Integrating Risks, Externalities and System Value of Energy Technologies in the Electricity Mix Planning Process: The Case for Brazil

A Study of the Cost Valuation of Electricity Generation Technologies as part of an Optimally Integrated Power System

by

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Abstract

This thesis analyses how electricity generation portfolios are affected by different risks, externalities and the system value of each generation technology, factors which are not considered in traditional energy valuation methods. The overarching goal of this paper is to inform policymakers about the energy expansion objectives that should be set in order to build towards a power system that maximizes social welfare. To that end, this thesis presents a risks and externalities accounting cost valuation method for power generation technologies, followed by a discussion of the system features that can further affect the value of each technology within a power system.

The methodology put forth in this paper is then applied to analyse the Brazilian power sector and define a possible energy planning scenario for the expansion of the country's electricity mix. This case study complements the theoretical analysis of this paper, and confirms a key finding of the research, which is that the internalization of environmental costs, market risks and technology risks, not considered in commonly used valuation methods, is merely but the first step in order to identify the socially optimal electricity mix for a given nation. This study uncovers the importance of understanding and utilizing the complementarities between different technologies constituting a power system in order to maximize the system value of each technology and infer the most informed and accurate recommendations to help a policymaker build towards a reliable, sustainable and economic power system that maximizes social welfare.

In the case of Brazil, the thesis finds that by using its large potential for storable and dispatchable hydropower and bioelectricity as a balancing power, rather than as the base load, as it is currently the case, Brazil could be a true leader of the energy transition and implement a high share of VREs in its generation portfolio.

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Chapter 1: Introduction

1.1 Motivation

Energy has an important impact on many aspects of our modern society. It plays a crucial role in any country's economy, it directly affects geo-politics, can easily create diplomatic conflicts, and it is a major factor of resource scarcity and climate issues. Globally, access to energy or electricity is a proxy of increasing living standards, as outlined by Figure 1, which graphically shows the correlation between a country's Human Development Index (HDI) and Energy Development Index (EDI)[1]. In the past couple decades, the growing demand for energy combined with the need for alternative sources of energy, have triggered prominent investments in research and development for new and/or improved energy generating technologies, as well as investment in infrastructure, both of which significantly mobilized the academic world and labor market.

Figure 1: Comparison of the new Energy Development Index and the Human Development Index in 2010
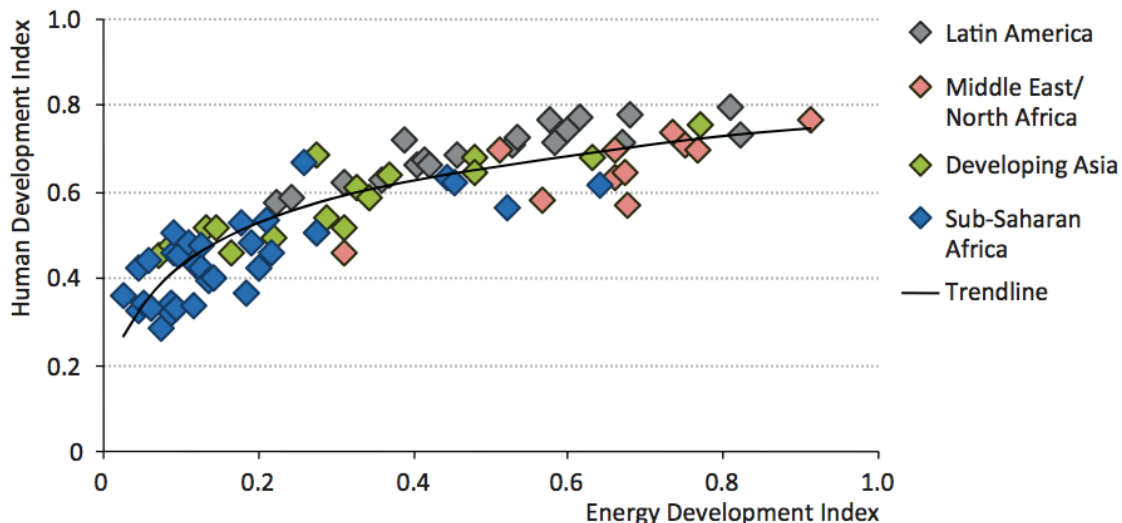
Source : (OECD/IEA, 2012)

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[1] The Energy Development Index is a multi-dimensional indicator that tracks energy development country-by-country, distinguishing between developments at the household level and at the community level. In the former, it focuses on two key dimensions: access to electricity and access to clean cooking facilities. When looking at community level access, it considers modern energy use for public services (e.g. schools, hospitals and clinics, water and sanitation, street lighting) and energy for productive use, which deals with modern energy use as part of economic activity (e.g. agriculture and manufacturing) (IEA, 2012).

Power generation and consumption being the complex issue it is, with every decisional aspect bearing great economic, social, environmental and political stakes, it is not surprising that the decisions related to the nature, extent and structure of its deployment are of national and international interest, and prone to governmental interventionism.

The need for optimal power system comes from the necessity to maximize the utility of electricity production and consumption, taking into consideration different - and sometimes conflicting - constraints or interests.

Traditionally, the valuation of new investments in the power sector has been done by means of stand-alone methods, which only consider the costs that are directly incurred by the operation of the potential power plant. Consequently, these methods give a rather incomplete valuation, as they fail to consider different market risks and externalities. More specifically, externalities here refer to two elements: environmental cost externalities, and system cost externalities. Additionally, by nature, these stand-alone valuation methods do not portray how the complementarities between some power generation technologies can positively impact the power system, nor can they reveal the high costs that can be incurred if the system lacks these complementarities. Therefore, they cannot inform a utility or country on the optimal technological choice for an additional power plant, given the current portfolio it operates (Bazilian & Roques, 2008).

A considerable amount of literature has been put forward throughout the years to attempt at finding optimal energy mix in power systems. However, the notion of optimality is very subjective, and this can result in a large disparity of outcomes, varying according to researchers' interests and objectives, the constraints they are willing to consider and the data that's available to them.

This paper will consider a definition of an ***optimally integrated electricity generation system*** that attempts at capturing the interests of a benevolent social planner, whose objective is to maximize the utility of power generation systems for both present and future generations.

Therefore, the notion of optimality for power systems in this paper will refer to the combination of the following factors:

1) *The use of **the highest possible amount of renewable energy sources**, allowing for environmental sustainability;*
2) ***Diversity of energy sources**, enhancing the security of power supply and the reliability of electricity generation systems;*
3) ***Cost minimization**, allowing for an economically feasible and viable energy reform.*

Chapter 2 will further describe these three concepts and justify their use to define the notion of optimality of power systems throughout this paper.

1.2 Research Purpose and Objectives

1.2.1 Purpose of Research

The purpose of this research is to suggest a cost valuation method for energy generation technologies that integrates the different risks and externalities that are not considered with usual stand-alone methods. Additionally, this papers aims at analysing how the complementary features of generation technologies can affect the role and value they take within a given power system. The consideration of these two aspects would ultimately allow for a better assessment of power generating technologies' costs as part of an optimally integrated power system.

On a social planner and policymaker perspective, using such a valuation method is of crucial importance, as it would allow for better informed decisions when it comes to planning energy policies, and can help reach a greater efficiency of power systems. Moreover, it can yield a better trade-off between cost minimization, environmental sustainability and energy security, in a long-term perspective, whilst expanding the power system as to fulfill a growing demand. Evidently, these considerations require a holistic and long-term approach. Therefore, the research and analysis of this paper will be conducted adopting the perspective of a **benevolent social planner**.

Incidentally though, pondering the results of such a holistic valuation method could also be very informative from a utility or investor perspective, as it may help assessing what types of energy investments are likely to be preferred as a new entrant in a system, or what policies are most likely to be enforced. Such information might help the private energy sector plan their business development strategy, bearing these factors in mind. However, despite this interesting angle of analysis, the investor viewpoint will not be considered further in this paper.

The research and analysis conducted in this paper will attempt to provide an answer to the following questions:

- ***How can a social planner integrate the different risks and externalities of energy generation in the cost valuation of each technology?*** This information should help providing a more comprehensive assessment of the cost of each power generation technology than the traditional methods, allowing to pose better informed recommendations to shape a country's power system expansion.

- From there, ***how can a policy maker plan towards an optimally integrated power system to fulfill the present and future energy need of this country?*** The answer to this question shall describe what other elements must be taken into account when planning the expansion of a country's power system, especially regarding technologies' complementarities and system costs.

This paper will cover both the theoretical and practical aspects of these questions, and will use the Brazilian energy market as a case study.

1.2.2 Research Objectives

The analysis conducted throughout this paper will build towards the achievement of different objectives:

1) To identify, summarize and critically discuss a selection of relevant literature about methods that have been put forth in the field of electricity mix planning;

2) To select relevant criteria and parameters and to suggest a cost valuation method that accounts for the different risks and externalities of electricity generation.

3) To discuss how other elements, not accounted in the cost valuation of generation technologies, can affect the cost, risk and efficiency of a power system.

4) To research and summarize the main elements of the Brazilian energy context (power sector structure, political and regulatory landscape, resource base analysis and demand growth trajectory).

5) To utilize the Brazilian energy sector as a case study to test the proposed methodology, which should allow the identification of a potential trajectory for a cost efficient, reliable and sustainable electricity mix for the future needs of the country.

1.3 Structure of Thesis

Chapter 1 of this paper outlines the topic of the research and the motivation behind it. Chapter 2 will describe and justify the use of the three factors that will feed into the definition of an optimally integrated system power for the purpose of this paper. In Chapter 3, a review of selected literature about relevant energy planning methods will be presented. The main theories will be given a brief overview and a presentation of the method utilized. Following this, a short analysis on the findings yielded by the method will be suggested, as well as a description of the main limitations it is thought to encounter. Chapter 4 will draw both from the literature review and the author's own elaboration to set forth a methodology that will aim at solving this papers' research question. Chapter 5 will provide a thorough understanding of the Brazilian energy context and will gather all the data necessary to proceed to the case study and test the methodology. Chapter 6 will present the results of the experiment, which will be thoroughly and critically discussed in Chapter 7. Finally, Chapter 8 will summarize the findings and present the conclusion of this paper.

Chapter 2: Definition of Optimality Criteria

As mentioned in Chapter 1, this paper will consider three main factors to define the notion of an optimality integrated electricity generation system:

1) *The use of **the highest possible amount of renewable energy sources**, enhancing environmental sustainability;*
2) ***Diversity of energy sources**, improving the security of energy supply and the reliability of electricity generation systems;*
3) ***Cost minimization**, allowing for an economically feasible energy expansion and viable power system.*

This chapter to describe each of these criteria and give sufficient justification for their use in fulfilling the purpose of this paper.

2.1 Renewable Energies to Mitigate Climate Change and Resource Depletion

Electricity generation systems are one of the major factors of climate change and resource depletion. As global population and standards of living increase, demand for electricity increases along with them. As can be seen in Figure 2, the global electricity generation has rapidly increased in the past few decades, especially in the non-OECD countries.

Figure 2: World electricity generation* from 1971 to 2012 by region (TWh)

*Excludes electricity generation from pumped storage

**Asia excludes
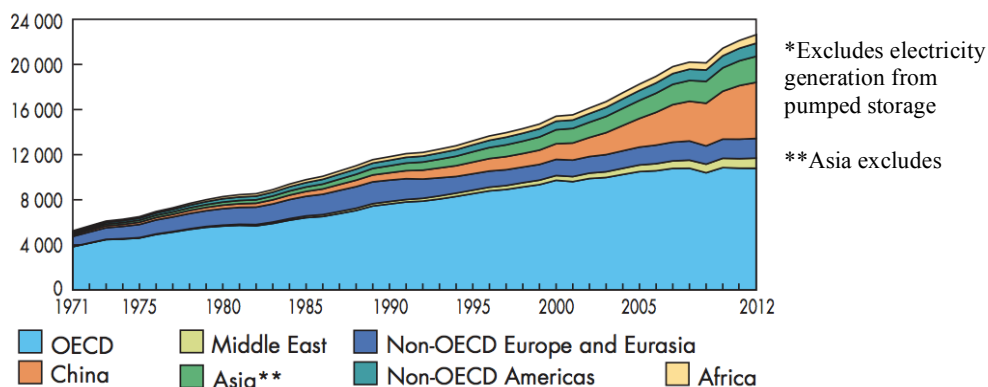
Source: (International Energy Agency, 2014)

According to the U.S. Energy Information Administration's forecasts, the world net electricity generation will go from 20.2 trillion KWh in 2010 to 39.0 trillion KWh in 2040, a 93 percent increase (EIA, 2013). Most of this growth originates from non-OECD countries, whose share of consumption of the world's total electricity supply is expected to increase from 49 percent in 2010 to 64 percent in 2040 (EIA, 2013). However, according to these forecasts, most of this new demand will be fulfilled with fossil fueled generation. Figure 3 shows that fossil fuels (coal, natural gas and liquids) account for most of the world electricity generation, both in the data baseline (67 percent in 2010) and in the forecasted future (62 percent in 2040) (EIA, 2013).

Figure 3: World net electricity generation by fuel, 2010-2040 forecasts
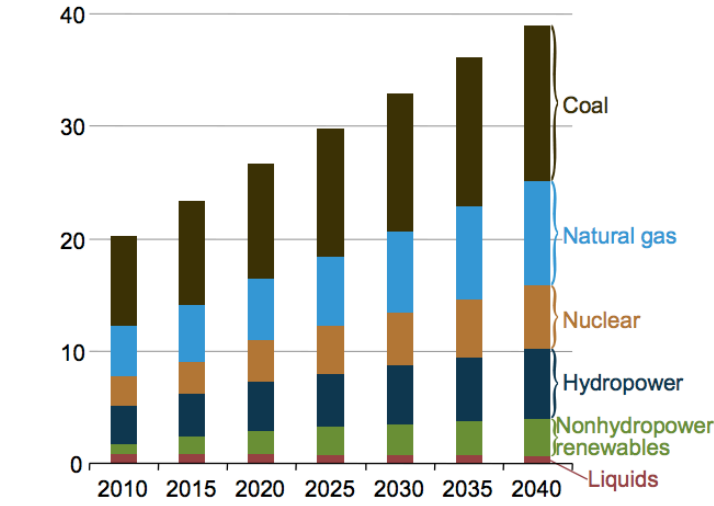
Source : (EIA, 2013)

Even though the *proportion* of electricity produced with fossil fuels is expected to decrease slightly, the absolute world electricity generation from fossil fuels sees an important increase. For example, coal-fired electricity generation, by far the most CO_2 intensive source of electricity (Centre for Climate and Energy Solutions, 2013), is predicted to be 73 percent higher in 2040 than its 2010 level, remaining the most important source of electricity generation, accounting for 36 percent of the mix. Disturbingly enough however, as shown in Figure 4, the burning of coal, natural gas and oil for electricity and heat generation is the single largest source of global greenhouse gas emissions, accounting for 25 percent of global greenhouse gas emissions in 2010 (EPA, 2014).

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Figure 4: Global greenhouse gas emission by economic sector and CO$_2$ emissions per fuel
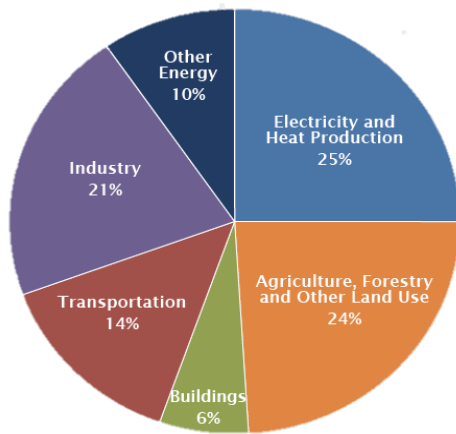
Source : (EPA, 2014)
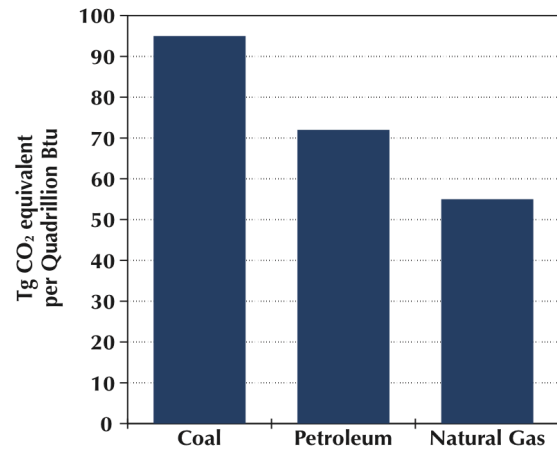
Source : (Centre for Climate and Energy Solutions, 2013)

These figures call for an immediate shift towards renewable energies in order to respond to electricity demand growth in a way that keeps future carbon emissions to a minimum. Notwithstanding this, EIA's forecasts show a quite different trend. In comparison with fossil fuels, renewable energy is predicted to grow faster, but the absolute amount of energy generated remains a small fraction of that of fossil fuels, especially if we look only at non-hydro renewables, predicted to account for only 9 percent of the total generation mix in 2040 (EIA, 2013).

This can be explained by the barriers that most renewable energy technologies must cope with when it comes to large scale implementation. First, non-hydro renewables are particularly capital intensive, which makes it difficult for a project to economically compete with a conventional fossil fueled power plant. Second, the intermittent generation pattern of wind and solar energy, in particular, can further hinder the competitiveness of these technologies. Intermittence could be partly compensated with investment in battery storage technologies or dispersion and decentralization of generation facilities, both of which come at great costs (EIA, 2013). For these reasons, government policies or incentives have historically been necessary to carry out renewable energy projects, and will remain necessary, at least in the short and medium-term horizons.

Nevertheless, the reference case used by EIA to forecast the energy outlook did not incorporate assumptions about future policies and regulations limiting or reducing greenhouse gas emissions, such as quotas or taxes on carbon dioxide emissions, but only incorporates existing regulations as of 2013, such as the European Union's 20-20-20 plan (EIA, 2013). According to the results of the forecasts, these policies are clearly not sufficient to significantly reduce carbon emissions caused by the electricity sector and mitigate climate change. However, "any new and unanticipated government policies or legislation aimed at limiting or reducing greenhouse gas emissions could substantially change the trajectories of fossil and non-fossil fuels consumption presented in the outlook" (EIA, 2013).

Global efforts from governments, the private sector, NGOs and all actors at stake, to discuss and coordinate actions on issues like carbon emissions, reflect that the question is no longer *whether* we need to change our traditional ways to go about economic development and resource exploitation, but *how* to conduct this change whilst ensuring a smooth transition and a certain form of justice. The historical Paris Climate Deal, signed upon by nearly 200 countries, shows a worldwide willingness to acknowledge nations' responsibility in climate change, as well as the role they must bear in preventing its aggravation and mitigating its consequences. A crucial part of it is the need to quickly increase the share of renewable energies in most countries' electricity mix. This is one of the measures that is most agreed upon, which can be partly attributed to the relative ease with which it can be implemented and measured.

Finally, planning a large proportion of low or zero-emission energy sources in an electricity generation portfolio is a clever way to avoid exposure to future financial retributions that might be incurred due to a climate policy, like carbon taxes or quotas, and can therefore be considered as a risk mitigating strategy for carbon intensive industries.

This paper will assume that governments are taking into account the environmental costs of human activity, and are willing to adopt and implement policies that minimize the environmental impact of energy generation. For the purpose of this paper, and keeping in mind the benevolent social planner perspective that is assumed, the environmental cost of

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electricity generation will be internalized into the generation cost of each technology, as to ensure that an optimally integrated power system would include the highest possible share of renewable energy sources.

2.2 (Sustainable) Diversification as a Proxy for Energy Security

Energy issues have been of national and international interest long before the rise of environmental concerns. Nations are and have always been extremely involved in ensuring a significant level of energy security within their borders. Energy security is defined as "the uninterrupted availability of energy sources at an affordable price.[…] Lack of energy security is thus linked to the negative economic and social impacts of either physical unavailability of energy, or prices that are not competitive or are overly volatile" (IEA, 2015).

Consequently, a country's energy security policy generally comprises measures taken to reduce the risks of supply disruptions and the vulnerability to fuel prices volatility below a certain tolerable level. Such measures need to be balanced to ensure that a supply of affordable energy is available to meet demand at all time (Bazilian & Roques, 2008). In order not to have to rely on economic measures, international treaties, reserves or offensive military actions, energy security can be enhanced with two factors: self-sufficiency and fuel mix diversity (Bazilian & Roques, 2008).

Self-sufficiency reduces dependence on imports, which can go a long way in increasing security of supply. Indeed, importing energy brings its complete menu of risks, such as geographical source of fuel imports and risks associated with transit routes, disruptive event or political instability in exporting country, etc. (Bazilian & Roques, 2008). Self-sufficiency can therefore reduce the risks on energy security caused by a high amount of imports. However, a country's capacity to provide to its own need for energy is no sufficient guarantee of energy security. If a country relies on one main source of energy, or few similar sources that are affected by the same risk elements, the country's supply of energy can be very vulnerable to external factors, such as price shocks or weather conditions.

Fuel mix diversity is thus necessary to ensure a greater level of energy security. Fuel mix diversity can enhance the robustness and reliability of an electric system and provide hedge against price shocks affecting one type of fuel, as well as supply shocks due to physical or natural disruption in the supply chain (Bazilian & Roques, 2008). However, as intuitive as this might seem, it is actually quite tricky to define and quantify diversity, and the literature on the topic is rather extensive. According to Stirling (2007), three concepts are necessary but individually insufficient to define diversity:

1) *Variety*, which refers to the number of options or categories available;
2) *Balance*, which refers to the evenness of contribution of these options;
3) *Disparity*, which refers to the nature and degree to which these options are different to one another (Stirling, 2007).

Number of indices have been developed to quantify the different aspects of diversity, and a significant amount of literature applying them to energy contexts can easily be found. For example, the Shannon-Wiener index measures the variety and balance aspects of diversity, and can be applied to electricity generation portfolios by calculating the probability that one unit of electricity was produced by any particular option. The more diversified the system, the more uncertainty there is over which option will have generated the next sampled unit of electricity (Bazilian & Roques, 2008).

Additionally, a measure of disparity can be determined by assessing the distance between two options in terms of their intrinsic characteristics. Using a branching structure, such as the example shown in Figure 5, disparity is measured by the distance, moving from left to right, before two options meet along the tree. The distance between two similar options, e.g. offshore wind and wave energy, is relatively small, whereas the distance between non-combustion renewables and fossil fuel is large (Skea, 2010). The greater the distance between each two options within a system, the less affected will the system be by external factors, therefore increasing its robustness and reliability.

Figure 5: Branching structure describing the disparity between UK electricity generation options
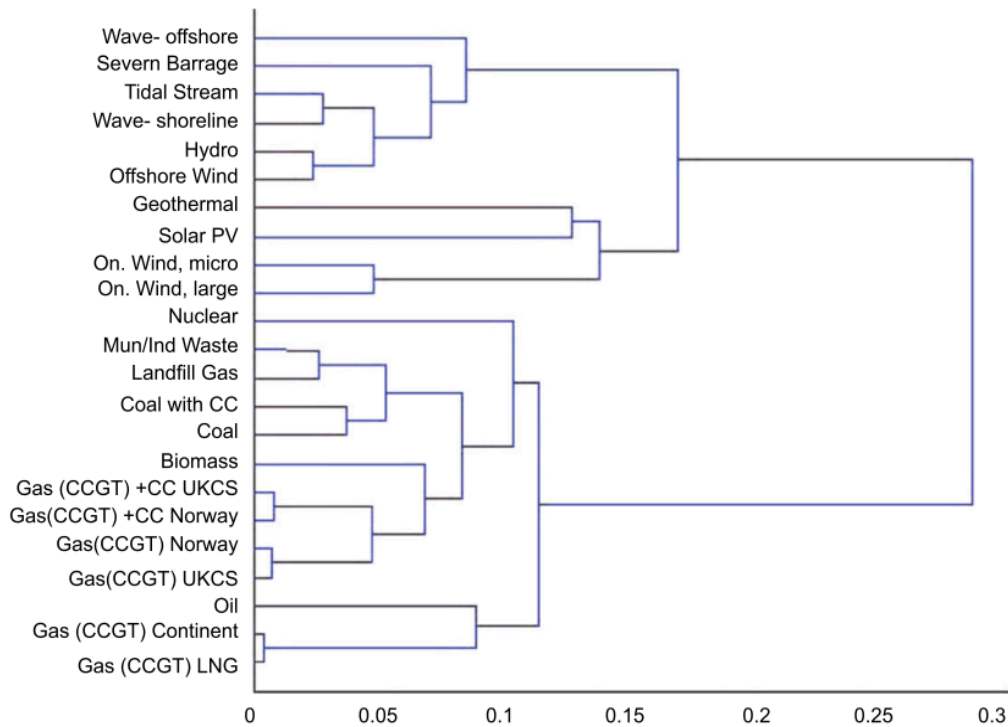
Source : (Skea, 2010)

Quantifying the exact value of all the properties of diversity is a topic worth of entire studies and will therefore be considered outside the scope of this paper. Besides, quantifying diversity is not an indicator of how valuable this diversity is to reach certain objectives. Rather, the value of diversity, or the extent to which diversity is to be pursued, depends on the balance between the extra costs and the degree of risk reduction achieved. Therefore, investing in generation technologies which help a country mitigate its exposure to supply disruption or price risks can be thought as a type of insurance (Bazilian & Roques, 2008).

Investments in power generation must be approached considering the cost and risk analysis of the whole system, which can yield results that are significantly different from the traditional static valuations of the "least cost option", on a stand-alone basis. Fuel mix diversity should not be perceived as an end, but as a mean that has the capability to generate benefits less costly than other alternatives in achieving the same objectives (Bazilian & Roques, 2008).

Moreover, even though energy security and sustainability have curiously always been treated in parallel, diversity is also a key element in the sustainable agenda, more specifically looking at two important aspects: sustainable energy generation and resource depletion (Bazilian & Roques, 2008). First, most zero-emission technologies have the disadvantage of generating electricity at an intermittent pace, which does not match with the non dispatchable nature of electricity, especially in regards with the inelasticity and regular variation of its short-term demand. However, increasing the variety of uncorrelated energy sources (or disparity) smoothens the energy generation of a system. For example, a 1MW wind power plant and 1MW solar power plant will most likely generate a more constant output of electricity than a 2MW wind power plant (Bazilian & Roques, 2008). Therefore, an electric grid counting with a large amount of renewable energy sources that rely on uncontrollable weather conditions, gains a lot from diversifying generation sources, reducing the volatility and unpredictability of its total output.

Second, diversifying away from depleting natural resources like fossil fuels goes with the Brundtland Commissions' definition of sustainable development: a "development that meets the needs of the present without compromising the ability of future generations to meet their own needs" (UNECE, 2004). Therefore, "to diversify away from present dependences on scarce, diminishing fossil fuel supplies thus addresses both security and sustainability agendas" (Bazilian & Roques, 2008), for present and future generations.

Investing in renewable energies is thus not only a way to avoid exacerbated CO_2 emissions, but it also allows a country to diversify its energy sources and ensure a greater energy security. If the golden rule of investing is that a more diversified portfolio yields a safer investment, the same should apply for energy generation. As electricity is a nonexpendable service, a more diversified portfolio of energy sources is essential for any country to become self-sufficient and resilient to any market failures or volatility, as well as any natural or weather variation.

To summarize, an overall greater diversity of energy generation sources is a proxy of improved energy security, as well as a less volatile electricity system and price. Additionally,

in a context where the environmental cost of energy generation is accounted for, having an increased proportion of renewable energy sources in the electric grid not only plays an important role in reducing the cost risk arising from the volatility of fossil-fuels, but also serves to hedge against the cost risk of future environmental policy. Finally, it is important to note that "there is no right level of diversity, this question must be determined politically, [and a] suitably designed incentive can ensure that system cost and system diversity are traded off in an economically efficient manner" (Skea, 2010).

For all of the above reasons, this paper will assume that countries have the intention of adopting and enforcing policies that foster the diversification of their electricity generating portfolios, including a continuously growing proportion of renewable energy sources in the energy mix. As mentioned, the calculation of the value of diversity will not be within the scope of this paper. However, discussions about the extent and nature of energy diversity that may be relevant according to a specific energy context will be presented in later chapters.

2.3 Cost Minimization as a Key Factor for Energy Reforms in Emerging Countries

In the midst of climate change and climate change mitigation, most industrialised countries have adopted policies – of which, admittedly, the seriousness, credibility and efficiency is sometimes debatable – to transform their energy generation and consumption so as to reduce their impact on the environment, namely by reducing CO_2 emissions. An important debate around these policies, which can be seen as an obstacle to industrial growth and economic development, is whether emerging and under-developed economies should be held to the same standards of reduction, since their role in actual levels of pollution have historically been insignificant, in comparison with the industrial world. One approach to this debate is that if industrialised countries should be expected to conduct drastic changes in their economies in order to become more sustainable, emerging countries should make sure that at least their future growth will be conducted in the most sustainable way possible, thus avoiding a later need for a drastic and costly change.

Emerging economies are often characterized by a fast paced growth in wealth, which results in the increase of populations' living standards and in turn, the growth of the demand of

consumer goods and services, which include energy and electricity. Indeed, as mentioned beforehand (see Figure 1) there is a high correlation between long-term economic growth and increasing demand for energy. As discussed in section 2.1, most of the new demand for electricity in the future will come from emerging economies, which is why a sustainable growth is essential. However, some characteristics of emerging countries also include high poverty levels, uneven repartition of wealth, low levels of social security, as well as political instability.

Growth in electricity demand induces significant need for investments in the construction and operation of electricity generation plants, as well as all the infrastructure needed for distribution. Measures to increase the proportion of renewable energy sources in a country's electricity generation system have generally been rather expensive, both for the governments and the rate-payers. For example, in Germany, "since the feed-in tariff (FIT) program supporting renewables started, in the early 2000s, electricity prices have more than doubled, from 18 cents per kilowatt-hour in 2000 to more than 37 cents in 2013. [As of 2013], the FIT subsidy program, […] had cost more than $468 billion" (Altman, 2014). It is unthinkable to put such economic pressure on rate-payers in countries where an important part of the population can barely afford their power bill as it is, whereas others still do not have access to electricity altogether. As observed by Pielke (2010), cited in Bazilian, et al. (2011):

> "When GDP growth comes into conflict with emissions reduction goals, it is not going to be growth that is scaled back … when rich countries wanting emissions reductions run into poorer countries wanting energy, it is not going to be rich countries who get their way. When energy access depends upon cheap energy, arguments to increase energy costs or deny energy access are not going to be very compelling".

In emerging countries, where investments are desperately needed in budgetary items such as health and education, heavy public spending to push renewables into the system might be politically unrealistic. Consequently, policies to increase renewable energies need to be as cost efficient as possible, and need not transfer the surplus cost of implementation onto the

rate-payers. Learning curves of renewable technologies have made them significantly more affordable now than they were only a few years ago, and it is still expected that their cost will continue decreasing as utilities gain experience in manufacturing, installing and operating them. However, there is much debate as to whether they will ever get to grid-parity. It is very likely that some sort of governmental support will remain necessary to foster renewables penetration into the grid.

Interestingly, the sole fact of planning energy expansion with a view on the energy system as a whole, instead of the traditional stand-alone economic valuation, can significantly reduce the system cost on a long-term basis.

With these aspects in mind, this paper will consider that the cost minimization factor of an optimally integrated power system should yield the best cost trade-off, on a social planner perspective, between the short-term, direct costs of implementing policies to expand technologies that are not cost competitive, and the long-term or indirect costs, such as the costs of environmental externalities, or other energy risks.

2.4 Chapter Summary

The previous section presented the main elements that make it necessary for today's societies to rethink and develop the electricity generation sector with an optimal system approach. It also described what will be the three factors that will be considered essential throughout this paper to define and build towards an optimally integrated power generation system. The next section is dedicated to outlining and understanding some of the most relevant theories that have been utilized thus far in different attempts to plan the optimal deployment of power generating technologies.

Chapter 3: Literature Review of Planning Methods for Electricity Mix

Assessing the energy sources that should compose a country's electricity mix has traditionally been done on a stand-alone basis, with objectives of financial profitability and energy security. Methods that are generally used to value and compare the economic profile of different technologies are either the Levelized Cost of Energy (LCOE), which assesses the cost structure of electricity generation technologies, or the Net Present Value (NPV), which assesses the financial profitability prospects of a project. Both methods tend to advantage the "least-cost" technology for a project development, without considering factors external to the power plant as such. As the realization arose that these stand-alone methods often yield larger risks and efficiency loss on the system level, many academics started focussing their research on possible solutions to optimize electricity generation planning, as considered from a portfolio or system perspective.

The overarching goal of a literature review is to "provide the reader with the necessary background knowledge to the research question and objectives, establish the boundaries of the research [and] enable them to see [the ideas exposed in the paper] against the background of previous published research in the area" (Saunders, et al., 2009). Accordingly, the following section will outline some of the most relevant literature in the field of electricity generation portfolio planning methods. The objective of this review is to examine some of the methods that have been put forward and used by researchers so far, the criteria or parameters that they have considered, the relevance of the results they have achieved and the possible limitations of their method, which could raise the opportunity for further research.

3.1 Mean-Variance Portfolio and Frontier Study

3.1.1 Overview

Mean-Variance Portfolio (MVP) and frontier study is certainly one of the most utilized method in the literature to study optimal electricity portfolios. First developed for use in the financial sector in 1952 by economist Harry Markowitz, the MVP technique has since been routinely used by professional investors, fund managers and financial institutions in order to find the optimal investment portfolio that will yield the highest possible return, given the level of volatility, or risk, investors are willing to bear (Berk & DeMarzo, 2014). MVP will

thus analyse all possible portfolios based on two characteristics: their expected return and their risk.

The expected return ($E[R]$) of a portfolio is the weighted average of the expected returns of the different assets composing the portfolio (R), where weights correspond to the proportion (x) of each asset within the portfolio:

$$(1) \qquad E[R] = \sum_R xR * R$$

To calculate the risk of a portfolio, two things must be considered: the volatility of the expected return of each asset of the portfolio (P), as indicated by its standard deviation (SD) as well as the correlation between each asset's risk factors. The total volatility of a portfolio ($SD(R_P)$) can be calculated as shown in equation 2:

$$(2) \qquad SD(R_P) = \sum_i [x_i * SD(R_i) * Corr\ (R_i, R_P)],$$

where the total standard deviation of the portfolio is given by the sum of each security i's contribution to the volatility of the portfolio, calculated by multiplying, for each security, the proportion x_i held by its standard deviation and its correlation with the portfolio (Berk & DeMarzo, 2014). Each security contributes to the volatility of the portfolio according to its volatility, or total risk, scaled by its correlation with the portfolio. For instance, the volatility of a portfolio can be decreased by an asset that has opposite risk factors than the rest of the portfolio, even if this asset has a higher individual risk than the other assets in the portfolio. In financial markets, this measure is calculated with beta (β), an index that uses historical data to measure the sensitivity of a security to market-wide risk factors. In other words, whereas the expected return of a portfolio is equal to the weighted average expected return, the volatility of a portfolio is less than the weighted average volatility (Berk & DeMarzo, 2014). Therefore, it is well accepted in the finance world that a well-diversified portfolio will significantly reduce investors' risk.

The MPV approach uses these data to establish a number of portfolios for varying levels of returns, each having the least amount of risk achievable. A similar analysis can be conducted for different levels of costs and their respective risk, depending on the objective of the study. The portfolios that yield the best level of expected return (or cost) at any given level of risk are known as optimal portfolios and lie on the efficient frontier which, on an axiomatic representation of expected return (or cost) vs. risk, graphically parts the unfeasible portfolios and the inefficient ones, as shown in Figure 6. In this case, the efficient frontier, which extends from point MV to point MC, shows the portfolios that allow for the lowest cost, at any given of risk within the feasible scenarios.

Figure 6: Electricity generating efficient frontier: an example
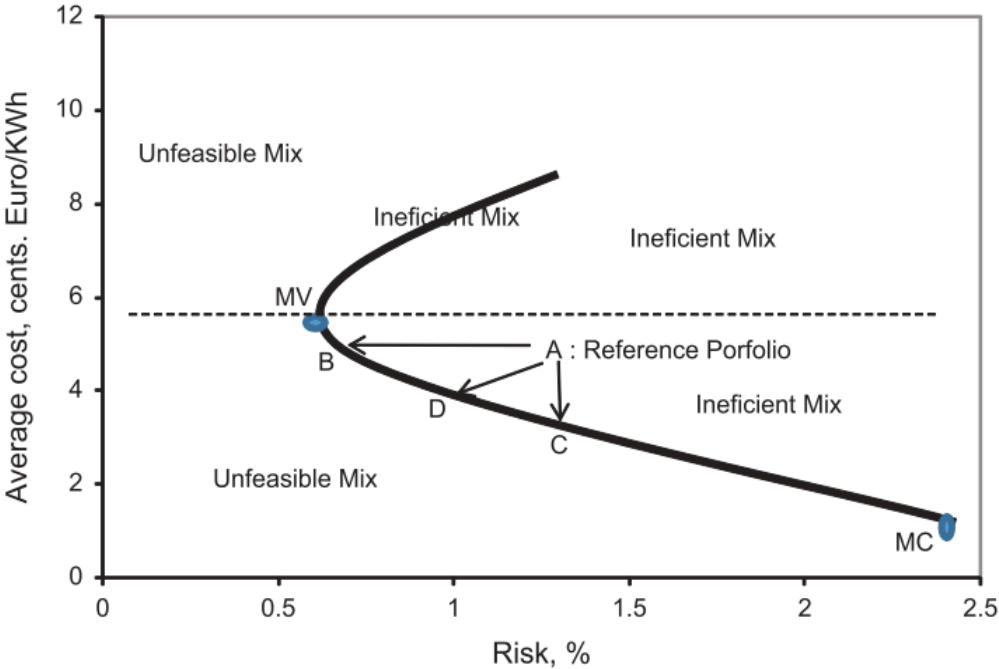
Source : Marrero and Ramos-Real (2010), retrieved from (Losekann, et al., 2013)

Here, optimality refers to the Pareto optimality in the trade-off between risk and return/cost, as for each efficient portfolio, the risk cannot be decreased without decreasing the return or increasing the cost, and the return cannot be increased, nor the cost decreased, without increasing the risk. The investor then simply has to choose which level of risk is appropriate to their particular circumstance or preference (Bazilian & Roques, 2008).

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According to Bazilian & Roques (2008), the chief justification for the use of the MPV method in the power sector is that the traditional valuation approaches, LCOE or NPV, do not account for market risks and uncertainties. As they are stand-alone valuation methods, they do not take into account the complementarity in the risk-return profiles of different power plants. Therefore, they cannot inform the utility or country on the optimal technological choice for an additional power plant, given the current portfolio it operates. MVP approach can complement traditional stand-alone basis approaches by capturing the interdependency between the next best option, according to the current portfolio (Bazilian & Roques, 2008).

3.1.2 Method

Bazilian & Roques (2008) and Losekann, et al. (2013) base their analysis on a social planner perspective. This means that the optimization function of their model is to minimize the cost of a portfolio, as opposed to an investor's perspective, which is to maximize their returns. The efficient frontier will then be on axes of cost vs. risk and contain portfolios that minimize the cost for each level of risk, just as represented in Figure 6. The data needed to conduct this analysis can then be divided in three categories: cost, risk and correlation coefficients.

Cost

The first step is to find the average generating cost of each available technology. To do so, authors break the generating cost (€/kWh) of each technology in four components: 1) capital cost, 2) operation and maintenance (O&M), 3) fuels and 4) CO_2 cost. Historical data and projections are used for the former three, whereas scenarios with different carbon prices are assumed for the later (Awerbuch & Yang, 2007), (Bazilian & Roques, 2008), (Losekann, et al., 2013). The costs are then summed up and expressed both in absolute terms and as the proportion each cost component has in the total cost of each technology.

Risk

The second step is to calculate the technology risk for each alternative, which proves a more complex endeavor. A percentage standard deviation must be found for each of the aforementioned cost components. The capital cost risk is related to the complexity and length of construction, and can be calculated with historical data. The O&M risk is very difficult to

estimate, as company records may not be available or may not reflect accurately the expenses (Awerbuch & Yang, 2007). In their research on the European optimal electricity portfolio, Awerbuch & Yang (2007) use data from the US Energy Information Agency, assuming they would be similar in Europe, whereas other researchers do not consider O&M risk, as "they represent a small proportion in the overall generation cost in most cases […] and many authors conclude that results do not vary significantly when [they] are excluded from the analysis" (Losekann, et al., 2013). Fuel cost risk is based on historical fuel price variation. At last, the CO_2 cost risk, relevant for fossil fuel technologies, is estimated at 26 percent by Awerbuch & Yang (2007). The authors used both analytic techniques and Monte Carlo simulations to estimate the CO_2 cost standard deviation and the correlation between CO_2 cost and fuel prices (Awerbuch & Yang, 2007) (see Appendix 1).

Correlation

Awerbuch & Yang (2007) conclude that the most important correlations are found among the different fossil fuel prices, as well as the relationship between fossil fuel prices and emission cost. For instance, "as gas becomes more expensive, electricity generation shifts to coal, putting upward pressure on CO_2 prices – be they market prices or shadow prices. Conversely, rising coal prices shift generation to gas, which emits about half as much CO_2. As a result, the price of CO_2 falls with rising coal prices" (Awerbuch & Yang, 2007) (refer to Appendix 1 for the correlations coefficients). As for the correlations of the other cost categories, capital cost and O&M, Losekann, et al. (2013) assume that they are very small and could be set to equal to zero without altering the results, whereas Awerbuch & Yang (2007) suggest a correlation matrix for O&M costs.

Finally, with the proportional values of cost components and their respective risk for each technology, along with the correlation coefficients, all the elements are in place to calculate the total risk of each generation technology.

Other constraints

At last, some logical or contextual constraints are added to the model. These differ according the the researcher's objective, or the particularities of the energy situation is the geographic

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area targeted by their study. Examples of these constraints are upper and lower bounds for the proportion of renewable energies in the portfolio, in order to respectively ensure a reliable and sustainable grid, or an upper limit for nuclear power, which might be favoured in the model for its high capacity and zero-emissions nature, but is highly controversial and unlikely to be socially and politically preferred.

3.1.3 Findings and Limitations

One of the key findings of the MVP is that due to the volatility or risk of the different fuels, as well as the internalization of carbon emission costs, adding fuel-less technologies to a risky electricity generation portfolio that relies heavily on fossil fuels lowers expected portfolio cost at any level of risk, even if the fuel less technology costs more on a stand-alone basis. "This underscores the importance of policy-making approaches grounded in portfolio concepts as opposed to stand-alone engineering concepts" (Bazilian & Roques, 2008).

MVP and the efficient frontier study can also be a powerful tool in assessing or improving the efficiency of a national electricity mix that is not fossil-fuel intensive. In their paper, Losekann, et al. (2013) use it to evaluate Brazil's DPEE 2020 (Decennial Plan for Energy Expansion). Their findings suggest that the portfolio decided upon by Brazil in 2010 with the DPEE was quite close from the efficient frontier. The average cost of the 2020 DPEE is only 3 percent higher and the risk is 10 percent higher than the estimated average efficient portfolio. Therefore, there was more room to reduce the risk than the cost of the 2020 DPEE, through a higher level of diversification.

Using the MVP theory and frontier study in the field of electricity mix planning has ground-breaking implications for the types of technologies that are traditionally considered as more economic or less risky. It is a comprehensive method that could yield significant benefits on a long-term basis with respect to an electricity system's sustainability, reliability (or security) and overall cost.

Nevertheless, this method also presents significant **limitations**. First, the model is designed to be a static, one-period analysis, which is bound to discord with such a dynamic and fast-

changing field as energy generation, especially as it is more and more impacted by new or improved technologies. Important elements are not accounted for in such a static model. For instance, the growing demand for electricity, the declining cost of renewable technologies and the introduction of new generating technologies, are all factors that inherently signify the need for a dynamic, multi-period investment decision method. Whereas the MVP and efficient frontier method allows for the identification of efficient portfolios in a certain target year, extending the framework to a multi-period analysis could additionally help determine optimal trajectories, from base year to target year, accounting for the different changing factors of the equation (Bazilian & Roques, 2008).

Another limitation of this method is related to the correlation coefficients it uses. The financial market provides robust and continuously updated indicators such as betas (β) and market risk premium (RP), both of which feed in the Capital Asset Pricing Model (CAPM), a model that describes the relationship between risk and expected return (Berk & DeMarzo, 2014). "Beta, a measure of financial covariance risk, provides the basis for estimating discount rates for fuel and other generating project costs. CAPM discount rates are a simple linear function of beta" (Awerbuch & Sauter, 2005). These indicators are utterly useful for investors to make informed financial decisions.

Fossil fuel prices have always been subject to a high volatility. When this volatility is reflected through the CAPM, fossil fuel generation appears significantly costlier than standard engineering estimates, which ignore the impact of risk on generation costs (Bazilian & Roques, 2008). A number of researchers (Awerbuch, 1993), (Awerbuch, 2003), (Awerbuch & Berger, 2003), (Bolinger, et al., 2006), (Bazilian & Roques, 2008) have reported empirically estimated cash flow betas for coal, oil, gas, uranium and even CO_2 emissions, all of which are negative, which yields a lower discount rate and, in turn, a higher cost (see section 3.2.2). "This means that the true cost of fossil generation far exceeds commonly held beliefs. It also means that future outlay streams [especially of fossil fuels], are highly risky for project developers, although history suggests that most of this risk is passed through to electricity consumers" (Awerbuch & Sauter, 2005).

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These betas however, since they are not currently used for decision making concerning investments in the electricity sector, are not updated, nor adapted to different markets. This last point is a rather important one, and poses yet another limitation to the model; the correlations, covariance and betas applied to this model, and carried by other researchers to their own study on electricity mix, were calculated through studies that looked at specific markets, and therefore carried specific characteristics of these markets' context regarding fossil fuels. It is very likely that these financial measures vary significantly from one market to another, depending on whether a country is a net importer or exporter of fossil fuels, or the extent to which the power system is dominated by fossil fuel. Yet, no data is available to implement this differentiation. Therefore, whereas the financial markets provide a beta measure to help investors think in terms of portfolio performance, "the lack of a similar measure in energy markets prevents [the sector] from embracing the energy planning portfolio optimization approach" (Bazilian & Roques, 2008).

Even though the MVP method can capture some important risk factors that can affect the composition and overall cost of a power system, especially for fossil fuel technologies, it fails to fully grasp the notion that power generation technologies are heterogeneous when looked at from a portfolio angle, i.e. that the one unit of electricity output from a given energy source can have different values depending on the composition of the generation portfolio. For instance, one unit of hydropower output can be extremely expensive if a system is over-reliant on a hydropower generation that is put under pressure. However, the same unit can actually have a positive cost in a system where it is used to regulate other variable energy sources. As further describes in following sections of this paper, this differentiation is extremely important and therefore constitute an important shortcoming of the MVP.

Finally, as observed by IEA (2015), another criticism of the MVP method is that risk is only analysed through the prism of volatility, for which the past is assumed to assess the future. However, energy and technology risks have many other dimensions, such as physical supply interruptions, accidents, etc., which are not reflected in the portfolio analysis (IEA/NEA/OECD, 2015).

3.2 Model for Comparing and Projecting LCOE

3.2.1 Overview

The levelized cost of electricity (LCOE) method is a useful tool to assess and compare the generating cost of different technologies. However, it was first developed to assess electricity production from fossil fuels and nuclear power plants, back when carbon emissions were not a concern and renewables were not in the picture. The main shortcoming of the traditional LCOE method (presented in Appendix 2) is that it does not account for specific market risks or technology risks, such as fossil fuel volatility or the intermittence of some renewable sources (Narbel, et al., 2014) and therefore gives an incomplete view of the real cost of many technologies.

In their paper, Arapogianni, et al. (2009) present a methodology for calculating and projecting the LCOE that takes into consideration two main factors that might affect the future cost of different generating technologies: 1) the risk associated to the fuel and carbon price volatility for fossil fueled technologies and 2) the effect of technology learning, especially affecting newest technologies like renewables.

3.2.2 Method

As mentioned in the previous section on MVP, the researches of Awerbuch (2003), Awerbuch & Sauter (2005) and Bazilian & Roques (2008), suggest betas (β) that capture the risk of price volatility both for the different types of fossil fuel and for carbon price. In their paper, Arapogianni, et al. (2009) use these betas in order to come up with differentiated, risk-adjusted discount rates for each type of fossil fuel, used to discount the cost components of a technology which carry a high amount of volatility, i.e. fuel and carbon price, to their present value. To do so, the authors use the CAPM method, where the discount rate is found by summing up the risk-free discount rate and a specific rate associated to the level of risk of the specific investment. The risk-adjusted discount rate is calculated with the following CAPM equation:

(3) $$d_{risk-adjusted} = d_{risk-free} + \beta * RP,$$

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where β (beta) is a correlation factor, RP is the market risk premium associated with the specific investment, and $d_{risk-free}$ is the yield of a risk-free investment (in this case, the authors consider a 30-years government bond with at 3.9 percent). Equation (3) shows that the specific rate is a product of a correlation factor β and a risk premium RP. As mentioned by the authors, "Awerbuch and other researchers have already pointed out the negative correlation that exists between fossil fuel prices and indicators of economic activity" (Arapogianni, et al., 2009). Using the calculated negative values for the correlation factor β (Awerbuch, 2003), (Awerbuch & Sauter, 2005), (Bazilian & Roques, 2008), as well as the assumed values for the risk premiums (Bazilian & Roques, 2008), the authors can compute new adjusted discount rate for each for each type of fuel and carbon, which are lower than the risk-free discount rate, as can be observed in Table 1, which represents the value used by Arapogianni, et al (2009) to conduct their analysis.

Table 1: Risk assumptions

Cost Component	Gas	Coal	Uranium	Carbon
Risk-free discount rate	3.9%	3.9%	3.9%	3.9%
Correlation factor **β**	-0.2	-0.4	-0.1	-0.4
Risk Premium **RP**	5%	5%	5%	5%
Risk-adjusted discount rate	2.9%	1.9%	3.4%	1.9%

Source : (Arapogianni, et al., 2009)

For each of these elements, the authors then use the risk-adjusted discount rates to discount the future fuel and carbon cost by inputting it an annual discounted cost formula, illustrated by the following example for the fuel cost calculation:

$$(4) \qquad DC_f = CRF * AC_f * \sum_N \frac{1}{(1+d_f)^N},$$

where the discount rate d_f is used to find the sum of the present values of the annual fuel cost AC_f, which is then multiplied by the capital recovery factor CRF to give the annual discounted fuel cost DC_f. With this approach, the use of the lower, risk-adjusted calculated

discount rate on to calculate the fuel and carbon costs will result in a higher present value, avoiding underestimating these cost components throughout the lifetime of the project (Arapogianni, et al., 2009).

Another component of the methodology is the inclusion of projections for each technology's LCOE at different target years in the future, according to the learning effect theory. The logic behind learning curves is that the future cost of a technology will depend on its present cost as well as the present and future total installed capacity of each power technology. To express this relation between present and future costs, the authors use the following equation:

$$(5) \qquad C_{future} = C_{present} \left(\frac{P_{future}}{P_{present}}\right)^{\frac{\ln(1-LR)}{\ln 2}},$$

where C_{future} and $C_{present}$ are the future and present value for a specific cost component, P_{future} and $P_{present}$ are the future and present total installed capacity for the respective power generating technology [GW], and LR is the learning rate applied to each power technology.

Based on different sources, the authors make assumptions on the future installed capacity and learning rates of each technology, which are then factored in the projection of their respective LCOE.

3.2.3 Findings and Limitations

Much like the MVP theory, this method for projecting LCOE gives a much more comprehensive outlook of the elements that affect the cost of different electricity generating technology than the traditional approach to LCOE. One advantage of this method over the MVP though, is that it brings the risk components of each generation cost, at least for the fuel risk and carbon price risk, directly into the cost calculation, which simplifies the whole process by much. The results show that by adding the fuel and carbon price volatility component, as well as the technology learning effect, into the cost calculation, new renewable technologies have a much greater capacity to economically compete with traditional generation technologies, and that this capacity steadily increases over time, along with the

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renewable installed capacity. Moreover, a useful extension of this method on the MVP is that the calculation of LCOE projections over a given period, which is essential to conduct a multi-period analysis of portfolio trajectory.

However, one element to notice about this methodology is that it is not as comprehensive as the MPV as for the types of risks it includes in the calculation of electricity generation costs. As shown in section 3.1.2, the MVP method also includes the risk of the capital cost component and, depending on the author, the O&M component of the total cost. Additionally, it is important to mention that the same limitations as with the MVP method apply here regarding the betas that are used, which are neither updated, nor necessarily transferable from one market to another.

Another shortcoming of the model is that even though it includes certain risks and externalities, it does not adopt a portfolio perspective and thus fails to grasp the different factors that can also positively or negatively affect the cost of energy generation within a system (this notion will be further developed in section 4.1).

Finally, another limitation of the methodology is that even if it allows a multi-period analysis, it is still a static model, as the future values of the cost components depend on fixed assumptions about the future installed capacity. Ideally, these variables would interact together in a dynamic model to yield an optimal result. This type of study was realized by Cong (2013), whose more complex model takes account of the learning effects of costs, as well as the technology diffusion effects, in order to dynamically optimize the development path of renewable energies. Such a dynamic approach has the potential to yield more optimistic scenarios for renewable energies deployment, especially since past projections about installed capacity of renewable technologies have been drastically underestimated.

Figure 7: World Energy Outlook's projections for new renewable capacity throughout the years (excluding hydro)
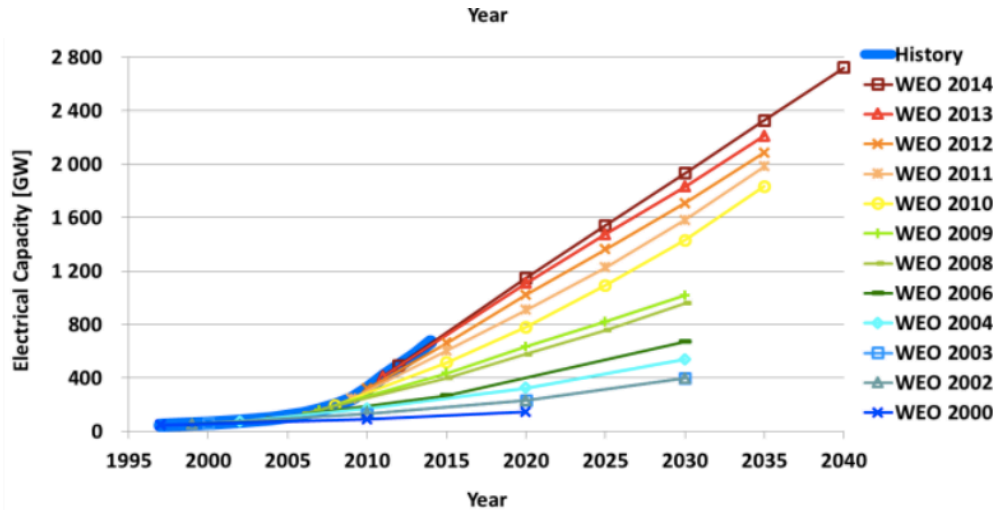
Source : (Metaver, et al., 2015)

3.3 Multi-Period Analysis of Power Generation Portfolios

As mentioned in section 3.1, the MVP method, which allows to create low risk and low cost portfolios of power generation technology, is a one-period, static approach. This is a significant shortcoming of the model, since it is inadequate for studying multi-stage and dynamic investment decision problems such as encountered in the energy sector (Glensk & Madlener, 2013).

The same issue was of course encountered in the finance sector when using portfolio theory, and many suggestions can be found in the literature to transform the MVP into a multi-period model, be it by solving a series of singled-period portfolio problems ([A] Elton & Gruber, 1974) ([B] Elton & Gruber, 1974) or much more complex methods like a multi-stage and multi-objective programming technique using a scenario tree (Korhonen, 1987) (27). However, as noticed by Glensk & Madlener (2013), the application of multi-stage portfolio theory is relatively new for the energy sector, and most seem to be done with a private investor's perspective. For instance, in their paper, Glensk & Madlene (2013) present a method that aims at helping utility owners to periodically rebalance their portfolio and make timely investments according to the different possible electricity price trajectories. Their

approach, although very interesting, is not in line with the social planner perspective used in this paper.

One other method that has been explored to cope with the single-period shortcoming of the MVP are real-options. "Real option theory has pointed to the shortcomings of the static valuation approaches for inputting a value on the ability of a utility to react dynamically to changing markets and other conditions. Real options allow for the adjustment of the timing of the investment decisions. It is therefore particularly well suited to evaluate investments with uncertain payoffs and costs" (Bazilian & Roques, 2008). If new information can be acquired before investing that would diminish the uncertainties about the investment's outcome, the financial disadvantage of waiting may be outweighed by the financial advantage of a less risky investment. The opportunity cost of waiting must be weighed against the potential avoided loss in order to decide whether to hold off the investment or not.

However, this method implies a great investment timing flexibility, which is not always the case. It also implies that the uncertain elements of the decision will eventually be decided upon, or that their future trajectory will otherwise unfold and become more certain. This might fare well with uncertain elements that are dependent upon a decision being made, for example the implementation of a new regulation on carbon emissions. It does not necessarily apply as well to other elements though, especially fuel cost risk, as fossil fuel prices are consistently volatile. In other words, the real-options method may be a good way for an investor to evaluate an investment decision when some uncertain elements are bound to be unveiled in a relatively close future, but it is not an appropriate approach for a social planner that must consider a constant stream of uncontrolled risks and costs.

3.4 Chapter Summary

Chapter three discussed several different models or theories that have been put forward in the literature to assess the real cost of energy generation technologies as part of a system. The main takeaways from these discussions are that the current cost valuation methods in the energy sector do not give an accurate picture of the cost of energy generation, as they only value each technology as an isolated power plant, inherently assuming that the electricity

generated from different sources has the same economic value. However, electricity generation is highly heterogeneous, and many factors can affect the cost that any given power plant actually has in a system. In order to better assess the real cost of electricity generation, the theories presented in the literature review propose to integrate different market and technology risks, as well as externality costs into the valuation of each technology.

The MVP theory is a sound method to include these elements in a portfolio perspective valuation, but fails to acknowledge system costs and complementarities between certain sources of energy. It also only takes the energy planning process so far, as it gives a very short-term perspective of the optimal development of the power system by failing to account for demand projections and cost trajectories.

The model to compare and project LCOEs as presented by Arapogianni, et al. (2009) is then very interesting, as it lays the basis to extend the traditional LCOE calculation by integrating some of the risk elements seen in the MVP, namely fossil fuel price risks and CO_2 price risks. Moreover, the introduction of a cost trajectory for technologies that are subject to learning effects opens the door to a multi-period assessment and the possibility to lengthen the outlook of energy planning. Nevertheless, the analysis is only taken so far, as it merely considers a handful of technologies and is discussed outside the context of a particular market, which also means that the importance of system costs and complementarities is not considered.

The contribution of this paper will be to suggest an extension to the latter methodology, one that would consider all the risk elements from the MVP analysis. The method will be used to assess the cost of all the power generating sources relevant to Brazil. Moreover, the analysis will also consider system costs and complementarities, demand projections and cost trajectories in an energy planning exercise, in order to pose a possible scenario for the expansion of the Brazilian generation mix towards an optimally integrated power system.

Chapter 4: Method

As discussed, the LCOE is one of the best method to compare the cost of various energy technologies (Narbel, et al., 2014), and it is commonly used to assess their economic value. The reason for this is the ease with which LCOE allows to see the cost composition of each technology, as well as to compare their overall cost. Yet, the traditional approach to LCOE calculation is poorly adapted to the complexities of the modern energy sector, as it considers only direct input costs and implicitly assumes that the electricity generated from different sources has the same economic value. Consequently, a comparison based on LCOE does not capture the full picture and thus may be misleading (IEA/NEA/OECD, 2015).

The main methodological objective of this paper is to suggest a valuation method that accounts for the different risks and externalities of electricity generation. The main advantage of such a valuation is its capacity to help a social planner gain a more comprehensive understanding of how different technologies compare to one another, therefore allowing for the implementation of the right energy policies, building towards a cost efficient, reliable and sustainable electricity mix for the future needs of a country.

4.1 Cost Valuation: Risk and Externalities Accounting LCOE Method

This section will suggest an approach to LCOE calculation that allows for the inclusion of the different risks and externalities that are considered in the MVP theory. This will result in a more comprehensive assessment of energy costs, hopefully overcoming some of the pitfalls of the traditional LCOE method, while laying the foundations that would enable a multi-period approach to energy planning, which is an important limitation of the MVP method. For each technology, the estimated risk incorporates the fluctuation of fuel costs and the risk related to investment disbursements during the construction period of the plant (Losekann, et al., 2013). If the cost of CO_2 emissions affects a particular technology, the volatility of its price would be an additional source of risk, and is thus also included. This section outlines the approach to the valuation of each cost component that will be considered in this valuation method: *capital cost, fuel cost, CO_2 cost, operation and maintenance cost (O&M) and system cost.*

Capital Cost

Every energy project is subject to capital cost, since investment is always needed to build a plant, regardless of the type of energy source or the size of the plant. The capital cost, or cost of the initial investment needed to build the plant, hereafter labelled c_i, is measured in monetary units by unit of installed capacity (e.g.: €/MW), and then converted into a unit cost basis of electricity produced (e.g.: €/MWh) using the capacity factor f of the plant (see Appendix 2) (Narbel, et al., 2014). Capital costs vary largely according to energy sources. Mature technologies tend to have a much lower capital cost per unit output. This cost can be accurately estimated with historical data. As mentioned in section 3.1.2, most of the risk associated with this cost component is related to the complexity of building certain types of power plants, resulting in longer construction times and a greater gap between the time of the investment and the beginning of the capital recovery period. In order for the LCOE to reflect this risk, the capital cost formula can be multiplied by a future value factor that will be adjusted according to the average construction time of the different types of energy plants. This way, the capital cost component will increase for every year for which the project needs to be financed without being operational. The risk-adjusted capital cost formula thus becomes:

(6)   Risk adjusted Capital Cost $= (1 + r)^n \left[\frac{R + c_i}{H * f} \right]$,

where n is the average years needed for a plant's construction before it is operational, and r is the chosen discount, which is also used to calculate the capital recovery factor R.

Fuel Cost

Fuel cost, which is non-existent for renewable energy sources like hydro, wind and solar, represent a significant proportion of the LCOE for fossil fuel based power plants. The fuel cost, hereafter c_f, can be expressed for the different types of fuel as a monetary unit per unit of energy produced (e.g.: €/GJ). This can then be converted to the cost by unit output of electricity (e.g.: €/MWh), using the efficiency factor of a technology and the conversion factor of GJ to MWh (i.e. 3.6 GJ/MWh). The efficiency factor, or thermal

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efficiency, is a measure of how efficient a technology is in converting the heat produced by a fuel into electricity. It can also be seen as a measure of how much fuel is needed to yield the same output as a a plant that would reach the physically impossible mark of 100 percent efficiency (Narbel, et al., 2014). The fuel cost per MWh is thus calculated as followed:

$$(7) \quad c_f = \frac{\text{Fuel Cost}}{\text{MWh}} = \frac{1}{\text{Efficiency Factor}} * \frac{3.6\text{GJ}}{\text{MWh}} * \frac{\text{Fuel Cost}}{\text{GJ}}$$

Additionally, the traditional LCOE method suggests to include a levelization factor, which would assume and integrate a steady rise of fuel prices during the lifetime of the plant (Narbel, et al., 2014). However, this very poorly reflects the risk factor brought by the effect of the high volatility and uncertain trajectory of fossil fuels prices. As mentioned in section 3.2, a more efficient way to account for this risk within the LCOE calculation is to use the CAPM model to tailor a fuel-risk adjusted discount rate for each type of fuel, as shown in equation (3): $d_{risk-adjusted_f} = d_{risk-free} + \beta_f * RP$, where the $d_{risk-free}$ is the discount rate r previously used.

A respective beta is used for each fuel (β_f), which as a result yields a different risk-adjusted discount rate according to the fuel type. The risk-adjusted discount rate for fuel costs, hereafter labeled, d_f, is then used instead of the general discount rate r for this cost component. Much like suggested by Arapogianni, et al. (2009), the fuel cost over the plant's lifetime T can be discounted to its present value, which is then multiplied by the capital recovery factor R, as shown in the following equation:

$$(8) \quad \text{Risk adjusted Fuel Cost} = R * c_f * \sum_t^T \frac{1}{(1+d_f)^t} .$$

CO_2 Cost

The traditional approach to LCOE usually does not include a CO_2 cost. From an investor's perspective, especially if only looking at the short-term horizon, it is generally unnecessary to include this cost component, as very few countries have adopted or enforced a policy that

sets a cost on CO_2 emissions. However, on a long-term horizon, and especially from a social planner perspective, including a CO_2 cost is the most straightforward way to account for the pressure that fossil fuels put on the environment.

In this paper, the cost of CO_2 is also included in the traditional LCOE calculation, such as to be able to observe how the risk-adjusted method of calculating the CO_2 price affects this cost for the technologies concerned. However, a sensitivity analysis with a CO_2 cost set to zero will also be displayed in order to show how this cost assessment might have looked if realized from an investor or utility perspective.

Defining exactly what this cost should be is a complex notion. In the literature, different scenarios and assumptions are generally compared to one another. For example, the *business-as-usual* scenario sets the CO_2 cost to zero, as to show a trajectory that will most likely occur if no policy is enforced. In other instances, a *probable-policy* scenario is considered, where a CO_2 cost that is considered realistic in terms of political or economic feasibility is proposed. Another approach, which is only considered in a social planner perspective analysis, is the *shadow-price* scenario, where the CO_2 cost reflects the estimated cost that emissions actually incur or will incur in the future, both in regards of damages to the environment and the affected populations.

In order to calculate the cost of CO_2, hereafter c_c, for a given technology, one first needs to determine the CO_2 factor of each fossil fuel generation technology, expressed in a volume of carbon dioxide emitted by output of electricity (e.g.: ton CO_2/MWh). These data are made available by the International Energy Agency (IEA, 2015) (see Table 8 of Appendix 3). This factor is then multiplied by the cost set for a ton CO_2 emitted to express the cost as a monetary unit per output unit (e.g. €/MWh).

Integrating the CO_2 risk in this cost component is also a key element of the method. It is done the same way as for the fuel risk, just like suggested by Arapogianni, et al. (2009). Therefore, by using CAPM the appropriate risk-adjusted discount rate for this cost component can be determined; in the following equation, it is labelled d_c. This discount rate is used to

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integrate the risk of CO_2 price volatility into each CO_2 emitting technology's cost. The risk adjusted cost of CO_2 can be expressed as follow:

(9) $\text{Risk adjusted } CO_2 \text{ Cost} = R * c_c * \sum_t^T \frac{1}{(1+d_c)^t}$,

where d_c takes the same value across all concerned technologies, whereas c_c, which multiplies the CO_2 price by the emission factor of a given fuel, differs for each technology.

Operation and Maintenance Cost

Much like the capital cost, the O&M cost, hereafter c_o, is relevant to all technologies but varies greatly according to the type of power plant. c_o is generally expressed as an annual expense per installed capacity (e.g.: €/MW/year). The levelized O&M cost includes an escalation rate, which accounts for the fact that the plant's O&M expenses will steadily increase as the plant ages. The cost component can then be expressed per unit of electricity output by using the capacity factor. As mentioned previously, assessing the risk associated to this cost component is very difficult, as company records may not be available or may not reflect accurately the expenses (Awerbuch & Yang, 2007). However, other academics concluded that this risk is not significant and would not impact on the assessment of a technology's cost (Losekann, et al., 2013). This assumption will be carried in this paper; therefore, the O&M cost will be calculated the same way as in the traditional LCOE valuation, which is shown in equation (9):

(10) $Levelized~O\&M~cost = l * \left(\frac{c_o}{H*f} \right)$

System Cost

One other cost that is not included in the stand-alone cost analysis of an investor is the system cost. Yet, failing to consider the factors that may trigger of attenuate this type of cost in a power system can results in steep, unforeseen charges and a great efficiency loss. The system costs can be divided in the following categories, in accordance with IEA (2015):

1) *Balancing costs*: This covers the cost of handling deviations from the planned production and the possible extra cost for investments in reserves for handling outages of power plants or transmission facilities.

2) *Profile costs*: The value of the electricity generated to the electricity system or electricity market. The value is compared to a common benchmark, such as the average electricity market price. If the technology earns less than the average electricity market price, the difference can be considered a profile cost (and if the technology earns more than the average electricity price, it is considered a profile benefit).

3) *Grid costs*: Extra costs for expanding and adjusting the electricity infrastructure.

System costs are mainly known to be incurred by the integration of variable renewable energies (VRE), especially wind and solar, in a power system. These costs can significantly vary with different factors, such as the share of renewables in the system, the market price of electricity, the complementarities between the type of VREs and the technologies that are used as baseload in the system, the balancing mechanisms in place, etc. (IEA/NEA/OECD, 2015).

The Danish Energy Agency (2015) pointed to a few hints that can help understand how VREs impact system costs. For instance, Denmark's experience has shown a decrease in the balancing cost of integrating wind into the system as the share of wind energy increased (3EUR/MWh in 2005 with a 25 percent penetration, compared to 2EUR/MWh in 2014 with a 39 percent penetration). The same effect has have observed in Germany for solar PV, with similar ranges for the balancing costs (Danish Energy Agency, 2015). Although it can seem counterintuitive, it is logical that an increased penetration of VREs would help the system be more stable, granted a sufficient geographical dispersion between the plants is planned for, fostering a more uncorrelated generation pattern.

Another factor plays an important role in Denmark's power system stability; its strong interconnectors to the Norwegian grid, facilitating a readily access to large hydro capacities. Wind and hydro power tend to complement each other very well, especially

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if hydro reservoirs are in place, as the intermittent nature of wind power can be compensated by the flexibility of hydropower (Danish Energy Agency, 2015).

To return to the analysis at hand, one key element to bear in mind is that for any given power system, the overall system cost will be higher when little flexibility and capacity to regulate the total power output is allowed. This can be caused by intermittency, with wind and solar, but also by non-dispatchability of output, which applies to other conventional sources of energies. For instance, nuclear power is by nature very large and inflexible (Danish Energy Agency, 2015), and although dispatchability is possible with conventional power plants, high cycling costs for certain types of technologies or fuels can make this option very expensive (Van den Bergh & Delarue, 2015). Dispatchable energy sources such as hydropower, especially with reservoirs, and gas turbines can mitigate system costs, and can even be credited with a system benefit (Danish Energy Agency, 2015).

Although they can be very important, system costs vary a lot from a power system to another, as they can be affected by numerous factors. Therefore, assessing the share of this cost that is bore by each technology in a given system is a very complex task. Additionally, assumptions can hardly be made as to whether the system costs of technologies will increase or decrease over time before knowing the composition trajectory of a power system. For these reasons, the system cost will not be included in the LCOE calculations conducted in this paper. Rather, it will be kept in mind as an important factor in planning the optimal mix of technologies of a power system and discussions on options to help minimize this cost will be held.

Discount rate and escalation rate

The discount rate r, which in this paper represents the risk-free discount rate, is a very sensitive parameter of the LCOE analysis. In their LCOE estimations for OECD countries, the International Energy Agency uses three different discount rates: 3%, 7% and 10% (IEA/NEA/OECD, 2015). According to the IEA, these would approximately correspond to, respectively, the social cost of capital (3%), the market rate in deregulated or restructured

markets (7%) and an investment in a high-risk environment (10%) (IEA/NEA/OECD, 2015)[2].

The choice of the discount rate used for a LCOE analysis has a great impact on how different technologies compare to each other, and different discount rates can easily modify the merit order of the technologies in a mix. Figure 8 shows that the more capital intensive a technology is, the more sensitive it is to changes in the discount rate (IEA/NEA/OECD, 2015). One measure that seems to be used across a variety of studies is to look at the long-term government bond rates of the country where the investment takes place (IEA/NEA/OECD, 2015) (Arapogianni, et al., 2009). Alternatively, the Danish Energy Agency (2015) used the country's interest rate, as determined by its central bank. In their study, Losekann, et al. (2013) used a range of standard values for the discount rate of energy investments, which they suggest goes from 5% to 10%.

Figure 8: LCOE as a function of the discount rate
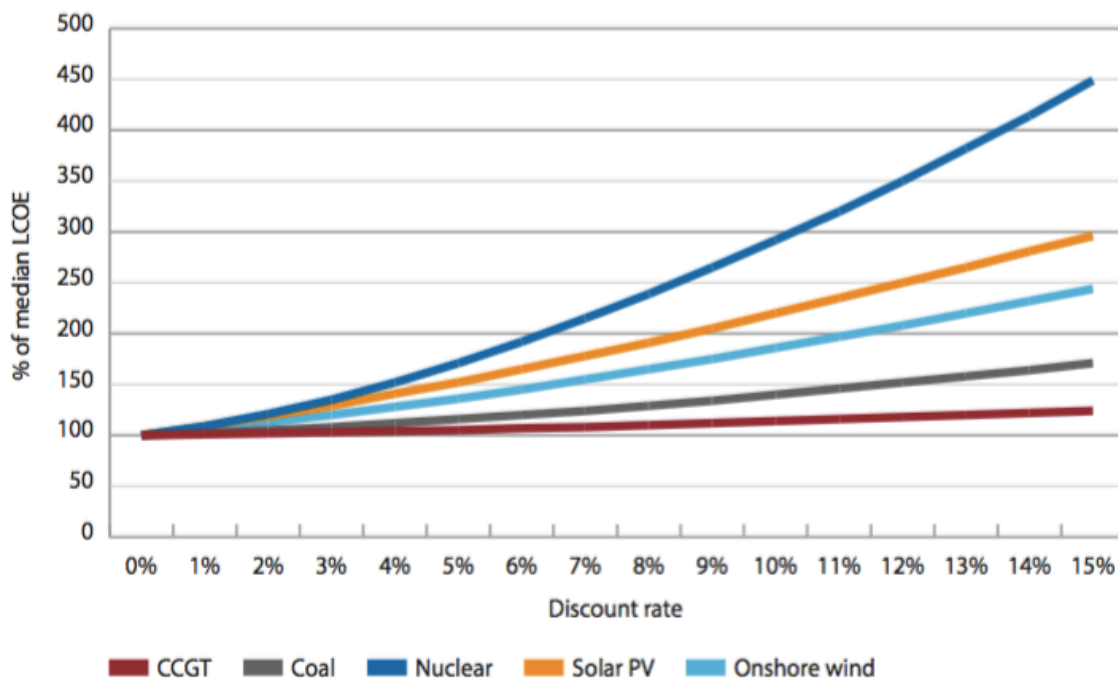
Source: (IEA/NEA/OECD, 2015)

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[2] These values all correspond to the IEA's estimate of the discount rates in real terms, for which inflation is factored in, as opposed to nominal discount rates.

Finally, the escalation rate is a measure of how a certain cost element is expected to increase over the lifetime of the plant. In this paper, the escalation rate is only used to calculate the O&M share of the LCOE. There is no straightforward way to calculate this variable, as it varies across technologies and utilities, but it is generally assumed to be in a range of 1% to 3% (Narbel, et al., 2014).

Risk-adjusted LCOE

The total risk-adjusted LCOE can be computed as the sum of all the aforementioned cost components, and reads as follows:

(11) $Risk - adjusted\ LCOE =$

$$\left[(1+r)^n \left[\frac{R+c_i}{H*f}\right]\right] + \left[R * c_f * \sum_{t}^{T} \frac{1}{(1+d_f)^t}\right] + \left[R * c_c * \sum_{t}^{T} \frac{1}{(1+d_c)^t}\right] + \left[l * \left(\frac{c_o}{H*f}\right)\right]$$

4.2 Cost projections: The Learning Effect

Conducting a multi-period analysis for electricity generation planning calls to the necessity of formulating assumptions regarding uncertain elements of the future energy context, such as the trajectory of the generating costs for different technologies. Indeed, by knowing how these elements are likely to evolve, it is possible to optimize the cost of the planned energy mix over the years by taking advantage of these factors. This is especially important since the power sector is composed of both mature technologies (e.g. fossil fuels and hydro), for which the costs are only predicted to marginally decrease – if at all – due to potential efficiency improvements, and newer technologies, such as solar or wind power, that are yet to reach cost maturity. Indeed, the primary obstacle to large scale development of renewable energies remain their high investment costs (Cong, 2013). However, just like any technology, renewable energies are subject to the learning effect, which shows a causal relation between the increase of cumulative installed capacity and the cost reduction of installing new generation capacity. These cost reductions are generally quite steep at first and gradually smoothen as a technology reaches maturity, unless new innovations are made. The learning curve model has become a mainstream method to describe and predict the cost decrease of renewable energies (Cong, 2013). Although it is nearly impossible to predict the learning

effect with certainty, various researches have suggested methods to estimate learning rates and reported projected cost trajectories (Arapogianni, et al., 2009) (IEA/NEA/OECD, 2015) (DNV-GL, 2014) (Tolmasquim, 2016).

It is likely that the use of a dynamic approach to the learning effect, as the one suggested by Cong (2013), which allows for the interaction between the new installed capacity and cost reductions due to the learning effect (linked to the total installed capacity), would yield more comprehensive results in projecting the future generation costs of new technologies, according to a specific development scenario. However, in their paper, Cong (2013) only accounts for the total installed capacity of wind and solar power in China to predict the learning effects and the possible decreases in costs of the Chinese power generation. This approach fails to consider the spilling effects from other countries' efforts to increase their share of renewables.

However, according to a report by the Renewable Energy Policy Network for the 21st Century (2014), one of the main factors that led to a global drop of these costs is Germany's pioneering role in the development and deployment of renewable energies. This goes to show that the spilling effects of technology learning previously mentioned have a great impact on the global expansion of renewable energies, meaning that one nation's learning curve will not only be affected by the amount of its own installed capacity of renewable energies, but also, to an significant extent, by the learning curves of the pioneers in the sector.

Nevertheless, assessing how spilling effects may extrapolate on the learning effect for a particular country adds yet another layer of complexity to the cost projections analysis, as it may vary according to different economic and political factors, such the structure of the power system of a country and its openness to foreign direct investments, the resource potential for the implementation of these technologies, or the degree of political willingness to foster their deployment. Therefore, for simplicity, this paper will not consider such a dynamic approach, and will rather simply consider the expected learning effects and cost projections that have been estimated by a series of reliable sources and discuss how can apply to the particular context of Brazil.

In point of fact, the impacts of the learning effect have already been significant in the past few years, as the cost of most renewable energy technologies – onshore wind, solar PV, bioenergy – decreased considerably. Solar PV probably shows the most striking cost decrease. As can be observed in Figure 9, prices for PV modules experienced an astonishing 97 percent decrease between 1980 and 2013 (REN21, 2014). Only between 2010 and 2014, costs for solar photovoltaic generators declined by around 50 percent (IEA/NEA/OECD, 2015).

Figure 9: Development of Solar Photovoltaic Module Prices, 1980 – 2013
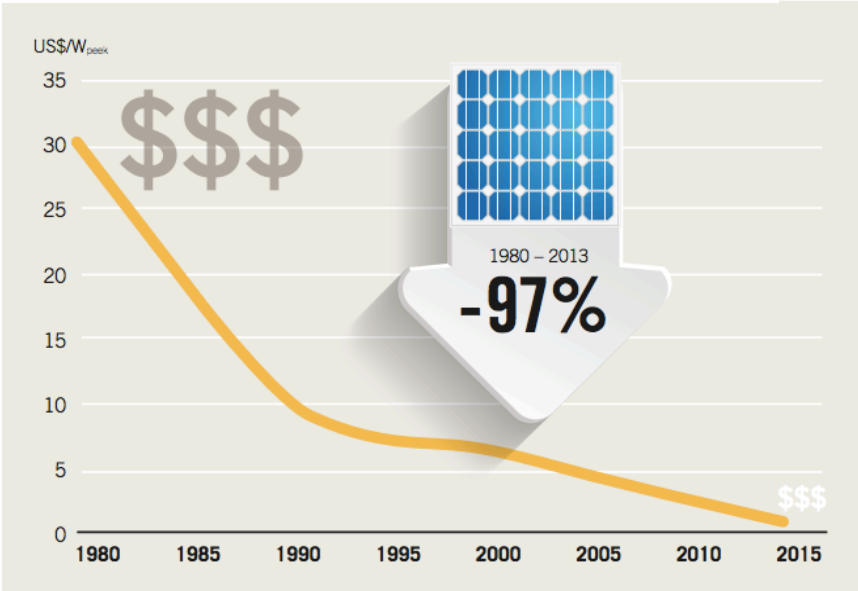
Source: (REN21, 2014)

Despite this sharp decrease, solar power is not yet as competitive as onshore wind power; in developed countries with good wind resources, onshore wind is often competitive with fossil fuel generation (IEA/NEA/OECD, 2015). Wind turbine prices fell significantly in the 1990s, but remained rather steady over the past decade. However, the average efficiency of the turbines kept improving, enabling a greater generation per turbine, which led to an overall reduction of the generation costs (REN21, 2014).

Projections show that offshore wind power and solar PV bare the greatest potential for cost reductions. According to the IEA (2015), onshore wind has become a mainstream technology. Seeing as it has already reached a cost allowing grid-parity in many locations, in

addition to the high capacity factor it can now reach, it is unlikely that onshore wind will see a significant cost reduction in the future.

As for offshore wind generation, the IEA predicts cost reductions of about 40 percent by 2030 – even though different uncertainties remain (IEA/NEA/OECD, 2015). Comparably, DNV-GL estimates that the learning rate or offshore wind power from 2010 through 2050 will be of approximately 10 percent. By applying this into the learning curve model, this means that the cost of this technology would fall by rate of 10 percent with every doubling of cumulative production (DNV-GL, 2014).

According to the IEA's projections, the LCOE of new utility-scale PV solar systems could fall on a global average below USD 100/MWh before 2025, while reaching this level before 2025 in the sunniest places (IEA/NEA/OECD, 2015). DNV-GL's projections are not as optimistic, with the LCOE of solar generation reaching these levels only between 2040 and 2050 (DNV-GL, 2014). Although, these projections are for Europe only, thus not including the most sun intensive locations. DNV-GL's projections for wind and solar cost through 2050 can better be observed on Figure 10.

Figure 10: Evolution of levelized cost of electricity (LCOE) for different RES technologies
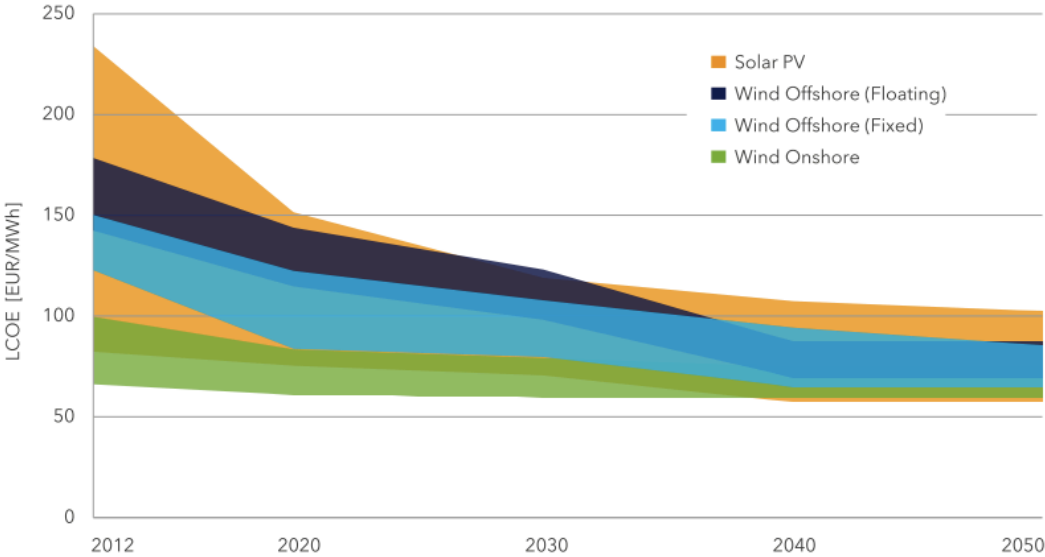
Source: (DNV-GL, 2014)

Finally, most other electricity generation technologies are considered mature, with little to no prospect for cost improvements. This assumption will thus be carried to this research.

4.3 Chapter Summary

Chapter 4 described the different elements that will be part of the methodological approach taken by this paper. Here the reader can find an outline of how they will be used in the rest of this paper to answer the research questions.

To summarize it step by step, first the cost of each technology will be evaluated through the risks and externalities accounting LCOE method presented in section 4.1, and considering the specificities of the Brazilian energy sector. This aims at providing a cost assessment, on the social cost-benefit viewpoint adopted by a social planner, that is much more comprehensive than the traditional LCOE method.

Second the results of this cost analysis will be combined with the projections of the cost trajectories, estimated by combining the learning effects presented in Section 4.2 and other specificities of the Brazilian energy market (Chapter 5), in order to propose a possible expansion scenario for the Brazilian power system. This scenario shall fit the demand projections for electric power in Brazil (see Chapter 5), and will be designed as to best fulfill the three criteria of an optimally integrated power system that were mentioned in Chapter 2.

Finally, a discussion will also be presented on how the different aspects of system cost and technologies complementarities can play a crucial role in the energy planning exercise of a policy maker, and how these elements play in the Brazilian energy planning scenario.

Before this analysis is carried out, Chapter 5 will describe the main elements of the Brazilian power sector in order to fully understand the underlying context and elements it comprises and be able to utilize it for the case study.

Chapter 5: The Brazilian Energy Context

Brazil, with a population of 202m and a GDP of $2,346bn (Bloomberg New Energy Finance, 2015), has a very particular and interesting energy situation. With an installed generation capacity of 138.4GW and a total generation of 526TWh in 2014, Brazil has the third-largest electricity sector in the Americas, behind the United States and Canada (EIA, 2015). Vast and filled with energy resources, Brazil would be in a position to lead the renewable energy transition. In fact, the Climatescope Report, which assesses countries' ability to attract capital for low-carbon energy sources, ranked Brazil to the second position worldwide, just behind China, in terms of the investment environment for climate-related investment (Bloomberg New Energy Finance, 2015).

However, Brazil is currently experiencing unprecedented political turmoil and economic instability; in 2010, Brazil had a growth rate of 7.5 percent in its GDP, whereas in 2013 the growth plummeted to a mere 2.5 percent, and in 2014 to 0.1 percent (Transfer LBC, 2015). Along with the continuously growing energy demand, and the ever more frequent droughts that diminish hydropower capacity, Brazil needs to quickly find solutions to avoid an energy crisis, without putting economic pressure on the consumers. This situation evidently creates a lot of uncertainties regarding the future of the energy situation in Brazil.

In order to use Brazil as a study case for this paper, it is important first to understand the underlying energy situation in this country. This chapter will provide a snapshot of some of the most important features of Brazil's energy context, providing information on the power sector structure, the political and regulatory landscape, the resource base, as well as projections of future demand for electricity. Finally, this information will be utilized for the cost analysis and the discussions of the case study analysis.

5.1 The Brazilian Power Sector Structure

In Brazil, the top authority of the energy sector is the Ministry of Mines and Energy. The policies developed by the government are regulated and controlled by the National Agency of Electric Energy (ANEEL). The authorized and regulated activities are then carried out by, the Energy Research Company (EPE), Electrobras, the state-owned utility company, other

utility companies that hold concessions for their operations and the National Development Bank (BNDES) – all of which are either public- private partnerships with open capital or non-profit organizations (Transfer LBC, 2015). EPE was established to assist the Energy Minister on sector planning and ANEEL to organize the auctions in order to acquire new generation capacity (Losekann, et al., 2013).

Brazil has a large interconnected electric system that can supply the country's main consumption centers. Brazil's geography made such an interconnected system necessary in order to fully exploit the hydroelectric potential and take advantage of complementarities between regional hydrology. As shown in Figure 8 the system is designed in such a way that in the event of a drought in one region, hydro generation in the others can compensate (Losekann, et al., 2013).

Figure 11: The Brazilian Interconnected Power System
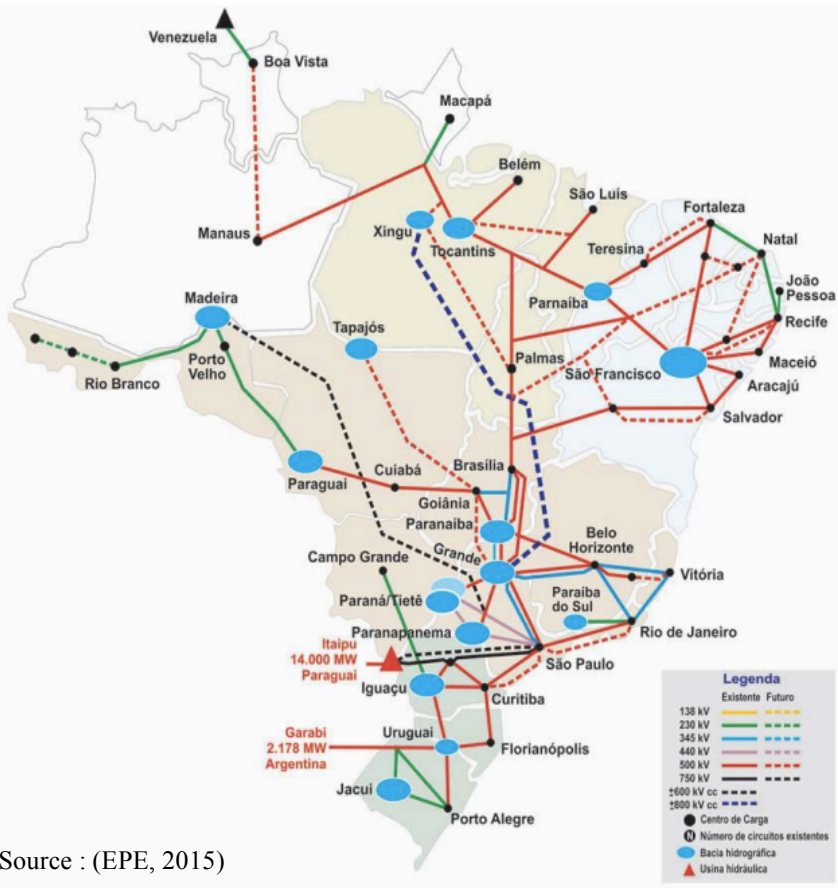
Source : (EPE, 2015)

5.2 Political and Regulatory Landscape

Even though there is no carbon charge in Brazil, the Brazilian government is invested in implementing energy policies that incentivize renewable power sources. The PROINFA (Incentive Program to Alternative Sources of Electricity) program was implemented in 2002 to promote small hydro, bagasse and wind power plants. It was a feed-in tariff scheme, where Eletrobras offered long-term contracts (20 years) with different prices for each source. This programme ended in 2011 and made room for new incentives to promote renewables through auctions dedicated to alternative sources (Losekann, et al., 2013).

The *Plano Decenal de Energia* (PDE) is one of the most important energy planning tools in Brazil, and the main guideline for the expansion of the energy sector in Brazil, especially for the power sector (Losekann, et al., 2013). It is regularly updated by the government to give insights and forecasts of the expansion of the energy sector for a ten-year horizon. Additionally, the Brazilian government is currently developing the *Plano Nacional de Energia 2050,* which will be a long-term planning tool for Brazil's energy sector. Finally, Table 4 gives a good overview of the policy instruments available to the Brazilian government in order to try to put the PDE into practice.

Table 2: Brazil's key policies to promote the expansion of renewable energies

Feed-in-Tariff	The government's PROINFA program guaranteed power prices at above-average market rates for 3GW of biomass & waste, small hydro and wind in 135 projects. It ended in 2011.
Auction	There have been 18 tenders in which renewable have competed, contracting a total of almost 17GW in the form of biomass (4.1GW), small hydro (0.7GW) and wind (12GW).
Biofuels	A mandate to blend 5% biodiesel with diesel and 27.5% ethanol with gasoline.
Debt/Equity Incentives	BNDES, the national development bank, offers credit lines for renewable energy, energy efficiency and ethanol projects.
Tax Incentives	These include a 2-year exemption for renewable energy from social contributions (PIS/COFINS tax) and exemption for large infrastructure projects through REIDI program.
Utility Regulation	A fee discount for renewable energy transmission and distribution.
Net Metering	Legislation for a net metering program has been approved, but deployment has been slow.

Source: (Bloomberg New Energy Finance, 2015)

5.3 Resource base analysis

5.3.1 Current Electricity Mix

The Brazilian electricity mix is largely dominated by hydropower, which currently corresponds to 63 percent of the total electricity generated (EPE, 2015), as shown in Figure 9. Additionally, the Brazilian hydro-electric plants count on reservoirs with great storage capacity; they can store the equivalent of half of Brazil's annual electricity consumption (Losekann, et al., 2013). Indeed, Brazil has long prided itself on its large hydro-based power matrix and, up until 2012, hydroelectricity has accounted for three quarters of all generation. However, the overreliance on one source, albeit renewable, came at a high cost for the country in the past few years, as prolonged droughts caused some reservoirs to reach critical levels, which revealed the system's limitations whilst exposing the market to costly balancing generation from fossil fuel thermal plants (Bloomberg New Energy Finance, 2015).

Figure 12: Brazil electricity generation by source (%)
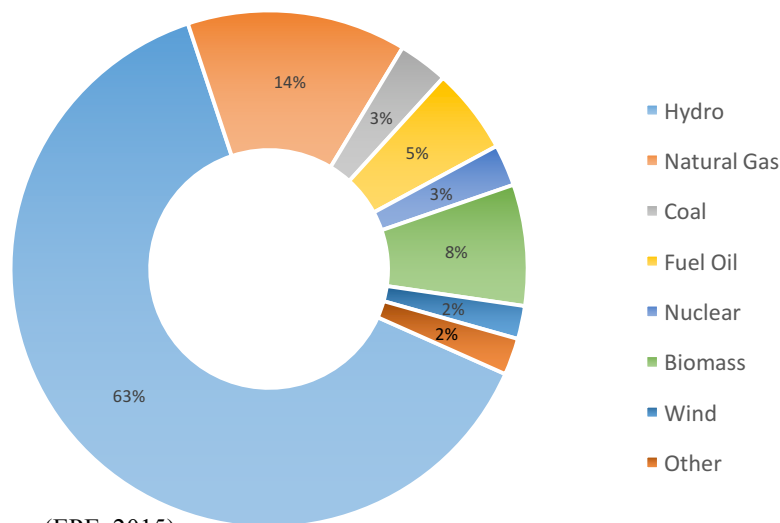
Source: (EPE, 2015)

One lesson that came out from the hydro crisis was the necessity for Brazil to diversify its electricity generation mix. Table 5 shows a constant decrease of hydroelectricity generation since 2011. This gap was mostly compensated by fossil fuels and biomass generation, however with much higher costs and losses (Transfer LBC, 2015).

Table 3: Electricity generation in Brazil, by source (GWh)

	2010	2011	2012	2013	2014	Δ% (2014/2013)	Part. % (2014)	
Total	**515.799**	**531.758**	**552.498**	**570.835**	**590.479**	**3,4**	**100**	**Total**
Gás Natural	36.476	25.095	46.760	69.003	81.075	17,5	13,7	Natural Gas
Hidráulica (i)	403.290	428.333	415.342	390.992	373.439	-4,5	63,2	Hydraulics (i)
Derivados de Petr. (ii)	14.216	12.239	16.214	22.090	31.668	43,4	5,4	Petroleum products (ii)
Carvão	6.992	6.485	8.422	14.801	18.385	24,2	3,1	Coal
Nuclear	14.523	15.659	16.038	15.450	15.378	-0,5	2,6	Nuclear
Biomassa (iii)	31.209	31.633	34.662	39.679	44.733	12,7	7,6	Biomass (iii)
Eólica	2.177	2.705	5.050	6.578	12.210	85,6	2,1	Wind
Outras (iv)	6.916	9.609	10.010	12.241	13.590	11,0	2,3	Other (iv)

Source: (EPE, 2015)

Natural gas is the most important fossil fuel in Brazil's electricity mix, with nearly 14 percent of the total installed capacity in 2014. From 2010 to 2014, the total share of fossil fuel based generation (natural gas, fuel oil and coal) went from 11 percent to 22 percent of the generation mix. As for renewable energies, where biomass and wind energy significantly grew, solar energy was only marginally developed. Indeed, despite Brazil's tremendous potential for solar energy generation, this technology had been used almost exclusively for rural electrification initiatives from the government, outside of the interconnected distribution system. This might be partly attributed to the historically high cost of solar. Only in 2012 was solar energy regulated by the state to integrate the system and, in 2015, connected solar generation capacity accounted for a mere 13,4MW (Tolmasquim, 2016).

5.3.2 Resource Potential for Future Electricity Needs

As previously mentioned, Brazil still has a tremendous unfolded potential in the power sector, which expands across most resources. This section will give an overview of the most important ones in Brazil: hydroelectricity, fossil fuels (fuel oil, natural gas and coal), nuclear, wind power, solar power and biomass.

Hydroelectricity

As of 2016, Brazil has an installed capacity of hydroelectric generation of 104,6 GW (Tolmasquim, 2016). Despite the difficulties encountered with the current hydro generation, the EPE (Energy Research Company, in English) put forward a study that show that a great amount of Brazil's hydro potential remains unraveled; it is thought that 67,7 GW of installed capacity could potentially be added to the grid (Tolmasquim, 2016). However, more than half of this capacity is located in the Amazônica province, the most remote and sparsely inhabited of Brazil. For large scale hydro projects, this result in higher capital costs, due to the necessity to invest in additional transmission lines linking the plant to the distant consumption centers.

Nevertheless, as pointed out by Tolmasquim (2016), despite the challenges that the construction of new hydroelectric capacity would raise, the operative flexibility facilitated by the large reservoirs are a great advantage that could foster the development of intermittent renewables like wind and solar. To this end, the author also mentions that it could be worth considering pumped storage hydroelectric plants, which can provide ancillary services and additional storage capacity.

Fossil fuels

Formerly dependent upon imports to satisfy its fossil fuels need, Brazil is now a net exporter. The country is economically self-sufficient in oil, with notable development of deep sea exploration and production (Transfer LBC, 2015). However, hit by the global decline in oil prices, high levels of debt (estimated at USD 110bn), and corruption scandals implicating the head of Petrobras, the state-owned company is struggling to meet its targets, and production growth is hindered in the short-term (EIA, 2015).

Additionally, Brazil has the second-largest reserves of natural gas in South America, which is located primarily offshore in the Campos Basin. Brazil seems to also be headed towards self-sufficiency in gas: in 2014, it produced the equivalent of 81 percent of its total consumption (EIA, 2015).

Finally, Brazil's annual coal production is approximately 6.3 million tonnes (Mmt) (EIA, 2014). Brazil's annual coal consumption, however, was estimated at 24.8 Mmt in 2012, relying on 18.0 Mmt of coal imports for its energy requirements (EIA, 2014). Brazil has recoverable coal reserves of approximately 6.6 billion tons, the third largest reserves in the Western Hemisphere, after the United States and Colombia (EIA, 2014).

It is safe to say that Brazil has a large capacity to develop its fossil fuel based power generation. Evidently, economic and political factors, as well as environmental considerations, might reduce the appeal of such an expansion alternative for the country's electricity mix.

On another note, as mentioned before, fossil fuel power generation has been used in the past few years to circumvent the hydropower shortage, however at a high cost. It is important to note that if fossil fuel power generation is usually among the cheapest sources when it serves in the base-load mix, using them as a peak-load sources, as was done in Brazil, can cause for significant additional costs (this is especially true for coal and fuel oil thermal plants, whereas gas power plants offer greater flexibility). Therefore, it might be the case that the use of fossil fueled power plants in the base-load would yield lower costs.

Nuclear

Nuclear power generation navigates in a very particular context. On the one hand, its carbon-free nature as well as capacity to generate important amount of electricity output at a reasonable price offer clear advantages. On the other hand, its deployment creates great controversy, mainly due to tragic occurrences experienced in the past, the most recent of which being the major nuclear accident of Fukushima following the tsunami that hit Japan in 2011.

Another controversial element of nuclear power is the high decommissioning costs it incurs, which are mainly due to the cost of storing nuclear waste for several years. This cost, along with the risk it might create, are often not included in the economic valuation of a nuclear plant investment and, in the past, often ended up falling on the tax-payers' shoulders.

In Brazil, the government has the exclusive right to invest in nuclear generation. This means that this type of generation is not submitted to auctions, and the government decides directly the importance of nuclear in the generation matrix (Losekann, et al., 2013). Brazil currently has two nuclear reactors, generating 3 percent of the total mix. As of 2013, the Brazilian government had halted the discussions regarding further expansion of the nuclear generation, observing the developments of the Japanese nuclear crises (Losekann, et al., 2013). No further information was found regarding the government's intention to either expand, maintain or reduce nuclear capacity.

Wind

Onshore wind power has grown exponentially in Brazil over the last few years. Only between 2013 and 2014, electricity generation from wind grew by an astonishing 85.6 percent (EPE, 2015). As of 2015, Brazil's installed wind power capacity was of 5.5GW (Bloomberg New Energy Finance, 2015). Brazil's potential for wind power is also remarkable. A study by EPE suggests that if we only consider onshore wind power, with 100m high rotors in areas where the wind blows at an average speed of 7m/s, the total potential installed capacity could reach 247 GW. Of course, constraints such as cost and land use are not considered in this estimation. However, this goes to show that the potential of onshore wind resource in Brazil is quite high. Moreover, this estimation leaves aside the potential for offshore wind power which is not currently developed in Brazil. However, considering the country's shore length, offshore wind would also increase by much the potential for electricity generation from this resource.

Solar

Even though there is remarkably little solar generation in operation at the moment, different factors seem to point to the fact that coming years will see a boom in solar energy development in Brazil. First, Brazil's weather conditions are ideal for solar power generation. Brazil receives more than 2.500 sun hours a year, and each day there are more than 4 kWh/m^2 solar irradiation (in the least sunny areas alone). In the Northeast part of the country, the solar irradiation per day reaches 6.5 kWh/m2. This part of the country also has large parcels of land available, which could serve as solar farmland (Transfer LBC, 2015).

Second, even if the Brazilian solar industry is still underdeveloped, it seems like things are about to change, as the government is getting more involved in the expansion of this resource. In December 2014, the Brazilian government awarded auctions for a total of 900MW, guaranteeing their price for 20 years (Transfer LBC, 2015). Other auctions took place 2015, amounting to 1.8GW (Tolmasquim, 2016).

Just as for wind energy, the potential to generate solar power in Brazil is not so much limited by the availability of the resource. For instance, the EPE considers that, only for Brazil's areas where solar irradiation is the most intense ($\geq 6kWh/m^2$), there is potential to generate solar power up to 506TWh/year (Tolmasquim, 2016). However, this potential is also significantly limited by the cost and intensive land use of solar power generation.

Biomass

With an installed capacity of 14 GW, biomass is currently the third most important electricity generation source in Brazil. Sugarcane biomass accounts for the most of it, with 11 GW (Tolmasquim, 2016). The availability of biomass is directly related to urban and rural activities (agriculture, cattle farming, forestry, urban residues, etc.). The wide variety of biomass material and processes make the task of accurately estimating this resource's potential to produce electricity very difficult. In 2014, the EPE considered the potential for bioelectricity generation in Brazil to be of about 125 TWh (Tolmasquim, 2016). The extensive studies conducted by the EPE in order to design the *Plano Nacional de Energia 2050* also offers projections for the growth of biomass potential through the year 2050, where the potential could reach 380TWh (Tolmasquim, 2016). These projections can be observed in Figure 10.

Biomass from residues, especially from agriculture, represent the main growth potential for bioelectricity. For the time being however, it is important to note that since most bio-electricity comes from sugarcane, it is subject to an important seasonality factor due to the plant's growth cycle, which restricts its availability to a determined time of the year (Tolmasquim, 2016). This could create a supply risk if this resource were to become more important in the power mix.

60

Figure 13: Estimations of potential for bioelectricity generation in Brazil, 2014 through 2050
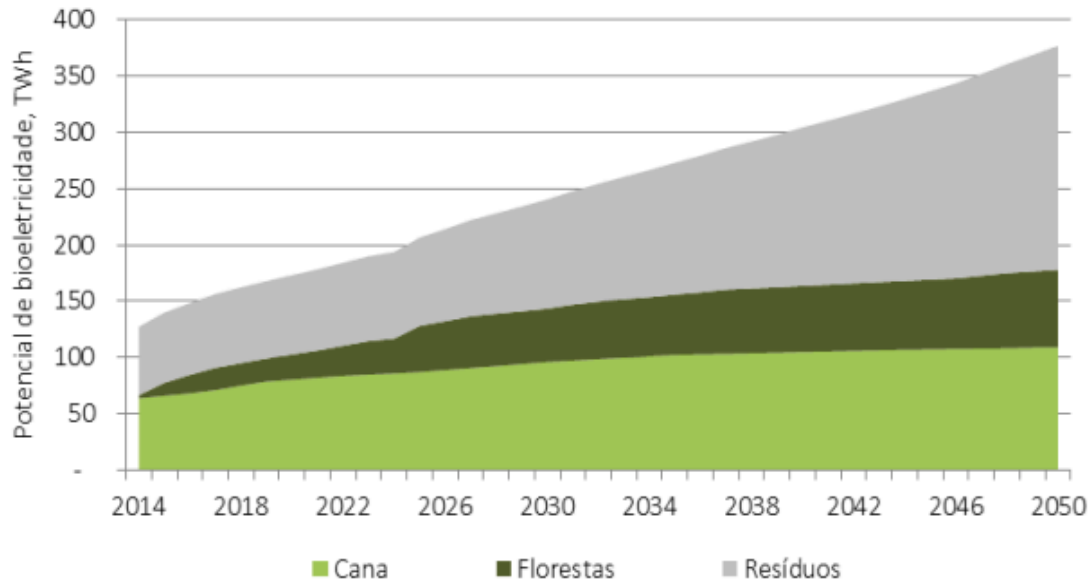
Source: (Tolmasquim, 2016)

5.4 Demand Projections for Electric Power in Brazil

Since Brazil's per capita electricity consumption is still quite low (2370kW h/year in 2014)[3], a sustained growth in demand can be expected in the long term (EPE, 2015). Figure 11 shows EPE's projections of Brazil's electricity consumption through the year 2050. These projections clearly outline a significant growth, which will create a necessity for Brazil to continuously expand its power generating capacity.

It is also worth mentioning that these projections, elaborated for the *Plano nacional de energia (PNE) 2050,* were revised downwards from the projections made for the PNE 2030, such as to account for the recession that has been slowing down Brazil's growth in the past few years (EPE, 2016). As a result, the demand grows much less in the years between 2010 and 2020 than what is it projected to grow in the following decades. This shows that these projections are moving targets, since they are highly dependent on the economic and political conjecture.

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[3] As a comparative indicator, the consumption capita is of 4,648kW h/year in Portugal, 9,486kW h/year in Australia and 23,486kW h/year in Norway (Index Mundi, 2014).

Figure 14: Projections of Brazil's total electricity consumption, 2010 through 2050 (TWh)
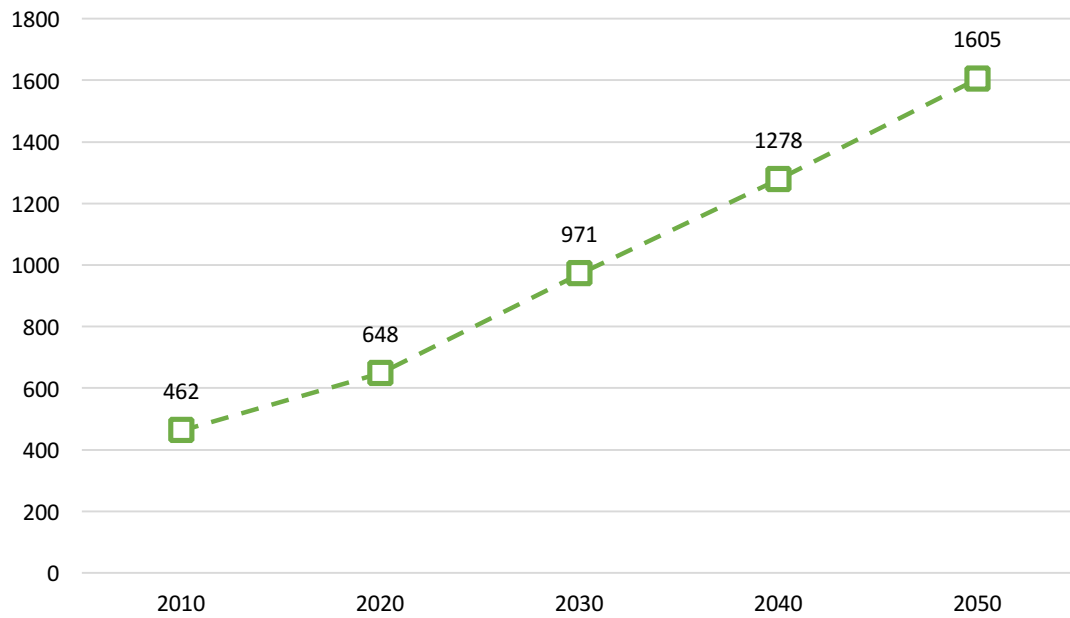
Source: (EPE, 2016)

5.5 Chapter Summary

Looking at Brazil's power sector, it is quite clear that the country needs to expand and diversify its power generation sources in order both to anticipate a strong demand growth, as well as to not be so reliant on hydropower generation. It is also evident, due to the country's immense resource base, that Brazil could proceed to this diversification with either a fossil fuels or renewable energies expansion, or some mix of both. Indeed, many possibilities are available to Brazil, hence the importance of choosing a path that yields the most utility on a social planner perspective, i.e. one that minimizes the overall risks and costs, while maximizing social welfare. To attempt at defining such an electricity generation portfolio, the methodology suggested in Chapter 4 will be applied to the case of Brazil.

Chapter 6: Results

One of the objectives of this paper was to apply the proposed methodology to the Brazilian energy sector as a case study. This section will therefore be dedicated to presenting the results of the cost analysis that was realized for the different energy technologies in Brazil, using the method suggested in section 4.1. Additionally, the cost projections discussed in section 4.2 will be used, along with the specificities of the Brazilian market outlined in Chapter 5, to discuss possible cost trajectories for the different electricity generation technologies in Brazil.

6.1 Applying the Risk-Adjusted LCOE Method to Brazil's Energy Mix

The numerous parameters necessary to the calculation of the risk-adjusted LCOE for each of the aforementioned energy technologies were retrieved from a pool of primary and secondary literature, including databases, international and national energy agencies' reports and scientific journals. When possible – and relevant, the data search was adapted to the specificities of the Brazilian energy market. In the instances where such specific figures could not be found, information was taken from a series of reliable studies from other markets and assumed to be transferable to the Brazilian case. The parameters are shown in Appendix 3, along with a short description of how they were retrieved.

Nevertheless, one important thing to keep in mind is that LCOE is a cost estimation that can vary to an important degree according to each energy project's specific characteristics. Therefore, there is no one LCOE that reflects with exactitude the cost of all projects for a certain type of power plant. Generally, LCOEs can be more accurately represented in a candlestick graph, which shows the cost range that a certain technology can be expected to fall into, rather than giving one specific LCOE value for said technology. However, for the purpose of this paper, estimations of one **average** LCOE for each technology are calculated.

This section will present the results of these calculations, along with sensitivity analysis based on the most critical assumptions of the method. For comparative purpose, both the results obtained by means of the traditional LCOE approach (Appendix 2) and the suggested risk-adjusted LCOE method (Section 4.1) will be presented for each cost scenario.

Risk-adjusted discount rate for fossil fuel risk and CO_2 cost

The first step to the calculation of the risk-adjusted LCOE was the identification of both the discount rate (r), and the calculation of the risk-adjusted discount rates for the fuel component of the total cost of each fossil fuel technology (d_f), as well as the risk-adjusted discount rate for the CO_2 cost (d_c).

The discount rate (r) is a sensitive parameter; too great a distortion between the choice of this variable and its actual value can affect the merit order of technologies. It is therefore essential to select it methodologically. In section 4.1, three methods were identified to help estimate (r).

First, in their report, IEA (2015) use a real discount rate of 10 percent when calculating the cost of investments in a high-risk environment, which would be the case for Brazil.

Second, the long-term government bond rates of the country where the investment takes place can be used. In Brazil, a 10-year government bond currently has a rate of 12,44 percent (Trading Economics, 2016). In their paper, Arapogianni, et al. (2009) use a 30 year bond to estimate (r), which is more consistent with the lifetime of most power plants. However, it would appear that the Brazilian government does not offer such long-term bonds. If they did however, the rate might be expected to be a bit lower than its 10-year counterpart.

Finally, a third method is to look at the country's interest rate, as determined by the central bank. Amid political uncertainty and economic recession, the Central Bank of Brazil has been keeping the key interest rate at a level of 14,25 percent for several consecutive periods (Trading Economics, 2016). Interest rate in Brazil has always been remarkably volatile, reaching an all-time high of 45 percent in March of 1999 and a record low of 7.25 percent in October of 2012 (Trading Economics, 2016), which makes it difficult to predict a trajectory for future interest rates, especially since it depends, in a large extent, on the outcome of the political turmoil the country is experiencing.

For the government bond and the central bank interest rate, it could not be determined whether the estimations used were expressed in nominal terms or in real terms, and were therefore assumed to be in real terms. Considering these three elements, the assumption of a discount rate (r) of 12 percent seems reasonable. Concretely though, 12 percent is rather high, more than what is usually used for LCOE estimations. It will be kept as a means to be conservative regarding the estimations for Brazil, bearing in mind that the capital intensive technologies' cost might appear inflated due to this parameter.

As for the calculation of the risk-adjusted discount rates for each fuel (d_f) and for the cost of carbon (d_c), the first step is to draw assumptions for the the risk premium RP, as well as the betas β_f of each fuel, in order to use the CAPM equation to determine the new discount rates. The values used by Arapogianni, et al. (2009) (see Table 1, section 3.2.2) were carried to this paper, despite the limitations already mentioned regarding the accuracy of these betas for the Brazilian market. Additionally, no recent data was found for the beta of fuel oil. However, older data had pointed to the fact that oil and gas had similar betas (Awerbuch, 1993). That assumption was therefore carried to this research. With a determined discount rate of 12 percent for the Brazilian market, the risk-adjusted discount rates for the different fuels prices and the carbon price, as calculated with CAPM, are presented in Table 3.

Table 4: Risk-adjusted discount rate for fossil fuel cost calculation

	Coal	Gas	Fuel oil	Uranium	CO_2
Risk-adjusted discount rate	0.10	0.11	0.11	0.115	0.1

With a negative beta for all five elements, the CAPM yields new discount rates that are lower than the original discount rate (r). It can seem counter-intuitive that the risk-adjusted discount rates are lower than the 12 percent discount rate used as the baseline. However, one must bear in mind that these parts of the risk-adjusted LCOE equation are calculated through a present value approach, just as Arapogianni, et al.'s model (2009), presented in section 3.2 of the literature review, which means that a lower discount rate yields a higher present value for these cost components.

LCOE calculations: traditional approach vs. risks and externalities accounting approach

Figure 15 shows the calculations of both the traditional LCOEs and the risk and environmental externalities accounting LCOEs, respectively labeled *LCOE* and *Risk-adj.*, for each of the power generation technologies that were identified as relevant for the Brazilian context. The detailed cost information for each component can be found in Table 8 of Appendix 3.

The first observation that can be made is that the risk-adjusted method yields a higher cost for all the technologies. This is the effect of the internalization of the diverse risks associated to power generation. Consequently, each technology's price is higher in the risk-adjusted method, but reflects more accurately the real price of these technologies by considering market risks and technology specificities, which the traditional LCOE fails to do.

Figure 15: Energy generation cost per technology in Brazil; traditional LCOE vs risks and externalities accounting LCOE (EUR/MWh)
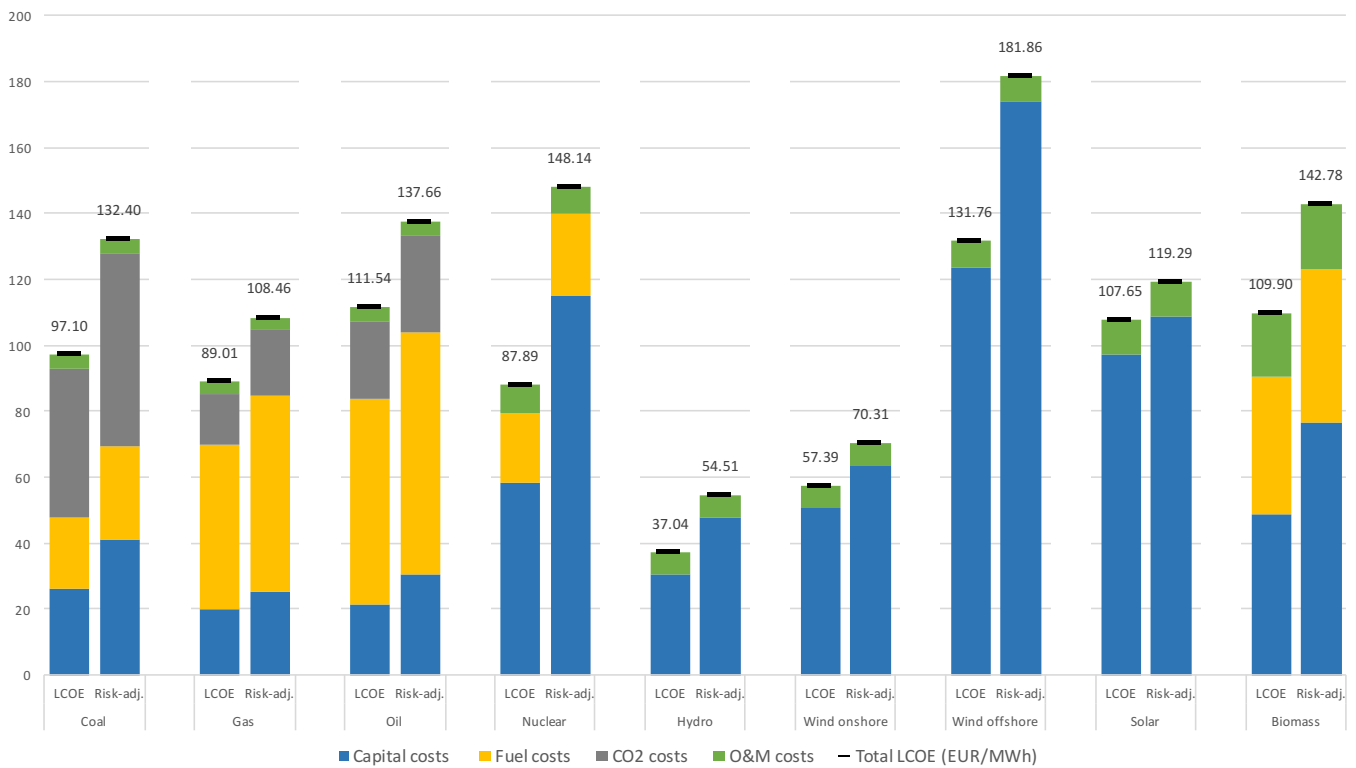
Taking a closer look at what risk factors seem to affect LCOEs the most, it is noticeable that the capital intensive technologies tend to be largely impacted by the risk-adjusted method, but only if they combine a high capital cost with a long construction period. For instance, nuclear and offshore wind are the two technologies that are impacted the most whereas solar, also a capital intensive technology, is only marginally affected by capital cost risk due to its short construction period. Additionally, the capital cost risk effect would be much lesser with a lower discount rate.

Evidently, only fossil fuel technologies and nuclear are affected by fuel price risks, and only fossil fuel technologies are affected by the CO_2 price risk. In this case, oil is the technology that is the most affected by fuel price risk, due to its higher price, and coal is the most affected by CO_2 price risk, due to its high emission factor. Interestingly, even though the risk-adjusted method affects the three fossil fuel technologies to different degrees, it does not change the merit order between them compared to the usual LCOE valuation. However, it does affect the capacity of solar energy to be cost competitive with both coal and oil power plants.

As mentioned, two sensitivity analysis were also conducted in order to acknowledge the outcome variation that occurs by changing two of the most sensitive variables of this cost valuation: 1) the cost of CO_2 emissions and 2) the capacity factors.

Critical factor 1: Cost of CO$_2$ emissions

One of the most important difference in cost across technologies is observed through different CO_2 cost scenarios. As mentioned in section 4.1, three scenarios are generally considered in the literature: *business-as-usual*, *probable-policy* and *shadow-price*. For each of these scenarios, Bazilian & Roques (2008) determined that the cost of emitting CO_2 would respectively take the values of €0/ton CO_2, €15/ton CO_2 and €35/ton CO_2.

Since this paper is written with a social planner perspective, the *shadow-price* scenario, with a cost of €35/ton CO_2 was used to calculate the LCOEs. The justification for it is that a social planner is interested in maximizing social welfare, and would therefore consider all external costs of generating electricity within the cost valuation, including environmental costs. This

has been included in both the LCOE methods calculated, as a way to compare the CO_2 cost and the risk-adjusted CO_2 cost. However, since these costs are rarely considered in an actual investment valuation, the calculations were also run for the two other scenarios, for comparison purpose. The results for both scenarios can be observed in Appendix 4.

As can be expected, the different scenarios affect how the fossil fuel technologies compare with non-emitting technologies; coal, gas and oil are much more cost competitive in the €0/ton CO_2 scenario, both with the usual LCOE method and the risk-adjusted method. In fact, aside from hydro and onshore wind, none of the renewable technology is remotely competitive with fossil fuel generation. The same arises in the €15/ton CO_2 scenario, although to a lesser extent; solar is then almost competitive with oil, but still much more expensive than coal and gas.

Additionally, the different CO_2 price scenarios also affect how fossil fuel technologies compete against each other. Due to coal's high emitting factor, its carbon cost rises sharply, which makes gas generation more competitive with the risk-adjusted calculation of the €15/ton CO_2 scenario, and with both the LCOE and the risk-adjusted method in the €35/ton CO_2 scenario, whereas it is cheaper than gas in the *business-as-usual* scenario.

Critical factor 2: Capacity factor

The choice of the capacity factor parameters, more specifically for coal, gas and fuel oil, turned out to be a highly critical element in the cost valuation of energy for Brazil, which is quite particular to this country. The capacity factor measures the power produced over a period of time, divided by the power that could have been produced if the plant was running at full capacity over the whole period (Narbel, et al., 2014). In general, when fossil fuel generation is included in a power system, it is used as baseload generation. In this case, the typical capacity factor for coal, gas and fuel oil generation is estimated at 0.85 (IEA/NEA/OECD, 2015) (Losekann, et al., 2013).

However, the current situation in Brazil is rather different; since hydropower constitute most of the baseload generation, fossil fuel plants tend not to function as much as they could. This

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results in lower capacity factors for coal, gas and fuel oil generation, which are estimated to take the respective values of 0.44, 0.29 and 0.28 in Brazil (EIA, 2015). This has a great impact on the LCOE of these technologies; since the unit output of electricity is smaller, each unit's share of the cost elements that do not vary with the number of unit produced, i.e. capital cost and O&M, is much larger, resulting in a much higher cost per MWh. This can easily be observed in Figure 16, for which the capacity factor figures of coal, gas and fuel oil are set to the values specific to Brazil's current situation.

Indeed, the costs of the three fossil fuel technology are significantly higher when they are calculated with a lower capacity factor. In fact, comparing the results of the risk-adjusted method with both cost scenarios results in a cost increase of 32 percent for coal, 51 percent for gas and 40 percent for fuel oil.

Figure 16: Energy generation cost per technology in Brazil: sensitivity analysis with fossil fuel capacity factors (EUR/MWh)
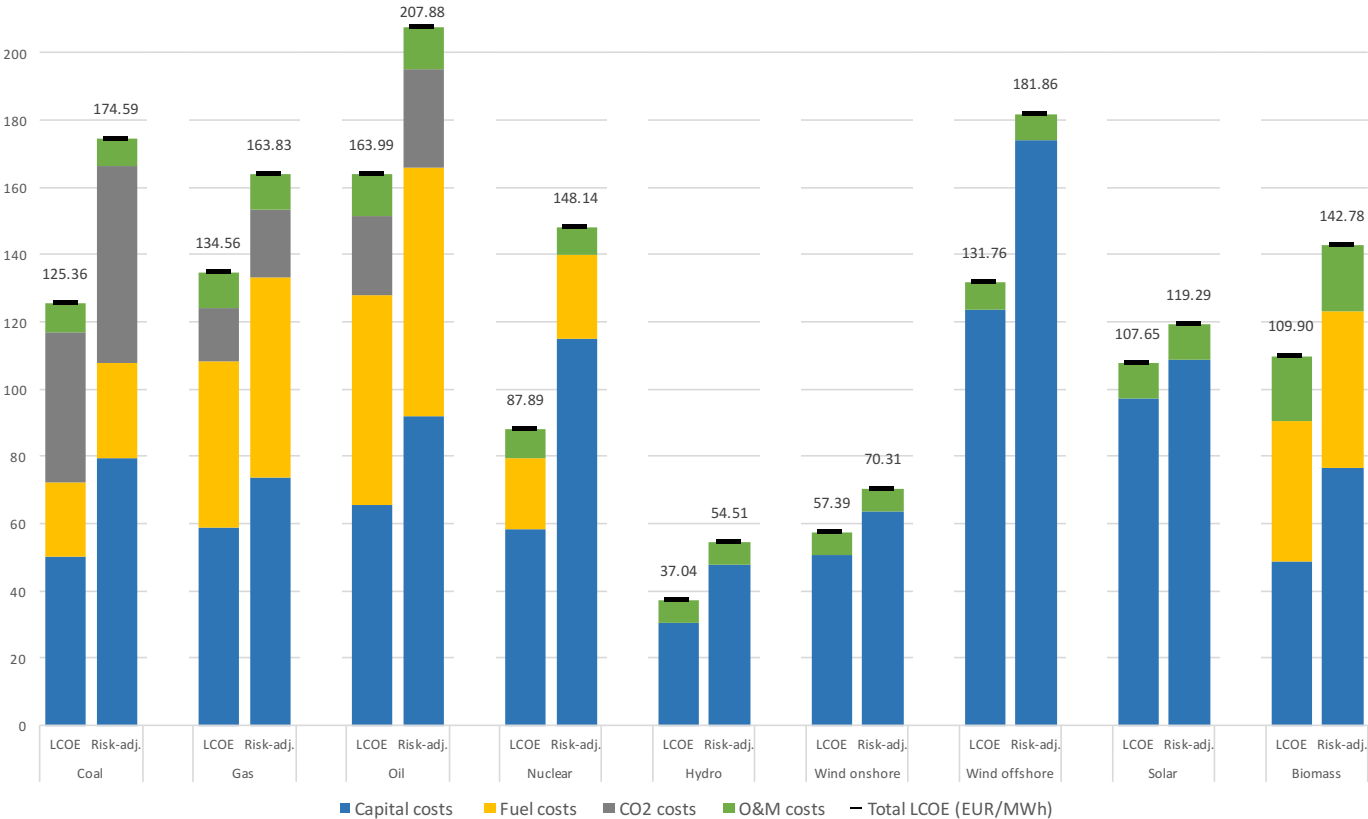
As mentioned in Chapter 5, in the last few years, Brazil had to use fossil fuel generation as peak-load electricity to balance the system, which has been disrupted by an insufficient hydro production caused by important droughts. It was also mentioned that using this solution resulted in very high costs, even though fossil fuel generation, especially gas and coal, is generally thought to be rather cheap; the differentiation between baseload and peak-load capacity factors certainly is an element of explanation to help understand this occurrence.

System cost

As mentioned in chapter 4.1, due to the high complexity of assessing them, the system costs are not included in the cost valuation presented above. However, as they can be substantial, they must not be overlooked. In most power systems, intermittent technologies, such as wind and solar, as well as inflexible generation sources, such as nuclear and coal, are known to potentially cause rather important system costs, depending on their role in the power mix, whereas easily dispatchable sources such as gas and hydro can potentially generate a system benefit (Danish Energy Agency, 2015). In the case of Brazil, it is especially important to consider system costs when looking at hydropower LCOEs. At first glance, hydropower seems to be, by far, the most advantageous electricity source. However, by taking a system perspective, it is evident that the over-reliance of Brazil on this energy source is the main cause of the aforementioned high costs incurred to balance the system with fossil fuels. To a certain extent, these cost should be considered as system costs spawned by hydropower shortages. If these costs were to be internalized in the LCOE, hydropower would appear much less cost competitive.

On the other hand, since droughts in Brazil continuously put pressure on the heavily hydropower-reliant power system, a system of reservoirs combined with an increased share of wind and solar power could go a long way in avoiding electricity crisis such as have been seen in recent years; wind and solar power would reduce the stress on hydropower plants, while allowing the reservoirs to fill up and, in turn, dispatch extra power when wind and solar capacity is low. An optimal combination of these technologies could significantly smoothen the overall electricity generation pattern in Brazil,

thereby enabling a drastic reduction of system costs that might otherwise be incurred by a poorly planned combination of intermittent resources or an over-reliance on hydropower.

6.2 Cost Projections

Evidently, in Brazil, the learning effect on the cost of new energy technologies does not depend only on their own installed capacity or level of expertise. As a later adopter of certain technologies, Brazil benefits from previous advances by accessing more evolved technologies at better prices than many other earlier adopters did.

This is also enhanced by the auctioning system of Brazil, in which most renewable energy projects are allocated to the project developer that can offer the better price for it. If that expertize happens to come from outside Brazil, this creates the occasion for companies to enter in foreign direct investment projects in the country and bring their high level of know-how. Moreover, Brazil's high potential for renewable energy sources can yield a highly efficient generation capacity, especially if power plants are well geographically distributed such as to take advantage of a disparity and complementarity weather conditions. This can also be a significant advantage in terms of LCOEs for renewable technologies in Brazil, as a greater efficiency helps reducing the cost per output unit. Combining these factors, it is safe to say that the cost reductions for wind and solar power in Brazil are likely to follow the global projections discussed in Section 4.2.

As for fossil fuel technologies, even though there is little potential for investment cost reductions, some improvements in efficiencies might have an overall LCOE reduction effect. However, uncertainties around fuel prices and CO_2 prices could easily offset these benefits. Consequently, fossil fuel technologies LCOEs will be assumed to remain stable over the forecasted period.

The same will be assumed for nuclear power, since much uncertainties remain about the desirability and feasibility of a nuclear power expansion in Brazil.

Bioelectricity is certainly a very interesting case for Brazil, seeing as the country shows a considerable potential for expansion of this resource. One the one hand, leveraging this potential could result in long term cost reductions due to the technology learning effect. Additionally, since biomass can be stored and easily dispatched, keeping a manageable share of it in the power mix can yield significant system cost reductions, as it can be used as balancing generation. On the other hand, planning too high a share of biomass generation might, on the contrary, increase the system costs; depending on the type of bioelectricity, biofuel supply can be subject to important supply irregularities, which could lead to supply shortages. Finally, very little is known as to the cost trajectory of different biofuels, especially if the demand were to increase. For these reasons, the cost of generating electricity from biomass will also be assumed to remain stable.

Finally, hydroelectricity, much as fossil fuel technologies, reached cost maturity and, on a global level, large-scale hydro power costs are not expected to decrease further. In Brazil, especially if we consider the costs of risks and externalities, hydro LCOEs should even be expected to increase; first, by internalizing the cost of balancing the disrupted hydropower generation, the high costs that were incurred by using peak-load fossil fuel generation to circumvent hydro shortage can be seen as system costs of hydropower. These costs might significantly decrease by using more appropriate peak-load solutions, but the fact remains that hydropower shortages must be considered as a cost of relying too much on this resource. Second, for further development of hydropower, Brazil would have to implement storage solutions, such as more reservoir capacity, or even pumped-storage solutions. These solutions would significantly add to the investment cost of hydro, but would also have the potential to greatly reduce the system cost by smoothing down the impact of a disrupted generation due to droughts or intermittent renewable technologies. At last, most new hydropower plants that can be expected to be built in the future are would also incur additional grid costs due to the increasingly distant locations of the available hydro basins. For all these reasons, the LCOE of hydropower will be assumed to progressively increase in Brazil over the forecasted period. With these considerations in mind, Figure 17 presents this paper's suggestion for the LCOE projections of renewable energy sources through 2050, specifically tailored for the Brazilian energy market.

Figure 17: Projections of cost trajectories for renewable energy technologies in Brazil
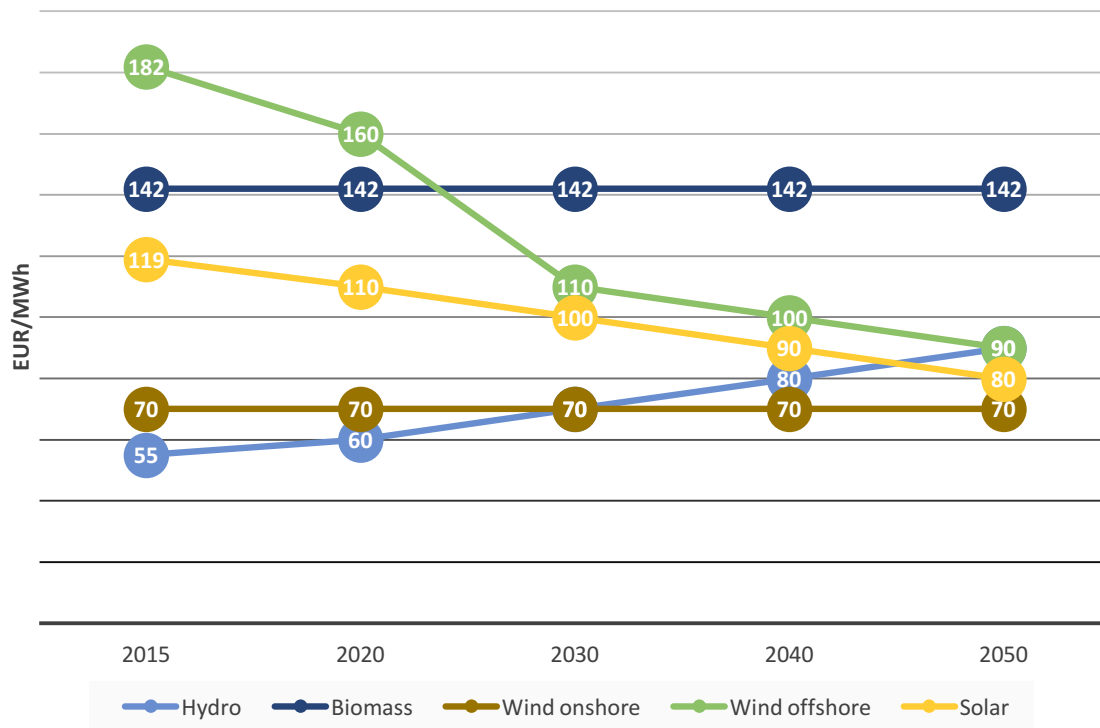
6.3 Chapter Summary

Chapter 6 presented the results of the cost valuations that were made with both the traditional LCOE method and the risk-adjusted method presented in Chapter 4. It also described how two critical variables of the calculations – CO_2 cost and capacity factors – can affect the merit order of technologies in a power mix. A discussion was also presented about how the different technologies may affect the system costs in the particular context of Brazil. Finally, cost projections were presented, taking in considerations both the learning effect presented in Chapter 4, and the specificities of the Brazilian power market.

The next chapter will gather all these elements in a discussion of a possible scenario for the optimal technology mix to plan for Brazil's power system expansion over the next few decades.

Chapter 7: Discussion

The main purpose of this paper was to to develop an approach to electricity generation cost valuation that accounts for the different market risks and externalities, and applying it to the context of the Brazilian energy market. In order to extend the contribution of this research, the impact of system costs and complementarities, as well as the learning curve effect on cost trajectories were examined. Section 7.1 offers a discussion on how all these elements can be tied up together in order to foster an energy expansion planning that builds towards an optimally integrated power system, for the present and future energy needs.

Indeed, considering all of the aforementioned factors as part of an interdependent system is essential and can help policy makers take the best informed decisions that would maximize the utility and social welfare of the power system, on a long term perspective. Section 7.2 will acknowledge and discuss the fact that energy policies will still have an important role to play in order to yield such a power system.

Finally, a discussion of the weaknesses and limitations of the method used in this paper will be presented in section 7.3.

7.1 Towards an Optimally Integrated Power System

The literature review of this paper allowed for a comprehensive understanding of the state of the art regarding energy planning theory, which laid the basis to the methodology proposed in this paper. Much like with the methods analysed in the literature review, the environmental externalities were integrated in the suggested cost valuation method via the integration of a cost on carbon dioxide emissions. This cost was directly related to volume emitted for each technology, therefore affecting the most polluting generation sources the more. The sensitivity analysis of the different CO_2 price scenarios showed that considering the environmental externalities of electricity generation significantly impacts the cost competitiveness of renewable energy sources with fossil fuel power plants.

Additionally, the risk and externalities accounting LCOE method presented in this paper allowed for a more comprehensive assessment of the generation cost of energy by including

the same risks as the Mean-Variance Portfolio method does, i.e. capital cost risk, fuel price risk and carbon price risk. As a result, the LCOEs calculated with the suggested method yielded a more diverse basis of cost competitive power generation technologies to pick from when planning the future electricity mix.

In order to use Brazil as a case study, it was important to understand the main elements that may affect the future expansion of the country's power system. Brazil is a resource rich country; it has the potential to develop a truly diverse electricity generation portfolio due to its immense energy resources potential, in terms of both fossil fuels and renewables. Brazil is also an emerging country, for which demand for electric power is planned to grow sharply in the upcoming decades. After having historically been reliant on almost exclusively hydropower generation, this resource has now started to fail Brazil due to frequent droughts. This makes it necessary for Brazil to plan a new configuration for their electricity generating portfolio, one that is not so dependent on one resource and vulnerable to its irregularities. However, Brazil is currently experiencing a serious economic recession and political instability. Combined with high levels of poverty and inequality, these factors make for a difficult context to implement an energy reform, especially one that would be expensive and put price pressure on the rate-payers.

Brazil has the potential to become a world leader in clean energy. It could also easily fulfill its future energy needs with mostly fossil fuel generation. The culminating point of the cost valuation method suggested in this paper was to show how accounting for the diverse risks and externalities of power generation could help a social planner, such as a policy maker, gain a more thorough assessment of the real cost of energy as part of a system, which will hopefully contribute to plan towards an optimally integrated power system.

As presented in Chapter 2, the notion of optimality applied to power systems in this paper refers to three essential factors:

1) *The use of **the highest possible amount of renewable energy sources**, allowing for environmental sustainability;*

2) ***Diversity of energy sources***, enhancing the security of energy supply and the reliability of electricity generation systems;

3) ***Cost minimization***, allowing for an economically feasible and viable energy reform.

By combining these factors with the projections for power demand for Brazil (Chapter 5), the results of the cost analysis of energy generation in Brazil (Chapter 6) and the LCOE projections for Brazil (Chapter 6), it is possible to draw a hypothetical scenario for the expansion of the electricity mix in Brazil, so as to fulfill the future demand whilst implementing an optimally integrated power system that would maximize social welfare. Figure 18 graphically shows this scenario for the energy expansion trajectory in Brazil, along with the percentage of each technology at any given period through the year 2050.

The main objective of drawing this scenario is to discuss the possibility for Brazil to expand its electricity generation system using mainly renewable energy sources. For simplicity purpose, a status quo was therefore assumed for the three fossil fuel technologies, nuclear and the category "other", meaning that the absolute output generated by these sources through the year 2050 will be set to remain at their 2015 levels. This assumption, admittedly quite far-fetched, should be understood by the reader merely as a means to observe the possible development of renewable energies in Brazil.

Moreover, the scenario was drawn such as to fit the demand projections for electricity consumption. It therefore displays the electricity output needed of each energy source rather than the planned installed capacity, and it also disregards electricity exports and imports.

Figure 18: Scenario of a renewable energy expansion in Brazil; 2015 through 2050
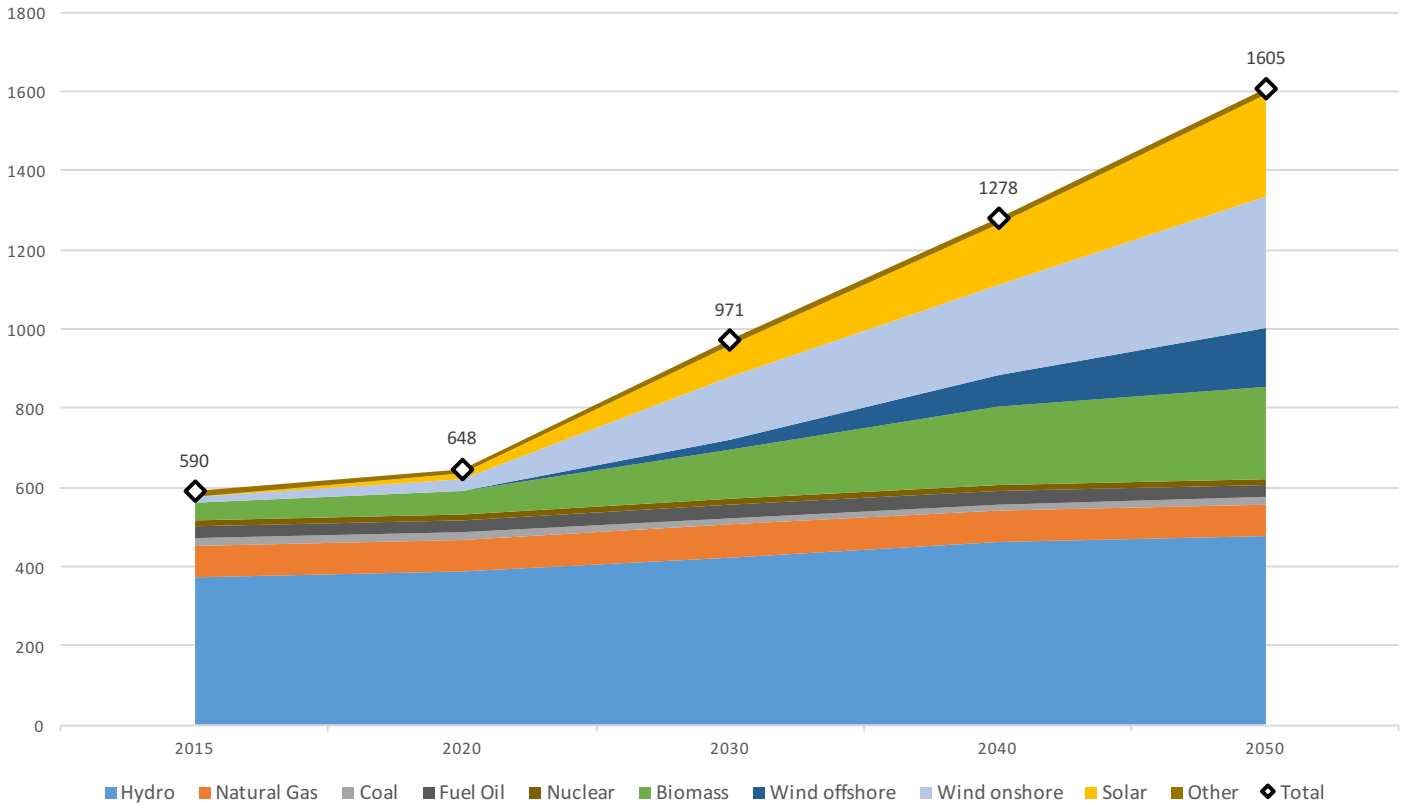
	2015	2020	2030	2040	2050
■ Other	2%	2%	1%	1%	1%
■ Solar	0%	2%	8%	12%	16%
■ Wind onshore	2%	5%	16%	18%	21%
■ Wind offshore	0%	0%	3%	6%	9%
■ Biomass	8%	8%	13%	16%	14%
■ Nuclear	3%	2%	2%	1%	1%
■ Fuel Oil	5%	5%	3%	3%	2%
■ Coal	3%	3%	2%	1%	1%
■ Natural Gas	14%	13%	8%	6%	5%
■ Hydro	63%	60%	44%	36%	30%

In the scenario drawn for the energy expansion in Brazil, the share of renewable electricity, including hydro, wind (onshore and offshore), solar and biomass, gradually increases to reach a proportion of 90 percent in 2050, thereby fulfilling the environmental sustainability criteria by integrating such **a high share of renewable power generation sources in the electricity mix**. By keeping the energy generation from coal, gas and oil at their 2015 level, Brazil would only have a share of 8 percent of CO_2 emitting technologies in their generation portfolio that

by 2050. It can also be observed that the scenario shows a much greater **diversity** of power generating sources than the current power mix in Brazil. As seen in section 2.2, diversity is described by the combination of **variety, balance and disparity**.

The future energy mix scenario represented in Figure 18 includes 10 categories of energy sources (including *other*), which is two options more than in Brazil's current electricity mix. These options also represent all the main energy generation sources that are currently known to be scalable, which means that the **variety** of the mix can be considered to be at its maximum possible.

The mix also shows a good **balance** between these options; according to this scenario, by 2050, no energy source accounts for more than 30 percent of the portfolio, which in itself can be a great indicator of a reduced risk, especially when compared with the 63 percent share that hydropower has in the current generation mix. Even though the absolute amount of hydropower remains the same, the risk that draught put on this 30 percent of the portfolio can be largely reduced by taking advantage of resources complementarities, as will be elaborated further below.

Referring back to the branching structure presented in Figure 5 (and assuming that the risk factors to which these different sources might be vulnerable are similar regardless of the area), one can see that the scenario also builds towards generation portfolio that offers **disparity** across sources ; even though hydro and offshore wind (amounting to a total of 39 percent in 2050) are quite correlated, there is a good disparity between both of them and solar (16 percent) or onshore wind (21 percent), and an even greater one with bioelectricity (14 percent), all of which, if we refer to Figure 5, show different degree of disparity, meaning that they are generally not affected by the same risk factors.

Above all, this discrepancy between these different technologies is the most critical element that makes such a diversity possible, as it creates the necessary complementarities across the system, allowing for a naturally smooth generation by allowing the different technologies to act as a back-up for each other. Indeed, since energy generation with such variable renewable

energies (VRE) as wind, solar and hydro (hydro can be considered as a VRE in Brazil due to the irregularity of its availability) mostly depend on weather conditions. Therefore, a balanced share of VREs that work optimally under different conditions would go a long way in mitigating the intermittency risk of VREs. Moreover, as Brazil is an immense country with an interconnected system, geographical dispersion of the VREs power plant also has the potential to yield further smoothing effects on the generation pattern. Since these complementarities are also a main factor for the cost minimization element of an optimal system, how they play concretely in Brazil's case will be elaborated further below.

Moreover, if diversity is an important factor of energy security, **self-sufficiency** also is essential. Even though the scenario disregards exports and imports, it can still be inferred from the resource potential assessment realised in Chapter 5, that Brazil definitely has the potential to be self-sufficient and even remain an electricity net exporter, as it currently is (EPE, 2015).

As for the **cost minimization** aspect, two angles must be considered; the cost of investing in each technology, as reported by the LCOE valuation, and the system cost of the electricity generation mix, which can be either pumped up or smoothed down according to the extent of the complementarities between the technologies in the mix. This differentiation is extremely important in the case of Brazil, especially when it comes to hydropower. Indeed, the LCOE analysis shows that this source has the lowest cost when considered as an isolated investment. However, as discussed previously, hydropower has been the cause of steep system costs in the recent years. Moreover, the potential for new hydropower plant is limited by the remoteness of the unexploited hydro basins, which means that every new hydro power plant will require significant grid investments and will therefore result in a much higher LCOE, assuming these costs are included in the capital costs of the power plant, or will be passed on as an additional system cost otherwise. Either way, this goes to show that a large increase of hydro generation, in addition to increasing the portfolio risk due to a lack of diversity, would also not be the economic choice for Brazil.

The scenario shows a fast increase of onshore wind power generation between 2020 and 2030. As the only renewable energy source that is currently cost-competitive, it really is the "low-hanging fruit" for a short-term renewable expansion. Even though the intermittent generation pattern of wind power is generally thought to increase system costs, it might actually be the opposite in Brazil; with the flexibility of dispatch offered by Brazil's large hydro reservoirs, wind power can serve as base load when the wind conditions are favorable, allowing the hydro reservoirs to fill up, gathering all the necessary capacity to circumvent wind intermittencies, and even save up extra capacity for times of droughts, which can reduce by much the risk that these weather occurrences put on the hydropower share of the portfolio.

After the year 2030, as the costs of offshore wind and solar become more and more competitive, these technologies progressively take up a higher share of the generation mix and could join offshore wind in the baseload generation. As stated previously, the fact that these VREs depend on different weather conditions is an important element that can help regulate the intermittency of the generation pattern of each individual resource. Some studies even suggest that there is a negative correlation between the output of wind power and solar power, especially when looking at seasonal variability (Bett & Thornton, 2016), (Stappel, et al., 2015). For instance, in Europe, "the monthly amounts of PV and wind power production [show] that decreasing wind power output in the summer is offset by higher PV generation and vice versa, with only slight differences between monthly output levels" (Stappel, et al., 2015). In short, the complementarity between the generation pattern of these technologies, combined with an optimal geographical repartition of the power plants across Brazil, would yield an overall smoother generation, thereby substantially reducing the system costs and risk, which are are generally seen as an obstacle to the scalability of these resources.

Additionally, hydropower shows a great potential for energy storage, as hydro reservoirs can act as a cheap and readily available battery. In Brazil, hydropower could play an important role in regulating and balancing the generation from wind and solar power, whether it is by using its already large reservoir capacity or, if need be, implementing pumped storage facilities. Using hydropower as a battery is not a new concept; it has been largely discussed in Europe that "Norwegian hydropower is the most cost-efficient source of energy that

Germany could adopt as back-up for solar cells and wind-power" (Tønseth, 2014). Although important issues related to transmission have been encountered, the fact remains that hydropower storage, if available in a targeted area, is an inexpensive and environmentally friendly way of fostering the large scale implementation of VREs in a power system without compromising on the reliability of the power system. Since hydro reservoirs are already available in key areas of the Brazilian interconnected system where they currently serve as baseload generation, the necessary transmission infrastructure is already available and would therefore not pose such an issue. Due to the droughts, however, it would be advisable not to plan to much of an increase in hydropower capacity. In the scenario shown in Figure 18, through 2050, hydropower would gradually shift from being the main baseload technology to serving as the main balancing technology of the Brazilian power system. This would reduce the pressure on the hydro-power plants, allowing the reservoirs to fill up when the VREs' capacity is high, while offering a much cheaper solution to output variability than than using peak-load fossil fuel generation.

Finally, the share of biomass could also increase due to the high potential of Brazil for this resource. Even though it is not known if and by how much the biomass LCOE will decrease, bioelectricity also offers a great generation flexibility, as it can be stored and turned on and off with the same ease as for gas and hydro power plants. The high LCOE of biomass would therefore be compensated by a positive system cost, as it would help hydropower in regulating the generation of intermittent renewables. Combined together, hydropower and biomass would represent 44 percent of the generation mix by 2050. Both storable and dispatchable, they would represent a strong asset in Brazil's generation portfolio, allowing the country to fully implement an expansion of VREs, which would account for 36% of the mix by 2050, without compromising on the reliability of the power system, and having a sufficient and diverse renewable back-up capacity to overcome the intermittence challenge.

Planning such an integration of hydro, biomass and VREs could drastically reduce the system costs that are currently running high because of a bad combination of generating technologies, and this cost reduction would offset the higher investment costs that might be necessary in order to push VRE technologies in the generation mix. This notion is also

coherent with portfolio theory, which states that the volatility of a portfolio can be decreased by an asset that has opposite risk factors than the rest of the portfolio, even if this asset has a higher individual risk than the other assets in the portfolio (Berk & DeMarzo, 2014).

7.2 The Need for Policies

When looking at the findings of this paper, one needs to bear in mind that if the LCOEs are so high for some energy sources, it is because different risk and externalities were internalized so as to give an overview of the cost from a social planner perspective. In fact, according to Bazilian & Roques (2008), other studies that have taken different approaches to energy planning by adopting a private investor perspective yielded substantially different optimal portfolios. In a *business-as-usual* scenario, the LCOEs of energy sources such as coal and gas, are much lower than the results found in the *shadow-price* scenario adopted by a social planner analysis such as this one. This can be observed in Figure 19 (Appendix 4), where the traditional LCOEs integrate neither the risks nor the environmental externalities that were considered throughout this paper. Diversity and environmental sustainability have little value to private investors. In a liberalized and deregulated electricity market, they will merely be interested in minimizing the cost of electricity generation, so as to be able to compete on electricity prices. Consequently, from an investor point of view, fossil fuel generation is still among the cheapest sources to invest in and, considering the hydropower situation in Brazil, a transition towards a more fossil fuel intensive power system, where fossil fuels are part of the baseload generation, can make much sense from an investor perspective.

This considerable difference between the results of the approach taken from an investor perspective and the approach taken during this study illustrates that the socially efficient portfolio cannot be reached by leaving the market forces to their own devices, but only by implementing a series of energy policies, which can modify the free market's characteristics in such a way that the socially efficient energy portfolio also becomes the best opportunities for investors.

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7.3 Limitations and further Research

The adjusted LCOE method presented in this paper is a useful extension the traditional LCOE method because it accounts for a variety of risk factors and externalities that the latter fails to include. Because the method presented in this paper includes the environmental costs and the market and technology risks related to generating power with each generating technology, it constitutes a more comprehensive cost assessment for a social planner and is therefore a valuable contribution to the academic literature on LCOE analysis.

However, even the adjusted LCOE method is subject to the important limitation also encountered by the theories presented in Chapter 3, that is, it does not account for the fact that the configuration and balance of a given system can be planned such as to drastically reduce the system cost of energy generation. The complementarities between the energy sources can be taken advantage of to optimize the utility, reliability, efficiency and cost of a power system.

Yet, these are not reflected in any stand-alone cost analysis, since they can absolutely vary from a power system to the other, according to many different factors, such as the availability of the different resources, the geographical spread of the power system, the readiness and efficiency of transmission infrastructure, and so on. For this reason, an assessment of an average system cost to include in the LCOE of each technology would both be extremely complex to conduct and only yield a low level of accuracy in a multi-period planning exercise where the evolving system considerably modify these costs.

Rather, discussions were held throughout this paper to try and grasp how considering these factors can affect the value that is attributed to each energy generation technology in Brazil. The culminating point of these discussions was the scenario presented in the previous section to describe how planning an optimally integrated power system for the energy expansion for the future decades in Brazil can be approached in a system perspective, by considering both the individual cost of each technologies and how they can affect the overall cost and efficiency of this specific power system.

Nevertheless, this multi-period energy planning exercise was merely a hypothetical scenario inferred from the different information gathered throughout this paper. To improve the robustness of the analysis presented in this paper, an interesting extension for future research would be to implement a mathematical optimization model that would include all the factors mentioned in this paper. Such a study should account for the risks and externalities cost of each technology, but also how the specificities of a given power system can affect the overall system cost, and how the different energy sources can interact together to improve the efficiency of said system.

Chapter 8: Summary and Conclusion

The research questions of this thesis ask how can a social planner or policy maker can 1) integrate the different risks and externalities of energy generation in the cost valuation of each technology and 2) plan towards an optimally integrated power system to fulfill the present and future energy need of this country? In analysing these questions, this study aimed to develop a cost valuation method that provides a more comprehensive assessment of the cost of electricity generation by including the cost of environmental externalities, as well as the different market risks and technology risks applicable, aspects traditional stand-alone valuation methods fail to include. Moreover, this research paper described other main important factors that are to be considered in energy planning, even though they are not integrated in each technology's cost, namely the system cost and the complementarities between different technologies. By default, the cost valuation does not account for factors like system cost and technology complementarities. Without understanding these aspects in addition to the knowledge gained from the valuation method, one cannot get a comprehensive insight of the subject matter and in turn, one cannot infer implications for the optimal policymaking in a specific context. The information discussed regarding how the system configuration can affect the cost and reliability of the power system should help providing a more comprehensive assessment of the cost of each power generation technology, as well as their value in a specific system, than the traditional methods, allowing to pose informed recommendations to shape a country's power system expansion.

The paper gave a brief overview and justification of the factors that would be considered as necessary to deem a power system optimal. The reader was subsequently introduced to some of the main theories that have been put forth in the energy planning field of research, which laid the foundations to the methodological approach adopted by this paper. The methodology employed consisted of both a cost valuation method, and a discussion of what critical elements a benevolent social planner aiming to transition the energy system towards clean energies must consider to maximize the utility and efficiency of the power system, from a system perspective rather than a stand-alone least-cost technology one. This thesis complements the existing academic literature in the field of energy planning, which has previously failed to combine valuation methods with power system considerations.

The case study analysis applied the methodology to the Brazilian power sector and allowed for a concrete understanding of how all these elements would interact together in the specific context of this market. This led the author to suggest a possible path for the expansion of the electricity mix a policymaker could consider in order to build towards an optimal, renewable energy-based, reliant and cost efficient power system that maximizes social welfare.

One key finding from the study case analysis is that, as helpful as a LCOE analysis can be to compare technologies, it should not be the sole basis of an energy planning exercise, even if the LCOE calculation is adjusted to include the different risks it usually lacks to account for. For instance, in Brazil, using the cheapest energy source, hydropower, to expand the power system in the future would be a grave mistake, as it would create an extremely risky, unreliable and costly energy mix. In order to avoid future price volatility and power outages, system risks and LCOE calculations must be considered in equal parts. As the literature research identified, no mathematical model in the energy planning sector has been developed so far that is comprehensive enough to include all the elements that must be considered in planning the electricity mix expansion as part of a system. Whether it is even possible to supply a standardized method for it is debated among researchers, as the notion of system costs depend on so many factors that can entirely vary from one market, system, location, etc., to the other. This thesis nevertheless constitutes a pivotal starting point for the aspects a more comprehensive analysis of an energy mix transition towards renewables should include.

Another key finding from the above discussion is that recognizing and analyzing the importance of factors vital for the energy mix alone is not enough; they actively have to be factored in to the energy mix transition towards renewables to develop an optimally integrated power system. For instance, in Brazil, such an endeavor is definitely possible, granted that the various sources of complementarities between different resources are accounted for and taken advantage of. Mainly, by moving hydropower from the baseload generation and using it, along with bioelectricity, as balancing power generation, would allow the country to implement a high share of VREs through the year 2050, thereby increasing the cost efficiency, reliability and environmental sustainability of the electricity sector, putting Brazil on the forefront of the global energy reform.

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Appendices

Appendix 1: Standard deviations and correlations used in the MVP method for energy planning

Table 5: Standard deviations for generating technology cost streams in %

	Construction	Fuel	O&M	CO_2
Coal	23.0	14.0	5.4	26.0
Oil	23.0	25.0	24.2	26.0
Gas-CC turbine	15.0	19.0	10.5	26.0
Nuclear	23.0	24.0	5.5	–
Hydro-large	38.0	0.0	15.3	–
Hydro-small	10.0	0.0	15.3	–
Wind	5.0	0.0	8.0	–
Wind-offshore	10.0	0.0	8.0	–
Biomass	20.0	18.0	10.8	–
PV	5.0	0.0	3.4	–
Geothermal	15.0	0.0	15.3	–

Source : (Awerbuch & Yang, 2007)

Table 6: Fuel and CO2 correlation coefficients

	Coal	Oil	Gas	Uranium	CO_2	Biomass
Coal	1.00	0.27	0.47	0.12	-0.49	-0.38
Oil	0.27	1.00	0.49	0.08	0.19	-0.17
Gas	0.47	0.49	1.00	0.06	0.68	-0.44
Uranium	0.12	0.08	0.06	1.00	0.00	-0.22
CO_2	-0.49	0.19	0.68	0.00	1.00	0.00
Biomass	-0.38	-0.17	-0.44	-0.22	0.00	1.00

Source : (Awerbuch & Yang, 2007)

Appendix 2: Traditional approach to LCOE calculation

The traditional method to LCOE calculation is presented by (Narbel, et al., 2014) as follow:

$$LCOE = \left[\frac{R * c_p}{H * f}\right] + \left[l * \frac{c_f}{H * f}\right] + + \left[l * \left(\frac{c_o}{H * f}\right)\right].$$

In this equation, c_p is the investment cost, or the cost of the plant, c_f is the fuel cost, and c_o is the operation and maintenance cost (O&M). All three are stated in terms of monetary units by unit of installed capacity (e.g. €/MW).

H represents the number of hours in a year (8,760h), which is the typical measure of time considered in an LCOE approach. The capacity factor f measures the power produced over a period time, divided by the power that could have been produced if the plant was running at full capacity over the whole period. Dividing the costs by the product of these parameters gives a close estimation of the cost per unit of electricity produced (e.g. €/MWh).

R is the capital recovery factor, which is the share of the plant cost that must be recovered each year of operation such as to balance out the whole project at the end of the plant life. It is calculated as follow:

$R = \frac{r * (1+r)^T}{(1+r)^T - 1}$, where r is the discount rate and T is the plant life in years.

Finally, l is the levelization factor, which allows for an integration of a cost increase as the plant ages. This factor depends on the discount rate r and an escalation rate e, which measures by how much the costs are expected to increase. It is calculated as follow:

$$l = \frac{r * (1+r)^T}{(1+r)^T - 1} * \frac{(1+e)}{(1-e)} * \left[1 - \left(\frac{1+e}{1+r}\right)^T\right].$$

Since this paper is based on a social planner perspective, the cost of environmental externalities was added into the LCOE calculation via a CO_2 cost.

Appendix 3: Parameters used for LCOE and Risk-adjusted LCOE calculations

Table 7: Parameters of LCOE and risk-adjusted LCOE calculations

Parameters	Measure unit	Coal	Gas	Oil	Nuclear	Hydro	Wind onshore	Wind offshore	Solar	Biomass
Technology data										
Plant lifetime	years	40	30	20	60	35	25	25	25	40
Construction time	years	4	2	3	6	4	2	3	1	4
CO2 factor	tonCO2/MWh	1.285	0.448	0.668	0	0	0	0	0	0
Efficiency factor (fuel)		0.380	0.55	0.45	0.34	-	-	-	-	0.25
Full load hours	hours/year	7446	7446	7446	7621.2	4818	3766.8	3504	2102.4	4993.2
Capacity factor Brazil		0.85	0.85	0.85	0.87	0.55	0.43	0.40	0.24	0.57
Capacity factor*		0.85	0.85	0.85						
Economic data										
Investment cost	EUR/MW	1,600,000	1,200,000	1,200,000	3,700,000	1,200,000	1,500,000	3,400,000	1,600,000	2,000,000
O&M cost	EUR/MW/year	26,296	22,408	26980	52,376	26400	21,210	24000	19,000	80,833
Fuel cost	EUR/GJ	2.3	7.6	7.8	2	-	-	-	-	2.9
Fuel cost	EUR/MWh	21.79	49.75	62.40	21.18	0.00	0.00	0.00	0.00	41.76
CO2 cost	EUR/MWh	44.975	15.68	23.38	-	-	-	-	-	-
Financial data										
Capital recovery factor		0.12	0.12	0.13	0.12	0.12	0.13	0.13	0.13	0.12
Betas (fuel risk)		-0.4	-0.2	-0.2	-0.1	0	0	0	0	0
Risk-adjusted discount rate fuel		0.100	0.110	0.110	0.115	0.120	0.120	0.120	0.120	0.120
PV risk adjusted fuel cost		234.388	480.049	551.572	205.021	0.000	0.000	0.000	0.000	385.571
PV risk adjusted CO2 cost		483.794	162.595	218.952						
Levelization factor O&M		1.208	1.190	1.155	1.221	1.200	1.175	1.175	1.175	1.208

The table above shows the diverse parameters that were used to calculate the LCOEs and Risk-adjusted LCOEs, for which the results are presented in Chapter 4. As mentioned then, the data was retrieved from a series of reports and articles: (Arapogianni, et al., 2009) (Bazilian & Roques, 2008) (Danish Energy Agency, 2015) (EIA, 2015) (EPE, 2015) (IEA, 2015) (IEA/NEA/OECD, 2015) (International Energy Agency, 2014) (Losekann, et al., 2013) (Narbel, et al., 2014) (Tolmasquim, 2016) (Trading Economics, 2016).

More specifically, the technology data such as plant lifetime, construction time, fuel efficiency factor and plant capacity factor come from historical data.

The capacity factor estimations specific to the use of fossil fuel generation in Brazil are estimations by EIA (2015), while the CO_2 factors for each fossil fuel technology come from calculations by IEA (2015).

For biofuel generation, the CO_2 factor was set to zero, even though the combustion of biomass also emits carbon dioxide. The logic behind it is that biomass fuels can be considered CO_2 neutral, since it is assumed that the same amount of CO_2 is removed from the atmosphere when growing the plant material used for power generation (Danish Energy Agency, 2015).

This argument is debatable, and a discussion could also be had on whether it also applies to other types of biofuels (e.g. urban residue) and, more generally, on the sustainability of bioelectricity as such. This is however outside the scope of this paper, and for simplicity reasons, the CO_2 neutral assumption will be adopted.

To resume the description of the different parameters choices; the economic data such as investment cost, O&M cost and fuel cost (EUR/GJ) were also retrieved from statistics and historical data, while the fuel cost (EUR/MWh) and the CO2 cost were calculated based on the formulas and assumptions presented in Chapter 4.

As for the O&M cost escalation rate, even though this parameter varies across technologies and differs according to utility specificities, it is usually between 1% and 3% (Narbel, et al., 2014). For simplicity, an O&M escalation rate of 2% was assumed for all technologies.

Finally, the financial data were also calculated based on the assumptions and formulas presented in the method section, expect for the betas and the risk premium that were used to calculate the risk-adjusted discount rate for each fuel, which were carried from the work of Arapogianni, et al. (2009).

Table 8 gives further specification on each cost element within both calculation methods, for all the technologies assessed.

Table 8: Cost components of each technology under both calculation methods

	Coal		Gas		Oil		Nuclear		Hydro		Wind onshore		Wind offshore		Solar		Biomass	
	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.	LCOE	Risk-adj.
Capital costs	26.07	41.02	20.01	25.10	21.58	30.31	58.32	115.12	30.46	47.94	50.77	63.69	123.72	173.81	97.03	108.68	48.59	76.45
Fuel costs	21.79	28.43	49.75	59.60	62.40	73.84	21.18	24.63	-	-	-	-	-	-	-	-	41.76	46.77
CO2 costs	44.98	58.69	15.68	20.19	23.38	29.31	-	-	-	-	-	-	-	-	-	-	-	-
O&M costs	4.27	4.27	3.58	3.58	4.19	4.19	8.39	8.39	6.58	6.58	6.62	6.62	8.05	8.05	10.62	10.62	19.55	19.55
Total (EUR/MWh)	97.10	132.40	89.01	108.46	111.54	137.66	87.89	148.14	37.04	54.51	57.39	70.31	131.76	181.86	107.65	119.29	109.90	142.78

Appendix 4: LCOE results with different CO$_2$ cost scenarios

Figure 19: CO2 cost sensitivity analysis: generation cost per technology in business-as-usual scenario with a cost of carbon €0/ton CO2 (EUR/MWh)
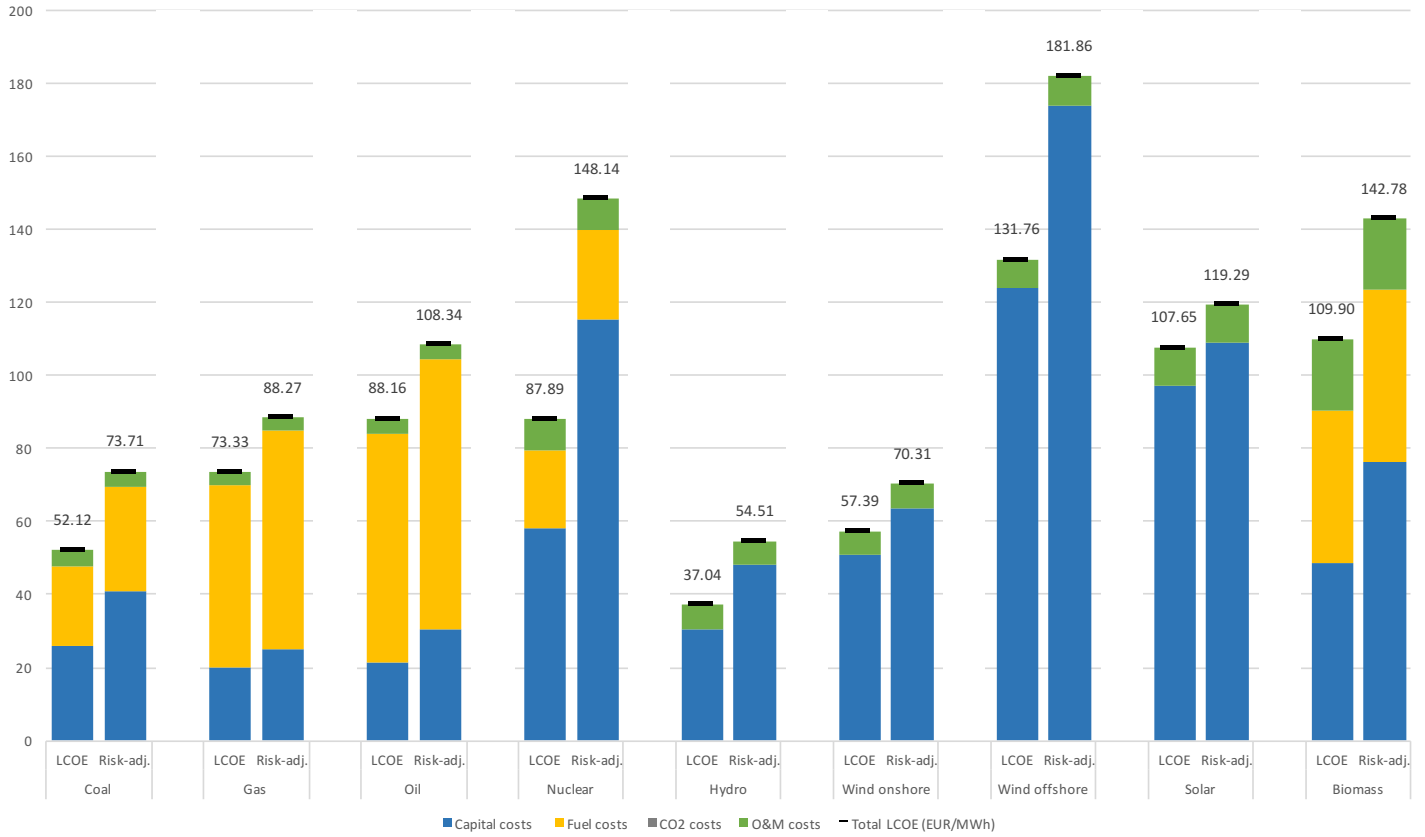
Figure 20: CO2 cost sensitivity analysis: generation cost per technology in a probable-policy scenario with a cost of carbon of €15/ton CO2 (EUR/MWh)