shows the behavior of the BESS on an average week day of January, winter.

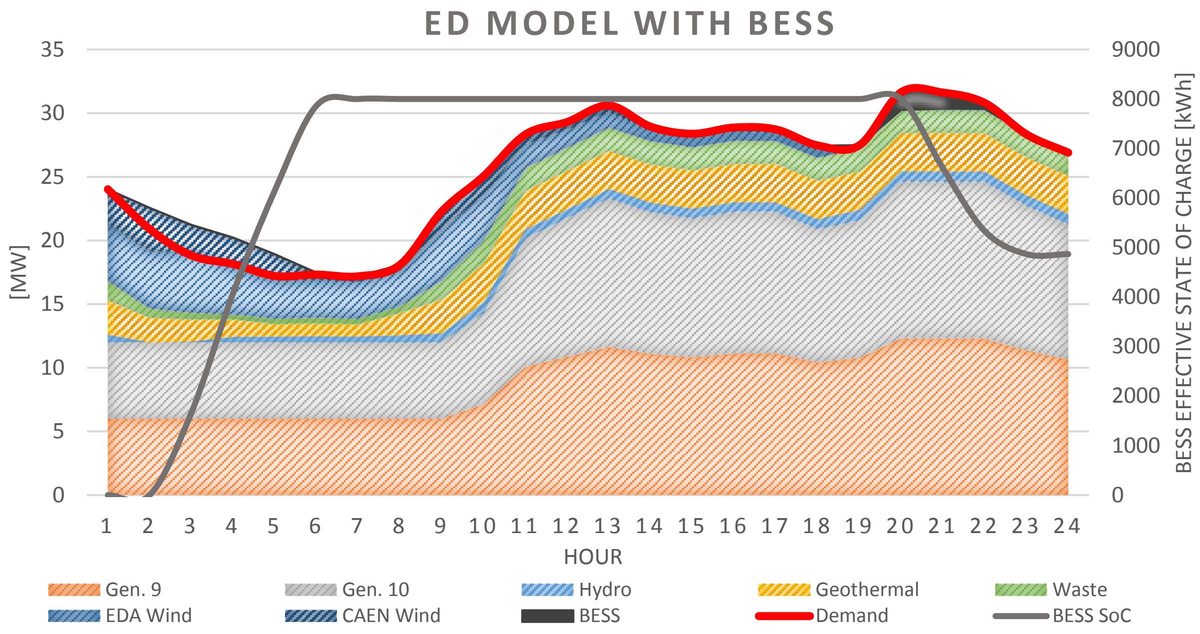

Figure 22: Economic Dispatch with a 13.5 MWh BESS for an average week day of January, winter.

In this case, the BESS dispatch cost was of 0.1245 €/kWh, falling in between the large and medium sized thermal generators. The stacked areas represent the power production, while the red line is the demand profile. It can be noticed that at night (01:00-06:00) the hourly sum of the generators' production is higher than the demand, this means that the BESS is charging, exploiting the excess VRE availability. The BESS then discharges during peak hours (20:00-22:00).

The impact of the BESS on RE production shares, production costs and CO_s emissions for the daily scenario is reported in Table 11.

Table 11: Impact of the BESS on RE shares, production costs and CO_2 emissions for an average week day of autumn.

$\beta = $ **30%**	No Storage	BESS [0.1245 €/kWh]
Wind	9.7%	10.8%
Geothermal	10.1%	9.8%
Hydro	2.2%	2.6%
Waste	5.4%	5.5%
Thermal	72.4%	71.3%
Prod. Costs [€]	60,330	59,904
CO_2 emissions [tonCO_2]	314.9	311.0

The energy dispatched by the BESS is accounted for during the charging phase, it is therefore part of the wind production share.

In this scenario, the impact of integrating a BESS in the system is positive. Resulting, in fact, in a decrease in thermal generators production and accordingly a decrease in production costs and CO_2

emissions. The decrease in production costs is due to the fact that, as opposed to thermal generators, BESS has no startup costs.

5.2.3 Integration of Pumped Hydro Energy Storage (PHES)

As mentioned previously, pumped hydro energy storage is considered as a large scale technology with a high technical maturity. With its installed capacity of 129 GW (in 2012), it represents more than 99% of worldwide bulk storage capacity and contributes to about 3% of global generation [50]. The development of a PHES model to be integrated in the ED model originated from the idea of transforming already existing hydroelectric power plants present on islands into PHES. In Terceira, there are three concatenated hydro power plants which are able to provide around 1% of the total electricity production over the year. The implementation of a PHES not only would allow the hydroelectric plant to significantly increase this marginal share, but it would guarantee a more secure and reliable water management as well.

Regarding the PHES model, as for the BESS, it designs the system starting from a vector of curtailed VRE. However, as opposed to the BESS model, it actually optimizes the storage system from a technical and economic point of view. Since the PHES model was developed by another team integrating the *Vulcano Project* [48], this section will not present the development or its critical aspects. Instead, it focuses on the integration of the PHES in the ED model and the analysis of its implementation regarding the case study adopted.

The PHES system was designed from the vector of curtailed intermittent RE as explained in 5.2.2 and its parameters are reported in Table 12.

Table 12: PHES optimal sizing considering a three-months period from September to November of curtailed energy [48].

Capacity [MWh]	41.2
Turbines Nominal Power [MW]	4.3
Pumps Nominal Power [MW]	3.6
Round-trip efficiency	70%

In order to assess the impact of such PHES in Terceira, several scenarios were developed for different VRE penetration factors and PHES dispatch prices. Since, as mentioned before, the VRE availability is constrained by the installed capacity in the island, in order to produce a more significant impact of the PHES on the power system, a configuration where neither the residual waste nor the geothermal power plants are operational was considered. Since PHES has a larger storage capacity than BESS, a time horizon of three days was considered more appropriate for conducting simulations. Moreover, this longer time horizon allows to simulate the energy storage of VRE surplus during weekends. In particular, the three days considered were Sunday, Monday and Tuesday of a week in October with overall average (relative to the season) wind penetration. The parameters considered for the sensitivity analysis were exactly as the ones in Table 10, previously presented in 5.2.2.

An example of the economic dispatch for the three days considered with a VRE penetration factor of 40% and a PHES dispatch cost of 0.1 €/kWh, which in [47] is reported as a realistic levelized cost of PHES, is presented in Figure 23.

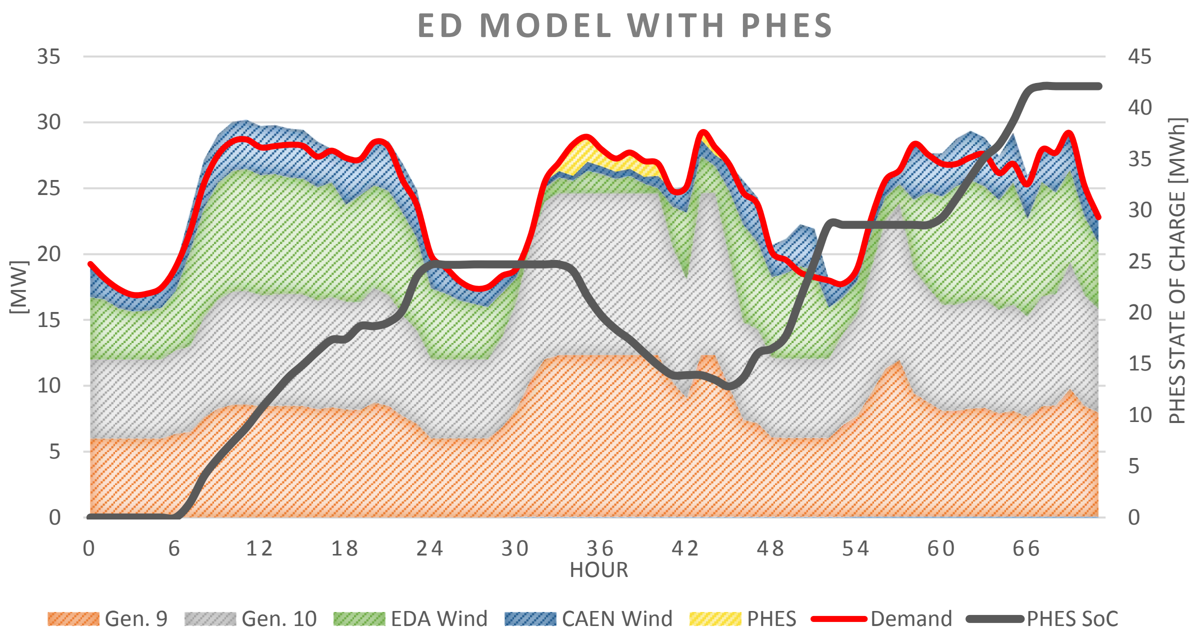

Figure 23: Economic Dispatch for three days in October, with a 42.1 MWh PHES, a dispatch cost of 0.1 €/kWh and a VRE penetration factor of 40%.

It is possible to notice that wind availability varies substantially over the time horizon considered. While on Sunday (0-24h) and Tuesday (49-73h) wind abundancy allows the system to meet the load requirements without committing additional generators (only the two base load ones), on Monday (25-48h) the wind deficit is filled by the PHES. As before, when the sum of the hourly production is higher than the demand (red line), the PHES is charging with the surplus VRE availability.

The impact of the PHES on the energy production shares, production costs and CO_2 emissions for the time period considered is reported in Table 13.

Table 13: Impact of the PHES on the energy production shares, production costs and CO_2 emissions for a three-day time period in October.

	$\beta = $ **40%**	
	No Storage	PHES (0.1 €/kWh]
Wind	29.6%	31.3%
Thermal	70.4%	68.7%
Prod. Costs [€]	171,950	170,620
CO_2 emissions [tonCO_2]	897.7	884.5

The energy dispatched by the PHES is taken into account during the charging phase, therefore it is part of the wind production share. The contribution of the storage system is, in fact, the difference between the wind production share in the presented scenario and in the reference (no storage) case, which results +1.7%.

5.2.4 Combination of different ESS technologies in the integrated model

The economic dispatch model allows the user to choose whether to implement only one of the ESS technologies proposed, or combining the two. However, in case both technologies are chosen, ESS characteristics (nominal capacity, charge/discharge rate and overall efficiency) have be input directly by the user. A different sizing methodology would, in fact, be needed in this case in order to avoid oversizing the two systems. Concerning charging/discharging phases, priority for both is given to the more economically convenient one (lower dispatch cost).

Ma et al. conduct a feasibility study and economic analysis on the integration of PHES and BESS in a remote island in Hong Kong [56]. Several scenarios are developed, from the implementation of only one of the two technologies, to the integration of both. The system is a quite small (average daily demand around 50kW) hybrid wind-solar, where battery banks are always connected to a solar PV system. Results demonstrated that the economically most convenient solution for such small system is the implementation of BESS with no PHESS. However, if power supply stability and energy conservation are taken into consideration as well, the combination of BESS and PHES would be the optimal solution.

5.3 Demand response management and future scenarios

Demand response (DR) is a voluntary and temporary adjustment of power demand taken by electric utility customers to better match power supply and demand. This behavior can be induced through changes in electricity prices or even direct agreements stipulated between utilities and end-users. Demand response strategies are used to increase flexibility in grid management, allowing to reschedule part of the load and adjusting the demand to the supply. Moreover, DR strategies may help to deal with the intermittency of renewable energy sources, minimizing operation costs while maintaining a reliable grid management. Renewable integration can be further optimized, if storage systems are coupled with demand response in order to enlarge the load shifting capacity [20].

DR management and efficiency measures were integrated in the model in order to enrich it with a wider range of optimization strategies applicable to the power system under study.

DR strategies can either be applied to the current system, or relating to future scenarios, as per example the introduction of electric vehicles. In the first case, the DR strategy consists in shifting a maximum daily flexible load (provided by the user) with the main objective of increasing RE penetration, in order to decrease production costs. In the second case, an auxiliary tool calculates the additional load that EVs would bring to the system, allowing the user to choose between several preset daily charging profiles. Efficiency measures consist in simulating the replacement/introduction of heating, cooling and domestic hot water (DHW) technologies in different scenarios at the residential level.

The current section is divided in three parts: first is presented the flexible load DR strategy, then the EV introduction and finally the efficiency measures scenarios. All these scenarios are supported by quantitative examples relative to Terceira's case study.

Figure 24 shows how the initial demand profile is modelled through efficiency measures, EV scenarios and DR strategies.

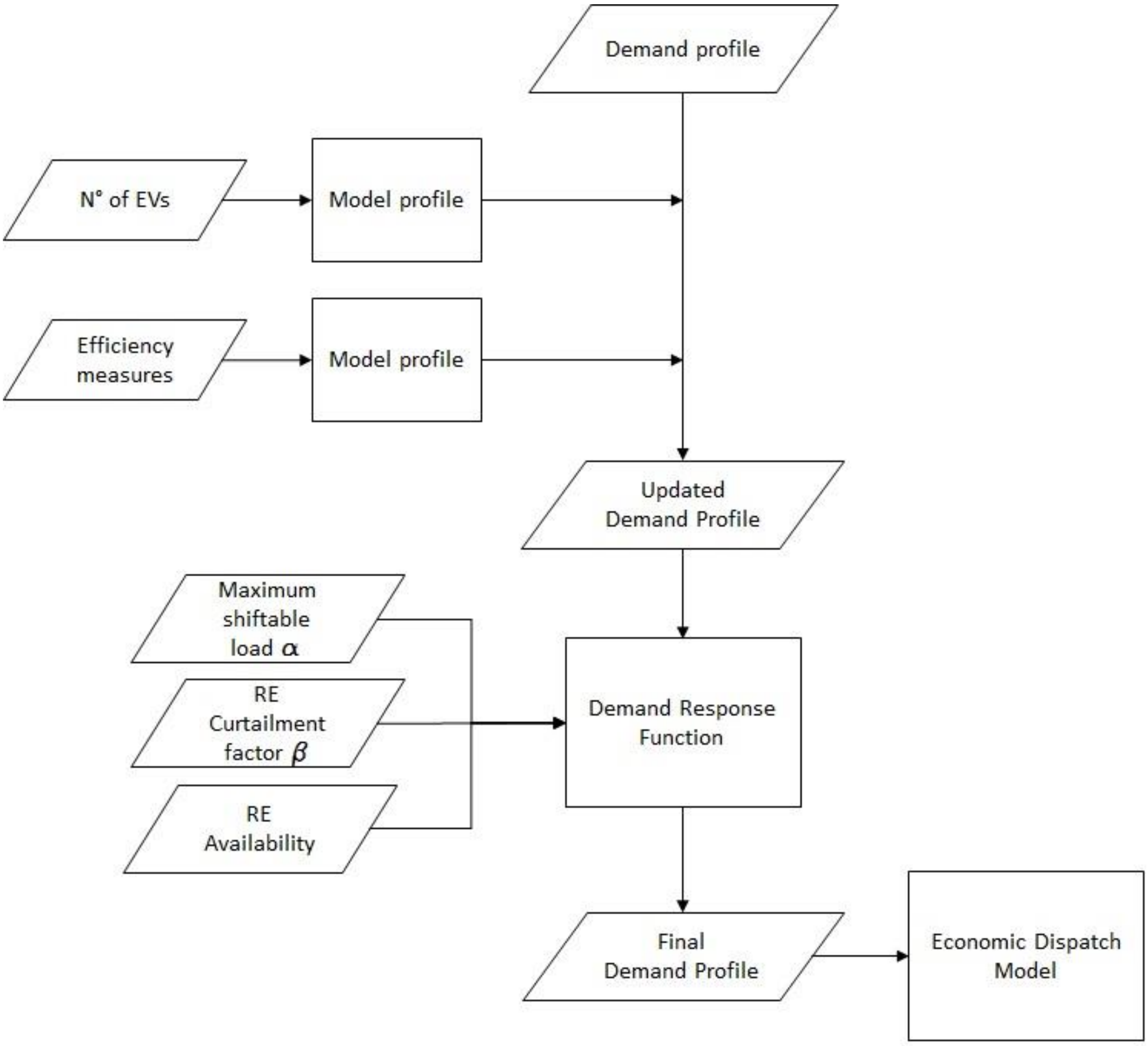

Figure 24: Flowchart of demand profile modelling through efficiency measures, EV scenarios and DR strategies.

It can be seen in Figure 24 that the demand modelling (Efficiency measures, future scenarios and DR) is completely done before the ED model, which means that the model does not run for both demand profiles, but only for the new modified one. In this preliminary version of the model, in order to avoid running the program twice and increase its complexity, the idea is to let the user compare the savings brought by the DR strategy, running a simulation for the normal scenario and one with the modified demand profile. Applying the DR flexible load strategy guarantees production cost savings, as it is built to maximize VRE penetration. However, the quantification of these savings, in this preliminary version of the model, has to be done by the user.

Moreover, regarding DR load shifting strategy, the time horizon considered is of one day, as it is thought to represent mainly electricity consumption shifts in residential applications.

5.3.1 Basic DR strategy: Flexible load

When introducing DR strategies in the economic dispatch model, the main objective is to maximize the penetration of renewable energy production and therefore minimize overall operation costs. In order to do so, the model uses a linear programming optimization (*linprog* MATLAB function) to adjust the shape of the demand curve according to renewable resources availability. To avoid running the dispatch model several times, the DR function is designed to use as inputs only three vectors already known at time-step "zero": the initial load profile, the available energy resources and the VRE penetration limit dictated by the grid manager. The only new input that has to be provided to the model is the amount of load that can be shifted during the day. This parameter will be called α and it is expressed as a fraction of the total daily load. The main objective of the DR function is to increase the load when there is excess of RE production and decrease it when there is a deficit.

The function separates the linear programming optimization into two different cases with its relative mathematical formulation:

1) $RE_{availability_i} > (\beta \times Load_i)$	2) $RE_{availability_i} < (\beta \times Load_i)$
Constraints: • $\sum_{i=1}^{NT} x_i = \left(\alpha \times \sum_{i=1}^{NT} Load_i\right)$ • $x_i \leq RE_{availability} - (\beta \times Load_i)$	Constraints: • $\sum_{i=1}^{NT} x_i = \left(\alpha \times \sum_{i=1}^{NT} Load_i\right)$ • $x_i \leq (\beta \times Load_i) - RE_{availability}$

Where x is the hourly load added to the demand profile in Case 1 and subtracted in Case 2 and β is the VRE penetration factor previously mentioned. *NT* is the number of time steps considered (in this case, the number of hours in a day).

Regarding the shiftable load (α), the necessity of implementing another parameter constraining the hourly shiftable load was identified. Without this further parameter, in fact, the function has no constraint on which hour to subtract the load from, and it could subtract large quantities from peak hours, which is not realistic. The solution was therefore to allow the user to input a vector (HF in Equation (14)) of coefficients indicating the maximum hourly percentage of shiftable load allowed. This vector is introduced in the *linprog* function as the upper bound of the optimized vector:

$$\begin{cases} LB_i = 0 \\ UB_i = HF_i \times DEMAND_i \end{cases} \tag{14}$$

Where LB is the vector of lower bounds, which is always zero as the shifted demand is positive by definition.

Moreover, another constraint was added to the DR that avoided shifting loads between days in order to respect the daily time horizon assumption mentioned above.

A sensitivity analysis was done for several days in order to evaluate the behavior of the DR function; the sensitivity parameters were α and β and the values chosen are reported in Table 14.

Table 14: Parameters for the sensitivity analysis on the DR function behavior.

VRE Penetration Factor (β)	Shiftable load (α)
30%, 40%, 50%	5% 10% 20%

Results were positive and indicated that the implementation of the DR strategy increases the penetration of RE and consequently reduces production costs and CO_2 emissions. However, the function is built in order to shift the load to where there is excess VRE, that is where VRE availability is higher than the penetration factor allowed. For this reason, it does not make sense to apply this DR function to the system when there is no constraint on the VRE allowed, as this would not produce any further RE penetration. This reasoning is pertinent to the power system at issue, where the VRE installed capacity is relatively low if compared to the remaining technologies. The function should be improved by testing it with other systems, where the VRE installed capacity is higher and consequently there would be more VRE availability.

Figure 25 shows, as an example, the application of the DR function described above to a week day in autumn with average RE availability. The VRE penetration factor β in this case is 30%, while the flexibility parameter α is 5%. No hourly constraint was set on the shiftable load in this case.

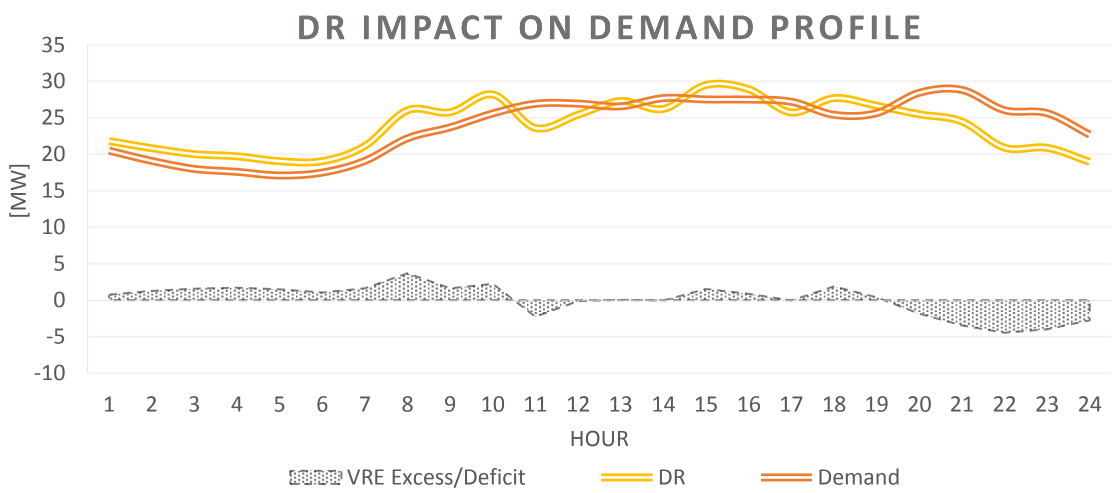

Figure 25: Example of the application of the DR function for day with RE deficit in October, autumn.

It can be seen that the implementation of this DR strategy induces a peak shift from 21:00 to 15:00, as well as an absolute increase of 669 kW (+2.3%). The shaded area represents the excess/deficit of VRE availability with respect to the maximum VRE penetration allowed. Regarding the impact on RE shares, production costs and CO_2 emissions, Table 15 reports the main figures for a 30% VRE penetration factor.

Table 15: Impact of DR strategy on RE shares, production costs and CO_2 emissions for a week days in autumn with deficit RE availability.

	β = 30%	
	Reference	α = 5%
Wind	25.1%	26.7%
Geothermal	10.8%	11.4%
Waste	5.8%	6.4%
Thermal	58.2%	55.5%
Prod. Costs [€]	49,397	47,723
CO_2 emissions [tonCO_2]	257.9	249.3

5.3.2 Electric Vehicles-to-Grid scenarios

Electric vehicles (EVs) are currently considered as a better alternative for the use of conventional fossil fuels in the transportation sector. However, the degree of benefit relative to the introduction of EVs is determined by the energy source used to recharge the vehicles, which depends on two main factors: the power supply system configuration and the EV charging strategies adopted. In systems with lower RE or nuclear energy penetration, the environmental benefits of EVs are less significant, as traditional transportation fuels are replaced by electricity generated by other fossil fuels such as natural gas, fuel oil or coal. This intermediate conversion process is more inefficient than the direct combustion of traditional transportation fuels, and may therefore result in paradoxically higher GHG emissions. On the other hand, in systems with high RE and nuclear penetration, GHG emissions relative to the transportation sector are expected to be significantly reduced [13]. Regarding EV charging strategies, peak consumption hours generally have higher marginal GHG emission factors due to the greater use of fossil fuel power plants. Instead, low consumption periods (i.e. overnight) are most likely to have excess RE availability, that could be used to charge EVs.

Recently, several studies have been made in order to understand the potential of exchanging energy between the electrical grid and EVs not only during charge phases, but during discharge phases as well. In this scenario, which is known as “Electric Vehicles-to-grid (V2G)”, EV batteries are used as storage systems that provide the electrical grid with more stability and penetration of RE sources.

Concerning the integration of V2G applications to the ED model, charging scenarios were accessed from a Master thesis developed by Mário dos Santos Martins [57]. Therefore, only a brief description of its features and illustrative examples of its application will be reported in this section. This V2G simulation tool models the charging profile of a standard EV battery connected to the grid, where the inputs necessary to obtain the total EV load profile are:

- Inhabitants, vehicle density and percentage of vehicles to become EVs;
- Capacity of the single EV battery in kWh;
- EV consumption in kWh/km;
- Average distance covered by one EV in a day in km/day;
- Maximum charging power of one EV in kW.

The tool is able to simulate four different scenarios, that can be seen in Figure 26:

1. EVs charge mainly during the evening (18:00-22:00).
2. EVs charge overnight, taking advantage of time-of-use tariffs (00:00-9:00).
3. EVs charge during working hours (09:00-18:00).
4. Weighted average between the previous profiles.

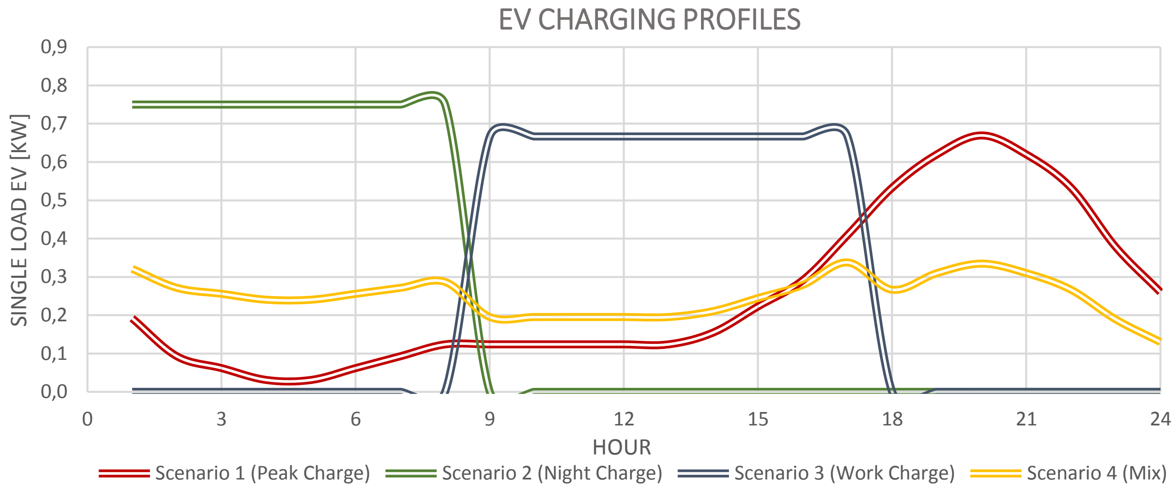

Figure 26: Four different charging profiles simulated by [57].

In order to conduct a complete analysis of the impact of V2G applications in the economic dispatch model, six different scenarios were simulated with the model for a fixed β = 100% (no VRE curtailment). For an autumn day with wind excess and a summer day with wind deficit, scenarios with fleet shifts[2] of 10, 25 and 50% to EVs were simulated and are reported in Figure 27 and Figure 28.

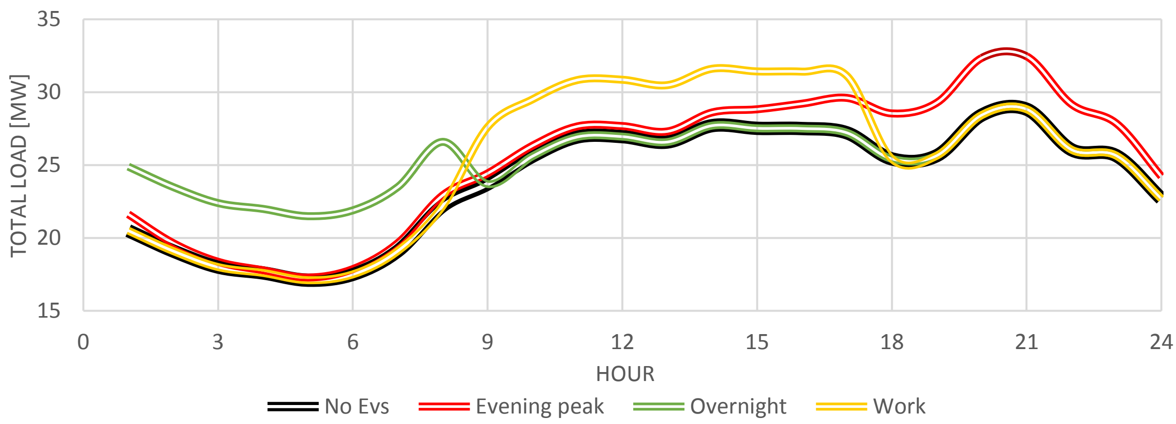

Figure 27: Load profile considering a 25% shift to EVs for a week day in autumn.

[2] Share of the total number of vehicles on the island that would become electric.

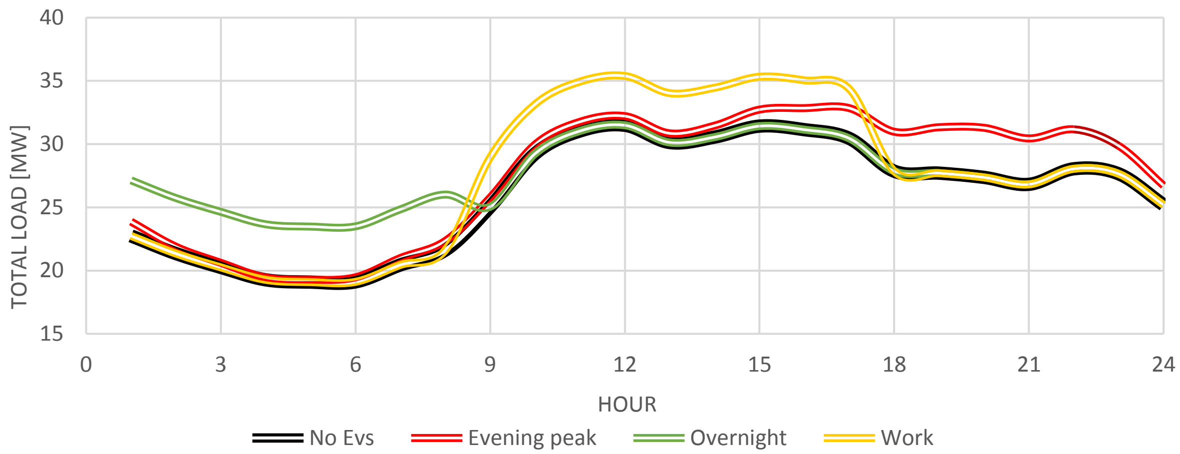

Figure 28: Load profile considering a 25% shift to EVs for a week day in summer.

The overnight charging scenario appears to be the best option as it never increases the peak demand. Moreover, since Terceira's demand profile changes significantly depending on the season, different EV charging profiles have different impacts on the total demand. For example, the evening charging scenario increases by 12.6% the evening peak (21:00) in autumn, while in summer it shifts the peak from 12:00 to 16:00 increasing it only by 4.3%. Regarding the additional energy consumption due to the integration of EVs, in summer the total daily energy consumption is higher and therefore EV charging has a relatively lower impact (in autumn EVs bring a +12.3% of energy consumption, while in summer this value is +11.2%. The impact of the different EV charging profiles on RE shares, production costs and CO_2 emissions for the two case scenarios previously mentioned (autumn and summer) are reported below in Table 16. Moreover, since no constraint on the allowed VRE (wind in this case) to be committed to the grid is set, the maximum hourly wind penetration is reported as well in the table.

Table 16: Impact of EV charging profiles on RE shares, production costs and CO_2 emissions for week days in autumn and summer.

	Autumn				**Summer**			
	Reference	Evening	Overnight	Work	Reference	Evening	Overnight	Work
Wind	26.0%	25.2%	27.5%	25.0%	5.2%	4.9%	4.9%	4.9%
Geothermal	10.8%	10.4%	11.5%	10.2%	11.5%	10.9%	10.9%	10.9%
Waste	5.8%	5.7%	6.8%	5.5%	6.9%	6.5%	6.5%	6.5%
Thermal	57.4%	58.8%	54.2%	59.3%	76.4%	77.6%	77.6%	77.6%
Max Wind Penetration	35.6%	36.2%	36.8%	33.9%	13.0%	12.4%	13.0%	11.6%
Prod. Costs [€]	48,920	51,669	49,030	52,168	63,990	68,384	67,409	68,182
CO_2 emissions [tonCO_2]	255.4	269.8	256.0	272.2	334.0	357.0	351.9	355.9

For the week day in autumn, the most favorable charging scenario is the overnight one: RE penetration is increased and both costs and CO_2 emissions are the lowest of the three EV charging scenarios analyzed. Likewise, despite the low wind availability in summer, the most favorable scenario is the overnight charge. RE shares are, in fact, lower than the "no EV" reference scenarios for all of the charging scenarios, but the overnight scenario brings a lower increase in production costs and CO_2 emissions.

Results show that regardless which strategy is adopted, V2G applications cause an increase in total energy consumption, production costs and CO_2 emissions. However, for this case study, it is possible to notice that depending on the RE availability (different seasons) the integration of EVs might allow the relative RE penetration shares to slightly increase.

5.3.3 Efficiency measures: heating, cooling & DHW

Scenarios providing efficiency measures are provided by a Master Thesis developed by Picoto da Silva [58] and the adaptation of a model for Corvo to Terceira Island [59]. The efficiency measures mentioned consist in replacing less efficient heating, cooling and DHW technologies with more efficient ones. These technologies are usually assured by fossil fuels, such as butane gas, and these efficiency measures represent a shift from fossil fuel to electricity consumption. The final goal of this shift is to replace the consumption of imported resources to endogenous resources, such as renewable energy production. Moreover, the tool adopts the same methodology in all three cases (heating, cooling and DHW).

The inputs consist in the total number of houses, with the relative shares of houses already owning a certain kind of technology. The user then decides what percentage of the total houses in the system would use a certain kind of electric technology, and the tool outputs a vector of hourly variations with respect to the initial total demand profile, based on standard demand profiles per house per technology. For example, out of the 19,200 houses in Terceira, 15,034 (78.3%) currently have heating systems installed. Figure 29 shows a possible scenario where the number of houses with heating systems would be increased to 90% of the total houses, and all of them would shift the existing ones to heat pumps. The red share represents the number of houses owning a heating system.

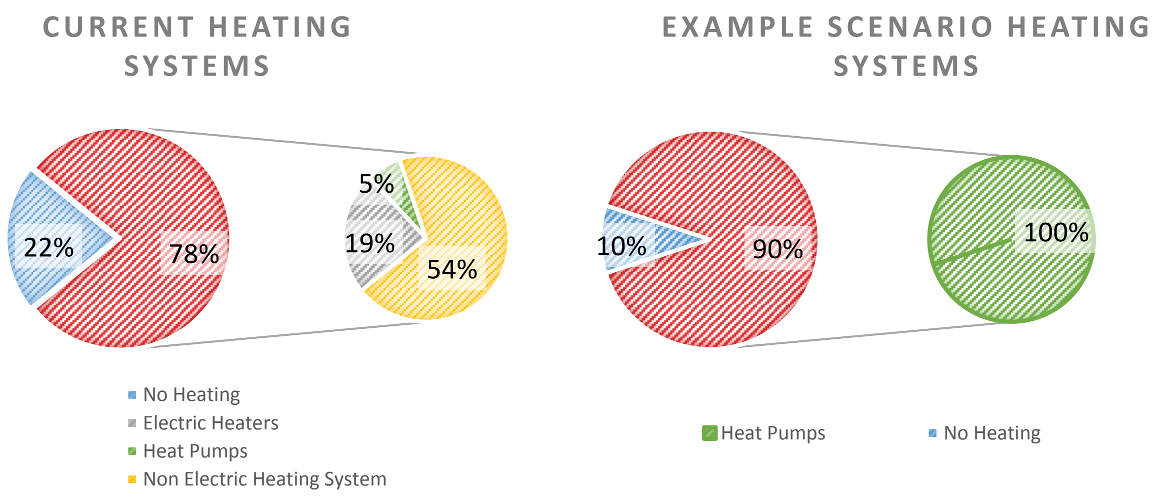

Figure 29: Transition from Terceira's current heating configuration system to a scenario with 90% of houses owning a heating system (of which 100% heat pumps).

The two major effects of this strategy on demand profile and energy production mix are:

- By incrementing the total number of heating systems on the island, being heat pumps significantly more efficient than traditional electric heating systems (commonly, radiators), the new load profile results slightly higher than the initial one. Moreover, variations in the demand profile are extremely small due to the dimensions of the system analyzed and the small share of electricity consumption attributable to heating systems. Peak demand and total energy production only increase by 0.3% and 0.5% respectively.

- This scenario was simulated for an average week day in winter, and no variations in the RE penetration were encountered. This is due to the fact that there is no direct correlation between the improvement in heating technologies and the economic dispatch behavior. However, since the total energy demand increases and the production shares remain constant, a slight increase in production costs and CO_2 emissions is found (both of +0.2%).

Similar scenarios were developed for cooling systems in summer and DHW in autumn. While replacements of cooling systems do not cause relevant changes in the energy production mix, the introduction of solar thermal and electric boilers in DHW systems does have a significant impact on the system. About 97% of the houses in Terceira have a DHW system, and 96% of them consist in gas boilers. Figure 30 shows the proposed scenario where 50% of the DHW systems in Terceira are solar thermal systems and the other 50% are electric water heaters. The shift from gas boilers to electric water heaters is currently being supported by the local utility in Terceira, through financial incentives.

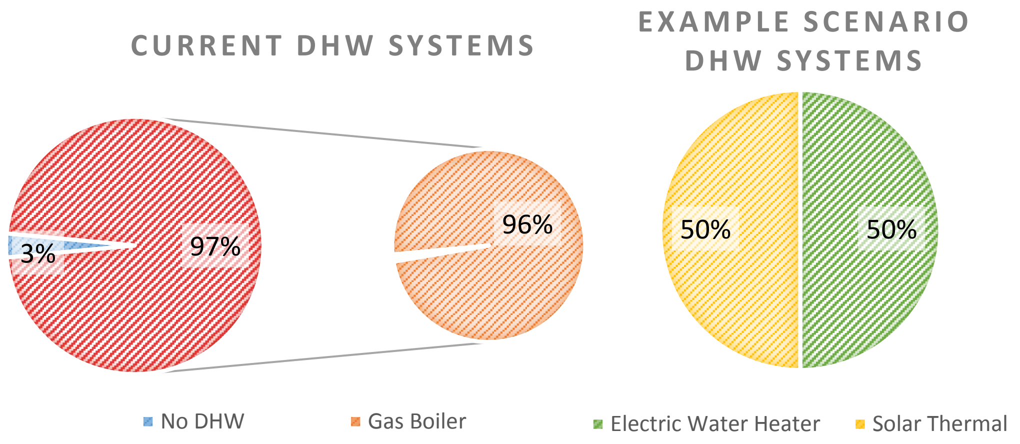

Figure 30: Scenario where all DHW in Terceira are replaced with Solar Thermal DHW systems.

The impact of this scenario on the demand profile can be seen in Figure 31.

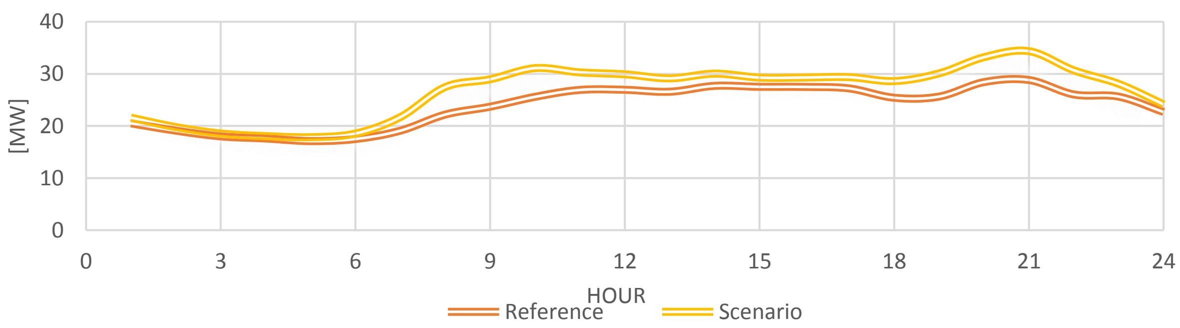

Figure 31: Impact of the 50% ST and 50% EHW scenario on the daily demand profile of an average week day in autumn.

The scenario presented produces a +19.2% increase in the evening peak (from 28.8 to 34.3 MW) and a daily energy consumption increase of +11.6% (66.75 MWh). These alterations of the demand profile have a negative impact on the energy production mix, production costs and CO_2 emissions, as seen in Table 17. As for the EV scenarios, no VRE penetration limit is set.

Table 17: Impact of the 100% Solar Thermal DHW systems on RE shares, production costs and CO_2 emissions.

	Reference	Scenario
Wind	28.3%	26.3%
Waste	6.6%	6.2%
Thermal	65.1%	67.5%
Prod. Costs [€]	53,298	59,652
CO_2 emissions [tonCO_2]	278.1	311.3

The increase in production costs and CO_2 emissions is due to the large increment of daily energy consumption.

Scenarios consisting in the implementation of efficiency measures were simulated under the assumption that the geothermal power plant was not operational yet. This plant is expected to start operating in a few years, while the efficiency measures are imminent.

6 Investment Planning

Until now, no operating costs were associated to renewable power generation as the focus was set on the modelling of the energy system, where priority of dispatch was given to endogenous energy resources regardless their operating costs. However, since the objective of the presented integrated model is to provide valuable parameters for taking investment planning decisions, this section will focus on this particular aspect. First, the methodology adopted for the calculation of levelized costs, both of renewable energy storage systems and of renewable electricity, will be presented. Then, an example for the Terceira case study will be developed and analyzed in order to demonstrate the usefulness and the benefits of this feature to the integrated model.

6.1 Levelized Cost of Electricity (LCOE)

Since an introduction on LCOE was already presented in 5.1 and the methodology adopted for calculating this parameter is exactly the same as in the ESSs case, this will be reported in the following subsection. Differentiation is made between LCOE of renewable energy generators and of ESSs because of the different assumptions behind their calculations. These assumptions will be presented in the case study subsection.

6.2 Levelized Cost of Renewable Energy Storage Systems (LCRES)

The economic dispatch model requires the user to input pre-defined power generators in the energy system under study, with their relative operating costs and size. However, concerning ESS solutions, the model allows either to input already known storage systems, or it offers the possibility of sizing these depending on the system configuration, load profiles and renewable energy availability. For this reason, it was decided to associate a specific cost to the storage system proposed. Moreover, in order to make ESSs comparable between each other and to other renewable power production technologies (which are characterized by a LCOE instead of direct operating costs), it was decided to express the cost of the ESS as a levelized cost in Euros per kilowatt-hour produced. In this subsection, a methodology for calculating ESSs costs for the particular solutions adopted is proposed [56].

The economic performance between different storage technologies and other power production technologies can be compared through the Levelized Cost for Renewable Energy Storage Systems (LCRES), which is calculated as the present value of the life cycle cost of the ESS over the total energy produced by the system during its useful lifetime. Life cycle costs are usually classified into: investment, operation, maintenance and replacement costs. However, in order to add and compare cash flows incurring at different times during the study period (i.e. O&M costs) these have to be converted to present equivalent values with the use of a fixed discount rate. The present value of the total system cost is known as Net Present Cost, and is calculated as in [56]:

$$NPC = \sum_{i=0}^{n} C_0 + \frac{C_{RC}}{(1+r)^i} + \frac{C_{RC_n} - RV_n}{(1+r)^n} \tag{15}$$

Where NPC is the present value of the total system cost, *n* is the study period in years, *r* is the discount rate, C_0 is the investment cost, C_{RC} are all O&M costs over the study period and RV is the residual value at the end of the study period.

The present value of the Life Cycle Cost is calculated as the NPC under the assumption that the study period considered is equal to the useful life of the system.

Regarding the total amount of energy produced over the ESS lifetime, this is calculated for one year and then multiplied for the useful life of the system. Since the purpose of this work is to calculate an indicative LCRES, variations in energy production between different years are not taken into consideration. Instead, being seasonal variations extremely significant within the same year, they are accounted for with the following methodology. Annual energy production is calculated under the assumption that one year is made of 52 weeks, of which 13 per season. Moreover, each season is considered as 13 equal weeks, therefore not considering weekly variations within the same season. This simplification allows to model the energy system behaviour for one typical week per every season, and extrapolate total energy production, operating costs and CO_2 emissions for the entire year. This simpler "seasonal" approach was adopted in order to decrease computational time and allow users to insert profiles for typical weeks, which are usually easier to encounter with respect to all-year round data.

LCRES can be then calculated according to [56]:

$$LCRES = \frac{NPC_{ESS}}{n \times E_{year}} \tag{16}$$

Where NPC_{ESS} is the Net Present Cost of the ESS calculated over its useful lifetime, *n* is the useful lifetime in years and E_{year} is the annual energy dispatched by the storage system calculated with the previous assumptions.

6.3 Terceira Island case study

In order to apply the presented methodology to the Terceira Island case study, the following assumptions were necessary:

- First of all, since the study period considered for calculating LCOE and LCRES of the different technologies is always their useful life, the residual value at the end of their lifetime was assumed to be zero.
- LCOE of renewable technologies were calculated assuming that both BESS and PHES were included in the energy system.

- The LCRES of the two technologies analysed (PHES and BESS) were calculated separately, assuming that either one or the other would be part of the energy system.
- Since the ED model was built to decide whether to dispatch the ESS or not depending on its dispatch cost, it was necessary to introduce values into the model. The first option considered consisted in not associating any dispatch cost to the storage, but because of the structure of the ED model, this created an unfeasible situation in which the ESS was cycled between 10 and 20 times per day. The second approach was to use average costs found in the literature and reported previously in 5.2.1. These dispatch costs were already calculated by [47] as levelized costs of storage; however, BESS dispatch costs were so high that the program never dispatched the ESS. Therefore, the final approach consisted in fixing an arbitrary ESS dispatch cost that would have located the ESS before thermal generators in the commitment priority list. This value is 0.1€/kWh, which falls between the range of realistic values for PHES, but not for BESS. However, the difference between this dispatch cost and the actual LCRES of the battery could be balanced by incentives and feed in tariffs in real implementations.
- Concerning LCOE of renewable technologies, it was possible to initially run the simulation for calculating energy production values with no operating costs associated. These are, in fact, regulated by technical constraints that grant priority to variable and dispatchable renewable energy over thermoelectric.

Results

Finally, a study was conducted for the presented case study in order to quantify the LCOE and LCRES of the different technologies proposed. The scenarios were all developed with the same energy system configuration, which is reported in Table 18.

Table 18: Terceira's power production system configuration used for future scenarios.

Power Plant	Energy Source	Generation units	
		N° of units	Installed Capacity [kW]
Belo Jardim	Thermic – Fuel	2	3,128
		1	3,000
		1	2,860
		4	6,100
		2	12,300
Nasce D'Água	Hydric	1	720
São João de Deus	Hydric	1	448
Cidade	Hydric	1	264
Pico Alto	Geothermal	1	3,000
TERAMB	Residual Solid Waste	1	1,800
Serra do Cume (EDA)	Wind	20	18,000
Serra do Cume (CAEN)	Wind	8	7,200
Total		**43**	**92,548**

It can be noticed that, in addition to the previously mentioned geothermal and residual solid waste power plants, the installed wind capacity is doubled. This assumption was made because the currently installed wind capacity in Terceira is not enough to justify the integration of an ESS (as explained in 5.2). Moreover, LCOE was calculated only for new technologies introduced in the system; namely geothermal, residual solid waste and the additional 12.6 MW of wind capacity installed. This decision was made in order to assess the introduction of new dispatchable and non-dispatchable RE into the energy system both from a technical and economic point of view.

Furthermore, while the total installed capacity results now almost 30% higher than the one recorded at 31st December 2014 (reported in 4.2), no assumptions regarding load evolution were made on the demand side. For this reason, it will be seen that medium and small size thermal generators will infrequently cover an active role in the power supply system.

The VRE penetration factor was fixed at 30% of the load for all the simulations, and the characteristics of the BESS and PHES are the ones obtained for the optimal sizing, reported in Table 9 and Table 12 respectively. Average specific costs per ESS were found in [47], and are reported in Table 19[3].

Table 19: Average specific costs per ESS technology [47].

	PHES	**BESS**
Useful lifetime [years]	25	10
Capital Investment [€/kWh_{cap}]	77 - 192	385 - 1,154
O&M costs [€/(kW x year)]	3.8	19

To be noticed that O&M specific costs found depend on the nominal power of the storage in kW, and not on the installed capacity as for the investment costs in kWh. Therefore, in the PHES case, this value was multiplied by the sum of turbines' and pumps' nominal power (8.1 MW), while concerning the BESS, it was multiplied by the discharge rate of 4.5 MW in order to calculate yearly O&M costs.

Considering the other renewable energy technologies proposed, average specific costs calculated from historical data (2007-2015) by the U.S. Department of Energy were found in [60] [61] and are reported in Table 20[3].

Table 20: Average specific costs per renewable energy technology [60] [61].

	Onshore Wind	Geothermal	RSW
Useful lifetime [years]	20	20	20
Capital Investment [€/kWcap]	1,562	3,015	2,592
O&M fix costs [€/(kW x year)]	24.4	86.3	76.5
O&M variable costs [€/(MWh x year)]	5.9	3.9	3.2

Useful life of geothermal power plants is of 20 years for internal components and 100 years for the ground loop; the shortest useful lifetime was chosen as worst case scenario.

A 10% discount rate was used for both ESS technologies and renewable energy technologies [56].

[3] Converted from USD with a conversion rate of 1 EUR = 1.13 USD [62].

Finally, since the range of capital investments for ESSs found in the literature was substantial, ranges of LCRES were calculated for minimum and maximum values. NPC and LCRES obtained are reported in Table 21.

Table 21: NPC, energy produced and LCRES for the two ESS technologies considered.

	PHES	BESS
NPC [k€]	3,194 – 7,600	5,319 – 14,760
Energy Produced [MWh]	2,225	4,975
LCRES [€/kWh]	0.06 – 0.14	0.11 – 0.30

It can be noticed that, as suggested by values found in the literature, PHES presents much lower ranges of levelized cost than BESS. In particular, the proposed PHES is considered as an extremely small system if compared to the dimensions suggested by the author that provided the specific costs [47]; therefore, LCRES of the pumped hydro system will most likely be closer to the 0.14 €/kWh extreme of the interval. Regarding the BESS, despite being specific costs extremely higher than the PHES (around 5 times), when comparing NPC and LCRES to those of PHES, these are only around twice as much. For the NPC, this is mainly due to the fact that the BESS system, in terms of capacity, is much smaller than the PHES, compensating for the higher specific costs (both investment and O&M). Instead, the limited difference of LCRES between the two technologies (around twice in this case as well) is due to the larger energy production of the BESS over its lifetime. This higher energy production of the BESS, at same dispatching cost conditions, is explained by the fact that there is no parameter taking into account the cycles of the battery system. Therefore, the relatively low dispatch cost used, causes the BESS to undergo many more charge/discharge cycles than the PHES, resulting in an overall higher energy production. Moreover, the BESS presents a larger range of NPC and LCRES values if compared to the PHES.

Concerning LCOE of the proposed renewable energy technologies, results are reported in Table 22.

Table 22: NPC, energy produced and LCOE for onshore wind, geothermal and residual solid waste renewable technologies.

	Onshore Wind	Geothermal	RSW
NPC [k€]	21,100	11,000	7,270
Energy Produced [MWh]	18,282	25,943	15,485
LCOE [€/kWh]	0.058	0.021	0.023

It is to remember that LCOE reported for onshore wind is calculated for the new installed capacity only; if the already existing installed capacity was to be calculated, the LCOE would be 0.03 €/kWh. Moreover, it can be noticed that the net present costs of the total investment in these renewable energy technologies are relatively higher if compared to the LCRES calculated above. However, the energy produced by these technologies is even higher, which results in lower LCOE.

Once the LCOE of the different technologies are obtained, these can be used as inputs to the model in order to develop scenarios for a one year-time horizon. In this work, the levelized costs were obtained through calculations external to the ED model. However, the methodology described could be integrated directly into the ED model in future work, in order to avoid breaking the simulation into two steps.

Levelized costs of electricity and storage depend on a combination of average specific values found in the literature and the particular behaviour of the energy system under study. The possibility of obtaining accurate LCOE for each renewable energy technology that could be implemented in the energy system allows the user to compare different solutions between them and to conventional fossil fuel power plants. This feature is necessary in order to quantify, for example, if and how much more economically (and not only technically) feasible it is to implement one particular RE instead of another. Another benefit of this feature, which identifies and associates an operating cost to RE generation, is the possibility of planning financial incentives to fill the gap between more expensive (but maybe technically more convenient) and more economic (but maybe less feasible) RE power production.

7 Implementation of the integrated model

Finally, a general overview of the integrated ED model is presented in order to have an idea of the variety of features available. The scenario analysed is the same as in 6.3 (Table 18), LCOE for dispatchable RE are the ones reported in Table 22, while LCRES used are the mean values of the ranges reported in Table 21: 0.1 €/kWh and 0.2 €/kWh for PHES and BESS respectively. These dispatch costs grant charging and discharging priority to the PHES over the BESS. No LCOE was associated to non-dispatchable RE (wind), to grant priority to this intermittent resource.

Simulations were done for a generic week of each season. Figure 32 shows, as an example, the economic dispatch under the mentioned assumptions, for a generic week in spring. The week is expressed in hourly time-steps, starting from Monday.

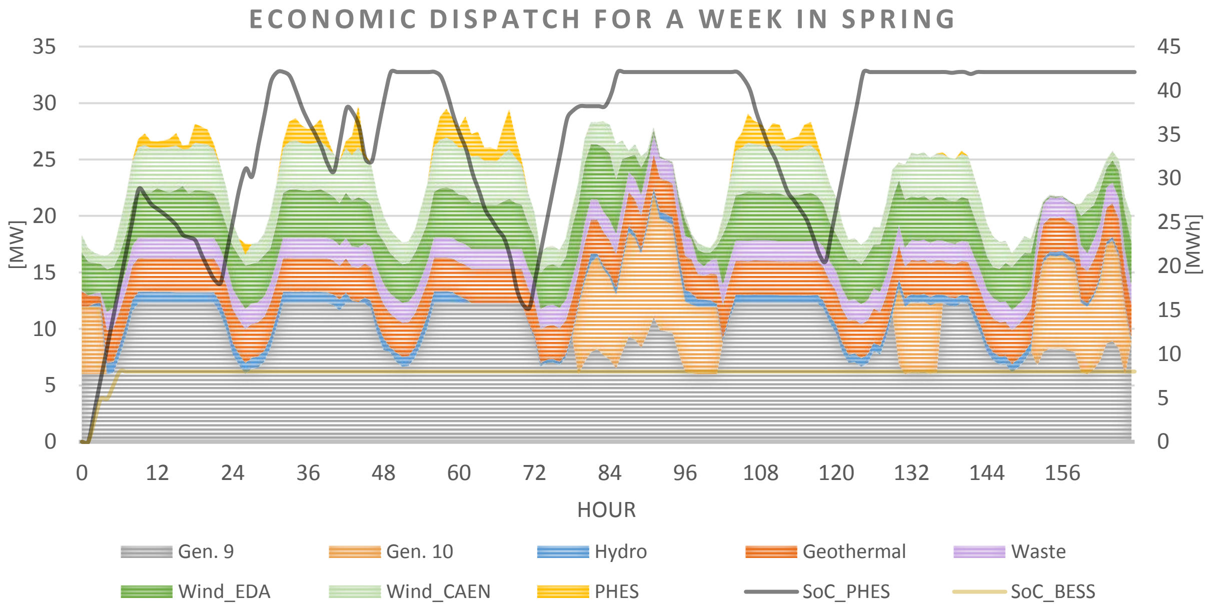

Figure 32: Economic Dispatch for a generic week in Spring.

The first thing to be noticed is that, despite being fully charged after only a few hours, the energy stored in the BESS is never dispatched. This is due to the high BESS dispatch cost, that prevents it from competing with other power production and ESS technologies. On the other hand, the PHES charges both overnight (when demand decreases) and in the same day between the mid-day and evening peak (i.e. on Tuesday). Concerning the large thermal generators, Gen. 9 is always committed in order to guarantee part of the base load, spinning reserve, and satisfy the minimum 25% of thermal generators' production referred previously. Instead, Gen. 10 is committed when there is a VRE deficit and the PHES discharge rate is not enough to cover this deficit (i.e. Wednesday and Sunday). The assumption that both PHES and BESS start the week discharged was made because of the model's structure, and it causes an overall slight decrease in ESS penetration.

Concerning the economic aspect, LCOE calculated for the geothermal and the residual solid waste power plants always resulted cheaper than the operating cost of the large thermal generator committed at their minimum nominal output. This allowed them to be committed almost constantly at their nominal value, resulting in a capacity (over the week considered) of 98% and 97% for the geothermal and the waste power plant respectively. This behaviour highlights the positive impact that the two dispatchable RE power plants would have on the overall energy system.

The energy production mix was then obtained for each season, and these can be seen in Figure 33.

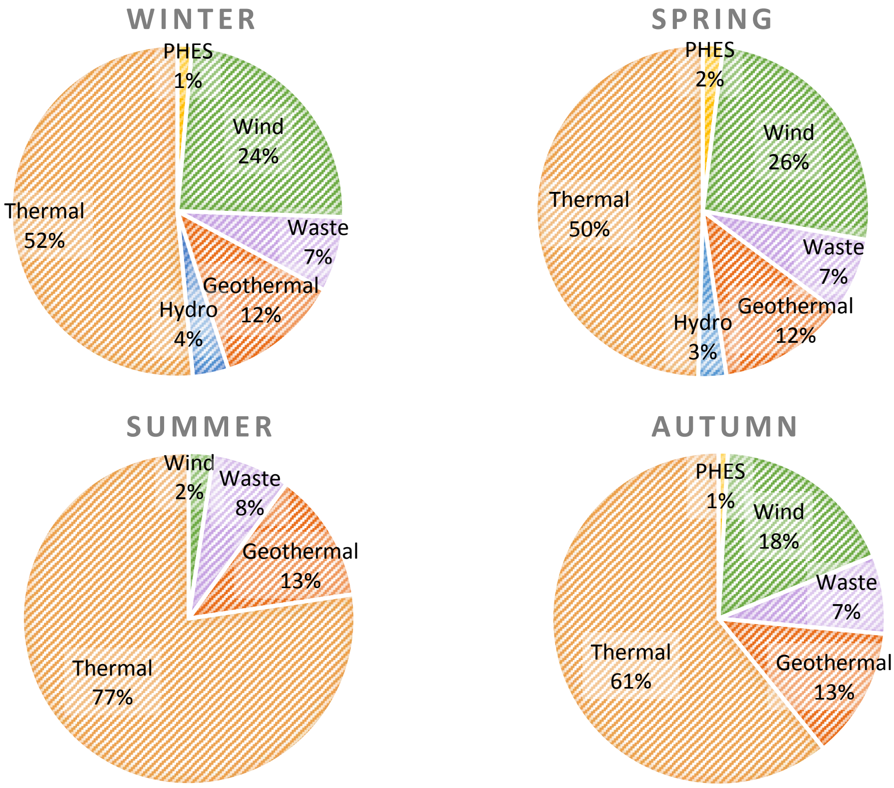

Figure 33: Energy production shares for each season.

Energy production associated to PHES must be considered as wind production, as this is the only VRE present in the power system. Moreover, it can be seen that due to the high deficit of VRE in summer, the PHES does not contribute to the production mix during this season. Non dispatchable renewable energy production (waste and geothermal) are roughly constant throughout the year, slightly increasing when VRE availability decreases (summer). Wind power production is relatively higher during winter and autumn, decreasing to less than ten times during the summer season. Finally, hydroelectric production is the less significant, and appears only during winter and spring due to climatic reasons.

Concerning absolute values of energy production, the largest amount of energy is produced during winter (53.7 GWh), while it results roughly 51 GWh per season from spring to autumn. The total amount of energy produced over the year is, in fact, of 207 GWh. The annual energy production mix can be seen in Figure 34.

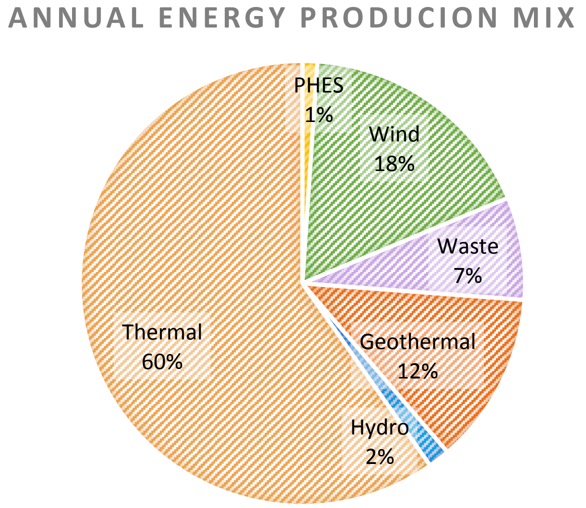

Figure 34: Energy production mix for Terceira Island over a one-year time horizon.

Production costs and CO_2 emissions are quantified as well by the ED model. Moreover, an additional output consisting in diesel and fuel oil consumption for electricity production was integrated into the model. All these outputs are reported in Table 23.

Table 23: Production costs, CO_2 emissions and fossil fuel consumption over the year time-horizon.

	Winter week	**Spring week**	**Summer week**	**Autumn week**	**Year**
Production Costs [k€]	294.8	272.8	415.1	326.0	17,012
CO_2 emissions [ton CO_2]	1506.2	1382.6	2167.0	1682.5	87,598
Diesel [kL]	2.0	1.3	0.6	1.7	72.5
Fuel Oil [kL]	524.2	481.7	756.3	586.1	30,529

Values reported under the season columns are for a generic week of that season. Instead, the year values are calculated by multiplying each weekly value for the number of weeks in a season (13) and then added together. As predictable from the seasonal energy production mixes presented above, summer is the season with higher production costs, CO_2 emissions and fuel oil consumption. Only diesel consumption is lower during the summer season, because this fuel is used for the transition phases (i.e. start-up) of thermal generators, and in summer they are turned on/off less frequently. Moreover, diesel oil is used to fuel the smaller generators, which in the scenario analysed are never committed.

8 Conclusions

In this final section, first some generic conclusions regarding the integrated operation modelling tool will be drawn, then, since a major part of this work was focused on the particular case study of Terceira Island, it was considered appropriate to dedicate a subsection to the results of the case study.

8.1 Integrated Operation Modelling Tool

The economic dispatch model developed in this research work should be considered as a preliminary integrated operational modelling tool. The tool is, after all, a first version, and therefore presents margin for improvements in several sections. However, it comprehends a variety of integrated features and is capable of providing valuable and substantial techno-economic parameters that allow the user to assess several scenarios considering the energy system under study.

The ED model is now able to work with a wide range of systems: from those that contemplate extremely high shares of fossil fuel power generation to more hybrid ones integrating large RE installed capacities. Moreover, it was noticed that technical constraints of thermal generators are more significant when the relative share of fossil fuel plants installed capacity is higher, since the most affected generators are the small-medium sized ones, which are used for meeting peak loads. When the RE (dispatchable and non) installed capacity is increased and the system becomes more "hybrid", technical constraints become less incisive as only larger thermal generators are used for meeting the baseload. This suggests a more focused research on the integration of technical constraints of renewable generators and ESS, which were not deepened in this work, in order to make the integrated model more realistic even for hybrid solutions with higher RE penetration.

The adoption of a particular case study with a large amount of available data resulted crucial for the development of the integrated model. The case study of Terceira Island was, in fact, not only used to validate the initial ED model, but to shape all the integrated features such as ESS, demand response and efficiency measures as well. However, due to the high dependence of the model development on data availability, it seldom resulted challenging to clearly separate the methodologies adopted from the implementation of the case study. Moreover, the final integrated model here presented should be validated with a different case study (as it was done in this work with the initial basic model), in order to assess its behavior and eventually improve its weaknesses.

The main goal of this research thesis was to integrate a wide range of different features in the ED model, in particular regarding long-term energy planning, in order to make it a valuable decision-aid tool for the optimal dispatch of island electric power systems taking into account large penetration of renewable resources. However, the model does not provide a direct comparison between different scenarios developed, which could be an additional feature to be integrated.

Some suggestions for future improvements of the integrated model are provided, keeping in mind that the model is not to become extremely detailed and technical.

- Regarding the transformation of RE resource availability (input of the user) to RE available power production, two main points should be considered. Firstly, the introduction of capacity factors for dispatchable RE that would be taken into account for the extrapolation of annual simulations. Secondly, the integration of a forecasting function able to model the stochastic nature of wind resource. Since average monthly wind speed is easier to access than hourly data, the possibility of introducing as an input this average value would be of great advantage for the user.
- Considering the integration of Energy Storage Systems in the model: only PHES and BESS were analyzed in this work in order to provide examples of both small and large scale ESSs. However, the development of other functions representing a wider variety of ESSs, such as hydrogen, compressed air and supercapacitors, would allow the model to accommodate more energy system configurations. Regarding the sizing procedure of the ESS, associating an additional parameter representing the true cost of the energy stored depending on the SoC of the storage system would prevent the excessive (and eventually unfeasible) number of charge/discharge cycles when ESS dispatch costs are very low.
- The calculation of LCOE of the different RE technologies present in the system is useful to evaluate the real operational costs of these technologies. However, eventually quantifying payback times of investments in these RE technologies would be another useful parameter for taking investment planning decisions.
- Since the tool was developed in *Matlab*, developing a user interface would allow users to implement the modelling tool without necessarily having a deep knowledge of the program.

8.2 Terceira Island case study

The present work often concentrates on the particular case study of Terceira Island. At the beginning, the currently operating energy system was analyzed in order to validate the model. Then, different scenarios ranging from variation of the demand characterization to the actual implementation of new renewable technologies were developed. Concerning the demand side, scenarios developed comprehended: introduction of EVs, demand response strategies and introduction of efficiency measures. For the power supply: the implementation of two different dispatchable renewable technologies (geothermal and municipal solid waste), the expansion of an already existing wind park and the impact of introducing ESSs were analyzed. The dispatchable RE plants are currently being installed, while the expansion of the wind park is being assessed together with the implementation of a storage system in the island. The integrated model was used to assess all these scenarios from both a technical and economic point of view. Results demonstrated that the implementation of dispatchable RE in Terceira Island has a great potential. In particular, because they would be able to partially replace the extremely large shares of fossil fuel based power generation, which are expensive and harmful to the environment. Moreover, the levelized cost of electricity of both geothermal and municipal solid waste power plants resulted lower than operating costs of the thermoelectric power plant, which reinforces the advantage of these endogenous RE over fossil fuels. Concerning the expansion of the wind park (VRE), this, combined with the implementation of a pumped hydro storage system, would allow a higher penetration of renewable energy production. Instead, battery storage systems, which resulted in more expensive operating costs, were not demonstrated to have a significant role in load levelling. However, frequency regulation aspects were not analyzed in detail in this work, and the possibility of implementing a smaller BESS in order to counterbalance frequency and voltage instabilities of VRE production could be a valuable solution to increase total RE production shares in the system. Despite being these technologies economically more convenient than thermoelectric power generation from an operating point of view, initial investments should be considered as well, since it would not be possible to invest in all the proposed solutions at the same time. The tool is useful to draw up a list of economically more convenient solutions (all technically feasible), and aid decision making in investment planning.

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ANNEX A Terceira’s Power Plants: technical details

Belo Jardim Thermoelectric Power Plant

Generator	Energy Source	Thermal Power [kW_{th}]	Rated Power [kW_e]
1	Diesel	8130	3128
2	Diesel	8130	3128
3	Diesel	7800	3000
4	Diesel	7430	2860
5	Fuel Oil	15850	6100
6	Fuel Oil	15850	6100
7	Fuel Oil	15850	6100
8	Fuel Oil	15850	6100
9	Fuel Oil	31960	12300
10	Fuel Oil	31960	12300

Hydroelectric Power Plants

Nasce Água

The first plant to exploit the Cabrito spring and Furna da Água is the Nasce Água plant. This is fed from a 6000 m^3 reservoir through an 830 m long steel conduct with an internal diameter of 600 mm and a maximum gross height of 182 m. The generation unit, consisting of a Pelton turbine and an alternator, is able to develop 720 kW_e of rated power. The output tension of the alternator is 0.4 kV, which is raised to 15 kV by a transformer in order for it to be injected in the grid [33].

São João de Deus

São João de Deus is the intermediate plant, situated between Nasce Água and Cidade. A Pelton turbine is fed by a 77.5 m^3 load chamber, located in between the two plants, through a steel pipe exploiting a maximum gross height of 120 m. The turbine is coupled with an alternator, being able to develop 448 kW_e of rated power at 0.4 kV. Once again, through a transformer, the voltage is raised to 15 kV before the injection in the grid [33].

Cidade

Finally, downstream from São João de Deus, is located the Cidade hydroelectric power plant. The technical configuration of the plant is analogue to the previous mini hydro plants. However, the Pelton turbine is of smaller dimensions: exploiting 72.5 m of gross height, the generation unit produces 264 kW_e of rated power [33].