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Long term Projections of Electricity Generation Costs in Portugal

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Abstract

Due to the current aims of reducing CO_2 emission levels and increasing energy efficiency, the electric energy market is one of the principal sectors to approach big changes in the next years. In fact, the emphasis on renewable energy sources seems to be the most adequate response to this challenge; however doubts exist regarding the sustainability and economic viability of these solutions.

Within this panorama, the present dissertation deals with the study of future electricity production costs for each type of production technology. Having these projections and the Portuguese electric system's historic background in mind, this research aims at foreseeing the electricity production costs in Portugal, through the creation and adoption of various penetration scenarios of each type of technology in the national energetic mix. Here, the final aim is to understand the relation between these results and the additional costs that the system entails with the incentives paid to electricity producers.

For that purpose, the methodology applied is based on the calculation of the levelized cost of electricity (LCOE) which considers the total costs, as well as the energy produced in each type of electricity generation technology from 2000 until 2030.

The results of this investigation enabled the verification of a decreasing trend of the electricity production costs in case of renewable production technology sources, with a special focus on wind onshore and solar PV. Contrarily conventional thermal centrals demonstrate relatively higher costs caused by the increase in fuel and CO_2 emissions licenses prices. Furthermore, regarding system costs with electricity production, it was verified that they should persist at current levels, while in scenarios of high renewables penetration costs tend to diminish.

In conclusion, all these findings confirm that renewable energy sources are a good solution in order to be able to fulfill the above-mentioned aims, while preventing an increase in prices for the system if the incentives for its development are applied in a sustainable manner.

Resumo

Com as metas atuais de redução dos níveis de emissão de CO_2 e do aumento de eficiência energética, o mercado de energia elétrica é um dos principais setores ao qual se perspetivam fortes mudanças nos próximos anos. A aposta nas energias renováveis parece ser a resposta adequada ao problema mas surgem dúvidas quanto à sustentabilidade e viabilidade económica destas soluções.

Enquadrada neste panorama a presente dissertação propõe-se a estudar o futuro dos custos de produção de eletricidade para cada tipo de tecnologia de produção. Com estas projeções e tendo em conta o historial do sistema elétrico português, pretende-se prever, através da criação de cenários de penetração de cada tipo de tecnologia no mix energético nacional, os custos de produção de eletricidade em Portugal. Como objetivo final procura-se perceber a relação entre estes resultados e os custos adicionais que o sistema acarreta com os incentivos pagos aos produtores de eletricidade.

A metodologia seguida baseou-se no cálculo do custo nivelado de energia elétrica, ou *levelized cost of electricity* (LCOE), que tem em consideração os custos totais e a energia produzida em cada tipo de tecnologia de produção de eletricidade, desde o ano 2000 até ao ano 2030.

Os resultados do estudo realizado nesta dissertação permitiram verificar que existe uma tendência decrescente dos custos de produção de eletricidade nas tecnologias de produção a partir de fontes renováveis, com especial foco na eólica *onshore* e na solar fotovoltaica. Contrariamente, as centrais térmicas convencionais deverão ter um custo mais elevado, proveniente do crescimento dos preços de combustível e de licenças de emissão de CO_2 .

Relativamente aos custos do sistema com a produção de eletricidade verificou-se que no contexto atual estes deverão manter-se nos níveis atuais, sendo que em certos cenários de elevada penetração de renováveis os custos tendem a decrescer.

Em suma, com estes resultados verifica-se que a aposta nas energias renováveis é uma boa solução para o cumprimento das metas anteriormente referidas, solução esta que não encarece o sistema desde que os incentivos ao seu desenvolvimento sejam realizados de forma sustentável.

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André Felício Carapito

*“Our virtues and our failings are inseparable, like force and matter.
When they separate, man is no more.”*

Nikola Tesla

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Acronyms

Btu	British thermal unit
CAPEX	Capital expenditure
CCGT	Combined-Cycle gas turbine
COE	Cost of energy
CHP	Combined heat and power
CSP	Concentrating solar power
EUR	Euros
GDP	Gross domestic product
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt per hour
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IRR	Internal rate of return
kW	Kilowatt
LCOE	Levelized cost of electricity
LHP	Large hydropower
MW	Megawatt
MWh	Megawatt per hour
MSW	Municipal solid waste
NEA	Nuclear Energy Agency
NG	Natural gas
OECD	Organisation for Economic Co-operation and Development
O&M	Operation and maintenance
OPEX	Operational expenditure
PC	Pulverised coal
PV	Photovoltaic
PRE	Special regime production
REE	Spanish electricity network operator
REN	Portuguese electricity network operator
RES	Renewable energy sources
SHP	Small hydropower
USD	U.S. dollar (\$)
WWW	<i>World Wide Web</i>

Chapter 1

Introduction

1.1 Context, Pertinence and Motivation

After the liberalisation of the energy sector that opened its doors to a free and more competitive market of buying and selling electric energy in Portugal and most other countries around the globe, the very structure of the energy sector was no longer centralised in one company only, but in diverse firms.

In the former structure, the planning has been made by considering the uncertainty of demand and the fuel prices only. Nowadays however, companies in the new market are increasingly confronted with new types of uncertainty and depend on the customers' choices, as well as their competitors' actions. Never before have the projection of the evolution of production costs, as well as electricity costs assumed that much importance as they assume today.

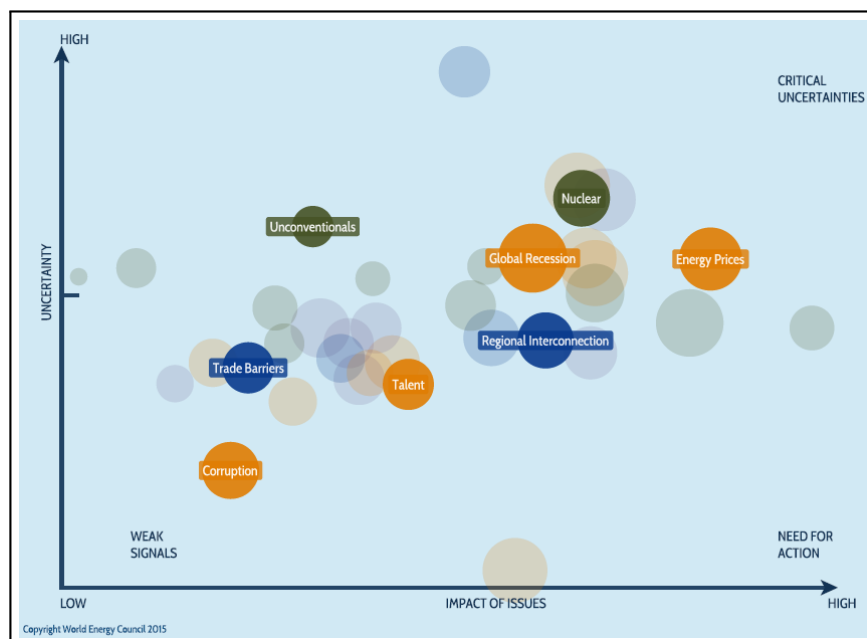


Figure 1.1: Global Energy Issues in 2015. Source: [1].

Figure 1.1 presents a graphic that includes a variety of problems and their degree of uncertainty, as well as its impacts. Here, the upper corner on the right hand side distinguishes the energy prices. In fact, it is the pertinence of this issue that is quite a motivating factor regarding the realisation of this research.

The commitment of a variety of nations around the world (such as Portugal) to reduce CO_2 emissions in electricity generation, as well as to improve energy efficiency leads to a strong incentive to increase the production via Renewable Energy Sources (RES) and causes an energy mix that is quite different from the former one.

Having this panorama in mind, this dissertation studies the evolution of electricity generation costs in Portugal until 2030. Furthermore, it is intended to provide answers to the following questions:

- What is the future evolution of the electricity generation costs of each electricity production technology and which are the most competitive ones;
- Knowing the background of Portugal, what is the future evolution of the electricity generation costs in this country in different scenarios;
- And finally, once having obtained answers and results to the above-mentioned questions it is intended to know which implications the latter have on the additional costs of the electric system when deriving from incentives made to electricity producers.

1.2 Structure

In order to be able to answer the above-mentioned questions and thus achieve the goals set for this research, this dissertation is structured as follows:

In Chapter 1 (the present one), an introduction to the dissertation topic, as well as the motivation and goals of the study get explained.

Afterwards, in Chapter 2 a review of the state-of-the-art is conducted to help to internalise the several subjects important to the dissertation;

Chapter 3 subsequently presents relevant information regarding electricity production, consumption and international exchanges, as well as power plants costs and other characteristics, which has been collected for the conduction of this investigation.

Chapter 4 describes the adopted methodology for the calculation of the electricity generation costs of each electricity generation technology and evolution of the latter in Portugal until 2030.

Chapter 5 explains the several scenarios created, regarding future projections of installed capacity in Portugal, starting with a base scenario and how further scenarios have been developed on the basis of the first one.

Hereupon Chapter 6 demonstrates the results obtained for the projections of the electricity generation costs of each power generation technology, as well as the electricity generation costs in Portugal. Moreover it studies the implications of the results on the additional costs of the system.

Finally Chapter 7, presents the main conclusions, as well as the limitations of this research and recommendations for future investigations.

Chapter 2

State-of-the-art

Projecting electricity generation costs implies that one follows a certain process that could assist to reach ones goals. Much of the literature which has been reviewed and will be discussed in the sections of this chapter makes use of energy models.

“Energy models are, like other models, simplified representations of real systems. Models are convenient tools in situations where performing tests or experiments in the real world are impractical, too expensive or out-rightly impossible.” [22, chap. Energy models]

The concept of energy models helps defining a strategy to follow and which approaches to use. In order to be able to select one’s path and once today exists a great number of models with diverse assumptions, it is important to make a classification that helps to categorise them. Three main articles [10, 22, 23] that explain the need for this classification and how it can be done were reviewed in Section 2.1. Moreover, in Sub-section 2.1.8 some examples of models are presented.

2.1 Energy Models: Classification and Examples

As explained before and present in [10], because of the great number of models that exist today it’s very useful to characterise energy models. Therefore articles [10, 22], based on articles [24, 25] present the following classifications:

1. General and Specific Purposes of Energy Models;
2. The model structure: internal and external assumptions;
3. The analytical approach: top-down vs. bottom-up;
4. The underlying methodology;
5. The mathematical approach;
6. Geographical coverage;

7. Sectoral coverage;
8. The time horizon: short, medium, and long term;
9. Data requirements.

Another classification can be found in article [26]. The principal differences to the previous is the inclusion of the category 'energy carriers considered' and the suppression of the categories 'mathematical approach' and 'model structure'. This classification was purposed in order to meet the needs of the article's goals, so it is clear that there is no rule or standardisation for energy models classification. The most significant categories purposed by [22] and [10] are briefly discussed below (the definitions are based on articles cited above) and examples of energy models are then presented.

2.1.1 General and Specific Purposes of Energy Models

Energy models purposes are divided by [10] into general purposes and specific purposes. General purposes identify how the future is addressed by uses of forecasting models, scenario analysis or "*backcasting*". The first one is based on extrapolation of trends and usually applied for analysing short-term impacts of actions. The second one relies on assumptions to compare a limited number of alternative scenarios with a reference scenario. These assumptions are mostly about economic behaviour, technical progress, physical resource needs and economic or population growth. "*Backcasting*" models use experts' opinions and looks for what must be changed to reach a desire future.

Specific purposes regard the focus of the models such as energy demand models, where the demand can be for the entire economy, for some sectors or a specific sector and is generally described as a function of income, energy prices and changes in population. Energy supply is another example of specific purpose that concentrates mainly on the effort of supply meeting demand and on technical aspects of energy systems. There are also impact and appraisal models. While the first studies the impact of the selection of different options, such as using certain energy systems or policy measures, the latter is applied when several options need to be compared, even if there is only one option, in which case it needs to be decided whether you choose it or not. These aspects are either used separately in models or in conjunction, such as demand-supply balance models or impact-appraisal models.

2.1.2 The Model structure: Internal and External Assumptions

This category is also important because the model must distinguish which assumptions are going to be determined by the user of the model and which are implicit to the model. Article [24] segregates the structure of the model in four dimensions, which can be then ranked from "more" to "less":

- Degree of endogenization, i.e a measure of the parameters incorporated within the model equations so the number of exogenous parameters are minimal;

- The extent of the description of the non-energy sector components of the economy. The more detail of this components are, the more suitable the model is for analysing the effects of the energy policy measures in the economy;
- The extent of the description of energy end-uses, that gives the perception of the suitability of the model when analysing the technological potential of energy efficiency;
- The extent of the description of energy supply technologies. When the model makes a detailed representation of the technologies available it is more clear to understand the potential for fuel substitution.

2.1.3 The Analytical Approach: Top-down vs. Bottom-up

Top-down and bottom-up models are two basic approaches that allow one to determine the existence of a connection between the economy and the energy system [23]. These two approaches have normally two different outcomes for the same problem. Top-down models evaluate the system performing an aggregation of the economic variables. The data is aggregated using generally statistical indicators defined by sector and type of end-use. To model the final demand and supply modellers, in the case of top-down approach, tend to use macroeconomic theory to historical data on consumption, incomes, prices and costs.

Bottom-up approaches normally use disaggregated data and consider technological options or climate change mitigation policies. It is common to refer that bottom-up models are an "engineering" approach, they give a detailed analysis of the technical and economic dimensions for specific policy options. Table 2.1 summarises the different characteristics of top-down and bottom-up models.

2.1.4 The Underlying Methodology

The methodology is the base of the model, in which the process of the inputs to obtain the results occurs. The selection of the methodology to follow depends on the available information and the goal of the model. The methodologies can be categorised and described as follows, based on [10] and [26].

- Economic methodologies: They can be divided into econometric models, macro-economic models and equilibrium models. Econometrics is defined by [27] as the application of statistical methods to the analysis of economic data and theories. Econometric models can be static or dynamic depending on the planner decision to cover a given period, defining the start and end time, or to give information about economic development and structural trends for the planning period. A disadvantage of this methodology is that it does not represent specific technologies and a reasonable stability of economic behaviour is required. Macro-economic models as the previous need a high level of expertise. The difference is that it focuses on the entire economy of a society and sectors interaction and are often developed for exploring purposes assuming facts that could not represent the reality faced.

Table 2.1: Characteristics of Top-down and Bottom-up Models. Source: Taken from [10].

Top-down Models	Bottom-up Models
use an “economic approach”	use an “engineering approach”
give pessimistic estimates on “best” performance	give optimistic estimates on “best” performance
can not explicitly represent technologies	allow for detailed description of technologies
reflect available technologies adopted by the market	reflect technical potential
the “most efficient” technologies are given by the production frontier (which is set by market behavior)	efficient technologies can lie beyond the economic production frontier suggested by market behavior
use aggregated data for predicting purposes	use disaggregated data for exploring purposes
are based on observed market behaviour	are independent of observed market behaviour
disregard the technically most efficient technologies available, thus underestimate potential for efficiency improvements	disregard market thresholds (hidden costs and other constraints), thus overestimate the potential for efficiency improvements
determine energy demand through aggregate economic indices (GNP, price elasticities), but vary in addressing energy supply	represent supply technologies in detail using but vary in addressing energy consumption
endogenize behavioural relationships	assess costs of technological options directly
assumes there are no discontinuities in historical trends	assumes interactions between energy sector and other sectors is negligible

Equilibrium models rely on perfect market equilibrium assumptions and their goals are to find the optimal allocation of resources regarding system constraints. These models do not provide adequate information on the time path for new equilibrium and so transition costs are understated.

- **Optimisation models:** The optimal solution for the energy investments planning is given in this type of models. The best solution that meets the given constraints is achieved. These models often use complex mathematical approaches and use some techniques like linear and non-linear programming, evolutionary and genetic algorithms or fuzzy logic.
- **Dynamic system methodologies:** Equations based on causality are used to express levels of stock variables. Article [26] describes that "this causality comes from the fact that all phenomena can be seen as a web of relationships between elements (or systems) and all elements have patterns, behaviors, and properties that can be understood and used to explore futures".
- **Simulation models:** This type of models include a detailed representation of energy demand and supply technologies. A simulation model can be static, if it represents the operation of the system in a single time period, or dynamic, if the output of the current period is affected by evolution or expansion compared with previous periods. Because of the complexity of

this models they are often used in scenario analysis. They are very helpful in cases where it is impossible or highly costly to experiment on the system itself.

- **Backcasting Models:** These models make use of expert's opinions and look to the trends that are required or must be broken to construct visions of desired futures.
- **Hybrid methodologies:** Models that do not fit in the described models above are usually labelled as hybrid. In here are included the spreadsheets or toll box models, that are not more than software packages to generate models that can be modified according to the users' needs.

2.1.5 Mathematical Approach

Another and more specific distinction of the models is made by identifying the mathematical approach or the procedures applied to obtain the results. The most commonly techniques used are listed and briefly explained bellow.

- **Linear Programming :** Gives quick results and is relatively simple to the user as no profound mathematical knowledge is required. It finds the best arrangement of activities which minimise or maximise the defined criterion, regarding operative constrains. This activities must be in the form of linear equalities or inequalities and the criterion is also linear.
- **Mixed Integer Programming:** Is an extension of linear programming that formulates technical properties and relations in modeling energy systems with more detail. Admits binary decisions (0/1) and nonconvex relations for discrete decision problems.
- **Dynamic Programming :** The complex problem is divided in several sub-problems which are then solved. The solutions are combined to reach an overall solution. A fundamental characteristic is the multistage nature of the optimisation procedure.
- **Multi-criteria techniques:** Used for solving problems with multiple objectives. It is required a decision-maker because objectives are usually in conflict. The solution is highly dependent on options of the decision-maker which must assume the risk of his options.
- **Evolutionary algorithms :** Based on biological evolution, creates a population of individuals each one with a solution. A fitness function determines the quality of the solutions as the population evolves. There are several evolutionary algorithms types, such as genetic algorithm, neuronal networks, among others. The different algorithms are well explained on literature and are not here reviewed.

2.1.6 Geographical Coverage

Article [10] divides the geographical coverage in global, regional, national, local or project depending on the level at which the analysis takes place. Moreover, it is argued that global, regional

and national levels requires highly aggregated data and the others require a bottom-up approach using disaggregated data.

2.1.7 The Time Horizon

Energy models also vary depending on the time horizon, which can be defined as short, medium or long-term. There is no standard definition for the scope of each horizon but Grubb et. al. [25] gives a scope of 5 years or less for short-term, between 3 and 15 years for medium-term and 10 or more years for long term. The time horizon is crucial because of the difference between processes on time scales. Many times long term analysis assume that resources are fully allocated and no disturbance on the energy system exists. On the other hand, short-term deal with disturbances by incorporating transitioning and disequilibrium effects.

2.1.8 Examples of Energy Models

Table 2.2 summarises typical energy models used for energy planning. Most of these models are used worldwide by companies and governments for planning strategies for the future with the goal of optimising resources at least economically and environmentally cost to meet the needs of the demand.

The review made in this section, particularly the outlined characteristics of energy models, allows one to construct a model that responds correctly to the needs of this dissertation. There are characteristics from the above-reviewed ones that are essential for this study. Figure 2.1 gives prominence to these elements. Included on them there are important subjects which need to be reviewed. To define the underlying methodology and the mathematical approach of the new model one must consult literature on the subjects of how to calculate electricity generation costs and how they impinge system costs. Long term electricity prices forecasting will also be reviewed. Moreover, a review of electricity generation technology trends is done. Sections 2.2 to 2.5 review the points mentioned before.

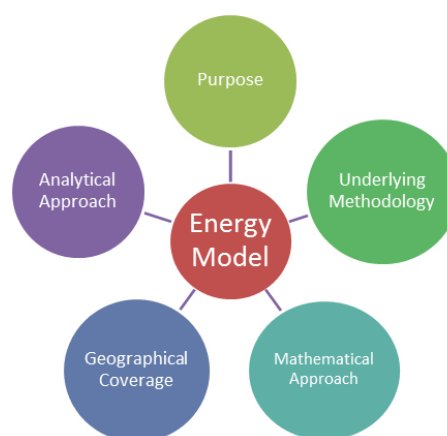


Figure 2.1: Essential Characteristics of Energy Models for this Dissertation.

Table 2.2: Some Examples of Energy Models.

Models	Features
LEAP	Long-range alternative energy planning (LEAP) is a tool that can be used to create models to perform a variety of tasks. It includes energy policies analysis, integrated energy planning, production of energy master plans, energy forecasting and energy scenario studies. It uses top-down strategy for demand and bottom-up for supply and follows an econometric methodology for the previous and simulation methodology for the latter. It covers local to global geography and is used for a medium or long-term scope.
MARKAL/TIMES	The model focuses only on the energy sector using a bottom-up strategy. It has two approaches to modelling energy: a technical engineering approach and an economic approach. Linear programming is used as mathematical approach over a medium to long-term time horizon. Its purpose is to explore the possible energy futures based on several scenarios using an optimisation methodology.
EnergyPLAN	An deterministic model that optimises the operation of a given energy system on the basis of inputs and outputs defined by the user [28]. It is used to assist national or regional strategies plans in a long-term time horizon. Inputs of the model can be demands, renewable energy sources, capacities, costs and regulation strategies. As for outputs, usually are annual production values, energy balances, fuel consumption and system costs.
IKARUS	This model is a dynamical bottom-up linear cost-optimisation scenario for national energy systems. It is a long term study and can be applied for studying the effects of stochastic energy prices on long-term energy scenarios, carbon capture and storage in reducing carbon emissions, the introduction of fuzzy constraints to provide a better representation of political decision processes in the energy economy and energy policy and the implications of high energy prices.
ORCED	The purpose of this model is to dispatch power plants in a certain region to meet the electricity demands for any given year up to 2030 [29].

2.2 Long term Electricity Prices Forecasting: Methodologies.

Since countries began with the deregulation of the electricity generation market allowing several power companies to compete with each other, the importance of price forecasting has increased. Before, one central company performed a unique optimised plan for capacity expansion regarding the amount of new capacity, the generation mix and the timing of investments on a regional or national level [30]. This planning was only affected by uncertainty on future demand and fuel prices. Nowadays, however, companies are confronted with new uncertainties and depend on customer's preferences and the action of competitors [31]. Therefore long term planning faces bigger challenges today.

Electricity prices forecasting are divided by time horizon of the forecast into short-term, medium-term and long-term forecasting. There are no specific scopes for these horizons but usually short-term involves forecast from a few minutes up to a few days ahead, medium-term from a few days to a few months and long-term with a scope of months, quarters or years [32]. Literature on electricity prices forecasting is extensive, but most of the articles focus on short or medium-

term forecast. However there are some main articles that refer which methodologies exist for the long-term horizon and others that use models to study the dynamics of electricity markets. The contents of these articles are in this section summarised focusing on information for the long-term electricity prices forecasting methodologies.

The formulation of the electricity prices forecasting problem found in the reviewed articles differ in the terms applied but the approaches are similar. In Figure 2.2 it is presented a classification based on those made by Articles [2, 11, 33, 34]. The different models dispose of diverse input data and results [2].

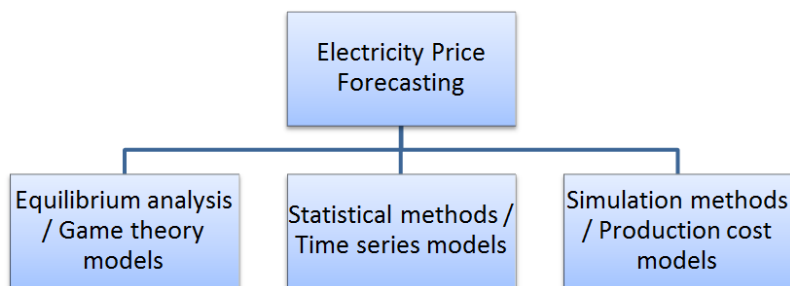


Figure 2.2: Electricity Price Forecasting Methodologies.

A definition based on previously-mentioned articles for the several methodologies is given below:

- **Equilibrium analysis:** These models use game theory to model the strategies of the market participants and how to solve them. The outcome of the study is the evolution of prices and the mathematical solution of the "games". The inputs and outputs of this model are visible in Figure 2.3. Examples of this type of model are the Cournot model, Bertrand model, and supply function equilibrium model;

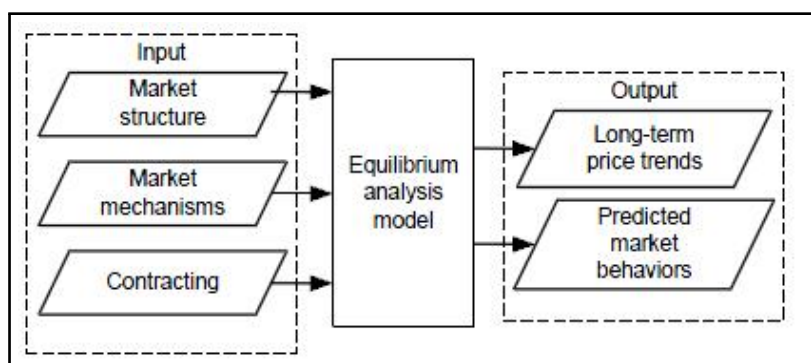


Figure 2.3: Equilibrium Analysis Model. Source: Taken from [2].

- **Statistical methods:** Time series data are the input and output of these models which use a statistical point of view to analyse prices evolution and do not take the physical processed

into detailed account. The articles reviewed present a more specific classification of these methods which contains among others stochastic models, artificial intelligence based models, regression or causal models and econometric models. Statistical methods are commonly used for the hourly market clearing prices in a day-ahead spot market;

- Simulation methods: When an equilibrium model cannot solve a problem because of its complexity, generally simulation methods are applied. The actual operation of the power system is simulated involving economical dispatch, computational power flow and physical system constraints. Most of the simulation methods are production costs models based on the local marginal costs. Two examples that use this methodology are the multi area production simulation software (MAPS¹) by General Electric and UPLAN network power model (UPLAN-NPM²) by LCG Consulting.

Articles [2, 11] highlight equilibrium models to conduct studies for the long-term forecast of electricity prices, justifying that the longer the time scope of the study the less detailed modeling capability and the more significant the response of all competitors. Also for long-term studies in market power analysis and market design, Article [11] refers to simulation and equilibrium models as the best alternative. Table 2.3 demonstrates a variety of studies and divides them according to the electricity market models that have been applied within the authors' investigations in order to study the listed aims and usages. Clearly equilibrium models are mostly used for long-term studies.

Table 2.3: Main Electricity Markets Models and their Usage. Source: Adapted from [11].

Major Use	Optimisation Models	Simulation Models	Equilibrium Models
Risk management	[35, 36]		
Unit commitment	[37, 38]		
Short-term hydrothermal coordination	[39]		
Strategic bidding	[40, 41]		
Market power analysis		[42]	[43–48]
Market design		[49]	[43, 47, 48]
Yearly economic planning		[50]	[51]
Long-term hydrothermal coordination			[52–56]
Capacity expansion planning			[57, 58]
Congestion management			[59–64]

To model the dynamics of the electricity markets on the long-run Articles [31, 65] developed methods based on system dynamics (SD) model. These articles argue that the traditional and few models that assess the long-term market development are not sufficient since they do not take the

¹<http://www.geenergyconsulting.com/practice-area/software-products/maps>

²<http://www.energyonline.com/products/uplane.aspx>

existence of feedback and system time constants in consideration. Moreover the system evolution is viewed by these models as a sequence of stable and optimal long-run equilibrium states [65] and can lead to excess of investments and over-capacity or the opposite, for instance.

“In general terms, the methodology of SD is based on identifying the structure of the system and the logic of the inter-relationships among the different system components to derive its dynamical response. Mathematically, this results in the formulation of the differential equations that represent the system behavior.” [65, chap. 3. Model Description]

The study of electricity prices is also related to the study of fuel costs. Articles [66, 67] are two examples that have studied this relationship. The previous examines the long-run relation and short-run dynamics between electricity prices and coal, natural gas and crude oil prices in the U.S. For this purpose the study uses historical data and a co-integration method. The latter uses time series methodologies to relate electricity market prices in two major U.S. markets and prices of major electricity generating fuels (Uranium, oil, natural gas and coal). From these articles one can conclude that fossil fuel prices have influence on the electricity market prices and the reverse also happens, but these influences depend on the market studied. The relations can differ depending for example on which type of commodities are more present in the market and their fuel resource and on whether they work at base or peak level.

Fossil fuel prices play an important role in electricity markets mainly because they affect production costs of commodities. So forecasting these prices is very useful to project electricity generation costs. Article [68] present a method to forecast oil, natural gas and coal prices in a range of ten years (2008 to 2018). The authors firstly present a review on methods used to estimate commodity prices in the future, which include Geometric Brownian Motion, mean reversion, stochastic price forecasting model and mean reverting jump diffusion model. Then a new model, called long-term trend reverting with jump and dip diffusion, is presented to accomplish the objective of fossil fuel price forecasting.

As the objective of this dissertation is not focus on this matter, a detailed explanation of this models is not given. More preminent is one of the conclusions of the article regarding the prediction results that says that real and nominal oil and natural gas price plus nominal coal price have an increasing trend, while real coal price has a decreasing trend in the future.

2.3 The LCOE Analysis

For the model that will be followed within this research it is necessary to use a tool to assist the comparison of the various power generation technologies' costs. Academic papers and reports on this subject (see [3, 14, 69–72]) often use a common metric called levelized costs of electricity (LCOE).

“The “levelized cost” of supplying electricity using a particular generating technology is a measure of the real total (capital plus operating cost) life-cycle cost per MWh

supplied.” [73, chap. Comparing Economic Values of Intermittent and Dispatchable Technologies]

Article [70] divides the LCOE calculation in two models: (1) the EGC Spreadsheet model widely used in research reports by the OECD and IEA/NEA and (2) the System Advisor Model (SAM) developed by National Renewable Energy Laboratory (NREL). [71] structures the EGC Spreadsheet model in three parts. The first contains five basic modules (identification, basic assumptions, questionnaire information, generating costs and lifetime generating costs) that provide the reader with the input/output information of the model. Second part includes models for calculating the fuel, CO_2 and co-generation costs and third part contains two discounting schedules. SAM is a performance and financial model that assists people involved in the renewable energy industry decision-making.

The analysis presented in [3] and also the article [72] use an approach based on a discounted cash flow (DCF) analysis for the calculation of LCOE and its future evolution for a certain period. This method is based on discounting financial flows (annual, quarterly or monthly) to a common basis, taking into consideration the time value of money [3].

The LCOE formula is based on Equation 2.1. This simplified equation can evolve into a more complex one depending on the components selected by the responsible of the study and also on the target of it, a specific project or a global one for example. Figure 2.4 presents some possible components that can integrate the LCOE equation. They are divided in three major criteria including investments, annual operations and financial analysis. An example to illustrate each criteria could be costs from project development for investments, fuel costs for operation and inflation for financial analysis. This figure was constructed regarding the reviewed literature on this matter ,mostly cited in this chapter.

$$LCOE = \frac{\textit{Life cycle costs}}{\textit{Energy production during lifetime}} \quad (2.1)$$

Table 2.4 shows some examples taken from the literature that has been reviewed for the LCOE equation. It is possible to see that all presented equations have equal components, such as investments, lifetime and operational and maintenance costs, but each one has its own way to represent them. It is possible to conclude that the LCOE formula is used in the same way by all articles read, namely in its basic equation, yet the aim of its use can be more or less complex. As an example, the equation used in [72], has special components that are used because the article aims to establish an analytical model for solar PV and CSP electricity costs. As seen, the LCOE has several considerations. It is important to notice that these considerations also depend on electricity generation technologies. For example when dealing with renewable technologies it is clear that no fuel cost exists. In Section 2.4 an analysis of actual and past data and perspectives of electricity generation technologies is conducted.

Another subject seen in the reviewed literature is the importance of how to estimate the evolution of LCOE in a certain time interval. Both [72] and [74] refer to this issue. The first article



Figure 2.4: Possible Components of LCOE Equation.

characterises the reduction in the production costs using learning or experience curves.

“...learning curves, or experience curves, which have become a powerful and widely used tool for projecting technological change [75–77], since they describe past evolution of the cost of the systems as a function of the cumulative installed capacity.” [72, chap. Future evolution of the LCOE using the learning curve approach]

The studies [14, 71] also call upon this tool to predict the future. The second article refers that, in reality, input parameters regarding costs and also energy production are uncertain and so by using probability distributions for these parameters and Monte Carlo simulation, one can build a LCOE output distribution that allows capturing these uncertain inputs. This approach was also performed in [78].

From the literature review made on this subject it is clear that the LCOE metric is largely applied to compare the different electricity generation technologies. However the use of LCOE for this purpose is said to be insufficient by some articles or companies. Exemplifying, Siemens³ come up with a new metric called *Society's Cost of Electricity* (SCOE) which takes into account not only the components of LCOE but also other components that can be seen as externalities: Subsidies, transmission costs, variability costs, geopolitical risk impact, environmental impact, social effects and employment effects. This calculation model was created to show that the technology of wind offshore is competitive when compared to other electricity generation technologies.

Article [79] refers also to the deficit of the LCOE analysis, by saying that it ignores the variability and integration costs. To surpass the latter, the authors present a new concept called *System LCOE* which contains generation costs and integration costs. The innovation of this method is in the definition of the integration costs which is directly linked to economic theory.

³ <http://www.energy.siemens.com/hq/en/renewable-energy/wind-power/SCOE.htm>

Table 2.4: Examples of LCOE Equation.

Source	Equation	Comments
[14]	$LCOE = \frac{I_0 + \sum_{t=1}^n \frac{A_t}{(1+i)^t}}{\sum_{t=1}^n \frac{M_{t,el}}{(1+i)^t}}$	<p>I_0: Investment expenditures in Euro ; A_t: Annual total costs in Euro in year t ; $M_{t,el}$: Produced quantity of electricity in the respective year in kWh ; i: Real interest rate in % ; n: Economic operational lifetime in years; t: Year of lifetime (1, 2, ...n) .</p>
[3]	$LCOE = \frac{\sum_{t=1}^n \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^n \frac{E_t}{(1+r)^t}}$	<p>I_t: Investment expenditures in the year t ; M_t: Operations and maintenance expenditures in the year t; F_t: Fuel expenditures in the year t; E_t: Electricity generation in the year t; r: Discount rate; n: Life of the system.</p>
[71]	$LCOE = \frac{(\sum_t I_t + O\&M_t + F_t + C_t + D_t) * (1+r)^{-t}}{\sum_t E_t * (1+r)^{-t}}$	<p>E_t: The amount of electricity produced in year “t”; $(1+r)^{-t}$: The discount factor for year “t”; I_t: Investment costs in year “t”; $O\&M_t$: Operations and maintenance costs in year “t”; F_t: Fuel costs in year “t”; C_t: Carbon costs in year “t”; D_t: Decommissioning cost in year “t”.</p>
[72]	$LCOE = \frac{C + L + \sum_{n=1}^N \frac{(OPEX + I) * C}{(1+r)^n}}{\sum_{n=1}^N \frac{S * TF * \eta * (1-d)^n}{(1+r)^n}}$	<p>C: Cost of the system; L: Cost of the required land; OPEX: Operation and maintenance costs; I: Insurance costs; r: Discount rate; S: Available solar resource; TF: Tracking Factor; η : Performance data; d: Annual degradation rate; N: Economic life time of the system;</p>

2.4 Electricity Generation Technologies: Data and Perspectives

Studying electricity generation costs and projecting their future evolution implies the knowledge of the state of various technologies, how they are integrated in systems and their state of maturity. In this section data is presented to understand these points.

Energy is produced from several technologies which use distinct resources. During the last decades an evolution from the conventional utilities to a system with high penetration of renewable sources has occurred. This situation will most likely continue to evolve in response to the ambitious targets of several world governments to reduce CO_2 emissions, external independence and

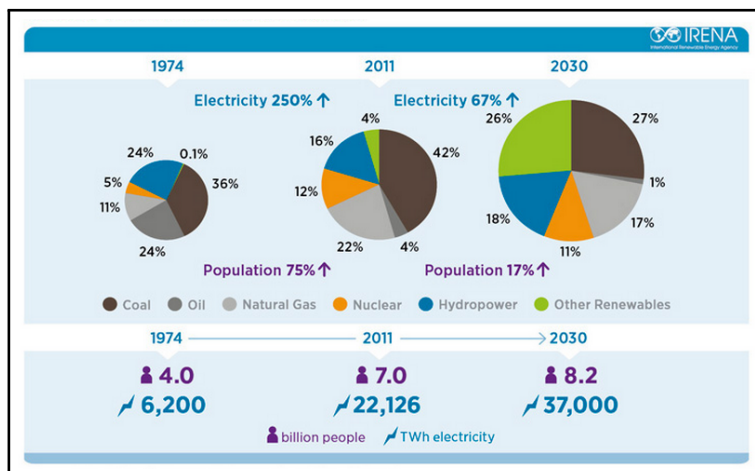


Figure 2.5: Electricity Generation and Population Growth. Source: World Bank(2014), IEA(2014a) and IRENA(2014a).

increase efficiency. Figure 2.5 clearly shows this statement, forecasting that in 2030 hydropower and other renewables will have a global share of 34% of the generation mix.

Renewable energy sources (RES) include various type of technologies. Figure 2.6 illustrates the evolution of the latter from 2000 to 2013. Here it is possible to see that wind energy is nowadays one of the most advanced and integrated RES.

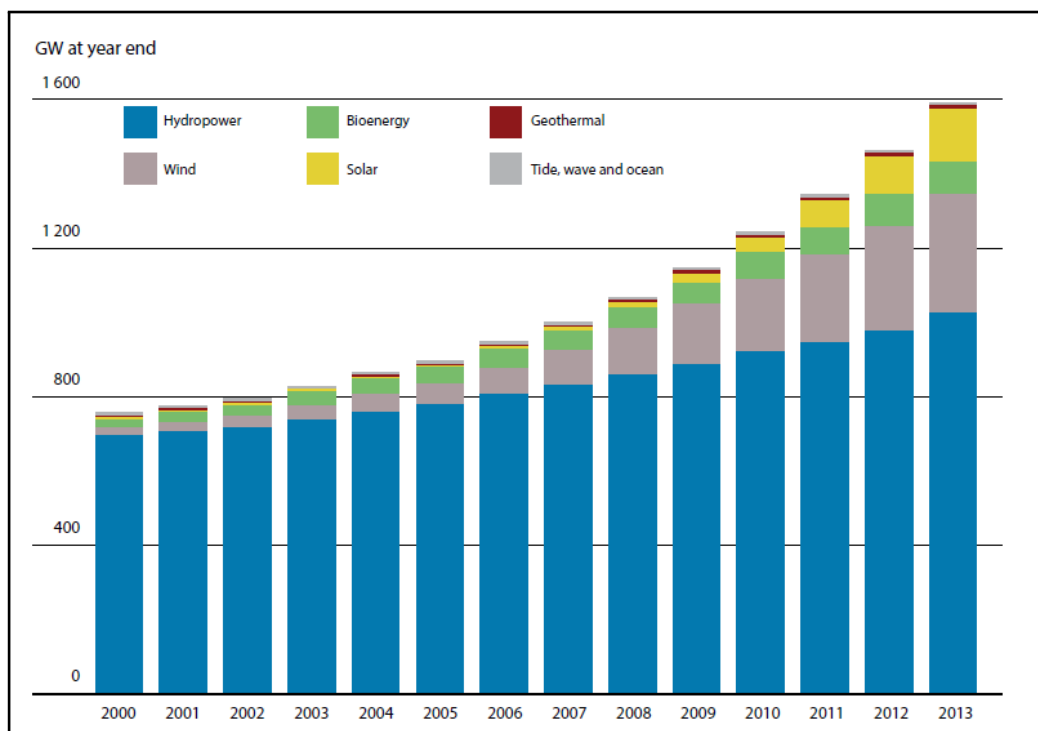


Figure 2.6: Global Renewable Power Generation Cumulative Capacity. Taken from [3].

Figure 2.7 shows the global growth of wind power capacity. From 2004 this type of technology grew almost 25% per year on average, being United States and China the biggest contributors in the last years. Wind energy can be onshore or offshore. The values of LCOE for these two possibilities differ as is to be seen in Figure 2.8, having offshore higher costs due to the sheer magnitude of the projects [5]. This figure also shows that LCOE values are stabilising, a fact that proves the high maturity of this technology. The costs of wind turbines have decreased significantly since 2007 as proven by Figure 2.9.

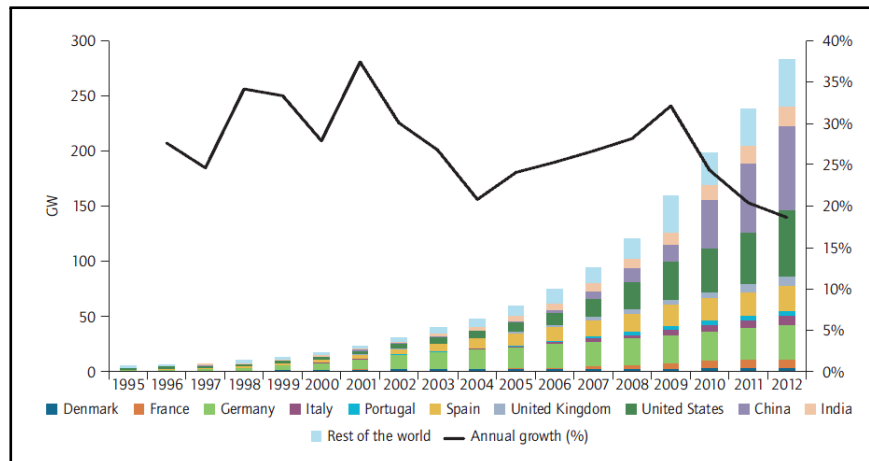


Figure 2.7: Global Cumulative Growth of Wind Power Capacity. Taken from [4].

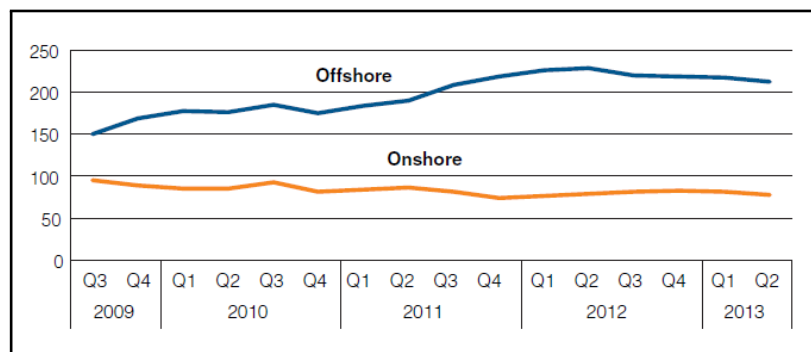


Figure 2.8: Levelised Cost of Wind Electricity over Time, developed Market Average (USD/MWh, 2013USD/EUR 0,75). Taken from [5] (Source: Bloomberg New Energy Finance).

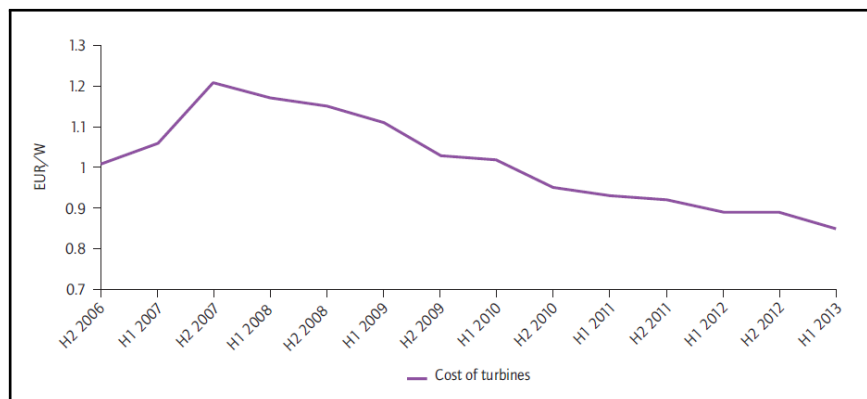


Figure 2.9: Cost Trend of Land-based Wind Turbine Prices, by Contract Date. Taken from [4].

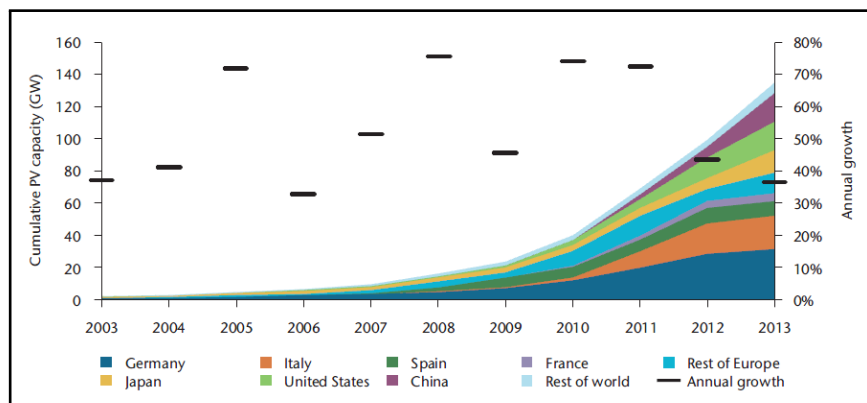


Figure 2.10: Global Cumulative Growth of PV Capacity. Taken from [6].

By using the energy of the sun, solar technologies are another possibility of producing renewable energy being solar photovoltaic (PV) and concentrated solar power (CSP) currently the main technologies available throughout the world. PV industry has faced a massive change since 2009, with considerable increases in manufacturing capacities and the move of module manufacturing from Europe and US to China [6]. Since 2009 module prices saw a sharp decrease as seen in Figure 2.11 followed by technology improvements. Decentralised solar PV systems LCOE have become lower than the variable portion of retail electricity price in 2013 in various countries, reaching grid parity (Figure 2.12). This situation provides an incentive to electricity customers to build PV systems and become serious players in electricity retail markets.

Since 2009 cumulative CSP capacity has been growing, being Spain and the United States the biggest players of these technologies (Figure 2.13). The main predominant CSP technologies are parabolic troughs, linear Fresnel reflectors (LFR) and towers. The costs of these technologies were expected to decrease, however market opportunities have diminished and the cost of materials increased leading to a slowly diminution of prices [7]. Figure 2.14 shows the LCOE evolution from 2009 to 2013 (Q2).

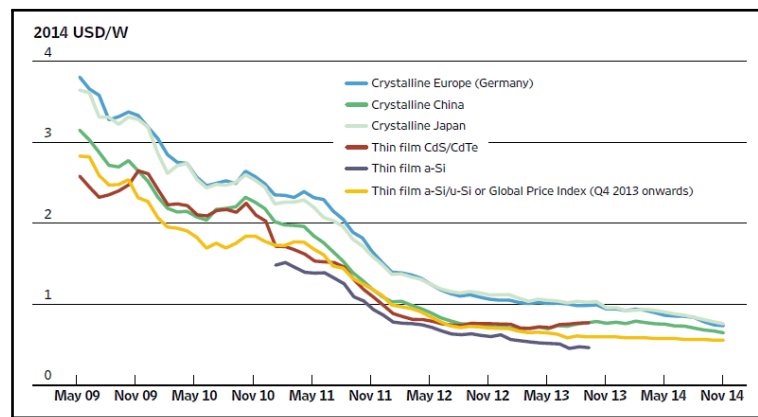


Figure 2.11: Average Monthly Solar PV Module Prices by Technology and Manufacturing Country sold in Europe, 2009 to 2014 (2014USD/EUR 0.75). Taken from [3] (Sources: GlobalData, 2014 and pvXchange, 2014).

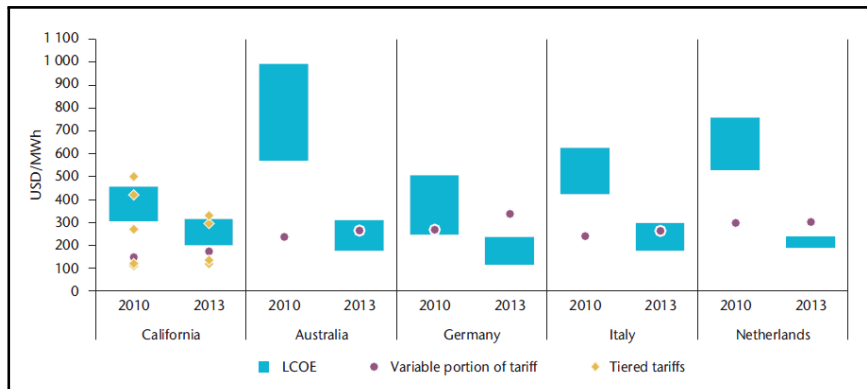


Figure 2.12: LCOE and Tariffs of PV in 2010 and 2013 (2012USD/EUR 0.78). Taken from [6].

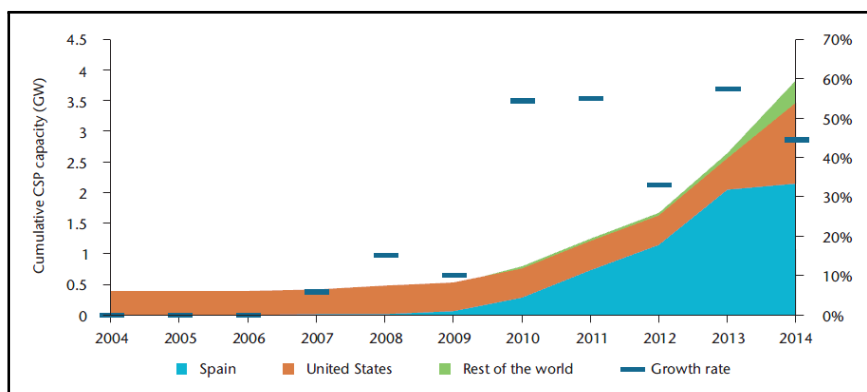


Figure 2.13: Global Cumulative Growth of CSP Capacity. Taken from [7].

Biomass is a competitive power generation option and is one of the largest technologies used. An important characteristic is that it can provide dispatchable baseload electricity. The various

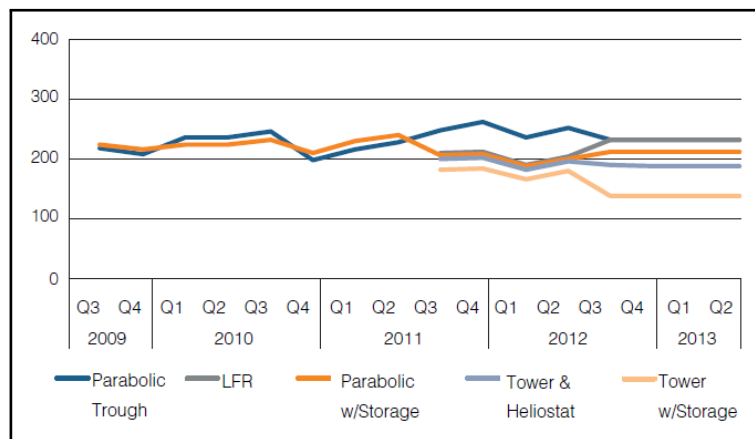


Figure 2.14: Levelised Cost of CSP Over Time, developed Market Average (USD/MWh, 2013USD/EUR 0.75). Taken from [5] (Source: Bloomberg New Energy Finance).

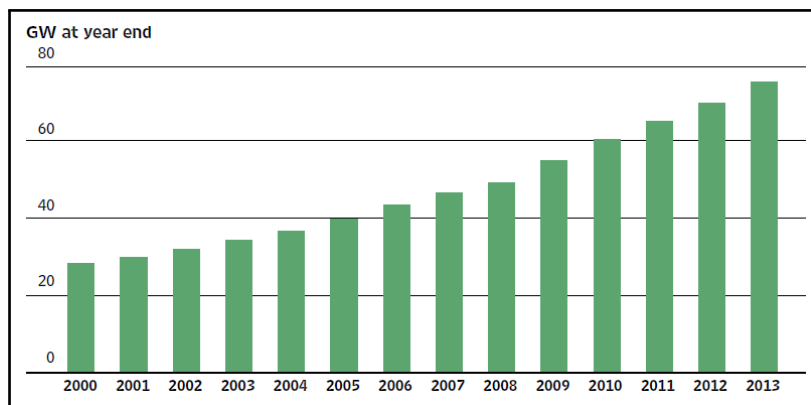


Figure 2.15: Global Cumulative Installed Capacity of Biomass Power Generation Technologies, 2000-2013. Taken from [3].

technologies for transforming biomass to electricity generation, such as incineration, anaerobic digestion, gasification, landfill gas or municipal solid waste incineration are mature and commercially viable. Cumulative installed capacity was near 80 GW in 2013 (Figure 2.15) and it is expected to grow in the next years. Great part of the costs of these technologies came from the feedstock costs, which depend on the region of installation and account for between 20% and 50% of the final cost [3]. The LCOE for biomass-fired technologies has a wide range of values because of the different costs mentioned above. Figure 2.16 proves the last statement and also shows that LCOE values have stabilised in the last years.

Electricity generation from geothermal and marine technologies are a small part of the renewable power generation capacity as shows Figure 2.6. Article [3] highlights that geothermal power generation is mature and a commercial available solution to provide low-cost base capacity where the resource for it exists. It also refers that between 2007 and 2014, LCOE of geothermal varied from $0.04\text{USD}/\text{kWh}$ to $0.14\text{USD}/\text{kWh}$. The investment costs for geothermal are high, because of

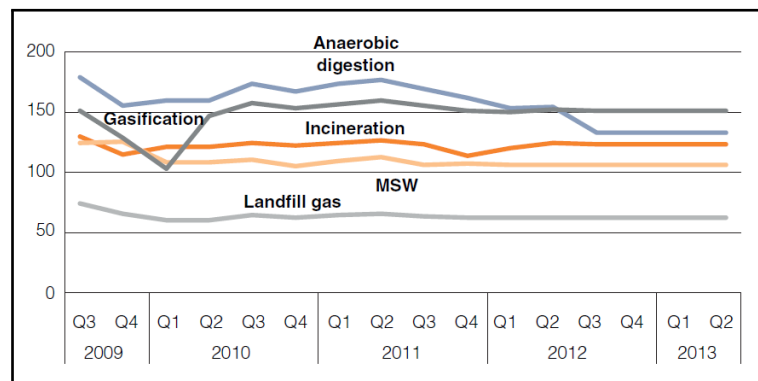


Figure 2.16: LCOE of Biomass Electricity Over Time, developed Market Average (USD/MWh, 2013USD/EUR 0.75). Taken from [5] (Source: Bloomberg New Energy Finance).

the costs of drilling and others, but running costs are low and predictable.

Marine technologies for electricity generation are divided in waves, tidal range, tidal currents, ocean currents, ocean thermal energy conversion and salinity gradients. Tidal and wave are the bigger contributors to the world capacity of ocean energy, which was about 530 MW at the end of 2013 [13]. The small capacity and big LCOE values (Figure 2.17) show that this type of technologies is still in a development phase.

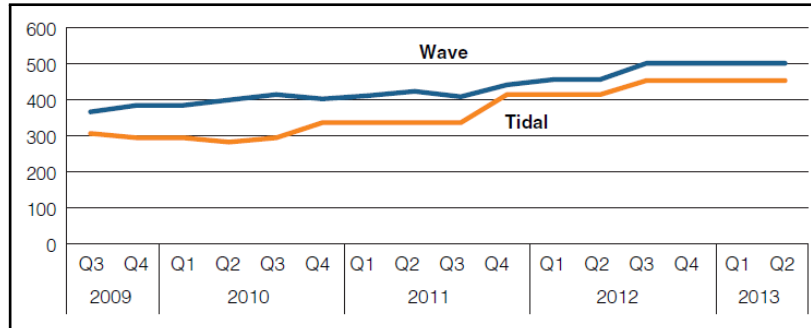


Figure 2.17: LCOE of Marine Electricity Over Time, developed Market Average (USD/MWh, 2013USD/EUR 0.75). Taken from [5] (Source: Bloomberg New Energy Finance).

Hydropower technology is one of the oldest and more used source of electricity being part of the conventional sources of electricity and the only one renewable on this group. The full maturity of this technology is proven by its installed capacity and electricity produced(more than 16% of the world’s electricity in 2010 [15]). Hydropower is classified in two major categories, run-of-river and dams and also if they are equipped with pumping systems. The versatility of working as base load or during peak demand is one of the greatest advantages of hydropower. The main costs of hydropower occur in the initial phase of project and construction and have a great variability depending on type and size of the plant. Study [15] puts the LCOE of Hydropower between 20 to 230 USD/MWh. This document also refers to the future trends of this technology saying

that the main improvements will take place in the efficiency and environmental performance of the turbines, the development of roller-compacted concrete dams and low-head and kinetic flow turbines, to apply in canals, pipes and rivers. These improvements will also help to decrease maintenance and operation costs and possibly investment costs.

Fossil fuel utilities remain the most used technologies in the process of generating electricity. They are dispatchable, reliable and provide safety to electrical systems. Three main fuels are used in the different types of utilities: Natural Gas, Coal and petroleum. In Portugal and in most world countries, utilities that use petroleum to generate electricity were closed but isolated systems like islands still use this resource. For natural gas and coal utilities the technologies are mature, the efforts are concentrated in efficiency and reduced emission improvements [80]. Most of natural gas plants installed today and in the last years are combined cycle (CCGT) which use a gas turbine and a steam turbine. Utilities that use coal are usually based on pulverised coal combustion. More recently to improve efficiency and reduce CO_2 emissions integrated gasification combined cycle (IGCC) plants are installed [80]. Table 2.5 gives values for the capital costs and the cost of energy of this type of generation technologies separated with or without use of CO_2 capture system. These values were collected from several articles. CCGT plants have less capital costs and consequently less COE. It is interesting to see that IGCC plants with CO_2 capture are a competitive technology.

Table 2.5: Costs of New Electric Power Plant with and without CO_2 Capture on Current Technology (2007USD/EUR 0,73). Source: Adapted from [12].

Performance and cost measures ⁴	CCGT plant		PC plant		IGCC plant	
	Range	Rep. value	Range	Rep. value	Range	Rep. value
Capital costs no capture (\$/kW)	515-724	568	1161-1486	1268	1169-1565	1326
Capital costs with capture (\$/kW)	909-1261	998	1894-2578	2096	1414-2270	1825
COE no capture (\$/MWh)	31-50	37	43-52	46	41-61	47
COE with capture (\$/MWh)	43-72	54	62-86	73	54-79	62

Figure 2.18 shows LCOE ranges of renewable energies at 2014,2025 and 2014 fossil fuel electricity costs. In the future it is expected that almost all renewable technologies will be competing and presenting a better solution, even economically, for electricity generation.

⁴COE = cost of electricity production; Rep. Value = representative value based on the average of values in the studies reviewed by the article.

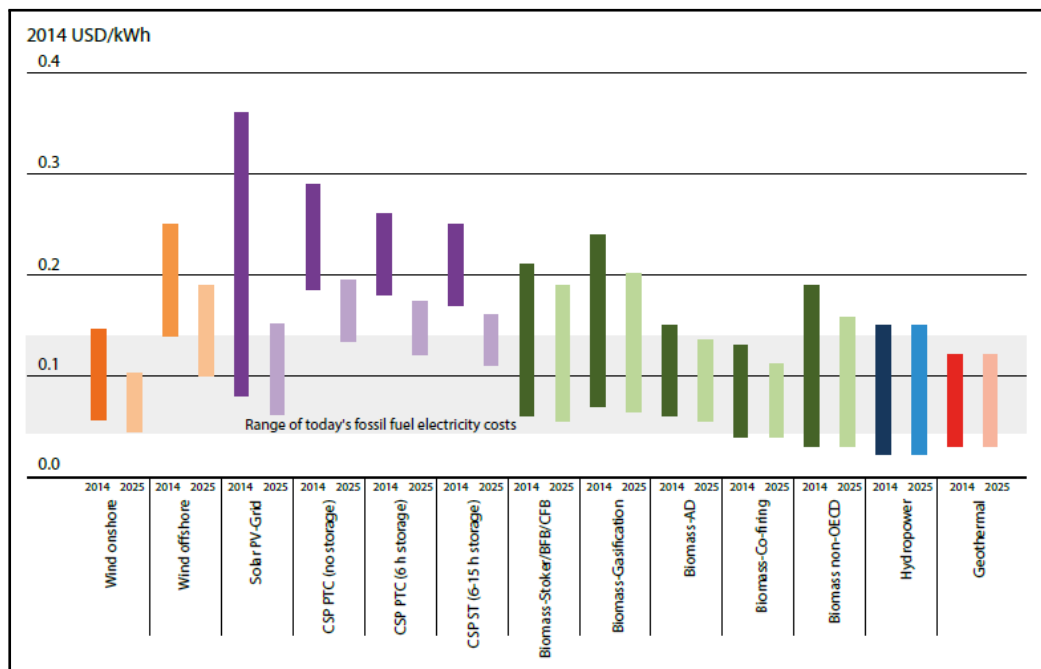


Figure 2.18: LCOE Ranges by Renewable Power Generation Technology, 2014 and 2025 (2014USD/EUR 0.75). Taken from [3].

2.5 System Costs with Renewable Energy

Since 2001, when the EU-directive concerning the promotion of RES (renewable energy sources) was launched, EU countries have implemented different promotional schemes to reach the directive's goals on renewable energy sources share. Also in 2009, member states of the EU agreed on legally binding national targets for renewable energies for 2020 [81] resulting in Directive 2009/28/EC [82]. In most cases, these measures may influence investment decisions, as well as electricity prices. Therefore reviewing the different schemes is a crucial part when studying the effects of renewable energies in system costs.

Several papers regarding this subject were found in literature, however only those relevant for the needs of this dissertation have been more closely analysed and reviewed. The different promotional schemes are firstly identified for each article reviewed. Then a definition for the ones that are more frequently applied is presented.

Older articles like [83] and [84], divide the promotional schemes in four main instruments. The first one refers to feed-in model, tender system (developed in the UK), certificates trading model and international trade of green certificates. The second article divides them into feed-in tariffs, quota obligations, tenders and energy tax exemptions. It also says that most of the countries decide for one of these instruments (or a combination of them, like Austria) connected with other political instruments (subsidy programs, soft loans, tax allowances, etc.). Both articles make an evaluation of the referring schemes and give examples of different countries' approaches.

More recent articles give a detailed list of the schemes. [85], for instance, makes an interesting

distinction between direct and indirect policy instruments. While the first one aims at immediately stimulating the renewable energy share in electricity generation, the latter focus on improving long-term framework conditions. Furthermore, it refers to the fact that voluntary approaches exist based on the consumers' willingness to pay premium rates for green electricity. Taking into account articles [81, 85–88] a list of the different schemes can be generated (Table 2.6). The following sub-chapters discuss the policies' main features, while Table 2.7 demonstrates the support policies that have been adopted, revised or removed by various countries.

Table 2.6: Renewable Energy Support Policies.

Regulatory Policies	Fiscal incentives	Public Financing
Feed-in tariff; Feed-in premium; Tradable renewable energy certificates; Net metering; Tenders; Obligation and mandate; Utility quota obligation.	Capital subsidy, grant or rebate; Tax incentives; Energy production payment.	Public investment, loans, or financing; Public competitive bidding.

2.5.1 Feed-in Tariffs (FIT) or Premiums (FIP)

FIT schemes are composed by elements such as priority dispatch to eligible generation, long-term perspective and guaranteed prices, which can be guaranteed for a specific period or for a predetermined amount of production [81]. This fixed tariff attracts much capacity, yet only in case it is set at a level sufficient to meet investor needs [85], so the investor is able to recover generation costs, while still generating profit. For the viability of this scheme, an institution (often the transmission or distribution system operator) must off-take the electricity at the guaranteed price, which costs are then passed on most commonly to electricity consumers [81].

FIP schemes are very similar to FIT, diverging by the existence of market risk in FIP, where a fixed add-on to the market price is paid. Generally speaking, a producer of renewable electricity receives a premium per unit (MWh) in addition to the proceeds of selling the power on the free market [81]. Figure 2.19 shows the number of countries with renewable energy policies by type. Here it is possible to verify that FIT is the most widely used instrument around the world.

2.5.2 Tradable Renewable Energy Certificates (RECs)

RECs, also named quota obligations based on tradable green certificates, are generation-based, quantity-driven instruments where governments define targets for renewable energy sources deployment and obligate a particular party of the electricity supply-chain to fulfil them [85]. These certificates represent every MWh generated from renewable energy technologies [86].

Article [81] divides these schemes in uniform and differentiated ones concerning the granting of certificates per generated unit of electricity. In case the schemes are uniform, all technologies

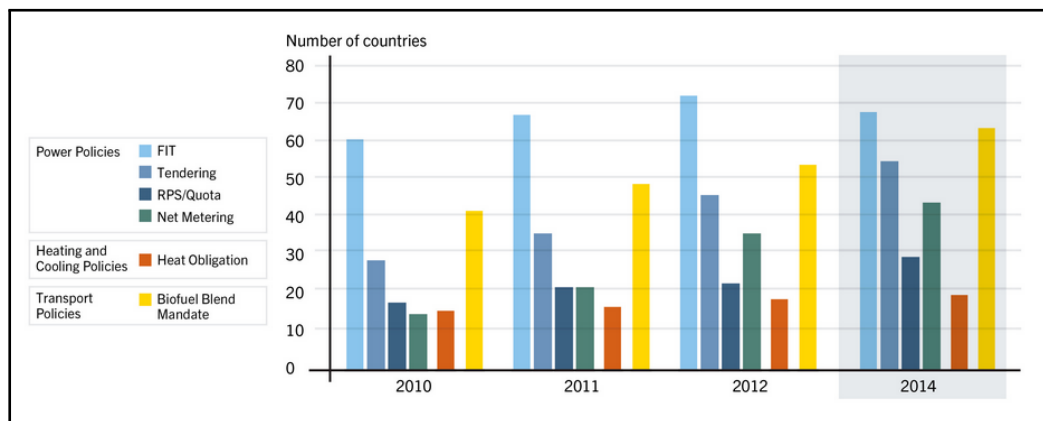


Figure 2.19: Number of Countries with Renewable Energy Policies by Type.
Taken from [13]

receive the same amount of certificates per generated unit of electricity, whereas if they are differentiated some technologies receive more certificates than others. This instrument is also very used around the world as shown in Figure 2.19.

2.5.3 Net Metering

Net metering schemes encourage small-scale renewable energy developments, particularly local distributed generation, which allow customers to offset their electricity consumption by injecting renewable energy into the grid [88]. However, investors and developers face market risk when facing this scheme, because electricity is usual unknown and the income can only be estimated [86]. As a matter of fact, during the last years net metering usage has increased. (Figure 2.19).

2.5.4 Tenders

Tendering schemes were used as a primary policy in the past, yet nowadays they are used in combination with other policy types. The process of tender according to Article [81], consists in calls for tenders by the responsible authorities for specific projects with a certain amount of capacities. Then investors give their bid for the required support level and other specifications (e.g. specific timing of the project, grid positioning and environmental impact) and compete to win the possibility to develop the project. The bid that offers the best conditions wins the tender. Article [81] also divides the tender process in tenders for fixed feed-in tariffs and for target-price feed-in tariffs.

2.5.5 Obligation/mandate and Utility Quota Obligations

Another way to promote renewable energy sources in electricity generation is the use of policies that define minimum shares of generations based on these sources. Such schemes can be applied to a group of renewable sources or to a specific source. These policies only define the minimum

share of renewable energy generation, they neither enhance returns nor lower risk, so investors and developers are mainly exposed to market risk [86]

2.5.6 Fiscal Incentives

Fiscal incentives can be categorised as shown in Table 2.7. Capital subsidies, grants or rebates provide renewable energy developers with direct cash incentives. Investment grants are granted in the form of non-reimbursable payments at the construction phase of a project and so the generated energy from the project is not directly targeted [81]. These type of policies reduce the upfront costs as well as the LCOE [74].

Energy production payment is a direct payment from governments to one unit of renewable energy generation, while tax credits (applied in production or investment) are an annual income based on the amount of money invested or the energy generation during a certain period [89]. These policies like the above-mentioned ones effectively reduce the LCOE, being tax incentives the most efficient ones [86].

2.5.7 Public Financing

The use of public financing is often made by using loans or investments. Loans consists in financing provided in return of a debt and investments in return of an equity ownership interest [89]. Public competitive bidding is made by governments who provide subsidies to private investors trough a competitive bidding process. The aim of this scheme is to foment competition to obtain the minimum subsidy possible. This process compels investors to develop and improve renewable energies. The subsidy is offered in the form of a feed-in tariff , which results in the establishment of a long term contact. Usually price is the most important factor, therefore market risk is most likely faced by developers and investors [86].

Table 2.7: Renewable Energy Support Policies by Country(EU-28, Norway and Switzerland)⁵Source: Adapted from [13].

Country	Renewable energy targets	Regulatory Policies							Fiscal incentives and public financing				
		Feed-in tariff / premium payment	Electric utility quota obligation RPS	Net metering	Tradable REC	Tendering	Heat Obligation/ mandate	Biofuels obligation/ mandate	Capital Subsidy or rebate	Investment or production tax credits	Reductions in sales, energy, CO2, VAT or other taxes	Energy production payment	Public investment, Loans or grants
Austria	O	O			O			O	O			O	
Belgium	O		•	•	O	O		O	n*	O	O		
Bulgaria	O	O						O				O	
Croatia	O	O						O					
Cyprus	O	O		n		O		O	R				
Czech Republic	O	X			O			O	O	O			
Denmark	O	O		O	O	O		O	O	O		R	
Estonia	O	O						O			O	O	
Finland	O	O			O			O		O	O		
France	R	R			O	R		O	O	R	O	O	
Germany	O	R					O	O	O	O	O	O	
Greece	O	R		n				O	O	O	O	O	
Hungary	O	O						O	O		O	O	
Ireland	O	O			O	O	•	O					
Italy	O	R	O	O	O	R	O	O	O	O	O	O	
Latvia	O	O		n		O		O			O		
Lithuania	O	R	O					O				O	
Luxembourg	O	O						O	O				
Malta	O	O		O					O		O		
Netherlands	O	R		R	O			O	O	O	O	O	
Norway	O		O		O	n		O	O		O	O	
Poland	O		O		O	R		O			O	O	
Portugal	R	R	O			O	O	O	X	X	O	X	
Romania	O		O		O			O				O	
Slovakia	O	R			O			O			O		
Slovenia	O	O			O	O			O	O	O	O	
Spain ¹	O			O	O			O	O	O	O		
Sweden	O		O		O			O	O	O	O	O	
Switzerland	O	O							O		O		
United Kingdom	R	R	O		O		O	O	R		O	O	

• - existing sub-national, O - existing national, n - new, R - revised, X - removed/expired, * - sub-national

⁵Spain removed FIT support for new projects in 2012. Incentives for projects that had previously qualified for FIT support continue to be revised.

Chapter 3

Relevant Background Information for the Study

The analysis of electricity generation costs in the past and the forecast of its future evolution requires research of several topics.

Once this dissertation pretends to study the case of Portugal, a variety of data from historical values of electricity generation capacities and production to electricity imports and exports, as well as on electricity consumption in Portugal needed to be collected.

In order to be able to define a research methodology, the costs for different technology plants needed to be searched for and subsequently also presented at this point. Moreover, information regarding the costs derived from the support given to the different electricity generation costs is exposed.

Most of this data was retrieved from the web-pages of the national transport grid operator (REN), the energy services regulatory authority (ERSE) and the general directorate for energy and geology (DGEG) - in cases other sources have been used to obtain the exposed information it gets referred to in the following chapter.

3.1 Historical Data Regarding Electricity Consumption and Production in Portugal

This section presents necessary collected information on electricity in Portugal.

In the past, electricity consumption was very predictable and growing about 3% to 4% per year. However, in the last years, mainly due to economic crisis, the reality is a different one as shown in Figure 3.1. This trend affects national plans for generation capacities and production mix.

Besides, electricity generation in Portugal is divided into different types of technologies. Hydropower and fossil fuel plants that use natural gas, coal and oil were the main electricity producers in the past as seen in Figure 3.2.

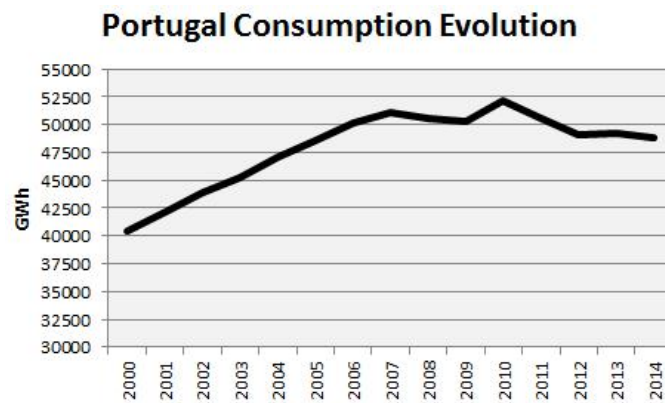


Figure 3.1: Evolution of Portugal Electricity Consumption since 2000.

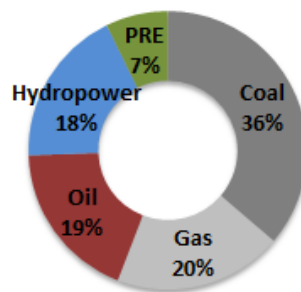


Figure 3.2: Electricity Production in Portugal Distributed by its Sources in 2002.

Since the year 2000 installed capacity in Portugal has changed drastically with great focus on renewable energy sources (RES). In case of the fossil fuel power plants, all oil power plants have been closed in mainland Portugal and no additional coal plants have been installed. Only in the case of natural gas, investments for new combined cycle centrals have been made. Figure 3.3 shows the evolution of the conventional fossil fuel plants capacity.

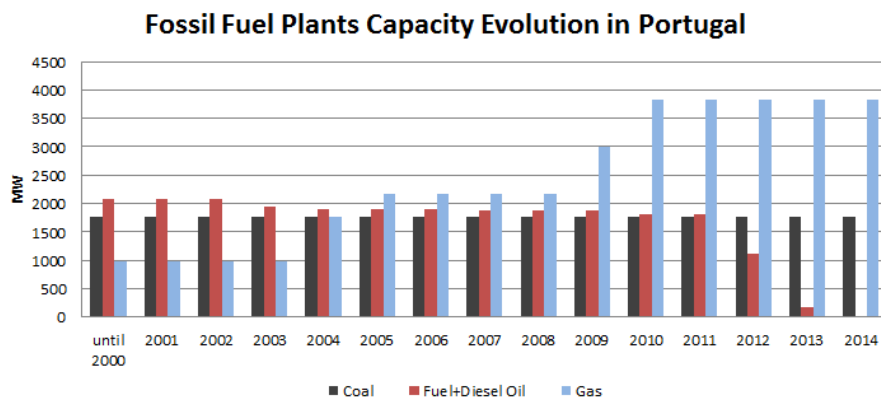


Figure 3.3: Capacity Evolution of Fossil Fuel Power Plants in Mainland Portugal since 2000.

Another way of producing electricity by using fossil fuels is known as "combined heat and power (CHP)" which is also frequently named "co-generation" in Portugal. This type of generation is comprised in a regime called special production regime (PRE). A feed-in tariff, whose definition was reviewed in Section 2.5.1, supports smaller electricity producers so that the projects are economically feasible. Figure 3.4 illustrates the evolution of CHP in Portugal.

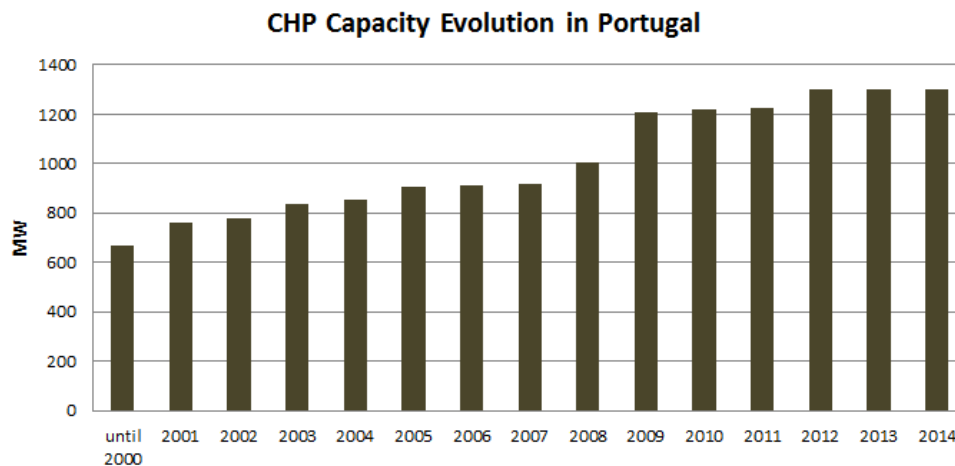


Figure 3.4: Capacity evolution of Combined Heat and Power in Portugal since 2000. Source: [8].

Hydropower is one of the oldest and most important power plant technologies in Portugal with the first centrals installed more than 50 years ago. This electricity source is often characterised by the power capacity of the central as large hydropower (LHP), when its value is larger than 10 MW, or as small hydropower (SHP), for values under 10MW. It can also be characterised by its infrastructure as run-of-river or dams. SHP capacity stagnated since 2009 around 450 MW (Figure 3.5). This type of centrals are also included in the PRE regime.

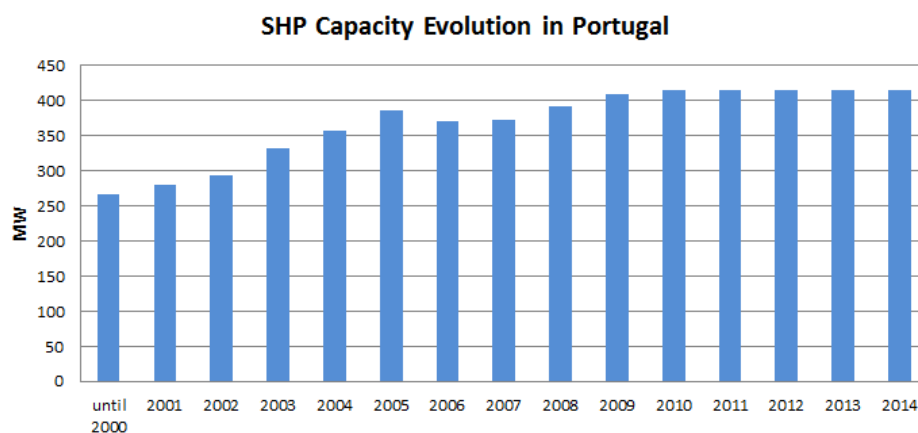


Figure 3.5: Capacity Evolution of Small Hydropower (<10MW) in Portugal since 2000.

Large hydropower has the greatest capacity installed in Portugal. It is a very important technology once it can provide a great amount of electricity in baseload or peak-demand periods using a renewable and clean primary source. Most of its capacity was installed before 2000, yet since this year until today it has increased 1000 MW:

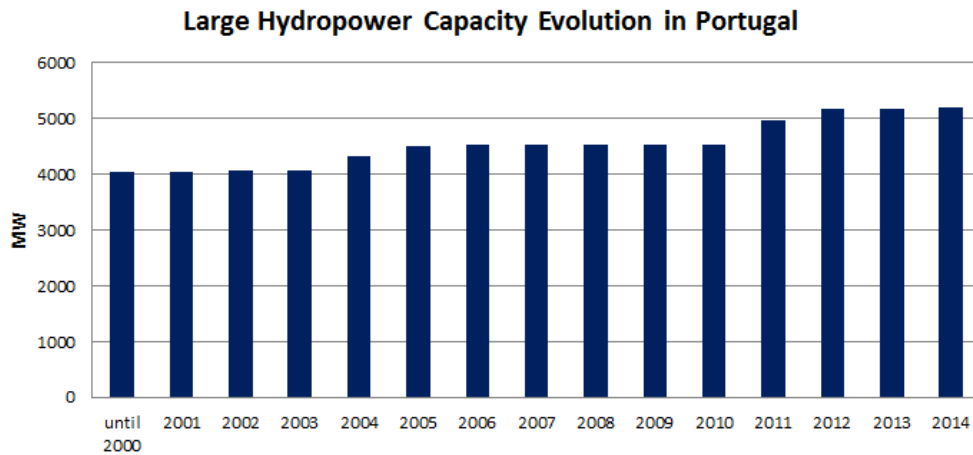


Figure 3.6: Capacity Evolution of Large Hydropower (>10MW) in Portugal since 2000.

Another important aspect of the hydropower plants is the possibility to have reversible pump turbines that allow centrals with storage to pump water from the lower reservoir to the higher one. For the electrical system, the energy used to pump water is similar to consumption, therefore one must take this fact into consideration on studying its effects. Figure 3.7 shows the evolution of the energy consumed for pumping.

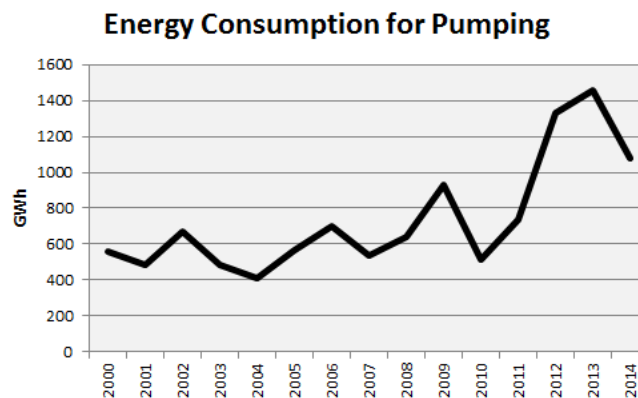


Figure 3.7: Evolution of Portugal Electricity Consumption for pumping since 2000.

More recently, renewable energy technologies supported by the PRE regime have been developed in Portugal. One of these renewable energy technologies is the generation of electricity by using wind, which has the greatest growing rate since 2000 regarding its installed capacity, reaching almost 5000MW today as demonstrated in Figure 3.8.

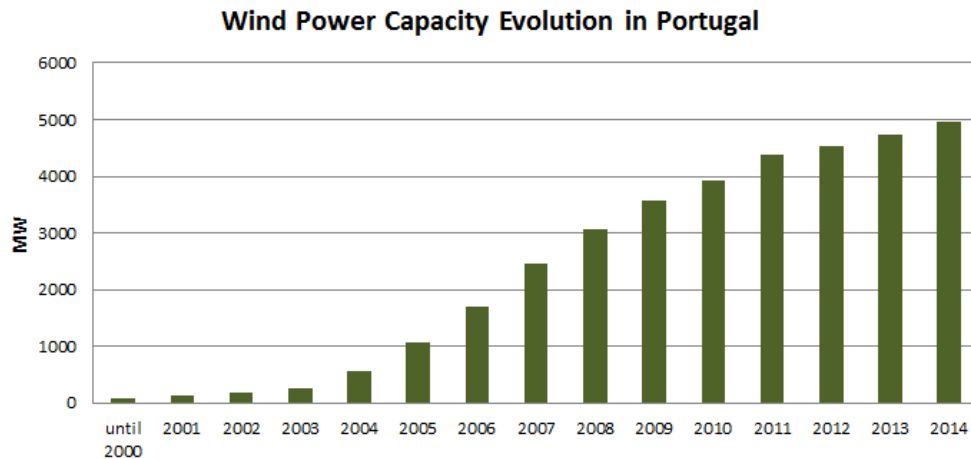


Figure 3.8: Capacity Evolution of Wind Onshore Power in Portugal since 2000.

Wind power plays a very important role in the electrical energy system, being the greatest provider among the PRE technologies.

Figure 3.9 separates the supply by technology to reach the demand on a typical day of autumn. It is a good example of the great contribution of wind power.

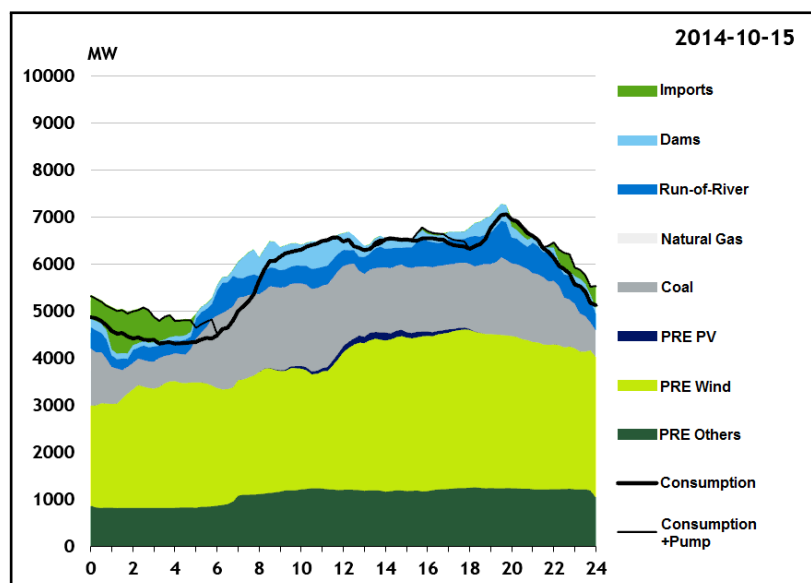


Figure 3.9: Load Curve Diagram for a Typical Day in Autumn in Portugal. Source: Taken from [9].

Biomass centrals are another electricity generation technology present in Portugal. These types of centrals usually include the ones that are using municipal solid waste (MSW), biogas, crop or forest residues and black liquor. There are two MSW centrals in Portugal that were installed before 2000, one in Lisbon (Valorsul) with 50 MW of capacity and another one in Porto (LIPOR) with 29 MW. The other biomass centrals were installed mainly after 2000. Like CHP, biomass

power provides base load capacity. The installed capacity has stagnated in the last years reaching around 700 MW:

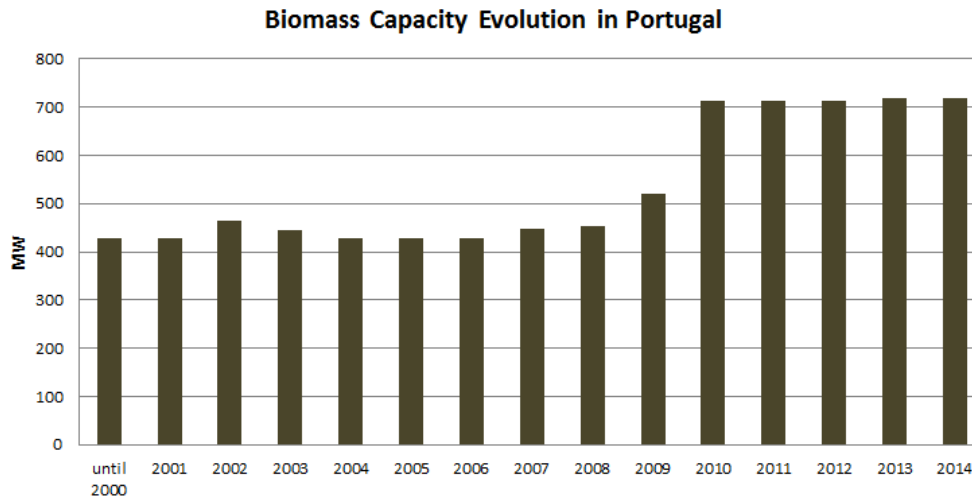


Figure 3.10: Capacity Evolution of Biomass Power in Portugal since 2000.

Furthermore, the conversion of sunlight into electricity, by using solar photovoltaic panels has great potential in Portugal. However, only in 2009 (Figure 2.11) module prices started to decrease to levels that made investments in this field in Portugal viable and that is also why the installed capacity has been lesser than 100 MW until then. During the last years this capacity has increased as seen in Figure 3.11 but it still has a long way to go to reach its full potential.

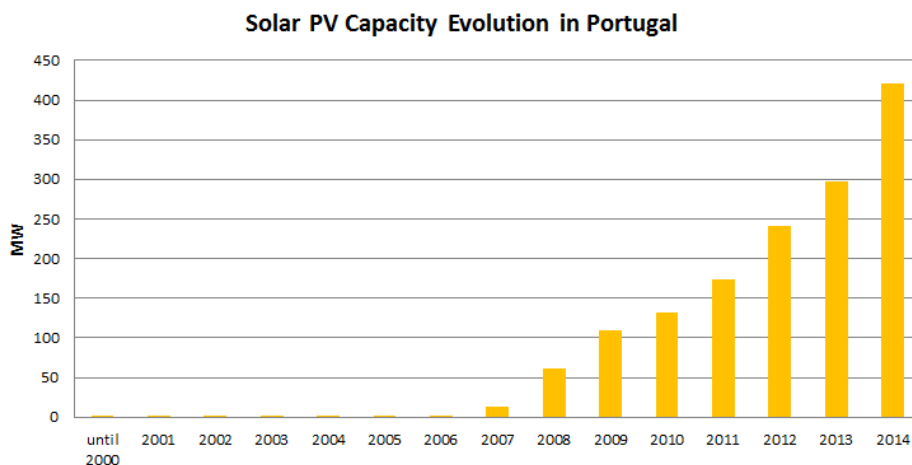


Figure 3.11: Capacity Evolution of Solar Photovoltaic in Portugal since 2000.

It is important to notice that the capacity showed in this figure also includes small electricity suppliers. One measure to increase the capacity of solar PV has been made by the Portuguese government who created a law (DL N°153/2014 [90]) that allows the production of electricity for

own consumption. It is expected that this law will help to increase PV capacity in the next years which can influence the study.

Moreover, renewable sources such as wind offshore or wave and tidal have only pilot projects in Portugal resulting in an insignificant capacity installed.

Concentrated solar power (CSP) has also potential in Portugal but until today there is no central installed in this country.

The capacity evolution of the technologies reviewed so far result today in a mix of production (Figure 3.12) with a higher penetration of RES.

Production Mix in Portugal (2014)

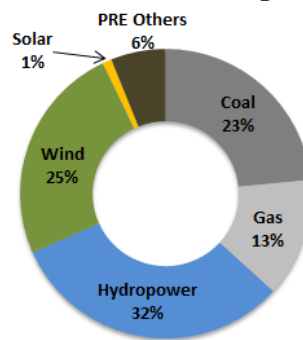


Figure 3.12: Electricity Production in Portugal Distributed by its Sources in 2014.

In the autonomous region of Azores, a region with geothermal activity, there are two centrals that use this resource to produce electricity. Together they have 29 MW of capacity and provide a significant part of the supplied energy to the electrical system of this region [91].

Annual Physical Exchanges PT - ES and net capacity

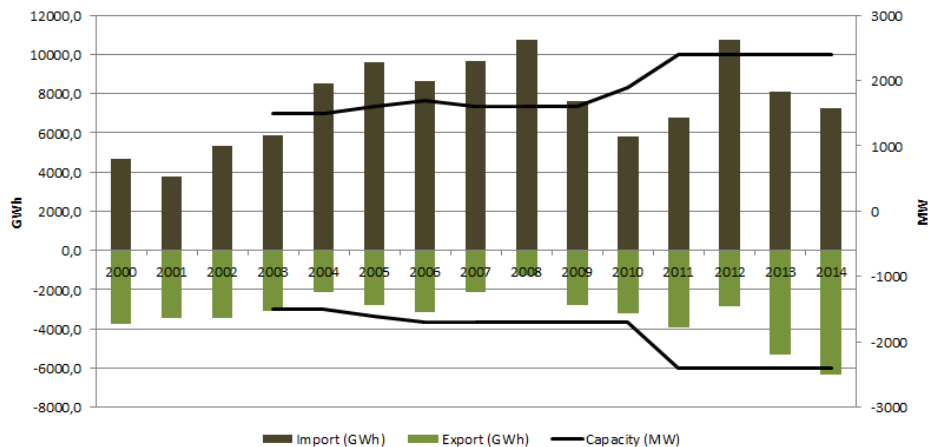


Figure 3.13: Net Capacity and Annual Physical Exchanges between Portugal and Spain since 2000.

To add more security to the electrical systems a variety of markets dispose of interconnections that allow to exchange energy. Portugal is electrically connected to Spain by having a common electricity market which is fully operational since 2007. Over the years additional transmission lines were installed thus allowing more energy exchanges. Exchange values and net capacity since 2000 are presented in Figure 3.13. Clearly Portugal has imported much more energy than it has exported, yet the export values of the last two years have increased.

3.2 Utilities Lifetime and Costs

For an LCOE analysis it is necessary to study information on different utilities' lifetime and costs. Table 3.1 summarises the lifetime of plants in years separated by the generation technology. These values were defined by consulting the literature reviewed in Section 2.4.

Table 3.1: Utilities Lifetime. Sources: [3, 6, 7, 14, 15].

Natural Gas	Coal	Large Hydropower	Small Hydropower
30	40	50	30
Wind Onshore	Solar PV	Biomass and CHP	Geothermal
20	25	20	20

The costs of utilities are separated in investment costs, operation and maintenance costs (O&M), fuel costs and CO_2 costs, yet on RES technologies the last two do not exist.

Table 3.2 shows historic fuel prices of natural gas and coal, resources used in Portugal utilities.

Table 3.2: Historical Prices for Natural Gas and Coal since 2000. Source: [16].

Year	Coal (USD/t)	Natural Gas (USD/MBtu)
2000	35,99	2,89
2001	39,03	3,66
2002	31,65	3,23
2003	43,60	4,06
2004	72,08	4,32
2005	60,54	5,88
2006	64,11	7,85
2007	88,79	8,03
2008	147,67	11,56
2009	70,66	8,52
2010	92,50	8,01
2011	121,52	10,49
2012	92,50	10,93
2013	81,69	10,73
2014	75,38	9,11

Future trends of fuel prices can be studied using methods like the ones reviewed on Section 2.2, however this is not the aim of this study. Forecasted values of coal and natural gas prices were taken from [17] and are presented in Table 3.3.

Table 3.3: Forecast Prices for Natural Gas and Coal until 2030. Prices of 2011. Source: [17].

Year	Coal (USD/t)	Natural Gas (USD/MBtu)
2015	104,2	10,1
2016	105,1	10,1
2017	107	10,3
2018	108,7	10,5
2019	110,9	10,8
2020	112,9	11
2021	113,5	11,1
2022	113,8	11,2
2023	114	11,2
2024	114,1	11,2
2025	114	11,2
2026	114,2	11,3
2027	114,3	11,3
2028	114,3	11,4
2029	114,2	11,4
2030	113,9	11,5

To use these values on the LCOE equation, units needed to be converted to €/MWh electric. Table 3.4 contains historical exchange rates to use for this purpose.

Table 3.4: Historical Exchange Rates, USD to EUR. Source: [18].

Year	2000	2001	2002	2003	2004
Rate	1,085	1,118	1,063	0,886	0,810
Year	2005	2006	2007	2008	2009
Rate	0,8	0,80	0,731	0,683	0,72
Year	2010	2011	2012	2013	2014
Rate	0,755	0,719	0,778	0,753	0,754

Both Btu and Wh are energy units which can be directly converted into one another by using the conversion factor $1MWh = 3.412MBtu$ [16]. To change USD/t of Coal to €/MWh it is firstly required to convert USD/t to USD/MWh which implies the calculation of energy density of coal (u) in MWh/t. The type of coal used in Portuguese power plants is mainly the sub-bituminous coal. The density of this type of coal, retrieved on [92], is 24 GJ/t. 1 MWh corresponds to 3.6 GJ [93], therefore energy density of coal in MWh/t can be obtained by using the following equation:

$$u(MWh/t) = \frac{u(GJ/t)}{3,6} = \frac{24}{3,6} = 6,67 \quad (3.1)$$

Moreover the efficiency of power plants needs to be taken into account. Nowadays, coal power plants can offer efficiency levels reaching 45%, however the average global efficiency is only 33% [94]. Taking into consideration that coal power plants in Portugal do not work at nominal capacity and thus efficiency is lower, the value used for these utilities was 33%. CCGT power plants efficiency can reach levels from 52% to 60% [95]. For the same reason of coal utilities the value used in this study for CCGT power plants efficiency will be 50%. Finally with equations 3.2 and 3.3 prices of coal and natural gas are calculated in €/MWh. For future years today's currency was used¹. New price values are presented in Table 3.5. Historical values (Figure 3.14) show that the cost of NG for electricity generation utilities is higher than coal and the biggest differences between the two prices happened in the last years, which explains why coal has recently been more used than NG to produce electricity (Figure 3.12). It is here noticed that the CCGT fuel prices were used in the calculation of the LCOE of CHP, due to the fact that most installed CHP plants use natural gas as fuel.

$$\text{Coal price}_i(\text{€/MWh}) = \left(\frac{\text{coal price}_i(\text{USD/t})}{\text{efficiency}} \right) * \text{exchange rate}_i \quad (3.2)$$

$$\text{NG price}_i(\text{€/MWh}) = \left(\frac{\text{NG price}_i(\text{USD/MBtu}) * 3,412}{\text{efficiency}} \right) * \text{exchange rate}_i, \quad (3.3)$$

$i = \text{year}$

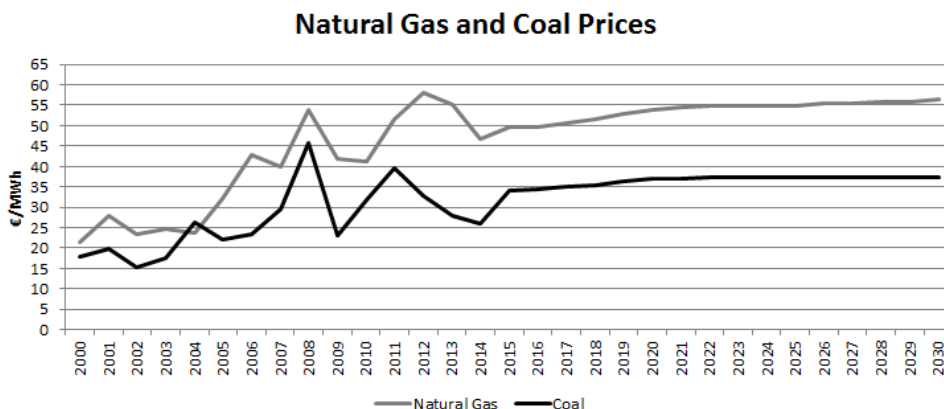


Figure 3.14: Natural Gas and Coal Prices from 2000 until 2030.

¹ 1 USD = 0,877 € [96]

Table 3.5: Natural Gas and Coal Prices in €/MWh from 2000 until 2030.

Year	Coal (€/MWh)	Natural Gas (€/MWh)	Year	Coal (€/MWh)	Natural Gas (€/MWh)
2000	21,398	17,750	2001	27,923	19,834
2002	23,430	15,293	2003	24,547	17,559
2004	23,731	26,375	2005	32,261	22,125
2006	42,694	23,225	2007	40,056	29,502
2008	53,879	45,845	2009	41,861	23,125
2010	41,268	31,744	2011	51,469	39,715
2012	58,028	32,711	2013	55,136	27,960
2014	46,874	25,835	2015	49,555	34,054
2016	49,555	34,349	2017	50,536	34,970
2018	51,518	35,525	2019	52,990	36,244
2020	53,971	36,898	2021	54,462	37,094
2022	54,952	37,192	2023	54,952	37,257
2024	54,952	37,290	2025	54,952	37,257
2026	55,443	37,323	2027	55,443	37,355
2028	55,934	37,355	2029	55,934	37,323
2030	56,424	37,225			

One of the targets of the Kyoto protocol , made by the united nations in 1997, commits its parties to reduce emissions of CO_2 to the atmosphere. One measure taken to accomplish this target was the creation of an emissions-trading system. This mechanism assigns value to the CO_2 emissions, meaning that thermal power plants have an extra cost related to the amount of CO_2 they send to the atmosphere. [17] gives projections for CO_2 licence prices until 2030. Information for historical values since 2000 were not found so for these years a medium value, 10 €/t, was assumed. From 2015 to 2020 and from 2020 to 2030 these prices followed a linear interpolation. Emission rights (Table 3.6) are given in €/t, therefore units must be changed to €/MWh as before, while taking in consideration the type of fuel used.

Table 3.6: CO_2 Emission Rights (2011 Prices).Source : [17].

Year	CO_2 Prices (€/t)	Year	CO_2 Prices (€/t)
until 2011	10,0	2012	9,0
2013	12,0	2014	14,0
2015	15,0	2016	16,5
2017	18,0	2018	19,5
2019	21,0	2020	22,0
2021	22,7	2022	23,4
2023	24,1	2024	24,8
2025	25,5	2026	26,2
2027	26,9	2028	27,6
2029	28,3	2030	29,0

According to Book [93] the amount of emissions from natural gas and coal is $2.8 \text{ t}_{CO_2}/\text{t}_{NG}$ and $2.3 \text{ t}_{CO_2}/\text{t}_{coal}$, respectively. Dividing these values by the respective energy density in MWh/t and correcting them with the same efficiency levels assumed before, it is possible to obtain the amount of CO_2 emissions per MWh (0.376 for NG and 1.045 for coal). These values are then used to obtain Table 3.6 prices in €/MWh by multiplication (Results on Table 3.7).

Table 3.7: CO_2 Costs for Natural gas and Coal.

Year	CO_2 costs of NG(€/MWh)	CO_2 costs of coal(€/MWh)	Year	CO_2 costs of NG(€/MWh)	CO_2 costs of coal(€/MWh)
until 2011	3,76	10,45	2012	3,38	9,41
2013	4,51	12,55	2014	5,26	14,64
2015	5,64	15,68	2016	6,20	17,25
2017	6,77	18,82	2018	7,33	20,39
2019	7,90	21,95	2020	8,27	23,00
2021	8,54	23,73	2022	8,80	24,46
2023	9,06	25,20	2024	9,32	25,93
2025	9,59	26,66	2026	9,85	27,39
2027	10,11	28,12	2028	10,38	28,85
2029	10,64	29,59	2030	10,90	30,32

Capital, fixed and variable O&M costs are summarised in Tables A.4 to A.6 presented in Appendix A.4. A great part of these amounts were obtained in OpenEI "Transparent Cost Database" [19]. The data presented by this source is collected from several public reports or articles cited and grouped by technology and year. The amounts presented in the mentioned tables are annual averages of all this databases' values. Additionally, the values of the database were defined in USD and therefore needed to be converted into euros. For this purpose exchange rates needed to be applied according to the article's year of publication.

The study that was made by the authors of document [20] show a different tendency for the future capital costs of solar PV. According to the authors, today's costs of PV systems in Germany are around 1000€/kW. Considering these facts and the difference between Portuguese and German economies, the values of solar PV retrieved from [19] have been corrected and subsequently included in Table A.5.

Hydropower capital costs have also been changed from the ones retrieved on [19]. The capital costs of hydropower are different for each central. The specific costs of the installed and projected centrals are presented in Appendix A.1 and have been used for large hydropower plants (capacity > 10 MW). For SHP, document [21] refers that capital costs are between 1000€/kW and 3000 €/kW being the lower limit for power capacities over 1000 kW and the upper limit for power capacities below 250 kW. When taking the installed plants since 2000 into consideration (see Appendix A.1), values of SHP capital costs have also been corrected and included in Table A.5.

Moreover, because of the lack of information on capital and O&M costs of CHP centrals over the years, it was assumed a single value of 700 €/kW for capital costs and a single value of 10

€/MWh for O&M costs. These amounts were defined by consulting document [97].

3.3 Costs with Electricity Production Incentives in Portugal

As already mentioned, in Portugal exists an incentive scheme based on feed-in tariffs that supports producers included on PRE. However these centrals are not the only ones comprised with this type of mechanisms, but there are also some ordinary centrals that still have supportive contracts, such as CCGT, coal and large hydropower plants.

Basically speaking there are three types of contracts in Portugal: CAE, an energy acquisition contract, CMEC, a mechanism to conserve the contractual balance and "power capacity payment", that gives a compensation in the first years of operation to the eligible centrals. Since 2003 CAE contracts have been discontinued, existing only two centrals that remain with CAE: a coal power plant with 576 MW ("Tejo Energia") and a CCGT power plant with 990 MW ("Turbogás"). CMEC were then created to replace CAE contracts and "power capacity payments" have been introduced and exist since 2011.

These supportive schemes basically result in additional costs that are reverberated on electricity tariffs and subsequently payed by customers. The value of the total costs with this schemes results of adding the additional cost to the market spot price. Figure 3.15 illustrates the evolution of electricity spot market prices in Portugal since 2009 and Table 3.8 depicts the additional costs by the different type of incentives.

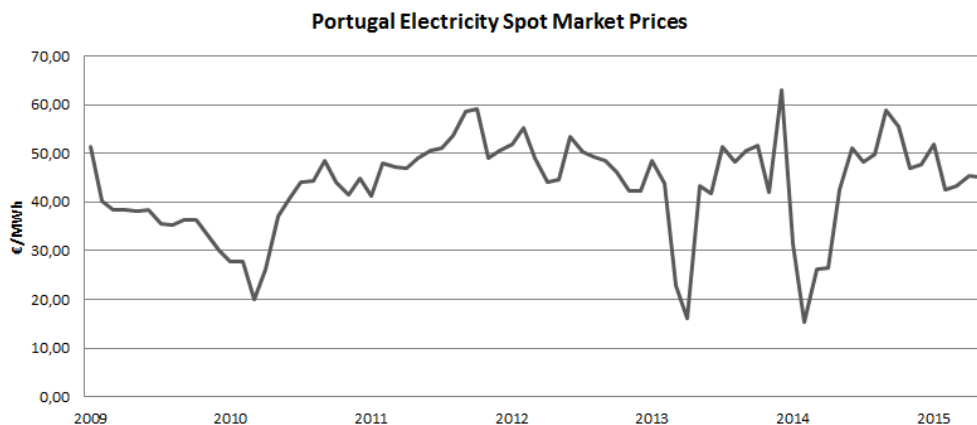


Figure 3.15: Monthly averages of Electricity Spot Market Price in Portugal since 2009.

The amounts of CMEC before 2011 were not found and the value of "power capacity payment" in 2015 is 0 because the incentives will only be incorporated in the 2016 tariffs. This happens due to the governmental decree n°215/2012, of 20 of August, which refers that this amount will only be considered in the year after the financial supportive programme in Portugal.

The above-presented information is relevant in order to be compared to the LCOE results that will be demonstrated and explained in Chapter 6. This comparative analysis allows one to understand and to make conclusions of the past and future additional costs of the system.

Table 3.8: Annual Electricity Spot Market Prices and Additional Costs of PRE Technologies, CAE, CMEC and "Power Capacity Payment".

Year	Units	Solar PV	Biomass	Biogas	CHP FER	CHP FENR	Wind	SHP	MSW	CAE	CMEC	Power Capacity Payment	Total	Market Spot Price (€/MWh)
2009	€/MWh	332,07	69,32	67,9	47,8	65,6	52,06	45,34	35,02	80,33	?	?	?	43
	GWh	294,77	63,4	61,2	35,89	33,8	41,07	38,7	30,9	9839	?	?	?	
2010	€/MWh	344,77	113,4	111,2	85,89	83,8	91,07	88,7	80,9	72,36	?	?	?	50
	GWh	83	590	58	3456	3441	7794	885	445	7990	?	?	?	
2011	€/MWh	270,59	72,29	72,19	68,88	56,88	56,19	53,9	46,1	40,99	23,13	6,57	34,99	52
	GWh	200	586,3	70	4215,7	1560,1	8477,7	727,5	455,5	7314	18482	9565	51654	
2012	€/MWh	299,68	77,07	75,21	88,13	58,49	52,15	55,49	46,92	19,65	16,03	5,92	32,38	55
	GWh	197,7	712,7	177,9	4855,5	1832,5	10311,5	1018	473,7	6799	18482	10215	55122	
2013	€/MWh	298,84	59,92	56,1	71,32	40,5	40,34	37,48	29,41	42,2	24,09	5,5	48,25	48
	GWh	211,9	722,1	190,4	4724,9	1815,8	10085,8	973,9	475,1	4217	18361	480	42350	
2014	€/MWh	290,7	69,18	64,72	70,88	51,14	47,29	47,21	38,4	40,69	14,83	7,33	55,01	46
	GWh	354,6	688,4	229,5	4876	1730	11014	1078,9	453,7	4019	15766	360	40780	
2015	€/MWh	266,06	70,76	67,86	67,86	54,16	47,56	49,96	45,26	36,83	15,03	-	51,13	45
	GWh	473	801	339	4791	1830	10803	1129	543	4050	15714	-	40729	

Chapter 4

Methodology

As the principal aim of this dissertation is to study electricity generation costs from the past and project them until 2030, the methodology applied is based on the calculation of the levelized cost of electricity (LCOE), a tool which is commonly used for this type of analyses as reviewed in Section 2.3 and that best fits the purpose of this investigation.

This chapter with its respective sections firstly focuses on explaining the LCOE formula that has been applied in this investigation and subsequently describes how the LCOE evolution was calculated for each technology, as well as for the system per se.

All the calculations and analysis were made recurring to Microsoft Excel®2010, where a simple and automatic model was designed to facilitate the study of electricity generation costs in the different scenarios that will be explained in Chapter 5.

4.1 LCOE Equation

As already mentioned in Section 2.3, the LCOE is the cost of producing one unit of electrical energy. When calculating LCOEs, one needs to consider all the costs and energy produced during the lifetime of the central. The costs are usually divided in capital expenditure (CAPEX), which includes investments, and operational expenditure (OPEX), such as maintenance costs or fuel costs. Considering these facts and having as base the NREL formula¹ for the LCOE calculation, the equation used in this research is the following:

$$LCOE (\text{€/MWh}) = \frac{CC * CRF + fixO\&M}{CF * 8760} + varO\&M + fuel + CO_2 , \quad (4.1)$$

where CC is the overnight capital cost, CRF is the capital recovery factor, CF is the capacity factor, $fixO\&M$ are the fixed operation and maintenance costs, $varO\&M$ are the variable operation and maintenance costs, $fuel$ are the fuel costs and CO_2 are the emission costs.

¹http://www.nrel.gov/analysis/tech_lcoe_documentation.html

The units of CC and $fixO\&M$ are in €/kW and $varO\&M, fuel$ and CO_2 are in €/MWh. The values of these components have already been summarised in Tables A.4 to A.6.

One of the components of equation 4.1 is the capital recovery factor which converts present value into a stream of equal annual payments over the lifetime of the central at a specified interest rate. It is given by Equation 4.2.

$$CRF = \frac{((1+i)^n) * i}{((1+i)^n) - 1}, \quad (4.2)$$

where i is the interest rate and n is the lifetime of the central.

According to the reviewed literature, the interest rate used to calculate the CRF can vary depending on the country and technology under consideration. However, in this study an equal interest rate (8%), equivalent to the medium interest rate of the energy sector in Portugal, is assumed for all electricity generation technologies. Another component of the LCOE equation is the capacity factor. The latter is a crucial part of the equation because it defines the number of hours the centrals work per year. In other words it represents the quantity of energy produced by the central in one year. Typical capacity factors of RES centrals in Portugal, excluding large hydropower, were assumed for the LCOE calculation. These values, presented in Table 4.1, were obtained by using historical amounts of energy produced and installed capacity and were calculated by using the following equation:

$$CF(\%) = \frac{Energy\ produced(MWh)}{Capacity(MW) * 8760}, \quad (4.3)$$

where 8760 is number of hours in one year.

One can notice that in Table 4.1 the capacity factors of wind onshore and solar PV have two values. This happens because in last years the ratio between the energy production from these sources and its installed capacity has raised when compared to the typical values of past years.

Table 4.1: Capacity factors of RES(excluding large hydropower).

Type of Central	Capacity Factor
Small Hydropower	26%
Wind Onshore	23% (until 2011),28% (after2011)
Solar PV	16% (until 2010),18% (after 2010)
Biomass and CHP	50%
Geothermal	90%

In the case of large hydropower plants, the capacity factor values were selected by a different procedure. In the same way specific capital costs of each installed central are known, so is the specific expected production (full list of expected production for each central in Appendix A.1). Once knowing these amounts it is then possible to calculate the capacity factor with Equation 4.3. In case several centrals were installed in the same year, a medium value for the capacity factor

was assumed. Figure 4.1 shows the CF values assumed for large hydropower plants in the years that new capacity addition occurs. When observing this figure, the existing difference between the several capacity factors' centrals become clearer.

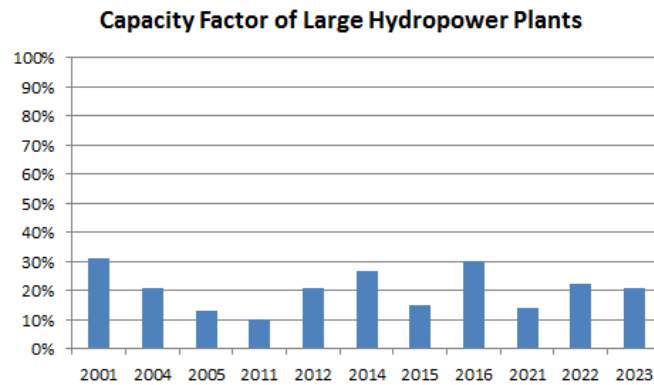


Figure 4.1: Capacity Factors of Large Hydropower Plants by Installation Year.

Another procedure was conducted in order to know the past and future values of CF from coal and natural gas utilities. On the one hand, the historical capacity factors were calculated using Equation 4.3 being its evolution represented in Figure 4.2. The latter figure demonstrates that natural gas utilities have been producing minimum amounts of energy in the last years.

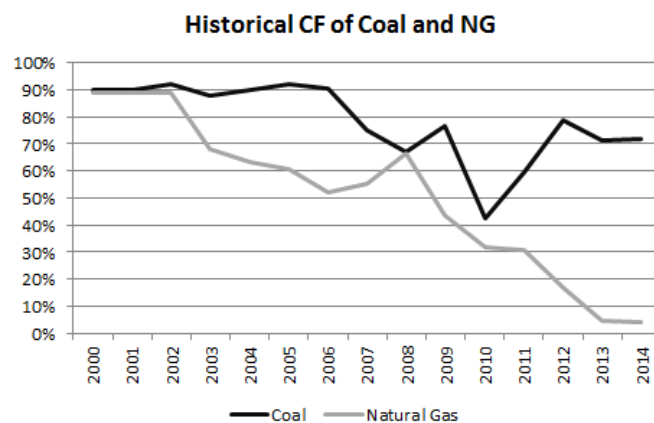


Figure 4.2: Historic Capacity Factors of Coal and Natural Gas Utilities.

On the other hand, the future CF values of coal and NG utilities were calculated depending on the electric energy they will produce. In order to know the amount of electric energy produced by these centrals, three methods were applied. The reason for this appliance is the need to allow a comparison between more and less electricity production from coal and natural gas utilities. The three methods apply Equation 4.4 to calculate the energy produced by both types of utilities, yet they differ in the way this energy is distributed within each one.

$$E_t = C + Pump - [E_{RES} + (Imp - Exp)] , \quad (4.4)$$

where,

- E_t is the total energy produced by coal and NG utilities;
- C is the energy consumption;
- $Pump$ is the energy consumption used by hydropower plants to pump water
- E_{RES} is the total energy produced by RES power plants
- Imp is the energy imported from Spain;
- Exp is the energy exported to Spain.

All components of this equation are in GWh.

It is important to refer that the total energy produced by RES utilities present in Equation 4.4 was obtained by adding the energy produced by each RES power plant, which was calculated by Equation 4.5, that use the typical capacity factors presented in Table 4.1. Moreover, the capacity factor of large hydropower plants used to calculate its total energy production was the same as for SHP plants.

$$\text{Energy produced (GWh)} = \frac{CF(\%) * Capacity(MW) * 8760}{1000} \quad (4.5)$$

The above-mentioned methods for the calculation of the energy produced by coal and NG power plants are:

1. The energy produced by the coal utilities follows the last year trends, where the capacity factor values stayed around 75%. For NG power plants, the energy produced is given by the following equation:

$$E_{NG}(GWh) = E_t(GWh) - E_{coal}(GWh) , \quad (4.6)$$

where,

- E_{NG} is the total energy produced by NG power plants;
- E_t is the total energy produced by NG and coal utilities, obtained by using Equation 4.4;
- E_{coal} is the total energy produced by coal power plants.

2. The energy produced by the coal utilities is proportional to its installed capacity and given by Equation 4.7. The energy produced by NG power plants is given by Equation 4.6.

$$E_{coal}(GWh) = E_t(GWh) * \left(\frac{P_{coal}(MW)}{P_{coal}(MW) + P_{NG}(MW)} \right), \quad (4.7)$$

where,

- P_{coal} is the power capacity of coal utilities;
 - P_{NG} the power capacity of NG utilities.
3. In this case the amount of energy assign to NG power plants is the majority of the total energy that these two thermal power plants can produce. However one must take into consideration that for security reasons of the electrical system, regarding the operating reserve, coal utilities must stay with capacity factors above 5%.

4.2 Method of Calculation of the LCOE Evolution

Having exposed the LCOE calculation used within this research in the last section, it is possible at this point to explain the manner the LCOE evolution will be calculated for each technology, as well as in case of the system LCOE evolution from 2000 until 2030.

To calculate the LCOE for each type of power plant and its evolution, it is firstly required to calculate the LCOE for each year in which new capacity was and will be installed. This LCOE is then extended through the lifetime of the central or at a maximum until 2030. Afterwards an overall LCOE (OLCOE) is calculated for each year, which is a weighted average by its installed capacity (Equation 4.8).

$$OLCOE_{x,i}(\text{€/MWh}) = \frac{\sum_{i=2000}^n (LCOE_{x,i} * P_{inst,i})}{\sum_{i=2000}^n P_{inst,i}}, \quad (4.8)$$

where,

- $OLCOE_{x,i}$ is the overall LCOE of the power plant technology x in year i;
- $LCOE_{x,i}$ is the LCOE of the power plant technology x in year i;
- $P_{inst,i}$ is the installed capacity of power plant technology x in year i;
- $n = i + \text{lifetime of power plant technology x}$.

Finally, it is possible to calculate the system LCOE (SLCOE) evolution by using the $OLCOE$ results for each power plant technology. This calculation (Equation 4.9) follows the same principle

as the calculation of the OLCOE, however in this case the weighted average is calculated by the energy produced by each power plant technology.

$$SLCOE_i(\text{€/MWh}) = \frac{\sum_x (OLCOE_{x,i} * E_{x,i})}{\sum_x E_{x,i}} , \quad (4.9)$$

where,

- $SLCOE_i$ is the system LCOE in year i;
- $OLCOE_{x,i}$ is the overall LCOE of the power plant technology x in year i;
- $E_{x,i}$ is the energy produced by the power plant technology x in year i.

Chapter 5

Scenarios

In order to enable the projection of electricity generation costs and the comparison between the different types of electricity generation technologies, a scenario needs to be created to simulate the evolution of installed capacity, electricity consumption, and electricity imports, as well as exports. Moreover, to compare the costs of different solutions in which installed capacity of some electricity generation technologies are changed, other scenarios need to be developed.

Therefore, this chapter explains the basic scenario that has been created in the first place, and subsequently clarifies how further scenarios have been developed and assumed on the basis of the first one.

5.1 Base Scenario

The creation of this scenario was based on the presuppositions of the Portuguese national action plan for renewable energies (PNAER) and national plan for climate changes (PNAC 2020/2030) [98, 99]. The PNAER was executed by the Portuguese government as a result of the European directive regarding the promotion of the use of energy from renewable energy sources [82], in which the European commission established that member states are to establish national action plans which set the share of energy from renewable sources.

Both PNAER and PNAC, that was available for consultation more recently, make projections for installed capacity and consumption, such as:

- The structure of the electricity consumption does not suffer significant changes, maintaining a structure similar to 2010;
- The installed capacity, on a reference case, grows 4,1 GW in 2020 when compared to 2010 values. This amount results from the shutdown of the coal central in Sines, the addition of two new CCGT centrals and the addition of wind onshore, hydropower and solar PV capacity, allowing a share of 63% of renewables in the production of electricity;

- For 2030 the installed capacity will raise 5.4 GW when compared to the capacity of 2010, which implies that the capacity levels of wind onshore will be 6.1 GW, solar PV 1.2 GW and hydropower 9.1 GW having coal utilities disappeared;
- In 2030, renewable sources will assure 62% to 70% of the electricity produced depending on the consideration of more or less energy produced by natural gas utilities. Moreover this document also includes, in the reference case, energy efficiency objectives which can lead to a lower electricity production in 2030 from 7% to 18 % when compared to 2010 levels.

As already mentioned before, the creation of the base scenario takes into consideration the above-described presuppositions, but will also take notice of the actual reality of the electrical system and the perspectives obtained by professionals in the area. The following sub-sections describe the projections assumed in the base scenario.

5.1.1 Capacity Projections

It is firstly important to refer that the projections made in this chapter refer to future years starting in 2015, however in most figures values are shown since 2010 as a means of comparison.

Starting with future projections of large hydropower plants, in 2007 a national plan regarding the high potential of hydroelectricity was elaborated [100]. This plan defined the investments that would take place until 2020, in order to achieve the adequate levels of the hydroelectric potential.

The past years showed that most of the initially defined capacity additions have not taken place and are not going to take place in the designated years of the plan. Therefore, the projection made for new installed capacity of large hydropower plants follows a different trend in this research and is illustrated in Figure 5.1 (full list of new large hydropower plants can be found in Appendix A.1). This figure shows that there is a strong addition of large hydropower capacity, reaching 8.77 GW in 2030.

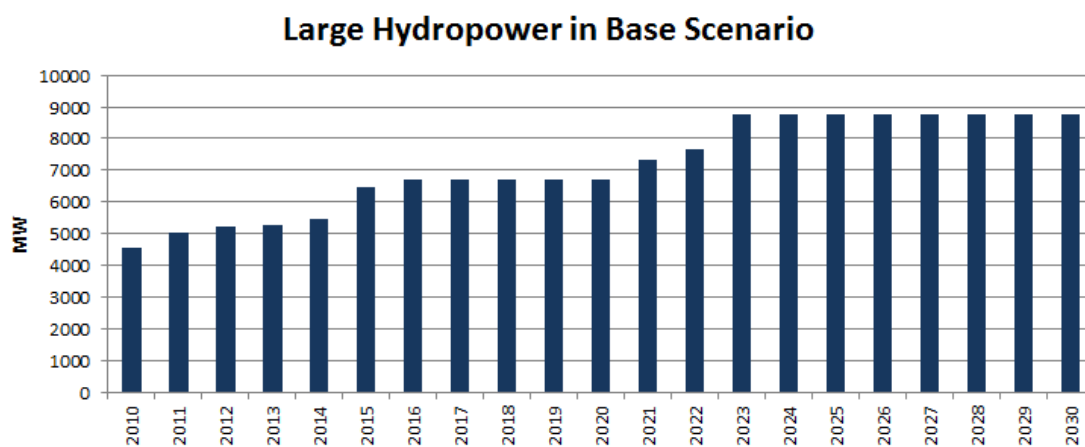


Figure 5.1: Projected Capacity of Large Hydropower (>10MW) in Portugal until 2030 (Base Scenario).

In the case of SHP plants, the installed capacity considered in this scenario until 2020 is based on the trend of the PNAER plan. In Figure 5.2 it is possible to verify that no great investments are expected to happen for this generation technology type in future years.

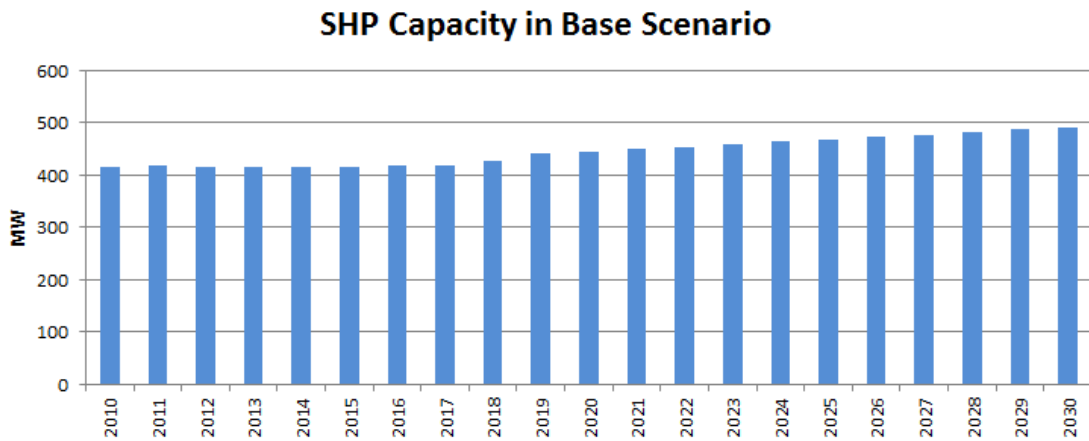


Figure 5.2: Projected Capacity of Small Hydropower (<10MW) in Portugal until 2030 (Base Scenario).

According to the PNAER plan, it is also expected that biomass power plants do not suffer great capacity developments until 2020. Moreover this scenario defines that the capacity of biomass power plants are going to stagnate until 2030 (see Figure 5.3).

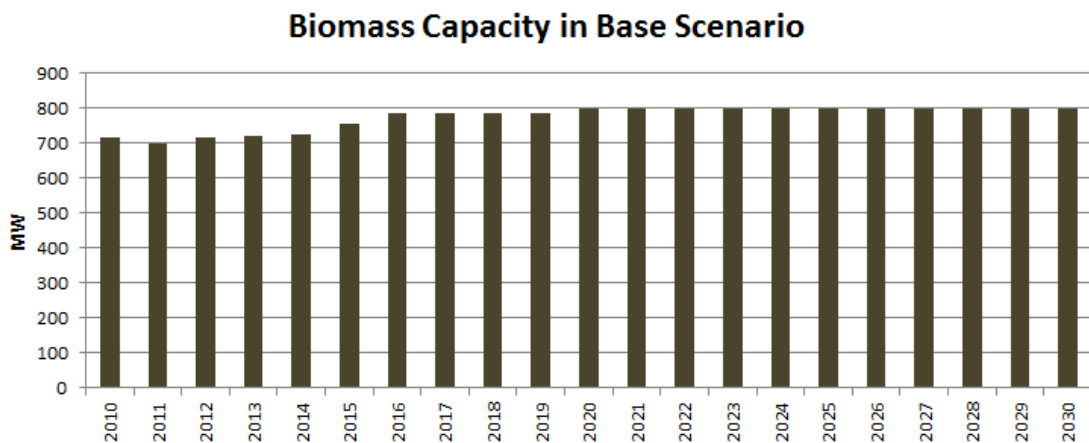


Figure 5.3: Projected Capacity of Biomass Power Plants in Portugal until 2030 (Base Scenario).

In addition to the PRE power plants capacities considered above, in this scenario wind onshore and solar pv power plants capacities are the ones with the biggest growing rates, excluding large hydropower plants. In PNAC wind onshore capacity reach 6.1 GW and solar PV reach 1.2 GW in 2030. The same values are assumed in this scenario, being the projections to reach them until 2030 represented in Figures 5.4 and 5.5.

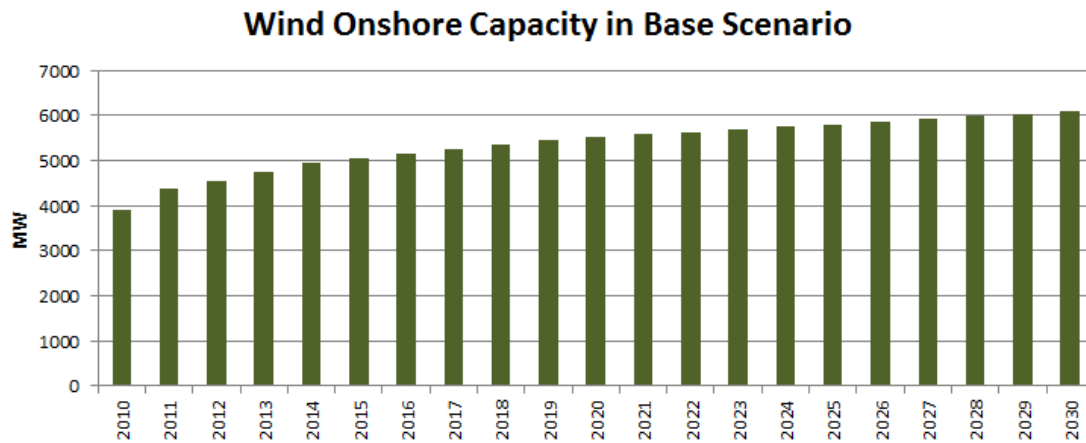


Figure 5.4: Projected Capacity of Wind Onshore Power Plants in Portugal until 2030 (Base Scenario).

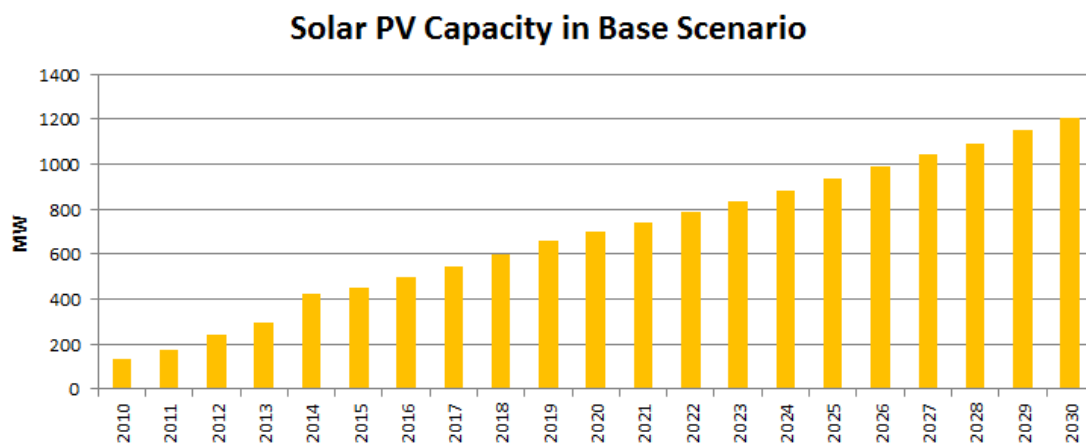


Figure 5.5: Projected Capacity of Solar PV Power Plants in Portugal until 2030 (Base Scenario).

In respect to the "combined heat and power" plants, this scenario presumes a decrease, due to the cutback of the supports that this type of power plants have previously been receiving.

The projected decrement of the capacity of CHP was performed as follows: Having in concern the year of installation of the CHP capacity and the respective decree in force, the activity period of the correspondent capacity centrals was extended by the lifetime of the contract defined by the decree, being then considered inactive. Figure 5.6 is demonstrates the projected capacity for CHP plants.

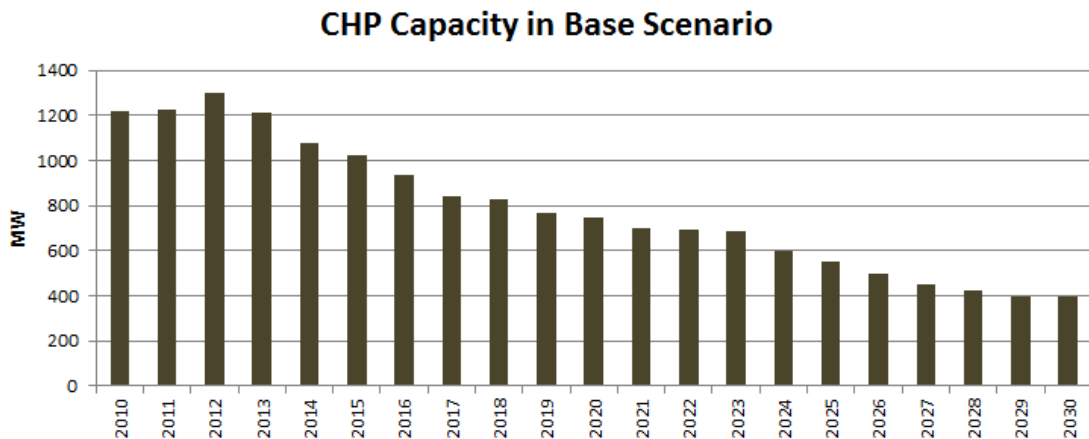


Figure 5.6: Projected Capacity of CHP Plants in Portugal until 2030 (Base Scenario).

Three complementary cases (A,B and C) were considered for the projection of coal and NG utilities:

- A. In this case the capacity of coal and natural gas remain at today's levels (Coal at 1756 MW and NG at 3830 MW). The energy produced by these utilities is calculated using the [first method](#) explained in section 4.1;
- B. Secondly, the coal central " Sines" with 1180 MW of capacity is closed. Moreover it is assumed that natural gas fuel prices follow a reverse trend than the one demonstrated in Figure 3.14. This presupposition is based on the theory that natural gas prices will become lower with the growing of competitiveness of shale gas, deriving from USA and that Portugal has enough capacity to receive this type of fuel in its ports.
In this case the electricity produced by coal and NG utilities is calculated by [second](#) and [third](#) methods, that are explained in section 4.1;
- C. This case is similar to the last one but adds the shutdown of the remaining coal central, which means that this type of utilities do not exist here.

For a better perception of the capacities projected in this scenario, Figure 5.7 illustrates the evolution of the large hydropower plants, the centrals in the PRE regime and the ordinary centrals (Coal and NG) in the three cases proposed. In this figure it is possible to identify that RES have a considerable growing rate reaching around 18 GW of capacity while total capacity increases when compared to the reference year 2010 with 6.7 GW, 5.6 GW or 5 GW for cases A,B and C respectively.

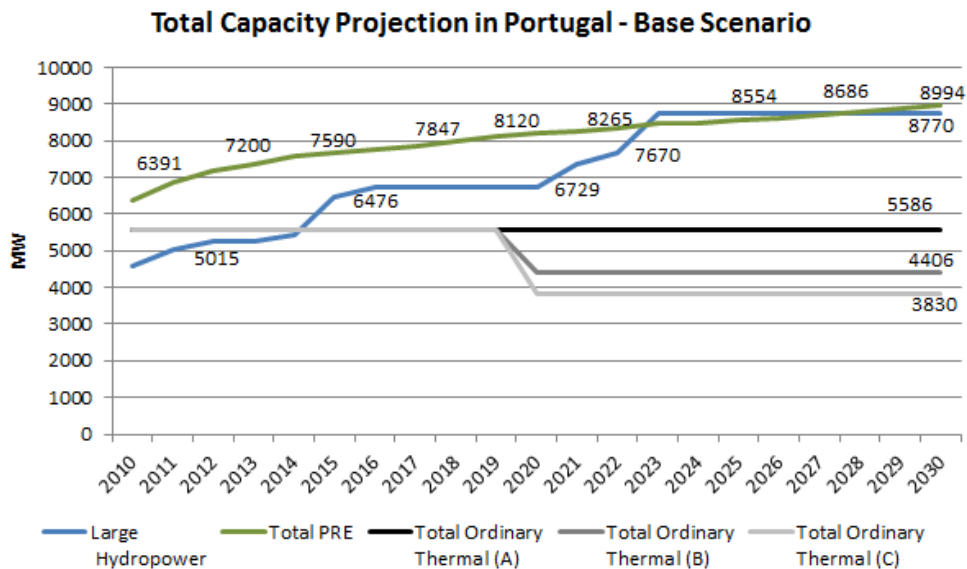


Figure 5.7: Total Projected Capacity in Portugal until 2030 (Base Scenario).

5.1.2 Consumption and Pump Projections

With regard to the future electricity consumption in Portugal, the PNAC plan predicts that the latter will not suffer significant changes, but will slowly return to the levels of 2010. This prediction includes the objectives of energy efficiency levels. However it was here considered that the effect of this fact over the electricity consumption is cancelled by the growing of the gross domestic product(GDP) [101], which is accompanied by an electricity consumption raise.

Once having projected the electricity consumption values for Portugal, the effect of the energy consumed by pumping turbines present at some large hydropower plants gets added. Historical values of energy consumed for pumping (Figure 3.7) show that these amounts represent less than 20% of the total capacity. This capacity is considered to grow at the same levels of the new large hydropower plants equipped with reversible turbines (full list in Appendix A.1). To calculate the energy consumed by pumping Equation 4.5 was applied in which a capacity factor of 15% was stipulated.

Figure 5.8 illustrates the projected consumption including energy for pumping.

5.1.3 Imports/Exports Projection

For the projection of future values of the imports and exports of electricity in Portugal, it is firstly required to study the historical values which allow one to understand how future net capacity affects these amounts. This study, described in this section, uses hourly data of electricity production and electricity imports as well as exports in Portugal in 2012 and 2013.

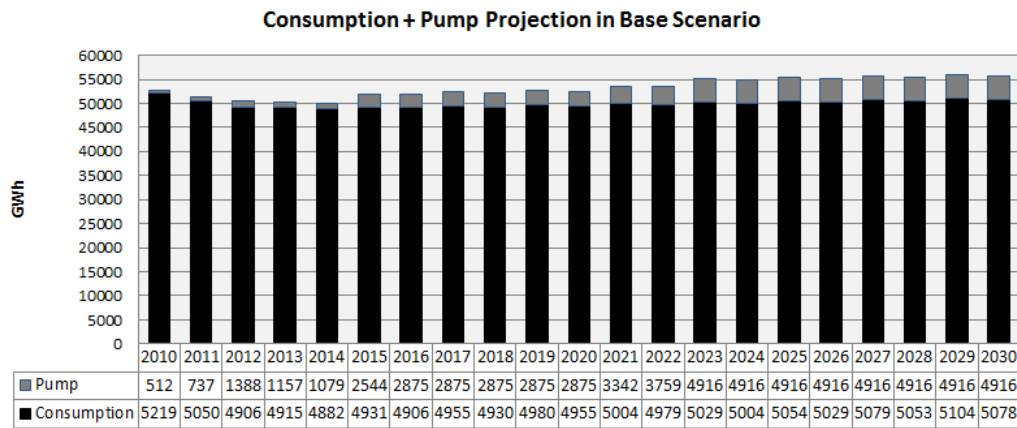


Figure 5.8: Projected Consumption including energy for pumping in Portugal until 2030 (Base Scenario).

From the data available it is possible to relate the production of electricity from renewable sources and the quantities that were exported from or imported to Portugal. This relation, represented in Figure 5.9, clearly shows that there is a limit in the export capacity of Portugal, therefore the amount of energy exported could have been bigger.

When applying this relation to the Iberian market (see Figure 5.10) the same conclusion can be drawn, although it is not as clear as in the previous case.

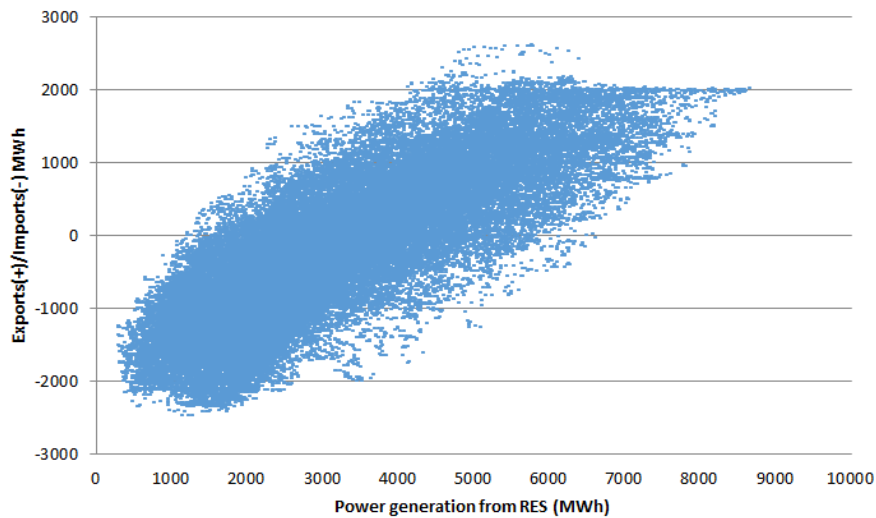


Figure 5.9: Relation between Electricity Imports/Exports and Electricity Production from RES in Portugal. Data from 2012 and 2013. Source: Data provisioned by ©Smartwatt

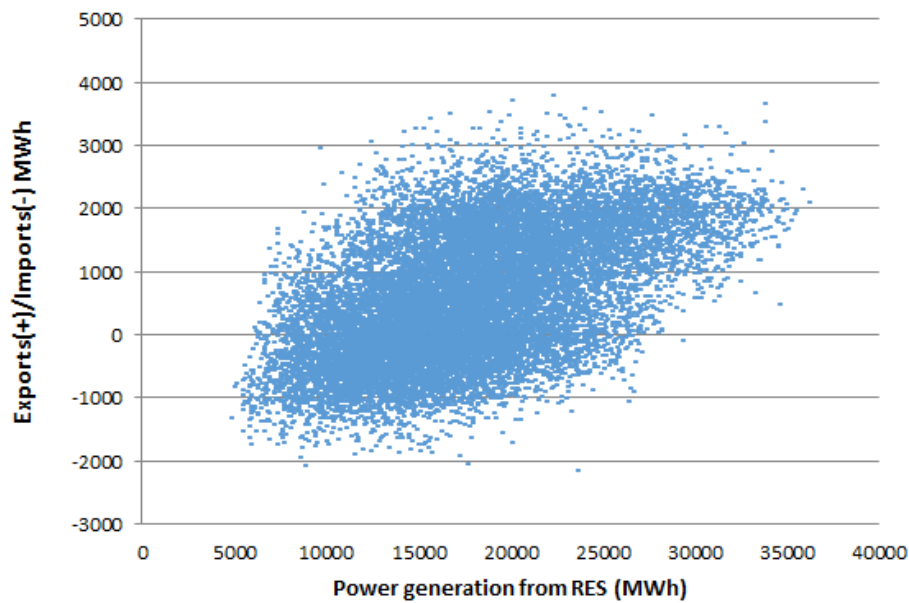


Figure 5.10: Relation between Electricity Imports/Exports and Electricity Production from RES in Iberia. Data from 2012 and 2013. Source: Data provisioned by ©Smartwatt

In addition, two histograms characterising the distribution of the quantities exported and imported for the case of Portugal and Iberia can be designed. It is expected that these histograms represent an unimodal probabilistic distribution, however the existence of limitations distort the distribution, as is to be seen in Figures 5.11 and 5.12. Furthermore, in Figure 5.11 it is possible to see the effect of the capacity limitation of electricity exports in Iberia (1100 MW between France and Spain and 900 MW between Spain and Morocco [102]) since there is a low frequency of values after 2000 MW.

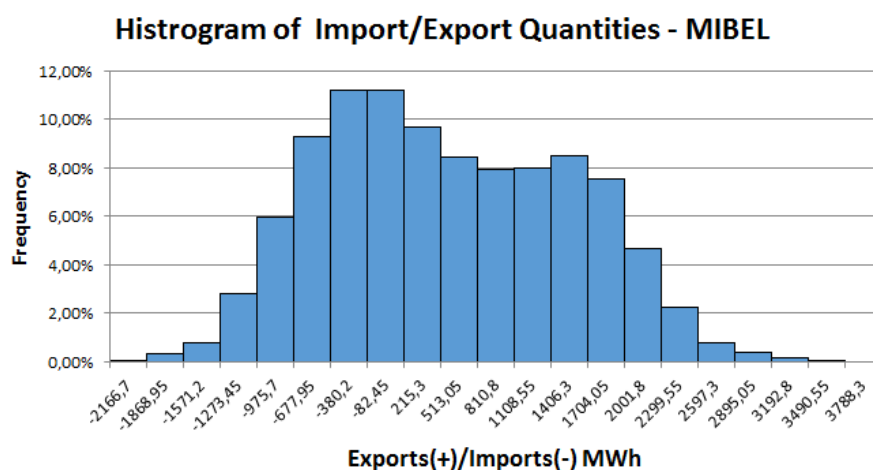


Figure 5.11: Histogram of Electricity Imports/Exports in Iberia. Data from 2012 and 2013.

Moreover, the net capacity for electricity exchanges between Portugal and Spain is not equal

during the year(this also occurs between Spain and France), due to unavailability of transmission lines and other elements of the network.

The annual reports of REN ([103, 104]) provide the annual export capacities, as well as the frequency of its occurrence. In 2012 and 2013, the export capacity interval with major occurrence was located in between 2000 and 2200 MWh. When observing figure 5.12, it is possible to verify that the distribution of the export and import quantities suffers major distortions on these levels. Additionally, in 2013 there has been a strong capacity limitation occurrence for 1300 MWh, which explains the accentuated distortion that can be verified within these amounts in the respective histogram.

In order for this effect not to occur, an increase of the capacity of interconnection is necessary. In case this limitation, which has been verified during the last years until today, would be overcome it would then also be possible to expect that the export values would increase 10%. Concerning the capacity of imports, the histogram of Figure 5.12 shows that there are no limitations, since the distribution is not distorted. It is then not expected that import values will suffer great changes in the future.

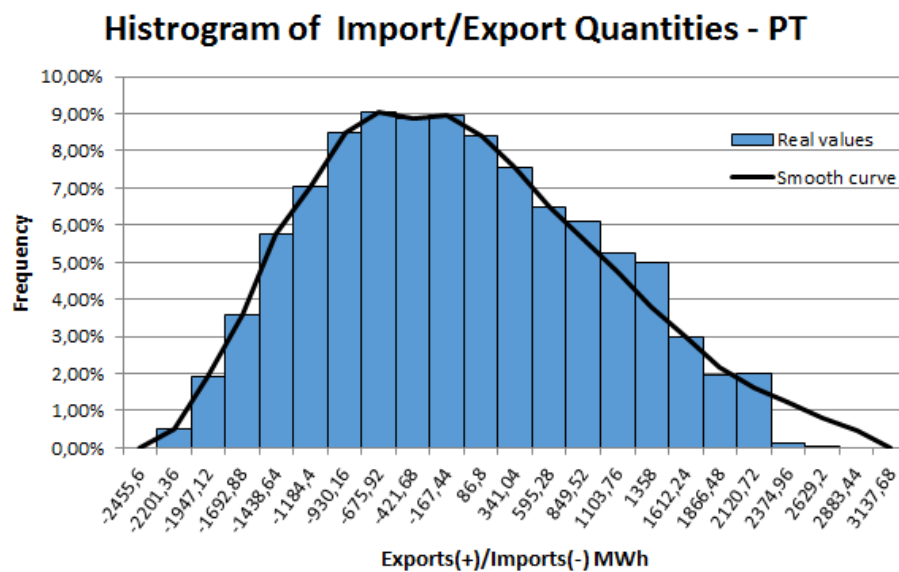


Figure 5.12: Histogram of Electricity Imports/Exports in Portugal. Data from 2012 and 2013.

By considering the above-mentioned facts, as well as the interconnection capacity between Portugal and Spain which is expected to augment to 2800MW in 2016 and to 3000MW in 2017, while that between Spain and France is also expected to increase to 2800MW in 2016 [105], the projection illustrated in Figure 5.13 has been realised based on/ concerning the import balance in Portugal.

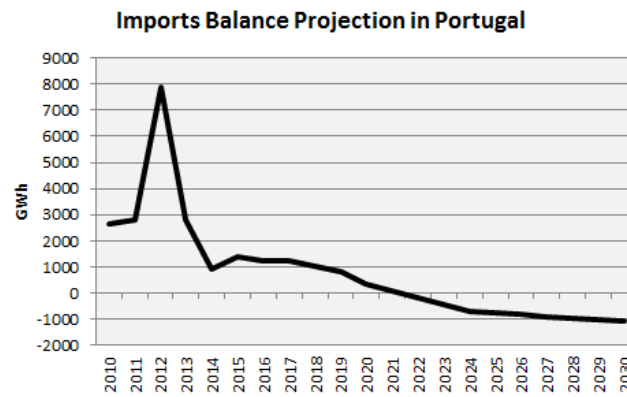


Figure 5.13: Projected Balance of Imports in Portugal until 2030.

5.2 CHP Scenario

For the conduction of this dissertation it has been highly relevant to study the effects of diverse power generation technology solutions on the system costs. That is why other scenarios that introduce small modifications to the base scenario needed to be developed.

In fact, one of the scenarios created projects a different trend for the evolution of CHP power plants. Contrarily to the assumption that the capacity of CHP centrals will decrease in the future, this scenario considers that the following two further situations may occur:

- The first one, named "CHP remains", defines that no future investments will happen but the actual capacity will remain operational, which represents an addition to the total capacity of PRE power plants when compared to the Base Scenario (see Figure 5.14);
- The second case considers the law allowing electricity production for auto-consumption [90], which means that the energy produced by these centrals is included in the consumption, decreasing its value when compared to the base scenario (see Figure 5.15). In fact this measure can be considered as an efficiency measure, since it decreases the consumption. That is why this scenario is called "CHP as efficiency".

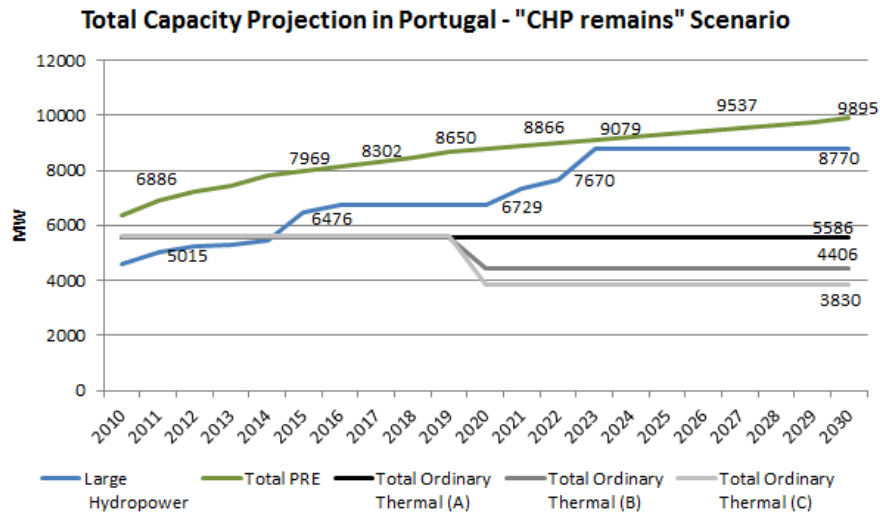


Figure 5.14: Total Projected Capacity in Portugal until 2030 ("CHP remains" Scenario).

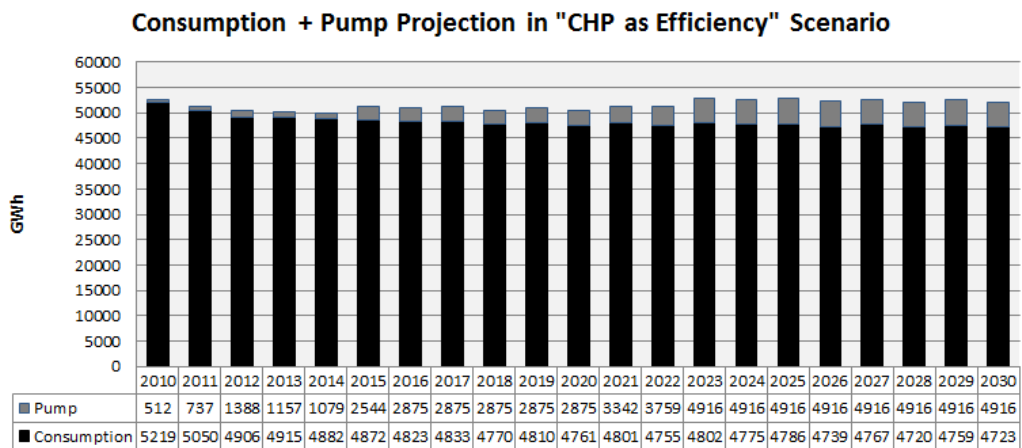


Figure 5.15: Projected Consumption Including Energy for Pumping in Portugal until 2030 ("CHP as Efficiency" Scenario).

5.3 Solar PV Scenario

In case of the Solar PV Scenario, the modifications made to the base scenario are the following:

- Taking into consideration the same fact explained in the "CHP as efficiency" scenario, regarding the law of own consumption, and that the module prices of solar panels have reached levels that made investments in this field viable [20], it is projected in this scenario that until 2020, 300 MW of Solar PV will be installed for own consumption and that this value will augment to 1200MW by 2030.

As in the "CHP as efficiency" scenario, the projection in this scenario affects the consumption of electricity, by decreasing its amounts (see Figure 5.16) and thus is named "PV as efficiency".

- This scenario, named "PV More", assumes that the capacity addition of the previous case is not installed for own consumption but has centralised solar PV centrals, which means that the capacity of solar PV power plants increase when compared to the base scenario, reaching 2.4 GW in 2030(see Figure 5.17). Figure 5.18 shows that this presupposition also increases the total capacity of the PRE power plants.

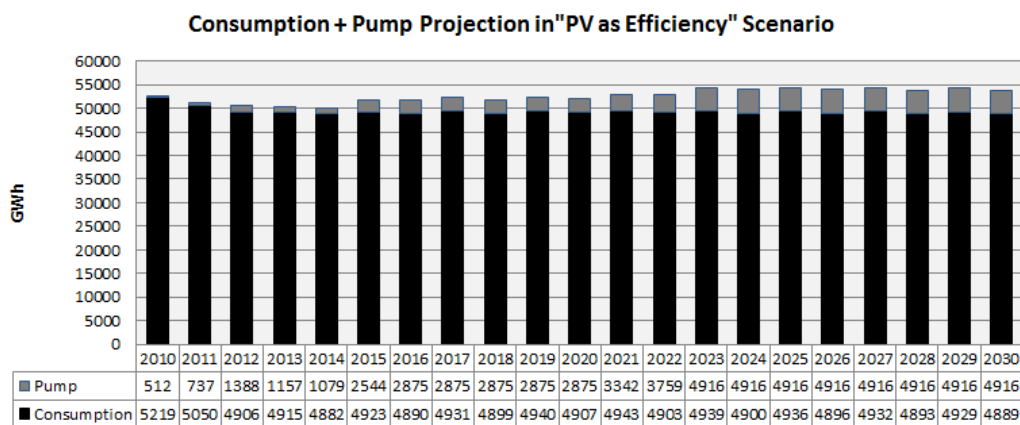


Figure 5.16: Projected Consumption Including Energy for Pumping in Portugal until 2030 ("PV as Efficiency" Scenario).

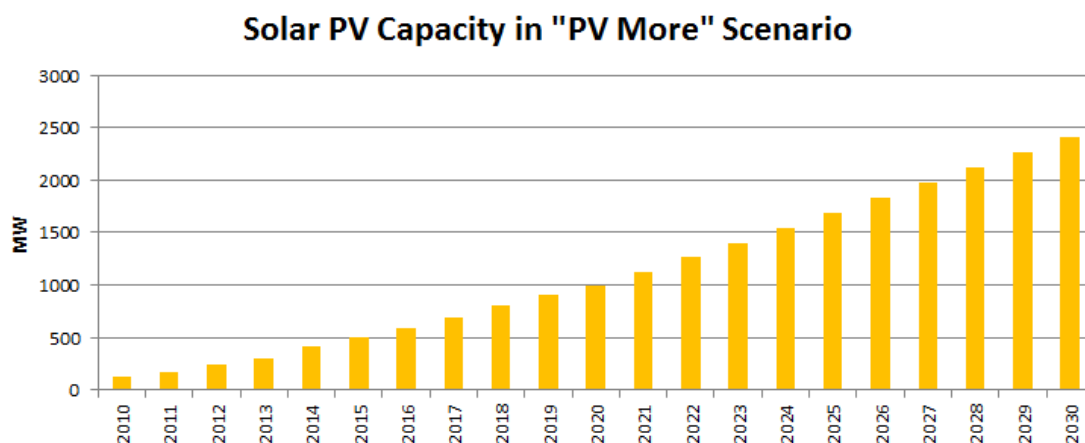


Figure 5.17: Projected Capacity of Solar PV Power Plants in Portugal until 2030 ("PV More" Scenario).

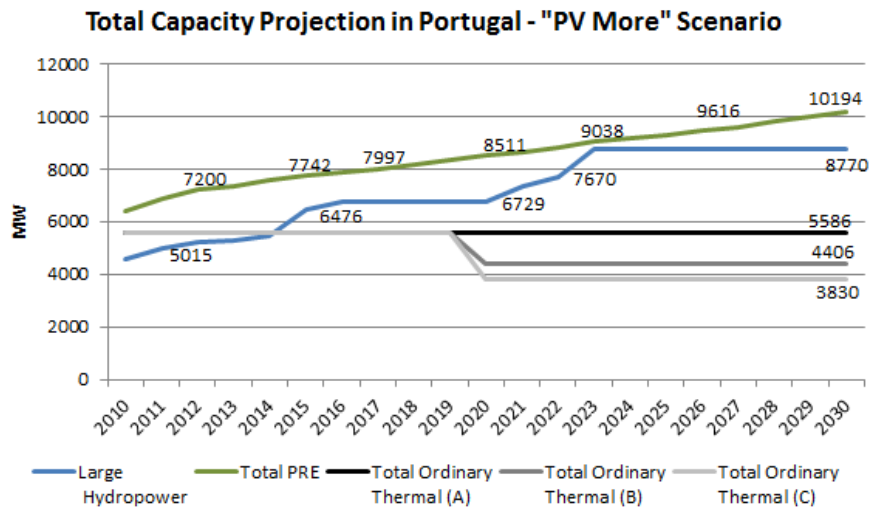


Figure 5.18: Total Projected Capacity in Portugal until 2030 ("PV More" Scenario).

5.4 Wind Onshore Scenario

Regarding the fact that onshore wind plants have high levels of penetration and maturity around the world, as mentioned in Section 2.4, the last scenario created changes to the projected installed capacity of onshore wind in the base scenario.

In this case the additions to the installed capacity of onshore wind result in almost "6000 MW" of total capacity in 2020 and "8300 MW" in 2030, as demonstrated in Figure 5.19.

As a consequence of this addition, the total installed capacity of PRE power plants will also increase, reaching more than "10000 MW" in 2030 (see Figure 5.20).

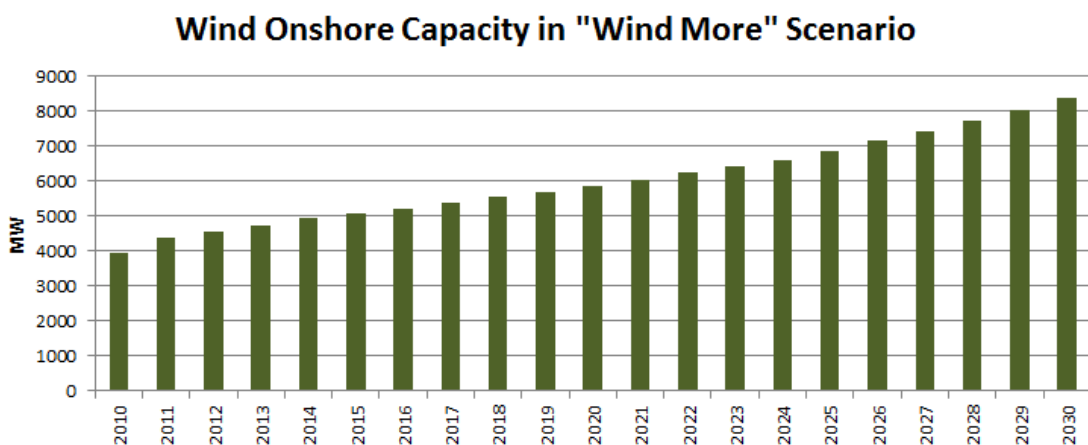


Figure 5.19: Projected Capacity of Wind Onshore Power Plants in Portugal until 2030 ("Wind More" Scenario).

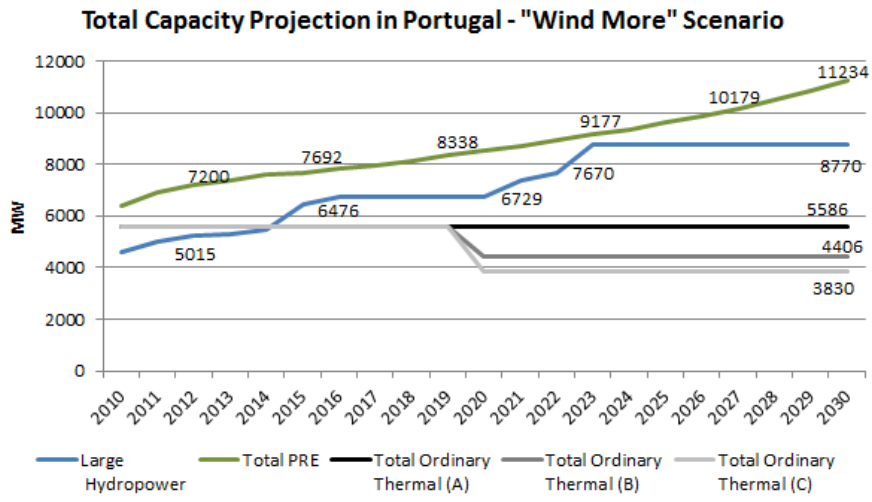


Figure 5.20: Total Projected Capacity in Portugal until 2030 ("Wind More" Scenario).

Chapter 6

Results

Once having retrieved the relevant information needed for the study (see Chapter 3) and created scenarios for future developments in the electric power system (see Chapter 5), it is now possible to calculate past electricity generation costs, as well as their future projections by applying the methodology designed and explained in Chapter 4.

Furthermore, with the above-mentioned results in mind, it is possible to study the costs that the electric power system had and will have with the production of electricity.

Consequently this chapter firstly presents the energy production results by each type of electricity generation technology according to the scenarios that have been previously elaborated (see Chapter 5) and are required for the appliance of the LCOE equation. Subsequently, the results of the past and future LCOEs, the overall LCOEs and the system LCOE are demonstrated in order to end this chapter in a way that it is possible to draw conclusions regarding the effects on the costs that the system has with the supportive schemes for electricity producers .

6.1 Energy production

This section summarises the results of the energy produced by each type of technology when regarding the different scenarios mentioned earlier.

For an easier reading, the information presented within this section is divided in various subsections that refer to the different electricity generation technologies, while applying the scenarios that have been exposed in the previous chapter and containing the energy produced during these scenarios. It should also be added at this point that in Appendix A.2 are presented the production mixes resultant from each scenario.

6.1.1 Energy Production of Large Hydropower

Since large hydropower plants have the same installed capacity in all developed scenarios, the energy produced by this source remains equal. Figure 6.1 shows these values. It is possible to verify an increase of the energy produced which corresponds to the additions of the capacity installed assumed in the [base scenario](#).

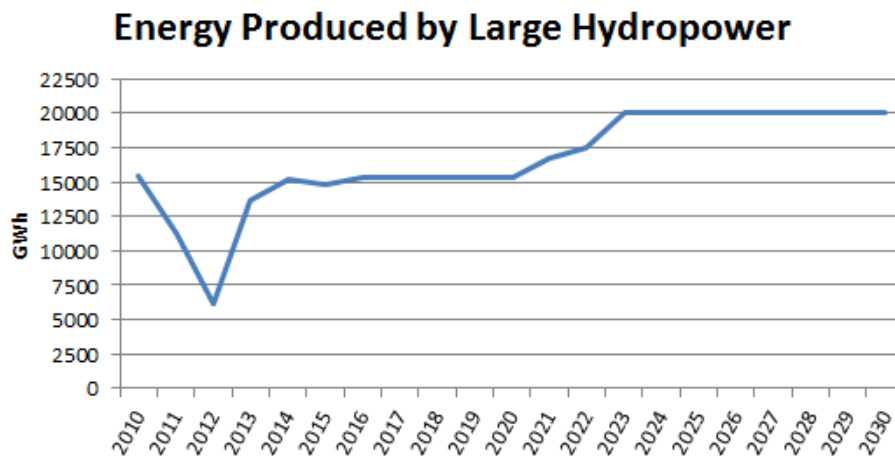


Figure 6.1: Energy Produced by Large Hydropower (>10MW) in all Scenarios.

6.1.2 Energy Production of SHP and Biomass

Both biomass and SHP, as in the case of large hydropower plants, have the same capacity in all the scenarios, which is defined in the [base scenario](#). Therefore, the energy produced by this source is equal for all the scenarios (see Figure 6.2)

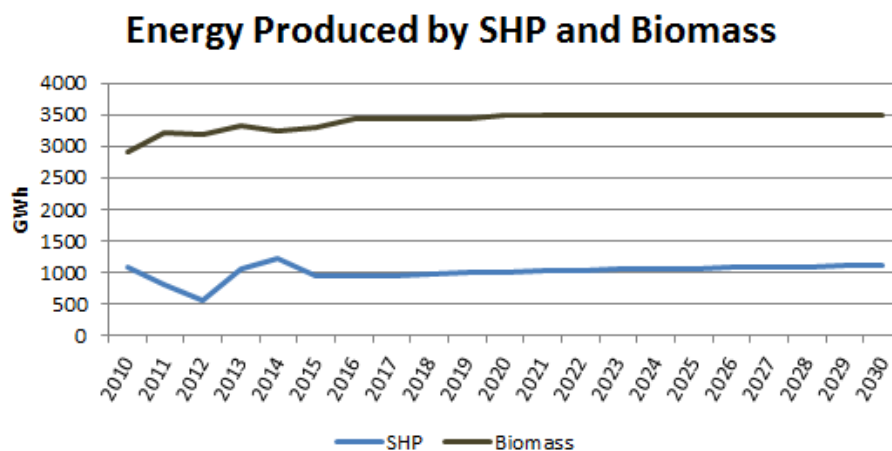


Figure 6.2: Energy Produced by Small Hydropower (<10MW) and Biomass in all Scenarios.

6.1.3 Energy Production of CHP

For CHP centrals there are two different situations that have different values of produced energy: The first one is related to the capacity defined in the ["CHP remains"](#) scenario and the second one is related to the capacity defined in the [base scenario](#). Moreover, the latter is also used in the remaining scenarios.

Figure 6.3 shows the energy produced by CHP centrals in both situations.

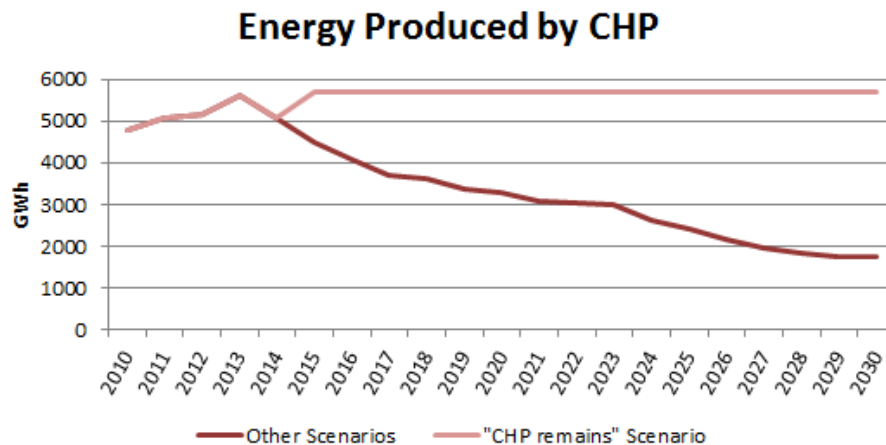


Figure 6.3: Energy Produced by CHP Centrals in the "CHP remains" Scenario and in the Remaining Scenarios.

6.1.4 Energy Production of Solar PV

The energy produced by Solar PV power plants also differs in two ways, depending if it is considered the [base scenario](#) or the ["PV More" scenario](#). Since in the "PV More" scenario the installed capacity over the years is greater than in the base scenario, the energy produced in the first has a more pronounced growing rate than the second (see Figure 6.4).

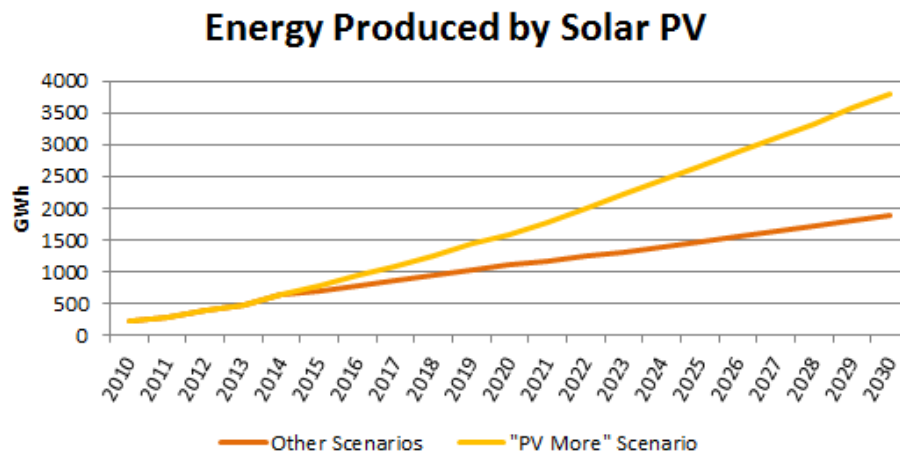


Figure 6.4: Energy Produced by Solar PV Centrals in the "PV More" Scenario and in the Remaining Scenarios.

6.1.5 Energy Production of Onshore Wind

Another electricity generation technology with two distinct amounts of energy produced, is the Onshore wind, with the respective values represented in Figure 6.5. Again, the growing rate of energy produced is more pronounced in the ["Wind More" scenario](#) than in the [base scenario](#).

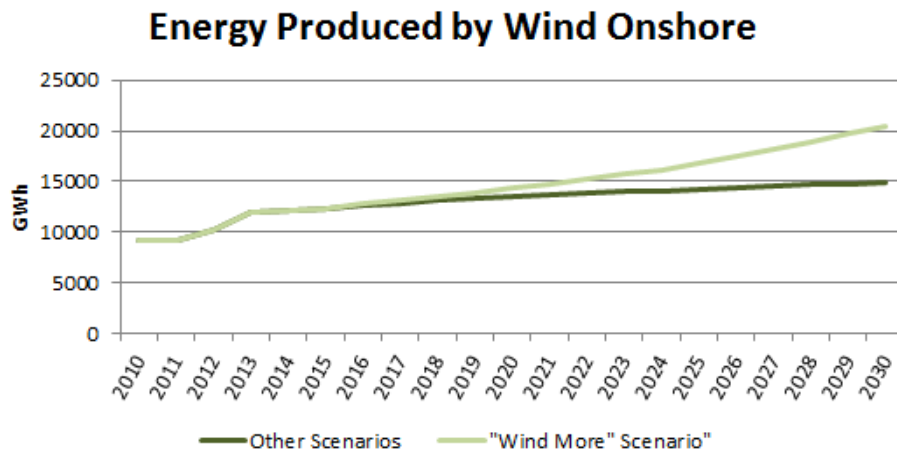


Figure 6.5: Energy Produced by Onshore Wind Centrals in the "Wind More" Scenario and in the Remaining Scenarios.

6.1.6 Energy Production of Coal and NG Power Plants

In the case of coal and NG utilities there are several situations with different amounts of energy produced, due to the fact that this electricity resources depend on the energy produced by the remaining power plants, as defined in Section 4.1.

As a consequence of the above-mentioned fact, the energy produced by coal and NG utilities change in each scenario considered. Moreover, these amounts also depend on the installed capacity that has been considered, defined by cases A,B and C in Sub-section 5.1.1 and on the methods used for their calculation.

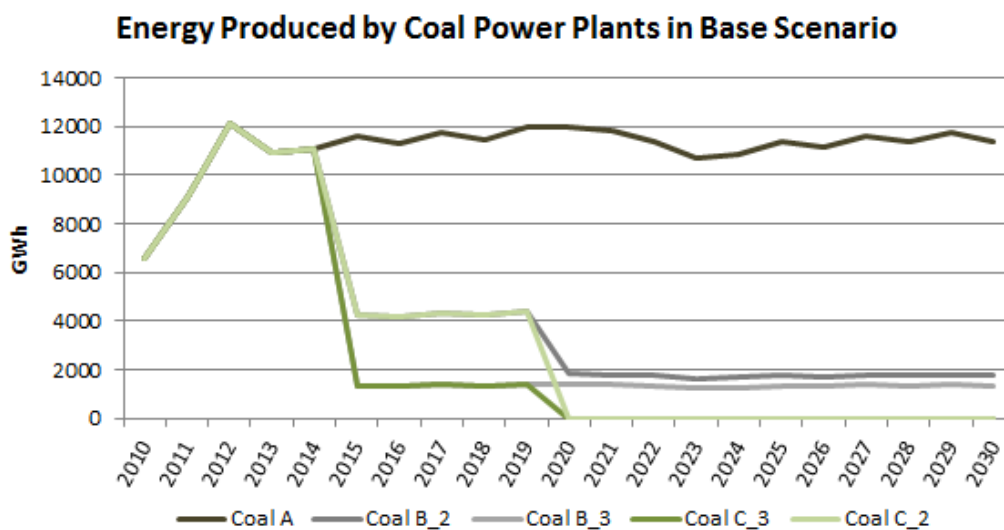


Figure 6.6: Energy Produced by Coal utilities in the Base Scenario, according to the case and method considered.

Figures 6.6 and 6.7 illustrate the energy produced by coal and NG utilities in the base scenario according to the case and method considered. Here it is possible to verify that in case "A" the energy produced by Coal utilities is greater than by NG utilities, and that the reverse happens in case "B" and "C". These results are expected since in cases "B" and "C" the capacity of coal decreases and the energy produced is calculated by methods 2 and 3, defined in Section 4.1.

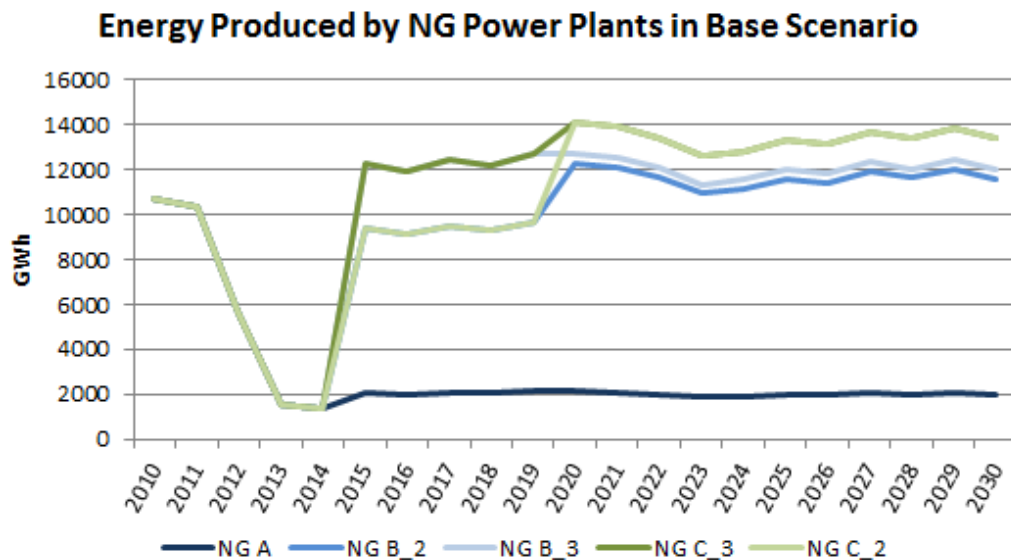


Figure 6.7: Energy Produced by NG utilities in the Base Scenario, according to the Case and Method Considered.

Furthermore, Figures 6.8 to 6.11 show the energy produced by coal and NG utilities in the remaining scenarios. Here, it is possible to verify that the amounts of energy produced calculated by applying method 3 are not represented. The reason of this exclusion is related to the fact that the results of energy produced in methods 2 and 3 are similar, as is to be verified in Figures 6.6 and 6.7, which implies that the results of these cases in terms of generation costs would also be similar and therefore it is irrelevant to study this case.

Additionally, since the values of the installed capacity in the "PV More" and in the "PV as efficiency" scenarios are the same, (and considering that they differ in the way of installation), their energy produced is equal. It results from this that only one Figure (6.10) is presented, that represents the energy produced in both scenarios.

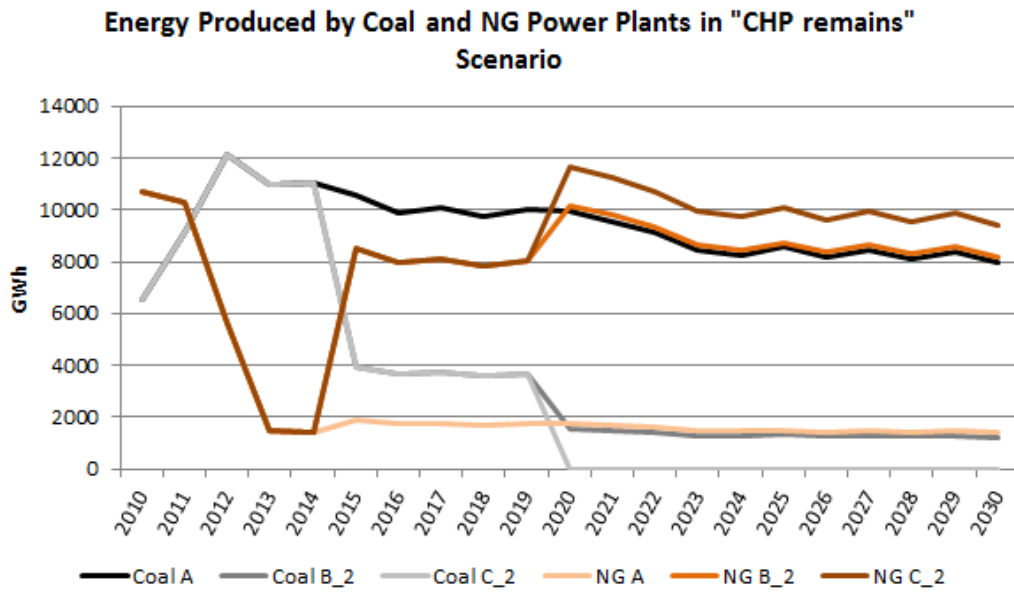


Figure 6.8: Energy Produced by Coal and NG utilities in the "CHP remains" Scenario, according to the Case and Method Considered.

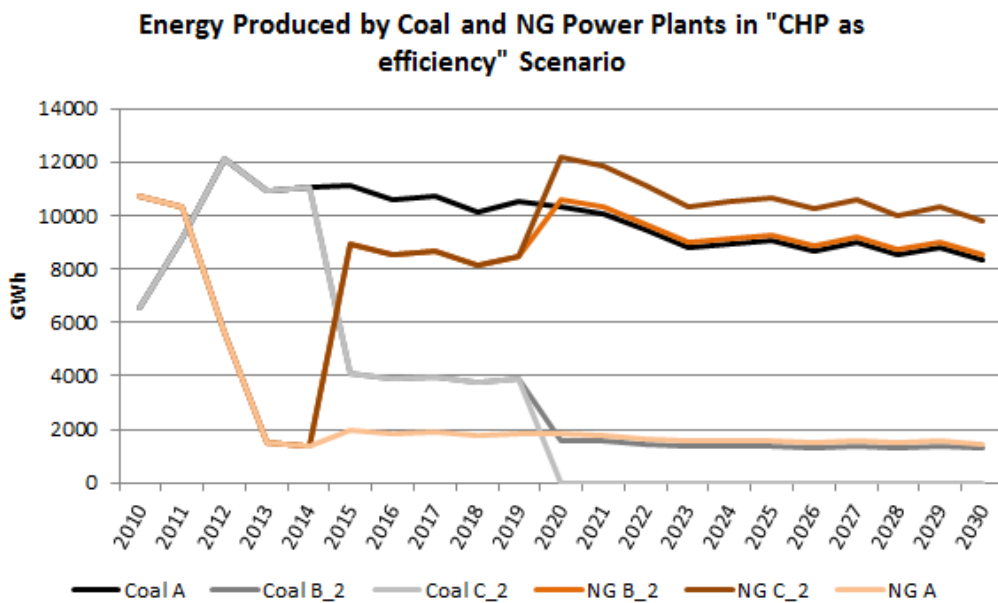


Figure 6.9: Energy Produced by Coal and NG utilities in the "CHP as efficiency" Scenario, according to the Case and Method Considered.

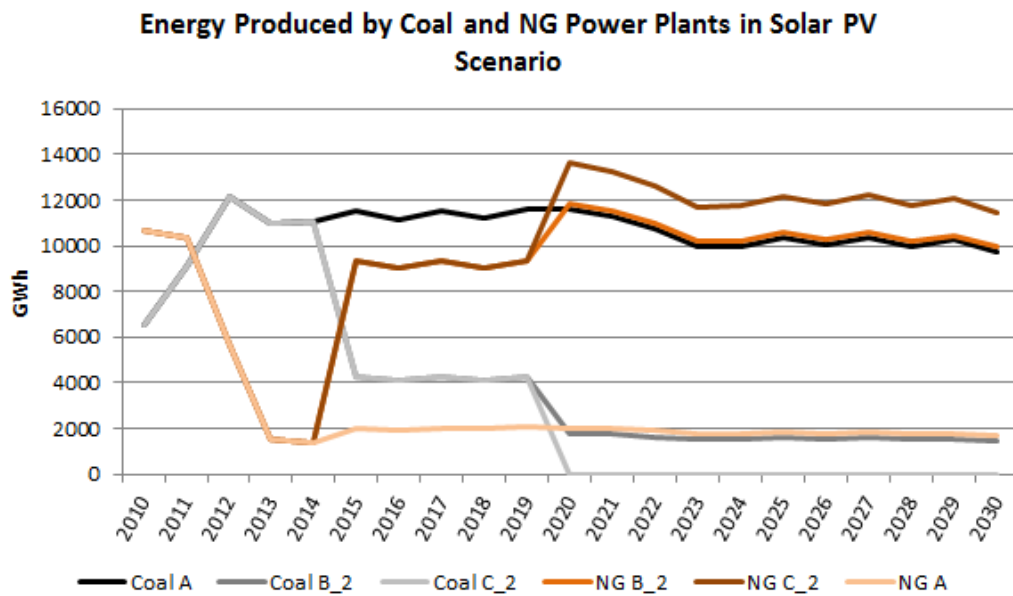


Figure 6.10: Energy Produced by Coal and NG utilities in the Solar PV Scenarios, according to the Case and Method Considered.

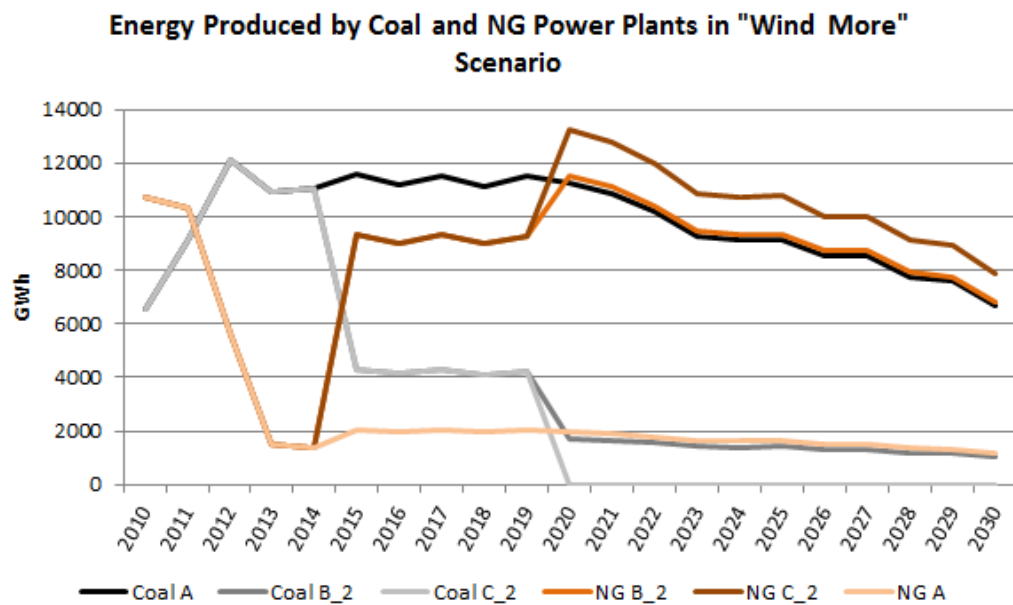


Figure 6.11: Energy Produced by Coal and NG utilities in the "Wind More" Scenario, according to the Case and Method Considered.

6.2 Electricity Generation Costs

Regarding the results of the previous section, it is possible to calculate the results of LCOE, overall LCOE (OLCOE) and System LCOE (SLCOE) in the past, as well as its future projections.

For this purpose, this section presents the information regarding the above-mentioned results with the following structure:

- Firstly, the results of the past values of the OLCOE, for each power generation technology, and the SLCOE are presented (see Sub-section 6.2.1);
- Secondly, the results of the LCOE projection for each type of generation technology are demonstrated (see Sub-section 6.2.2);
- Then, included in Sub-section 6.2.2, the results of the OLCOE projections for each power generation technology are identified;
- Finally in Sub-section 6.2.3 the results of the SLCOE projections for the different scenarios developed in Chapter 5 are demonstrated.

Yet before presenting the results, it is important to notice at this point that the costs of large hydropower, SHP, Biomass and CHP plants before 2000 have not been considered for the calculation of the OLCOE and the SLCOE. Besides, the geothermal centrals were not included in the results, since they are a particular case of the autonomous region of Azores. Nevertheless, the LCOE of this electricity generation technology gets mentioned in Sub-section 6.2.2 in order to allow comparability with the other technologies.

Moreover, for the coal utilities and for one of the CCGT utilities that were installed before 2000, 2000, for the calculations of the LCOE the information referring to the year 2000 exposed in Chapter 3 have been considered.

6.2.1 Past Values of OLCOE and SLCOE

The OLCOE and the SLCOE values, calculated for the period between 2000 and 2014 by using the methodology developed in Chapter 4 and the information retrieved in Chapter 3, are illustrated in Figure 6.12. Here it is possible to verify that in more recent years the OLCOE of SHP, CHP and biomass centrals have not been suffering significant changes. Additionally, the values of large hydropower plants increased in some of the years in which bigger investments have been made.

In the case of wind onshore the OLCOE values decreased in the last years and stagnated in 2014 around 65 €/MWh.

The biggest variations of OLCOE that are seen in Figure 6.12 concern Solar PV, coals and NG centrals. The first one has been decreasing over the past years fundamentally because of the decrease in the investment costs, as for the latter, the great disparity of the values happens because their LCOE values depend on the energy produced, which in the case of NG utilities has reached minimum values in the last years.

Moreover it is possible to verify that the system LCOE continued to increase between 2000 and 2010, and after that its values remained around 85 €/MWh.

It is interesting to observe that the SLCOE follows the same trend as large hydropower OLCOE (Figure 6.12), which can be explained by the great weight that this type of centrals play in the electric system of Portugal.

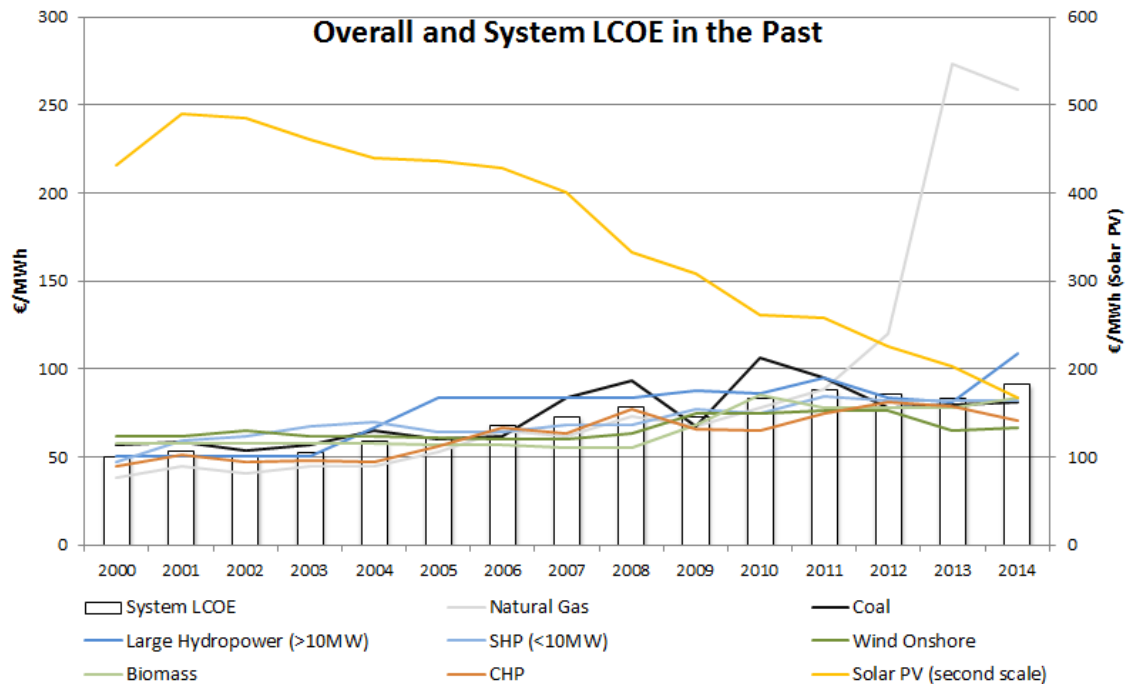


Figure 6.12: Overall LCOE of each Electricity Generation Technology and System LCOE over the Past Years.

6.2.2 LCOE and OLCOE Projections

Once having collected the data concerning the costs of each type of electricity generation technology (investments, O&M, fuel and CO_2 costs) and their typical capacity factors, which have been exposed in Chapter 3, it was possible to calculate and project their LCOE values until 2030. Figure 6.13 shows this projection, which includes the LCOEs of Coal and NG utilities calculated with medium capacity factors (50%) as a means of comparison. These values are equal for all the scenarios, since they do not depend on the energy produced.

When observing Figure 6.13 it is possible to verify that certain electricity generation technologies as wind onshore, geothermal, CHP or biomass follow a stable trend until 2030, being the wind onshore technology the one that presents the lowest values. Concerning the remaining RES technologies, it is possible to ascertain that the LCOE values for solar PV centrals follow a quite accentuated decreasing trend. The latter can be explained due to the strong decrease of investment costs, achieving 60€/MWh in 2030. Furthermore, SHP values vary significantly until 2025, yet subsequently they stabilise reaching 62€/MWh in 2030, whereas the values of large hydropower

plants demonstrate a strong fluctuation due to the fact that the values which have been used within this research, have been expected investment costs for the years in which capacity installation has been foreseen (see Chapter 5). Regarding conventional thermal utilities one may observe that due to the current coal and natural gas price trend as well as the CO_2 costs trend, the LCOE values of this type of centrals tend to increase, being coal utilities the ones with the higher LCOE values among all technologies that have been reviewed here.

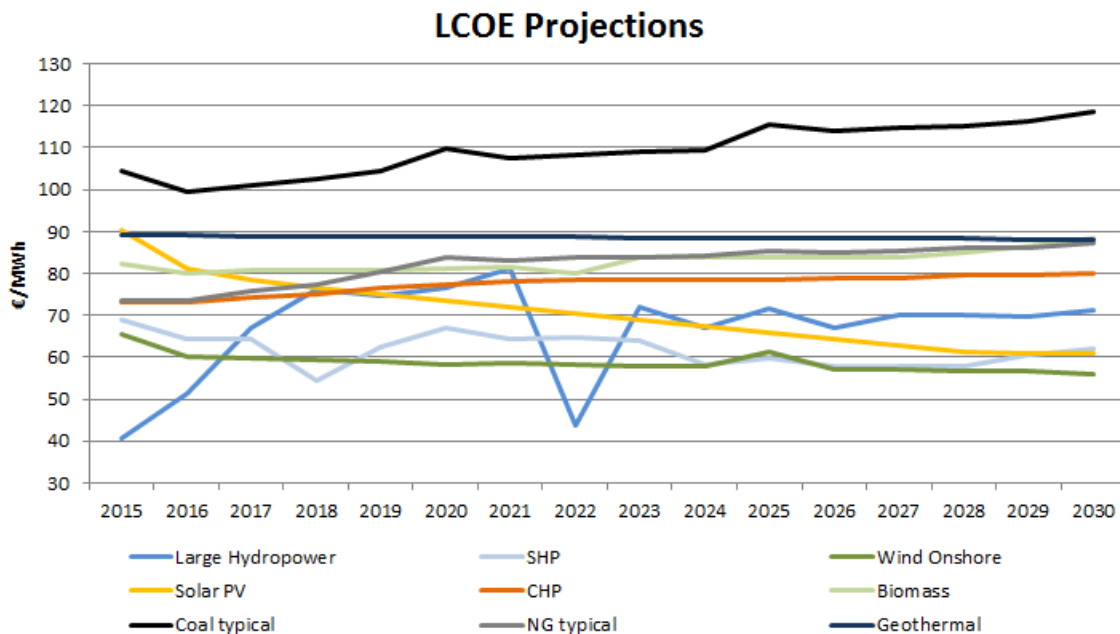


Figure 6.13: LCOE Projections of all Electricity Generation Technologies for the Year of Installation.

Afterwards the LCOE values of the different scenarios that have been created earlier for the coal centrals and GN (see Figures 6.14 and 6.15) have been calculated. In all scenarios case A presented smaller LCOE values for coal centrals whereas in case B NG centrals presented relatively better results. This may be explained by the existing difference between energy produced by each technology in both cases (see Figures 6.6 to 6.11). It is actually interesting to see that in any of the situations, both the LCOE of coal centrals, as well as the LCOE of NG centrals present values that are superior to the majority of RES centrals.

It should also be added at this point that the LCOE values calculated for each technology are to be found in the Appendix A.3 and have been separated by CAPEX and OPEX costs in order to highlight the weight of each one in the total LCOE value.

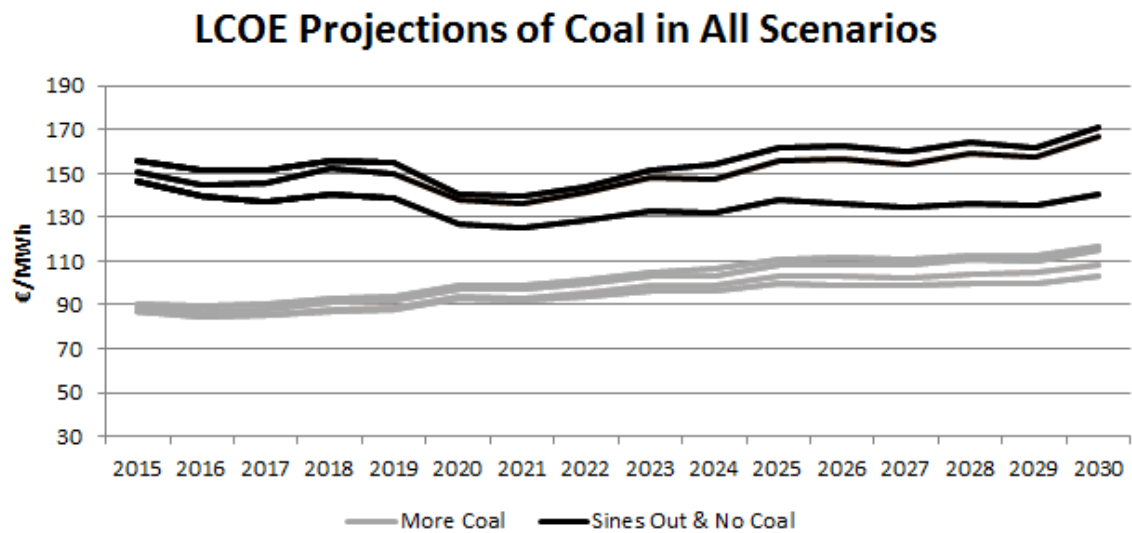


Figure 6.14: LCOE Projections of Coal Utilities in all the Created Scenarios.

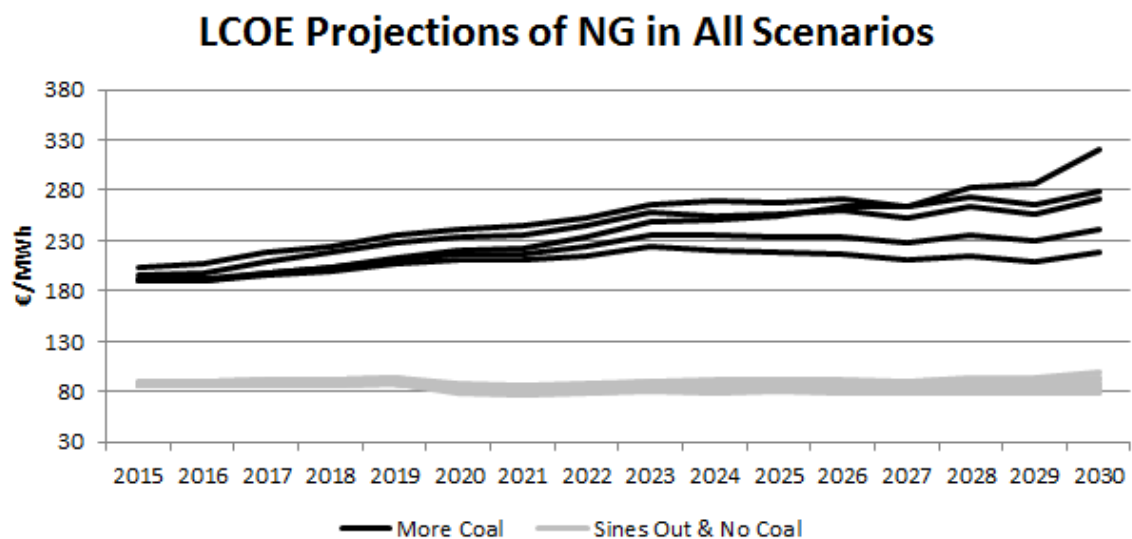


Figure 6.15: LCOE Projections of NG Utilities in all the Created Scenarios.

Once disposing of the LCOE projections until 2030, as well as of the past OLCOE values it is possible to project the OLCOE of a variety of technologies. Similarly as in the case of LCOE, these values are equal for all technologies in any scenario, except for coal and NG which depend on the energy produced in each scenario.

The results of these projections are located in figures 6.16 to 6.18. It is possible to observe in the first figure that only the OLCOE of solar PV technology decreases until achieving 110 €/MWh in 2030. In case of the other technologies, however, the OLCOE remains stable during the years, being wind energy once again the one that presents the lowest values.

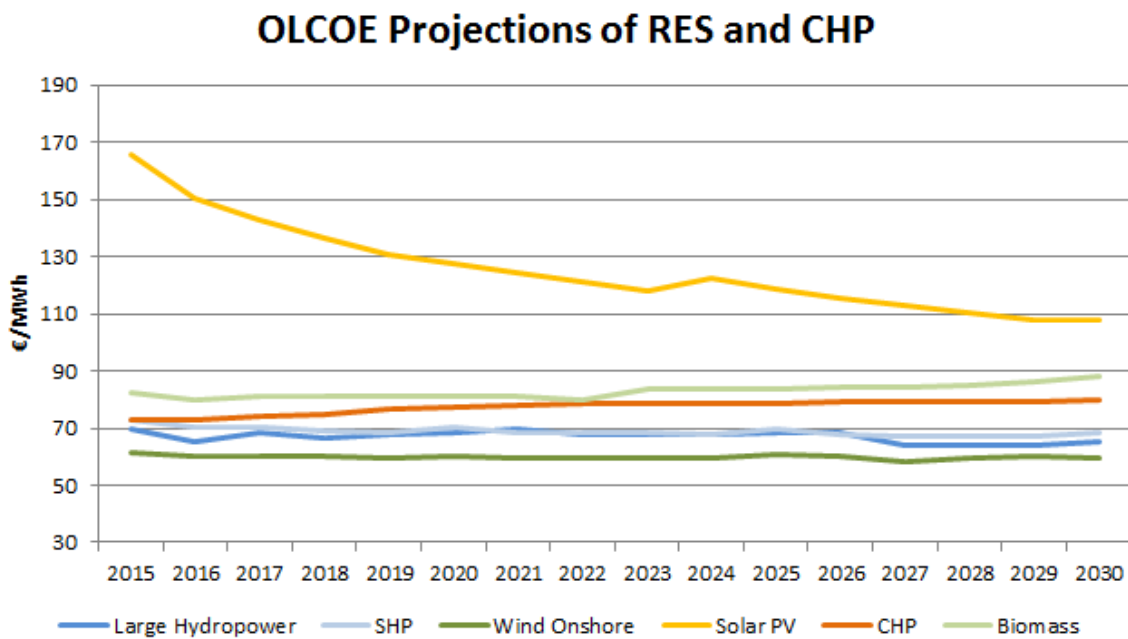


Figure 6.16: Overall LCOE Projections of RES and CHP.

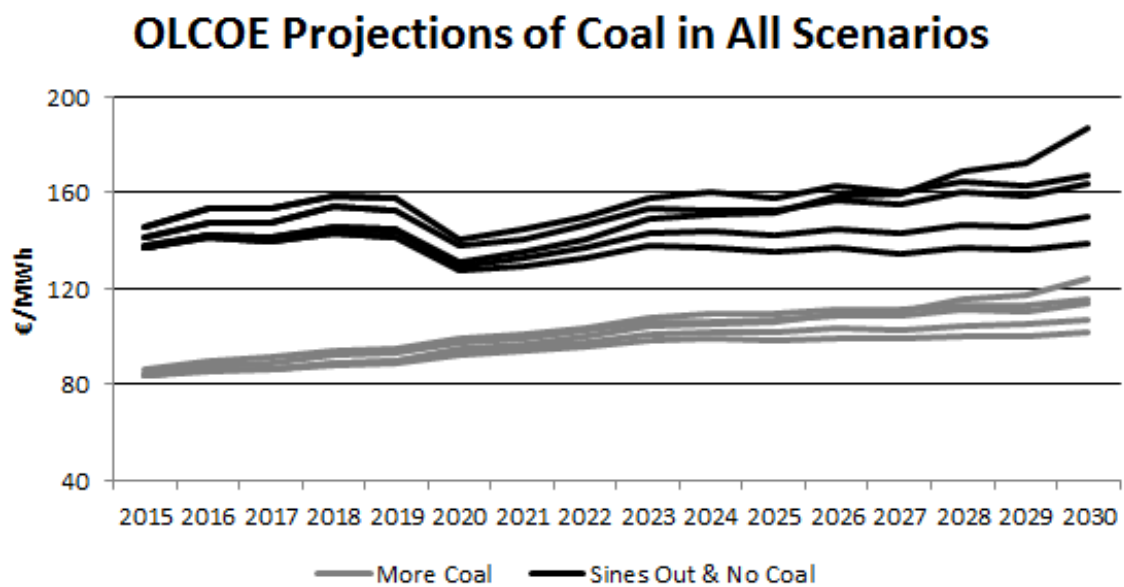


Figure 6.17: Overall LCOE Projections of Coal Utilities in all the Created Scenarios.

When analysing Figures 6.17 and 6.18 it is once again possible to recognise that coal centrals have the lowest values in case A, whereas NG centrals have the lowest values in case B for the same reasons that have been mentioned earlier. In addition, the existence of a certain kind of disparity regarding higher OLCOE values of various scenarios may be observed which will continue to have effects on SLCOE and will be analysed in the next sub-section.

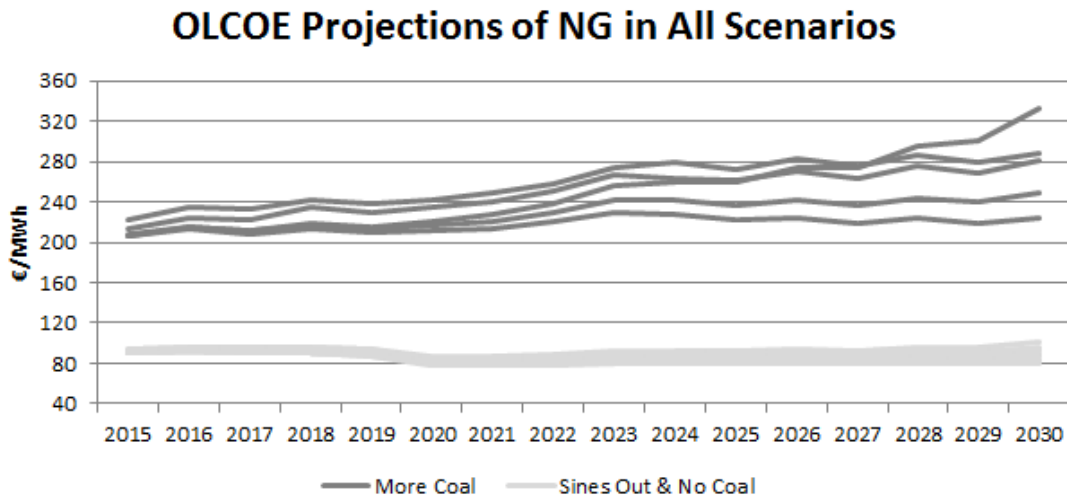


Figure 6.18: Overall LCOE Projections of NG Utilities in all the Created Scenarios.

6.2.3 SLCOE Projections

Having explained and demonstrated the OLCOE projections in the previous section, as well as the energy produced by each electricity production technology in the diverse scenarios, it is now possible to present the SLCOE results for each scenario. Contrarily to what happened to the LCOE and OLCOE values in RES and CHP centrals, these values depend on the energy produced and are therefore different in each scenario that has been created. First of all, Figure 6.19 presents the SLCOE projection within the current electric system panorama [106]. For electricity production, carbon prices are lower than natural gas prices and NG centrals work with very low capacity factors.

In this scenario the SLCOE should/will already decrease this year, being the peak in 2014 owed to the strong investment in the hydroelectric central “Baixo Sabor” (see Appendix A.1), and stabilise during the next years around 80€/MWh.

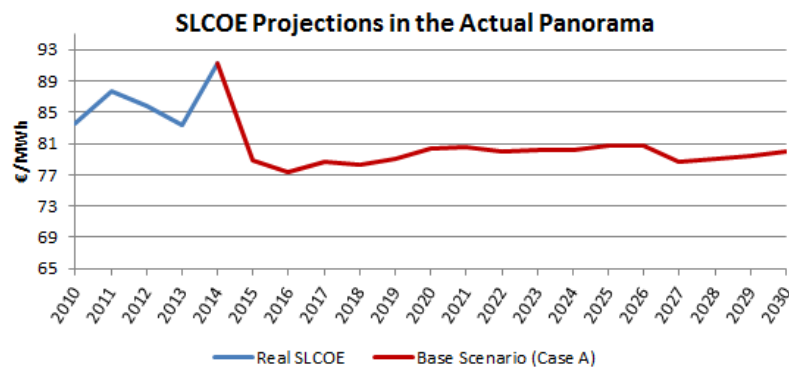


Figure 6.19: System LCOE Projections in the Actual Panorama.

Hereupon the results of SLCOE in all developed scenarios exposed in Chapter 5 are presented

(see Figures 6.20 to 6.23). In these figures it is possible to perceive that in any scenario the SLCOE projections assume lower values in case B and C. It is true that in these cases the NG price trend is inverse that of the base scenario, yet even if this tendency will retain, the results would be similar, because the LCOE of coal centrals is higher, as is to be seen in Figure 6.13.

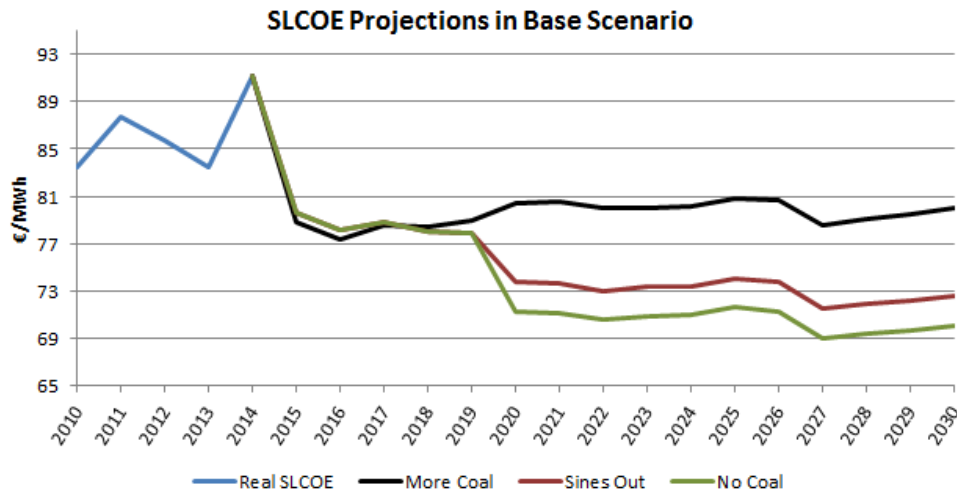


Figure 6.20: System LCOE Projections in the Base Scenario.

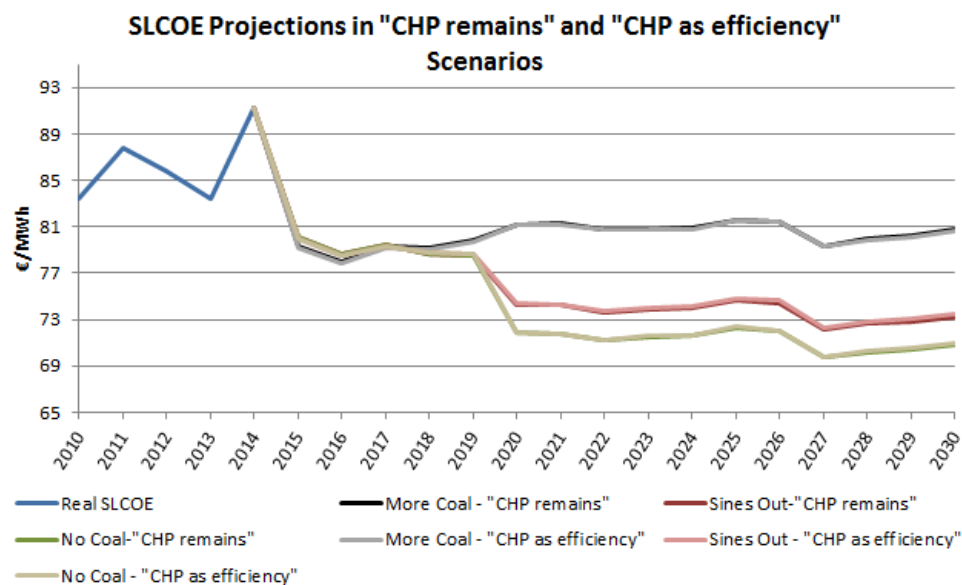


Figure 6.21: System LCOE Projections in the "CHP remains" and in the "CHP as efficiency" Scenarios.

In addition, it gets highlighted that in both CHP and Solar PV scenarios (see figures 6.21 and 6.22) the situations that may differ between installed capacity as centralised power plants or as own consumption, present almost equal results.

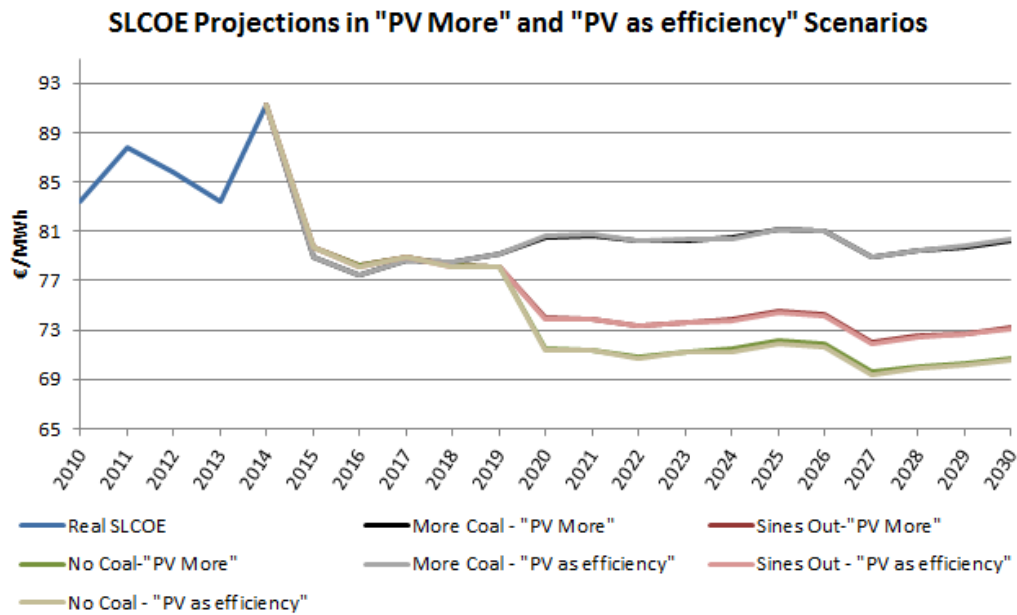


Figure 6.22: System LCOE Projections in the "PV More" and in the "PV as efficiency" Scenarios.

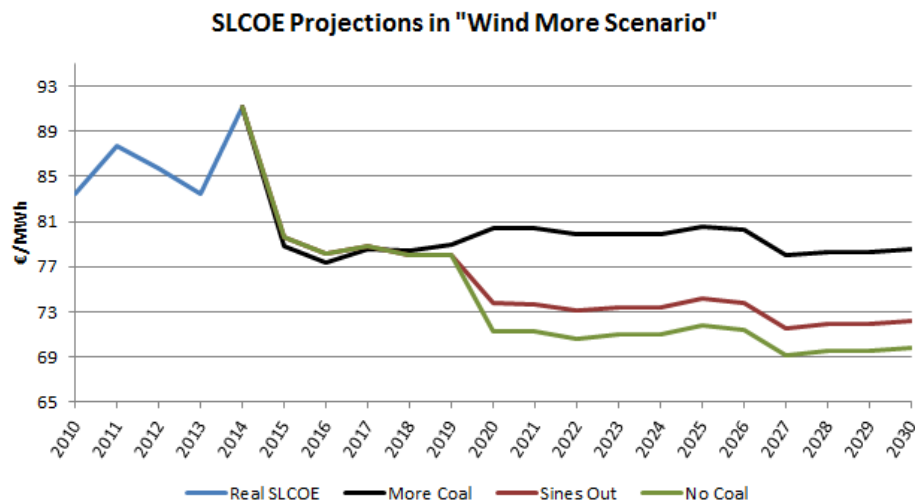


Figure 6.23: System LCOE Projections in the "Wind More" Scenario.

When comparing Figure 6.23 to 6.20 it is possible to deduce that the SLCOE values in the "Wind More" scenario are not worse than in the base scenario, which has not only to do with the fact that wind energy has a high installed capacity in Portugal and therefore a strong weight in its energy mix, but also with the fact that the LCOE of this technology is the lowest one within all technologies considered in this research.

In order to conclude this section, a comparison between the results with the lowest SLCOE values in each scenario gets presented (see Figure 6.24. Actually the values are quite similar, yet one may notice that CHP and Solar PV present worse results than the base scenario. In the first

case this is due to the fact that both the OLCOE as well as the LCOE of CHP are high (see Figures 6.13 and 6.16), while in the second case solar PV penetration is still low and its OLCOE on a level that will not achieve the foreseen LCOE for that technology until 2030. Even more, when comparing these values with those presented in Figure 6.19 it may be noticed that they present lower values, being the difference in 2030 of 10€/MWh.

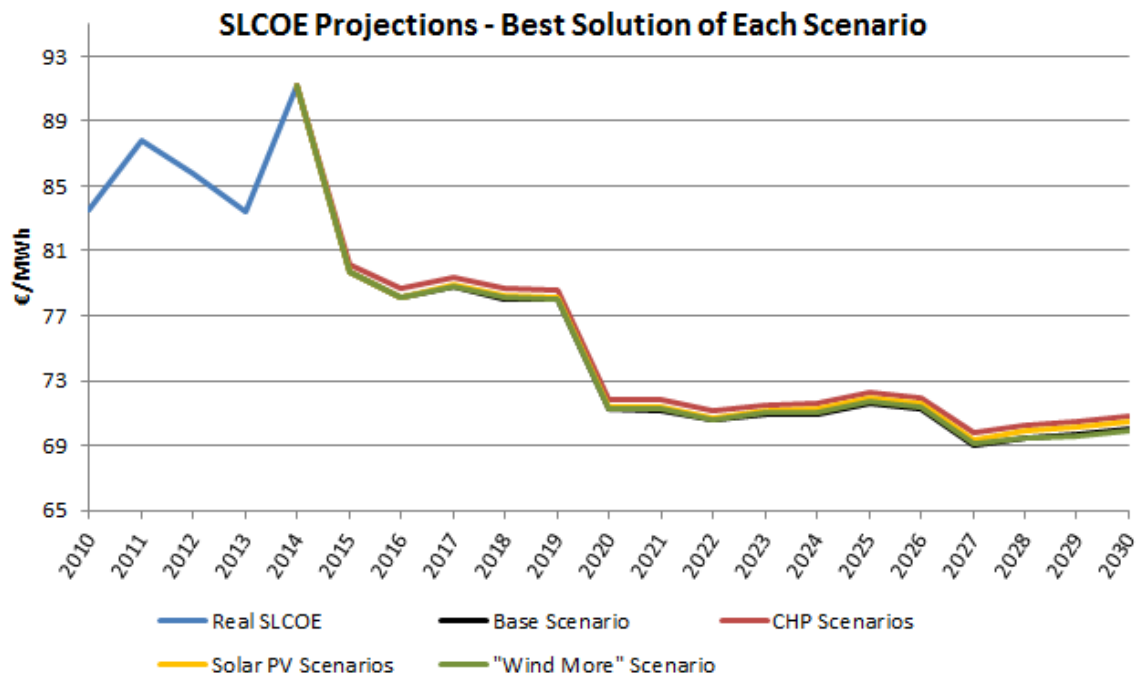


Figure 6.24: System LCOE Projections in the Best Case of each Scenario.

6.3 Comparison of the Results with the Additional Costs of the System

As mentioned in the beginning of this chapter, the final aim of this research is to use the OLCOEs and system LCOE results in order to be able to understand and compare them with the additional costs paid by the system to the electricity producing centrals. In chapter 3 the historical values of the additional costs from 2009 to 2014 have been exposed, including PRE, CAE, CMEC and “power capacity payment” supports. Additionally the market prices have been presented that originate the total cost of the system in each type of central when being added to the additional costs.

For this research it is necessary to dispose of a projection of the above-mentioned prices until 2030. It is foreseen that due to the increase of the interconnection of the European markets, as well as the creation of a single energy market the electricity costs would decrease to the European average which is situated around 40€/MWh.

Given these facts, the following projection for the electricity spot market prices in Portugal has been made:

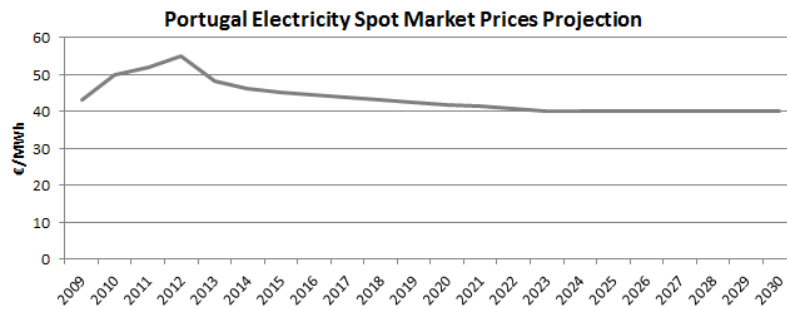


Figure 6.25: Projection of the Portuguese Electricity Spot Market Prices until 2030.

Figures 6.26 to 6.34 have been compiled by having in mind the above-mentioned, as well as the OLCOE and SLCOE values explained in the previous section.

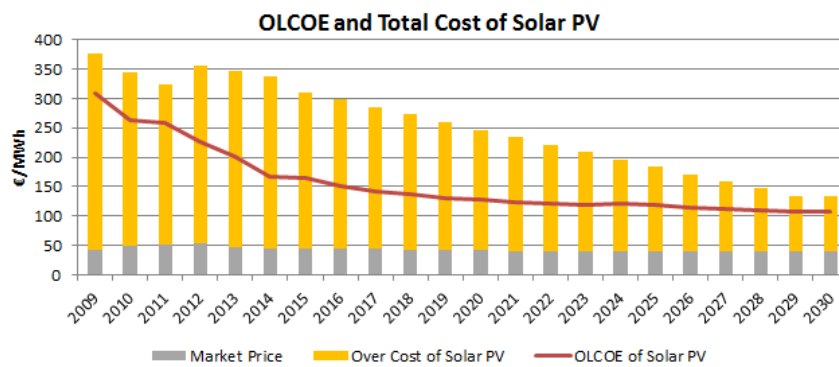


Figure 6.26: Overall LCOE and Total Additional Cost of Solar PV.

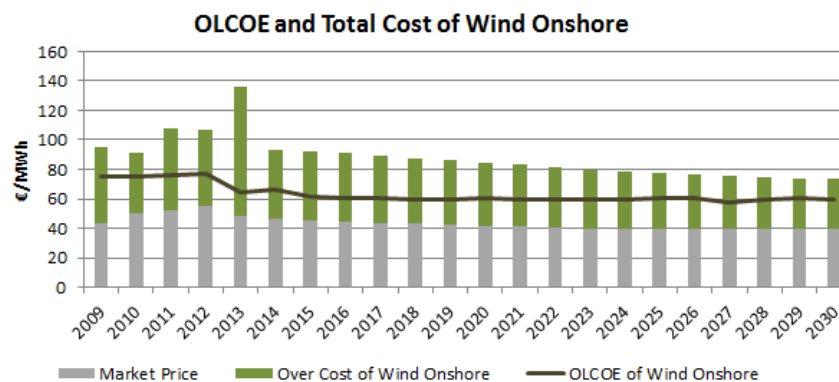


Figure 6.27: Overall LCOE and Total Additional Cost of Wind Onshore.

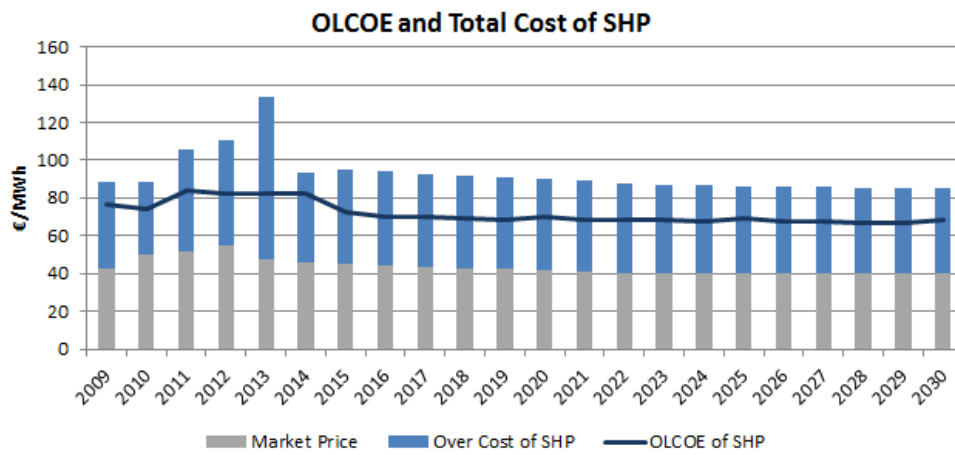


Figure 6.28: Overall LCOE and Total Additional Cost of SHP.

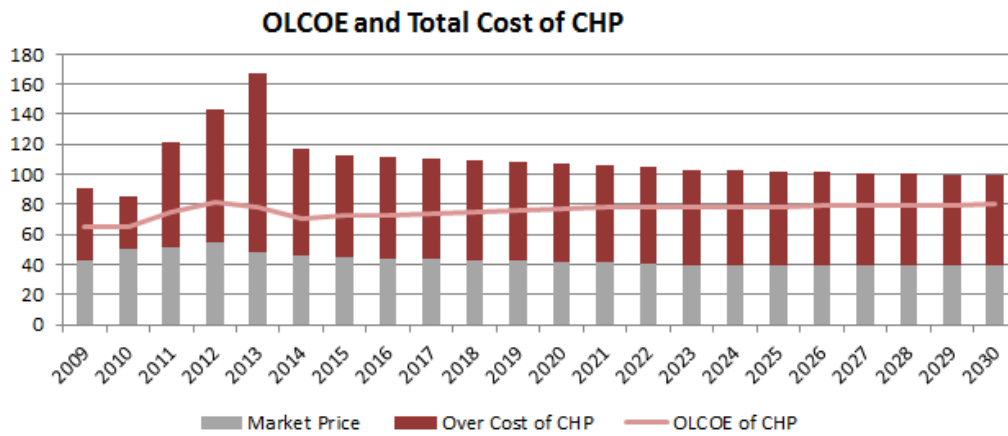


Figure 6.29: Overall LCOE and Total Additional Cost of CHP.

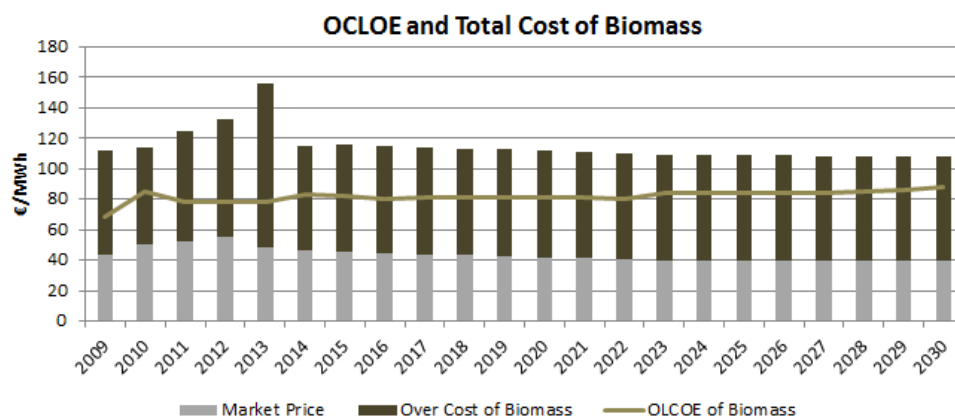


Figure 6.30: Overall LCOE and Total Additional Cost of Biomass.

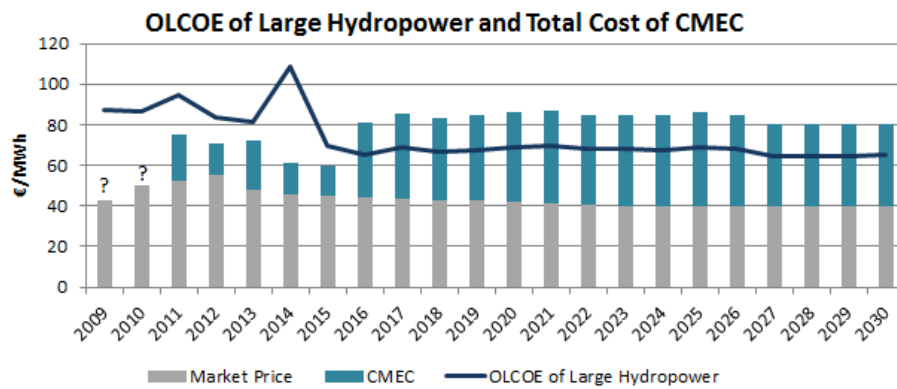


Figure 6.31: Overall LCOE of Large Hydropower Plants and Total Additional Cost with CMEC.

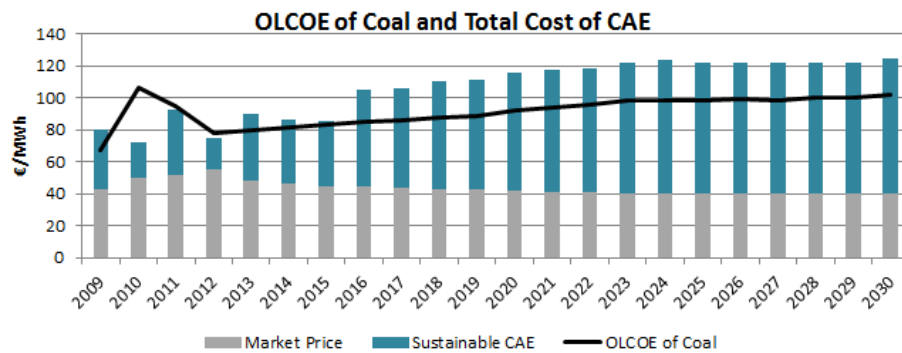


Figure 6.32: Overall LCOE of Coal Utilities and Total Additional Cost with CAE.

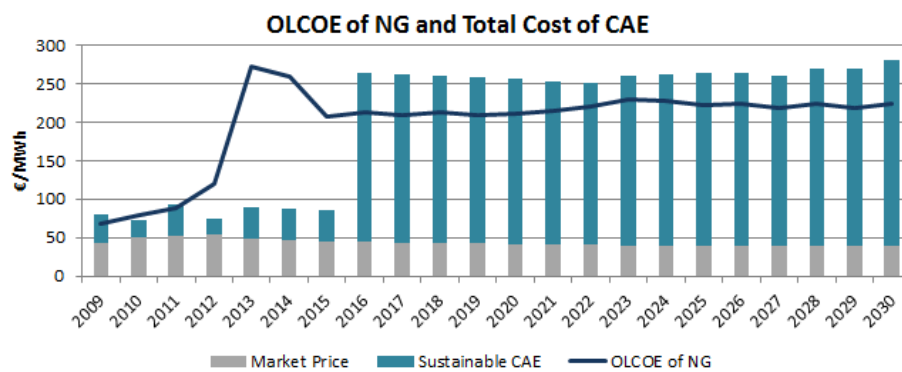


Figure 6.33: Overall LCOE of NG Utilities and Total Additional Cost with CAE.

In these figures it is possible to verify that until 2015 the values of the total cost of each PRE technology are higher than the calculated OLCOE. In fact, this was expected otherwise the investment in these technologies would not be viable. However, in case of the remaining technologies this does not happen. As already explained in Chapter 3, there are certain centrals (excluding PREs) that dispose of CAE or CMEC contracts such as coal or NG centrals in the case of CAE

contracts and NG or Large Hydropower centrals with CMEC contracts. The comparison between these additional costs and the OLCOE values of the respective centrals permits a better understanding of the fact that they get remunerated below their total costs.

Besides, once the additional cost “power capacity payment” has not entered during the past years it has also not been included in this research.

Regarding each PRE technology value, one notices that in some cases the additional cost which has been paid to these centrals has not accompanied the decrease of OLCOE, above all in the case of Solar PV (see Figure 6.26). The increase of the additional costs verified in the last years can be explained by the existence of adjustments, which derived from accumulated costs of the previous years. Yet, it was expected that the additional cost followed the OLCOE.

In order to be able to make the projections of the additional costs until 2030 it was assumed that they would follow a decreasing trend in PRE technologies, yet never falling to values that would not permit a margin between the OLCOE and the total cost below 20%. As for the remaining electricity generation technologies, to reach this margin and maintain it in future years the additional costs need to increase. The projections for the additional costs until 2030 are represented in the previous figures.

These projections result in a total additional cost for the system, which can be calculated with the previously mentioned additional costs and the energy produced by each electricity generation technology in the base scenario (Case A). The projections of the total additional cost of the electric system are presented in Figure 6.34.

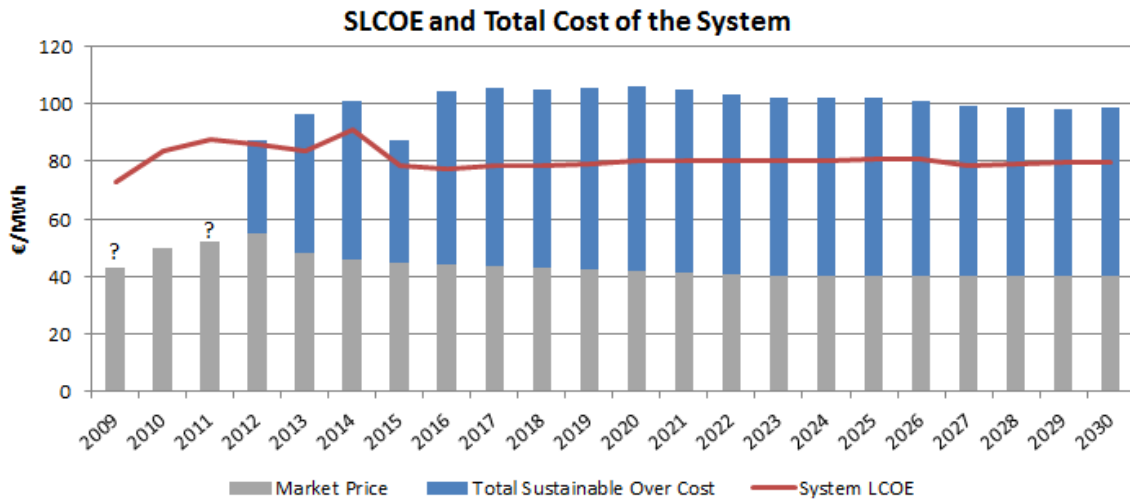


Figure 6.34: System LCOE (Base Scenario, Case A) and Total Additional Cost of the Electric System.

Chapter 7

Conclusions

The following section is going to present the main conclusions of the study that has been done in this dissertation. Analysis over the limitations of the work are then presented as well as recommendations for future works.

7.1 Conclusions of this Research

The main goal of this dissertation was to calculate and project electricity generation costs in different scenarios in Portugal. In order to accomplish this goal, a methodology based on the calculation of the levelized cost of electricity was conducted.

The review of the state-of-the-art showed the importance of the topic, yet it also demonstrated the complexity of this type of studies, since several facts and a great collection of information are required.

When observing the results presented in Chapter 6, the projections made for the LCOEs of different types of electricity generation technologies show that the continuous decrease of these values referred to some RES power plants, as well as the increasing costs of the fossil fuel power plants allow the competitiveness of RES technologies, such as Wind Onshore and more recently also Solar PV.

In the case of Portugal the results of the different scenarios developed showed that in this country large hydropower plants play an important role for the system costs. Moreover, it was possible to observe that the actual panorama, where coal utilities have a higher share in the production mix than natural gas utilities, do not lead to better values of system costs.

Another important conclusion on the results obtained is the equality, in terms of the system costs, of having new installed capacity as centralised centrals or as own-consumption. Moreover RES do not amplify system costs, in fact since their LCOEs are decreasing (for example the case of Solar PV) and they are reaching wholesale grid-parity, the system cost can be decreased.

Regarding the additional costs in Portugal, it is possible to conclude that the actual supportive mechanisms are not the most suitable ones. In today's panorama, total system costs are higher

than they could have been. Other solutions are required, like a mechanism that is linked to the capacity factor, but does not increase too significantly if capacity factors are very low.

Having said this, it is clear that incentives need to continue on the several technologies, including conventional thermal, in order to appeal for investments that are crucial if Portugal and other countries want to reach desirable improvements regarding CO_2 emissions and independence from external markets.

7.2 Analysis of Limitations and Recommendations for Future Research

Even having accomplished the goals of this dissertation, there are some limitations that need to be noticed. The methodology followed in this dissertation is a good and practical way to achieve the goals that have previously been set, however it does not take into consideration external aspects, like transmission costs, social effects or geopolitical risks.

Furthermore, the interest rate assumed in the LCOE equation usually differs from the electricity generation technology considered. A sensibility analysis could have been presented in order to study the effects of different values of the interest rate.

Regarding future research, it would be interesting to study with more detail the effects of increasing the net capacity among the border between Spain and France, as well as the effect of the creation of a single European electricity market on electricity generation costs.

Furthermore, the study of other supportive mechanisms and their effect on system costs would also be an interesting analysis.

This dissertation will hopefully stimulate other scholars to continue research in this field and by adding other factors to it and thus increasing the credibility of its results.

Appendix A

Appendix

A.1 Characteristics of Large Hydropower and SHP Plants

Table A.1: Characteristics of past and future Hydropower plants in Portugal.

Name	Capacity (MW)	Reversible Turbines	State	Open Year	Annual Expected Productivity (GWh)	Investment Cost
Vila Cova	23,4	No	Working	2001	64	?
Alqueva	240	Yes	Working	2004	?	?
Frades	191,4	Yes	Working	2005	220	?
Bemposta II	191	No	Working	2011	134	132.000.000,00 €
Picote II	246	No	Working	2011	244	140.000.000,00 €
Alqueva II	260	Yes	Working	2012	470	160.000.000,00 €
Baixo Sabor	172	Yes	Working	2014	230	625.300.000,00 €
Ribeiradio Ermida	77	No	Working	2015	139	213.300.000,00 €
Venda Nova III	746	Yes	Construction	2015	1441	322.500.000,00 €
Salamonde II	207	Yes	Construction	2015	386	205.000.000,00 €
Foz Tua	252	Yes	Construction	2016	667	370.000.000,00 €
Fridão	238	No	Project	2021	295	304.000.000,00 €
Bogueira	30	No	Project	2021	450	360.000.000,00 €
Girabolhos	355	Yes	Project	2021		
Paradela II	318	Yes	Project	2022	616	275.000.000,00 €
Gouvães	1100	Yes (880 MW)	Project	2023	2000	1.600.000.000,00 €
AltoTâmega (Vidago)			Project			
Daivões			Project			

Table A.2: Installed Capacities of SH in Portugal since 2000.

Name	Open Year	Capacity (MW)	Name	Open Year	Capacity (MW)
Manteigas	2000	6,5	Rego Naval	2007	0,9
Alva	2001	1,5	Canedo	2008	10
Moinhos	2001	0,9	Fronhas	2008	0,8
Penacova	2001	9,6	Granja do Tedo	2008	2,2
Ucanha	2001	5,7	Teixo	2008	7
Águas Frias	2002	2,4	Vale de Madeira	2008	1,2
Caneiro	2002	1,6	Açude de Viseu	2009	0,5
Catapereiro	2002	7,2	Negrelos	2009	0,7
Ponte Vouguinha	2002	0,3	Pisão	2009	0,6
Búgio	2003	0,5	Tecidos do Ferro	2009	0,8
Lagoa Comprida	2003	0,6	Trutas	2009	2,2
Amieiro/Galego	2004	1,2	Vales	2009	3,2
Assobio	2004	1	Alvito	2010	3,4
Fábrica Têxtil de Vizela	2004	1,2	Meimoa	2010	5,7
Pinhel	2004	6,8	Odivelas	2010	2,5
Vale de Amoreira	2004	0,4	Carvoeiro	2010	0,1
Barroca	2005	2	Roxo	2010	1,7
Armamar	2006	0,9	Serpa	2010	1,7
Bouçoais-Sonim	2006	9,9	Candemil	2011	2
Pedrógão	2006	10,4	Câmara de Manteigas	2011	0,1
Pereira	2006	5,2	Moinhos de Moiratão	2011	0,4
Rebordelo	2006	10	Agilde	2012	2
Ponte Europa	2007	1	Lourido	2012	2,8

A.2 Energy Produced and Energy Mix

Table A.3: Energy Produced by each Electricity Generation Technology in Portugal from 2000 to 2014 in GWh.

Year	Coal	NG	Large Hydropower	SHP	Wind	Solar	Biopower	CHP
2000	14326	7716	11040	675	168	1	1554	0
2001	14326	7716	13605	770	256	2	1600	0
2002	14326	7716	7551	706	362	2	1732	2621
2003	13641	5905	15163	891	496	3	1663	344
2004	13952	9813	9570	577	816	3	1797	1041
2005	14291	11491	4737	381	1773	3	1947	0
2006	14070	9907	10633	834	2926	5	1997	0
2007	11662	10494	9927	522	4037	24	2158	792
2008	10423	12573	6781	517	5757	41	2133	0
2009	11942	11463	8108	901	7577	160	2376	0
2010	6553	10700	15459	1088	9182	214	2902	4787
2011	9128	10316	11294	820	9162	280	3219	5055
2012	12136	5641	6093	567	10260	393	3196	5141
2013	10953	1502	13701	1050	12015	479	3337	5609
2014	11066	1405	15242	1214	12099	639	3246	5062

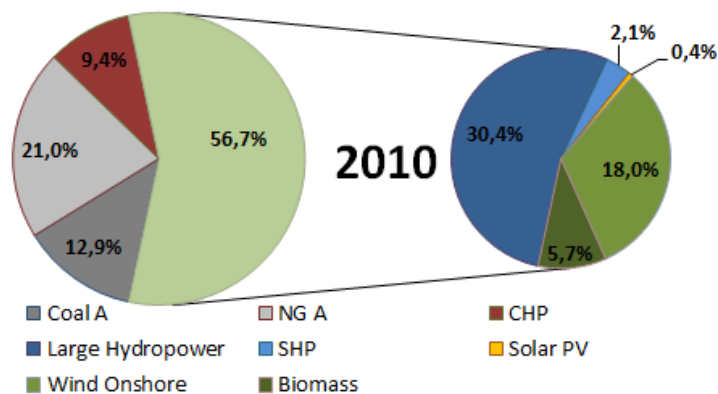


Figure A.1: Electricity Production Mix in Portugal in 2010.

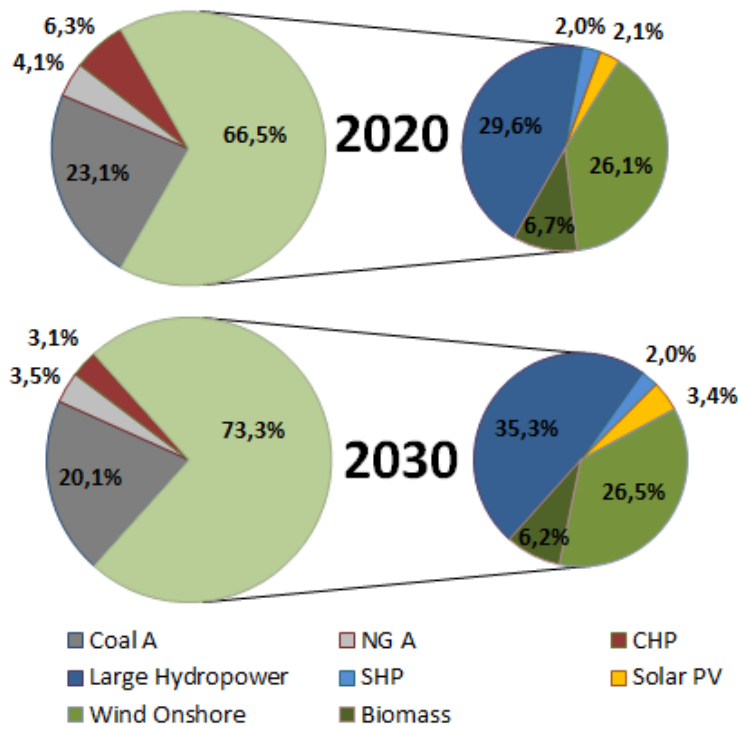


Figure A.2: Electricity Production Mix in Portugal in the Base Scenario (Case A).

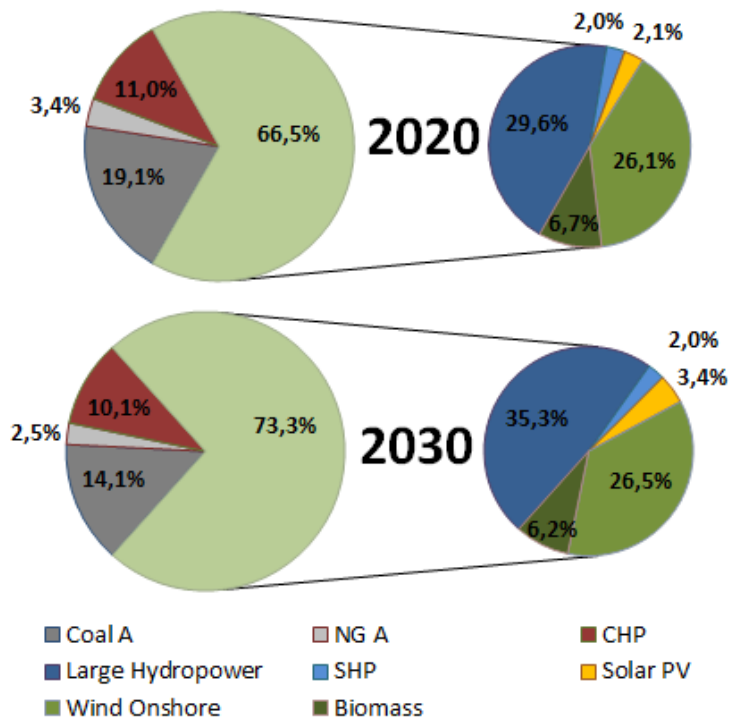


Figure A.3: Electricity Production Mix in Portugal in the "CHP remains" Scenario (Case A).

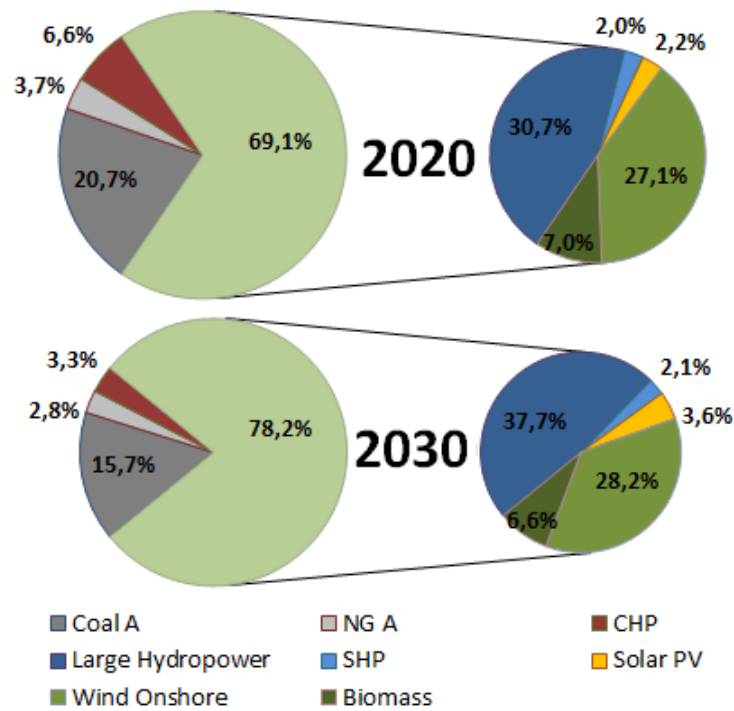


Figure A.4: Electricity Production Mix in Portugal in the "CHP as efficiency" Scenario (Case A).

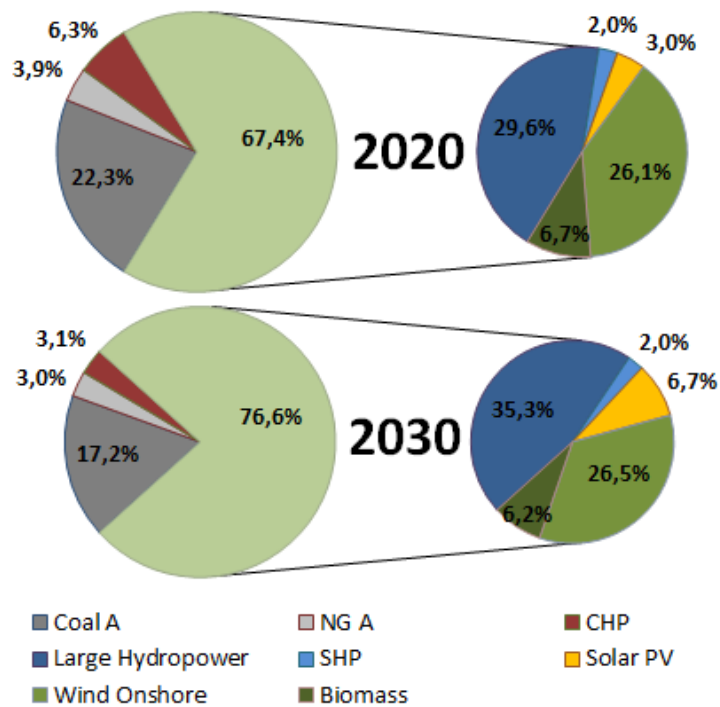


Figure A.5: Electricity Production Mix in Portugal in the "PV More" Scenario (Case A).

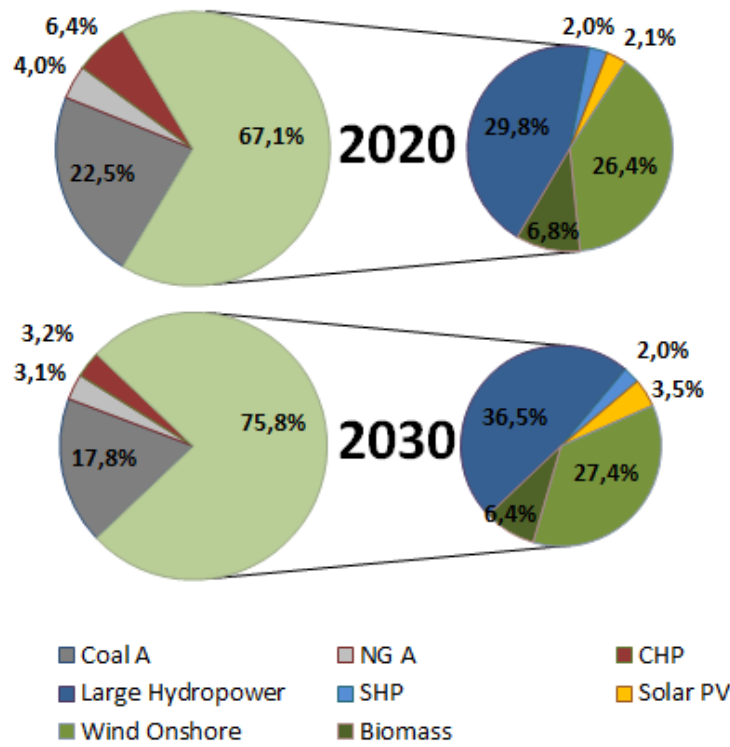


Figure A.6: Electricity Production Mix in Portugal in the "PV as efficiency" Scenario (Case A).

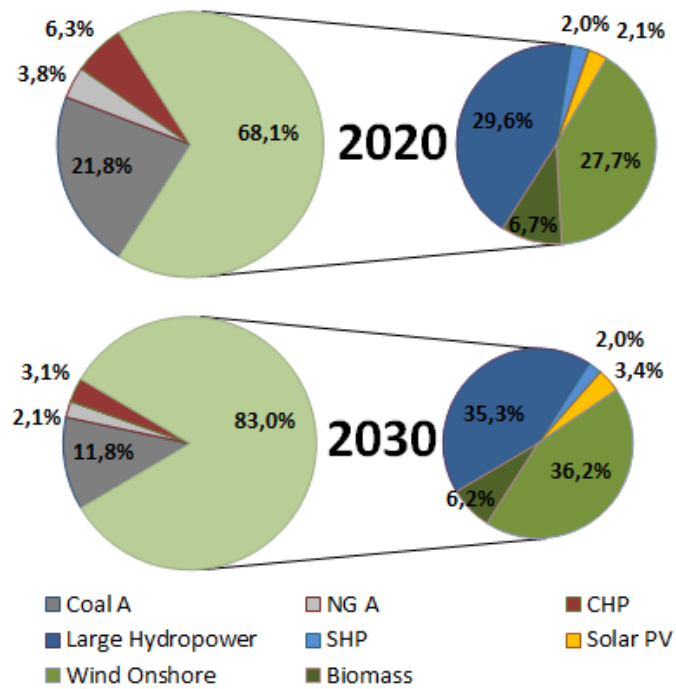


Figure A.7: Electricity Production Mix in Portugal in the "Wind More" Scenario (Case A).

A.3 LCOE Components

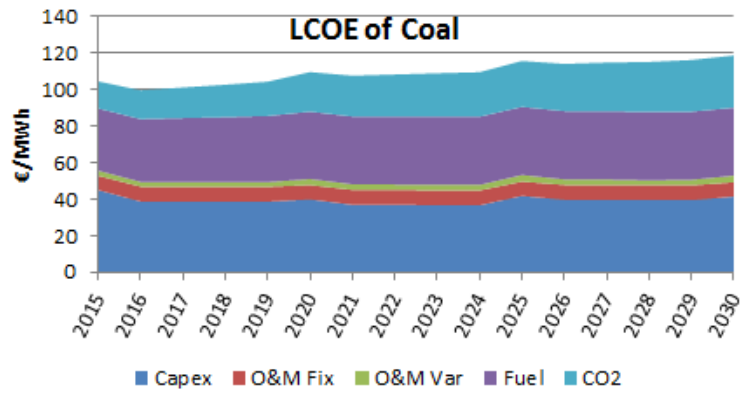


Figure A.8: LCOE of Coal Utilities Separated by each Component.

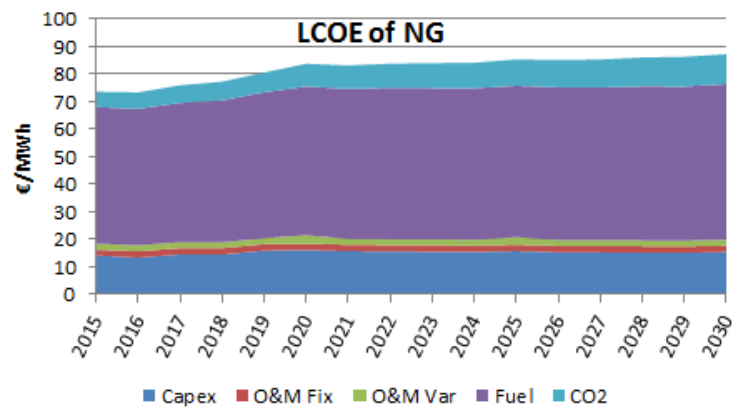


Figure A.9: LCOE of Natural Gas Utilities Separated by each Component.

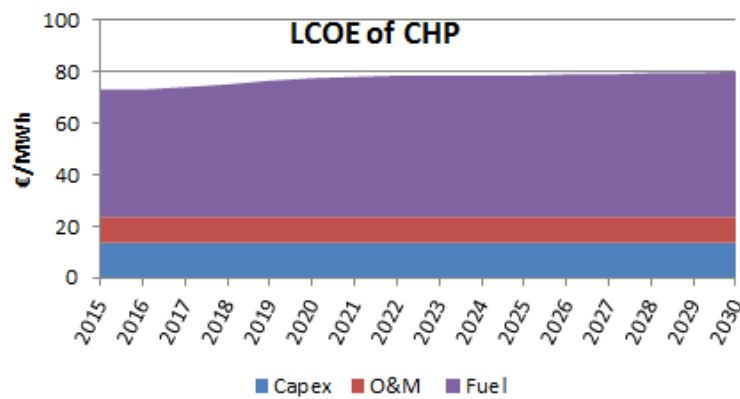


Figure A.10: LCOE of CHP Power Plants Separated by each Component.

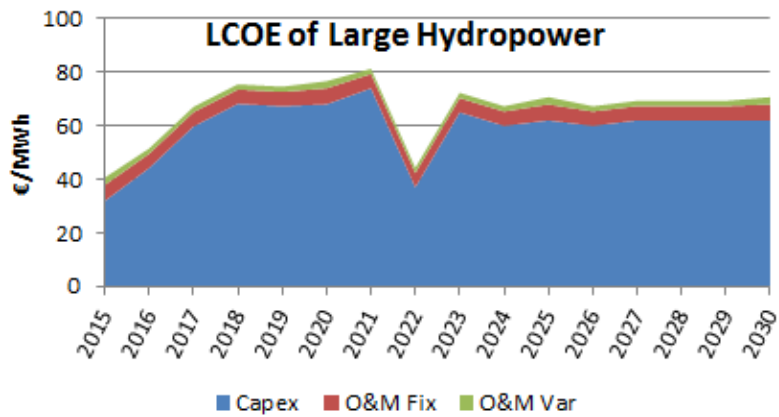


Figure A.11: LCOE of Large Hydropower Plants Utilities Separated by each Component.

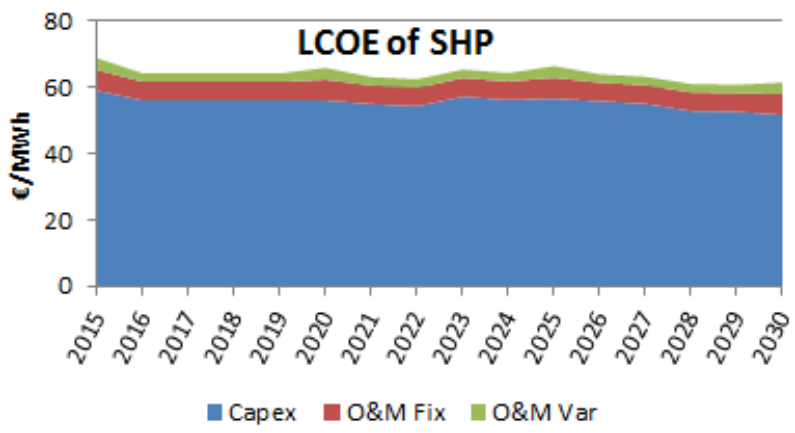


Figure A.12: LCOE of SHP Plants Separated by each Component.

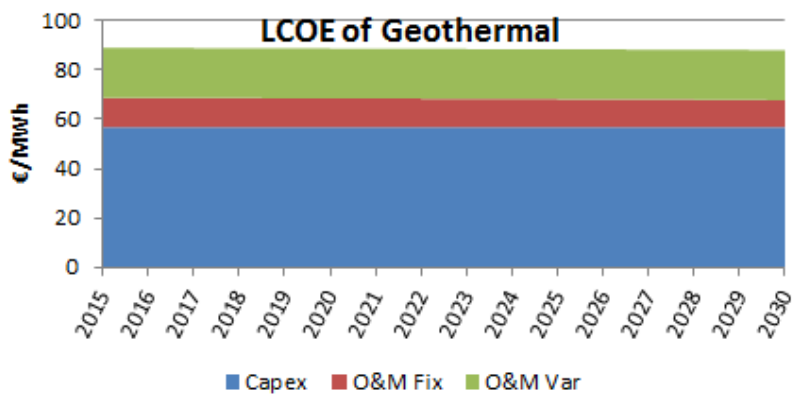


Figure A.13: LCOE of Geothermal Power Plants Separated by each Component.

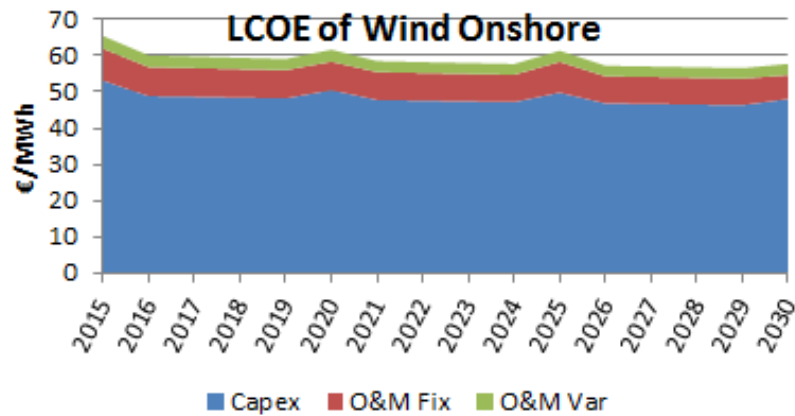


Figure A.14: LCOE of Wind Onshore Power Plants Separated by each Component.

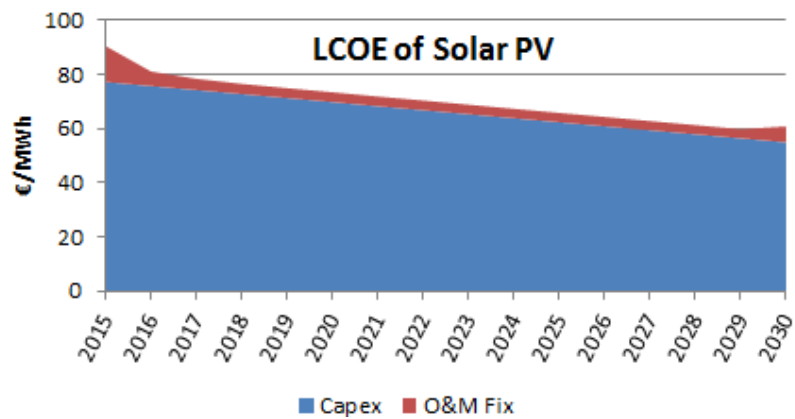


Figure A.15: LCOE of Solar PV Power Plants Separated by each Component.

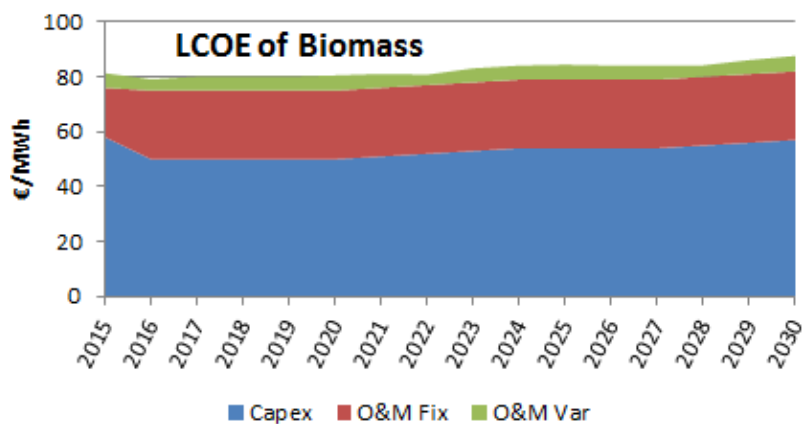


Figure A.16: LCOE of Biomass Power Plants Separated by each Component.

A.4 Capital and O&M Costs

Table A.4: Capital Costs in €/kW of the Different Electricity Generation Technologies Relevant for this Study. Source: [19–21].

Year	Wind	Solar PV	Geothermal	Large Hydro	SHP	Biopower	CCGT	Coal
2000	1072,64	5968,35	4779,49	901,56	1000,00	1600,61	721,46	2080,49
2001	1072,64	8147,35	4779,49	1500,00	1500,00	1600,61	721,46	2080,49
2002	1062,44	6679,34	4779,49	901,56	1500,00	1600,61	721,46	2080,49
2003	1072,64	6100,46	4779,49	901,56	3000,00	1600,61	721,46	2080,49
2004	1072,64	5600,15	4779,49	1372,78	1800,00	1600,61	721,46	2080,49
2005	1026,71	5840,88	4779,49	1372,78	1000,00	1331,63	637,67	2080,49
2006	1026,07	5476,57	4779,49	901,56	1666,67	1333,58	644,48	2082,05
2007	1025,43	5546,53	4779,49	901,56	3000,00	1335,53	579,81	2519,11
2008	1103,19	4237,59	4779,49	901,56	1400,00	1337,48	660,71	2085,17
2009	1517,90	3911,32	4089,58	1892,19	2333,33	2518,00	872,41	3667,40
2010	1570,93	3600,00	4201,03	2561,05	1333,33	2994,91	956,94	3119,78
2011	1265,80	3400,00	4201,03	630,10	2333,33	2482,08	709,06	3119,78
2012	1244,80	2500,00	4201,03	615,38	1271,86	2482,08	709,06	3119,78
2013	1244,80	1500,00	4201,03	1438,00	1438,00	2482,08	709,06	3119,78
2014	1206,40	1400,00	4467,45	3635,47	1438,00	2639,00	876,15	4524,00
2015	1278,20	1300,00	4779,49	719,22	1438,00	2165,21	696,67	2351,24
2016	1176,76	1275,00	4779,49	1468,25	1438,00	1787,65	656,31	2024,78
2017	1171,84	1250,00	4779,49	1277,31	1438,00	1890,59	715,67	2022,51
2018	1166,52	1225,00	4779,49	1467,27	1184,46	1885,81	712,13	2020,23
2019	1161,26	1200,00	4779,49	1441,49	1392,99	1881,14	784,89	2017,96
2020	1216,12	1175,00	4779,49	1452,36	1467,27	2079,57	794,03	2084,45
2021	1150,72	1150,00	4779,49	1065,81	1441,49	1870,78	772,57	1931,51
2022	1145,64	1125,00	4779,49	864,78	1452,36	1865,40	767,40	1926,47
2023	1140,80	1100,00	4779,49	1454,55	1431,88	1860,46	762,71	1921,44
2024	1136,27	1075,00	4779,49	1276,50	1284,05	1856,01	758,34	1916,40
2025	1199,58	1050,00	4779,49	1340,58	1279,84	2165,44	774,20	2182,73
2026	1128,25	1025,00	4779,49	1272,36	1276,50	1848,61	752,23	2074,69
2027	1124,36	1000,00	4779,49	1339,24	1274,65	1844,98	749,27	2070,77
2028	1120,31	975,00	4779,49	1336,51	1272,36	1841,10	745,86	2066,86
2029	1116,19	950,00	4779,49	1333,54	1339,24	1837,10	742,25	2062,94
2030	1157,05	925,00	4779,49	1333,52	1336,51	2042,76	758,49	2165,09

Table A.5: Fixed O&M Costs in €/kW of the Different Electricity Generation Technologies Relevant for this Study. Source: [19].

Year	Wind	Solar PV	Geothermal	Large Hydro	SHP	Biopower	CCGT	Coal
2000	7,48	35,22	136,39	8,69	11,29	65,69	9,36	22,63
2001	7,48	31,02	136,39	8,69	11,29	65,69	9,36	22,63
2002	14,01	28,92	136,39	8,69	11,29	65,69	9,36	22,63
2003	7,48	28,92	136,39	8,69	11,29	65,69	9,36	22,63
2004	7,48	28,92	136,39	8,69	11,29	65,69	9,36	22,63
2005	7,54	28,92	136,39	8,69	11,29	61,74	8,80	22,63
2006	7,54	27,28	136,39	8,69	11,29	61,74	8,80	22,63
2007	7,54	25,64	118,18	8,69	11,29	61,74	14,27	73,31
2008	12,76	32,74	117,77	8,69	11,29	61,74	8,80	22,63
2009	29,72	25,18	117,10	14,52	18,88	72,60	8,96	26,66
2010	23,14	24,60	160,34	10,95	14,23	74,80	11,75	38,50
2011	23,14	34,03	160,34	26,96	35,05	61,59	11,75	38,50
2012	23,14	22,62	160,34	26,96	35,05	61,59	11,75	38,50
2013	23,14	22,62	160,34	26,96	35,05	61,59	11,75	38,50
2014	28,28	14,51	160,34	26,96	35,05	71,63	4,41	50,99
2015	21,71	20,85	95,08	10,97	14,27	67,67	9,29	34,33
2016	19,53	8,48	94,61	9,81	12,76	68,19	10,16	35,60
2017	19,40	6,56	94,13	9,81	12,76	68,19	10,16	35,60
2018	19,27	5,91	93,65	9,81	12,76	68,19	10,16	35,60
2019	19,14	5,80	93,18	9,81	12,76	68,19	10,16	35,60
2020	19,18	5,71	92,70	10,97	14,27	69,64	10,01	34,35
2021	18,89	5,63	92,22	9,81	12,76	68,19	10,16	35,60
2022	18,77	5,58	91,74	9,81	12,76	68,19	10,16	35,60
2023	18,65	5,52	91,27	9,81	12,76	68,19	10,16	35,60
2024	18,53	5,47	90,78	9,81	12,76	68,19	10,16	35,60
2025	20,77	5,41	90,31	10,97	14,27	67,19	10,01	34,35
2026	18,30	5,39	89,83	9,81	12,76	68,19	10,16	35,60
2027	18,20	5,37	89,35	9,81	12,76	68,19	10,16	35,60
2028	18,09	5,34	88,88	9,81	12,76	68,19	10,16	35,60
2029	17,99	5,32	88,40	9,81	12,76	68,19	10,16	35,60
2030	16,18	9,27	86,74	10,97	14,27	68,72	10,01	34,35

Table A.6: Variable O&M Costs in €/kW of the Different Electricity Generation Technologies Relevant for this Study. Source: [19].

Year	Wind	Geothermal	Large Hydro	SHP	Biopower	CCGT	Coal
2000	4,55	20,22	2,19	2,84	4,11	3,74	4,03
2001	4,55	20,22	2,19	2,84	4,12	3,74	4,03
2002	4,55	20,22	2,19	2,84	4,13	3,74	4,03
2003	4,55	20,22	2,19	2,84	4,14	3,74	4,03
2004	4,55	20,22	2,19	2,84	4,16	3,74	4,03
2005	4,59	20,22	2,19	2,84	3,97	2,96	4,03
2006	4,40	20,22	2,19	2,84	3,98	2,96	4,03
2007	4,22	20,22	2,19	2,84	3,99	1,97	6,53
2008	4,43	20,22	2,19	2,84	4,00	2,96	4,03
2009	4,43	20,22	1,81	2,36	4,00	2,03	4,17
2010	5,16	20,22	2,90	3,77	6,51	3,02	5,44
2011	6,47	20,22	2,90	3,77	2,28	3,02	5,44
2012	6,47	20,22	2,90	3,77	2,28	3,02	5,44
2013	6,47	20,22	2,90	3,77	2,28	3,02	5,44
2014	6,47	20,22	2,90	3,77	5,34	2,07	5,84
2015	3,50	20,22	2,72	3,54	5,34	2,14	2,83
2016	3,27	20,22	1,97	2,56	4,13	2,16	2,61
2017	3,21	20,22	1,97	2,56	5,05	2,16	2,61
2018	3,15	20,22	1,97	2,56	5,06	2,16	2,61
2019	3,09	20,22	1,97	2,56	5,07	2,16	2,61
2020	3,35	20,22	2,72	3,54	5,53	3,09	3,29
2021	3,02	20,22	1,97	2,56	5,08	2,16	3,08
2022	3,00	20,22	1,97	2,56	3,82	2,16	3,07
2023	2,99	20,22	1,97	2,56	5,10	2,15	3,07
2024	2,97	20,22	1,97	2,56	5,10	2,15	3,06
2025	3,07	20,22	2,72	3,54	5,42	2,79	3,65
2026	2,93	20,22	1,97	2,56	5,11	2,15	3,04
2027	2,91	20,22	1,97	2,56	5,12	2,15	3,03
2028	2,90	20,22	1,97	2,56	4,20	2,15	2,67
2029	2,89	20,22	1,97	2,56	5,14	2,15	3,01
2030	3,09	20,22	2,72	3,54	5,65	2,23	3,61

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