The Modern Portfolio Theory Applied to Wind Farm Investments

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Abstract

According to the specialized statistics, the world has seen a continuous expansion of electricity generation from renewable energy sources in the past 20 to 25 years. Nevertheless, renewables are intermittent sources of generation, and therefore have a competitive disadvantage when directly compared to traditional fossil fuel generation. The expansion of the whole renewable energy industry and the subsequent development on the profile of investors – in particular wind energy investors - gave the assessment of alternatives to deal with the intermittency issue an urgent character. In this context, the objective of this work is to address the Modern Portfolio Theory as a risk management approach applicable to wind farm investments.

The Modern Portfolio Theory has been developed in a context of analysis of investments in financial assets, being heavily grounded on the principles of diversification. The theory basically demonstrates how the combination of assets subject to different and complementary specific or unsystematic risks on a portfolio leads to a reduction of the overall risk associated to the return on investments in these assets. A wind farm is a physical asset and is therefore intrinsically different from a financial asset. From this point of view, the main objective here is to analyze the limits of a theory developed for financial assets when applied to a physical asset such as a wind farm. This task is complemented by the assessment of the question to what extent the diversification of specific operational risks of wind farms (e.g.: variations of local wind regimes) contributes to improving the conditions of investments in wind farms.

The assessment of the limits of the Modern Portfolio Theory when applied to non-financial assets is based on the reflection of the main conclusions from the relevant literature dealing with this issue and the applicability of these conclusions to an asset such as a wind farm. Since the background of the research is strongly linked to investment decision processes, a review of the principles of capital budgeting supporting the analysis of investments in physical assets such as a wind farm is part of the work. The assessment of the impact of diversification on the performance of investments in wind farm portfolios has been developed on a quantitative basis. For this purpose, a new "diversification effect" quantification approach has been developed and is introduced here. The development of conclusions on the issue to what extent diversification benefits investments in wind farm portfolios is based on the outcome of several sensitivity analyses supported by a financial model developed specifically to this task. The methodology of analysis is introduced and discussed in two case studies presented in the final chapter. Both the diversification effect quantification approach and the financial model are detailed in the annexes.

The investigation has shown that the Modern Portfolio Theory has important limitations when applied as a risk management approach to wind farm investments. Its core concept, the definition of an efficient frontier between efficient and inefficient portfolios that supports investors through their investment analysis process is rather irrelevant to wind farms. Diversification however can be a powerful strategy to improve the performance of investments in wind farms. Notwithstanding, the decisive aspect behind diversification is a deep understanding of all the risks involved in a single project and how these can be reduced in a portfolio context.

Zusammenfassung

Einschlägigen Fachstatistiken zufolge hat es weltweit in den letzten 20 bis 25 Jahren einen kontinuierlichen Ausbau der Stromerzeugung aus erneuerbaren Energien gegeben. Allerdings liefern erneuerbare Energiequellen nicht kontinuierlich Strom und haben insofern einen Wettbewerbsnachteil beim direkten Vergleich mit konventionellen fossilen Brennstoffen. Aufgrund der Expansion der regenerativen Energien und der daraus folgenden Entwicklung im Investmentbereich (vor allem bei der Windenergie) wurde die Suche nach Lösungen für das Kontinuitätsproblem immer dringender. Die vorliegende Arbeit befasst sich daher mit der modernen Portfoliotheorie als Risiko-Management-Ansatz für Investitionen in Windparks.

Die moderne Portfoliotheorie bezieht sich auf die Analyse von Investitionen in Finanzanlagen und stützt sich weitgehend auf die Prinzipien der Diversifizierung. Die Theorie zeigt im Prinzip, wie die Kombination von Vermögenswerten, die unterschiedlichen und komplementären spezifischen oder unsystematischen Risiken unterliegen, in einem Portfolio zu einer Verringerung des Gesamtrisikos für die Investitionsrendite bei diesen Vermögenswerten führt. Als Sachanlageobjekt unterscheidet sich ein Windpark wesentlich von einer Finanzanlage. Insofern besteht das Hauptziel dieser Arbeit in der Analyse der Beschränkungen einer für Finanzanlagen entwickelten Theorie im Zusammenhang mit Sachanlagen wie Windparks. Zusätzlich wird die Frage behandelt, inwieweit die Bedingungen für Investitionen in Windparks durch die Diversifizierung der spezifischen betrieblichen Risiken von Windparks wie schwankende Windbedingungen verbessert werden.

Die Beurteilung der Grenzen der modernen Portfoliotheorie bei der Anwendung auf nichtfinanzielle Anlagegüter basiert auf der Abwägung der wesentlichen Schlussfolgerungen aus der einschlägigen Literatur und der Anwendbarkeit dieser Schlussfolgerungen auf einen Vermögenswert wie einen Windpark. Da sich die Grundlagen dieser Forschungsarbeit stark auf Investitionsentscheidungsprozesse beziehen, erfolgt hier auch eine Untersuchung der Kapitalbudgetierungsprinzipien, die bei der Analyse von Investitionen in Sachwerte wie Windparks zum Tragen kommen. Die Beurteilung der Diversifizierungseffekte bei der Wertentwicklung von Investitionen in Windpark-Portfolios wurde auf quantitativer Basis entwickelt. Für diese Bewertung von Diversifizierungseffekten wurde ein neues Quantifizierungskonzept entwickelt, das hier vorgestellt werden soll. Die Entwicklung von Schlussfolgerungen zur Frage, in welchem Maße Investitionen in Windpark-Portfolios von Diversifizierungseffekten profitieren, basiert auf den Resultaten mehrerer Sensibilitätsanalysen anhand eines speziell entwickelten Finanzmodells. Die Analysemethodik wird vorgestellt und anhand von zwei Fallbeispielen im Schlusskapitel behandelt. Das Quantifizierungskonzept für den Diversifizierungseffekt und das Finanzmodell werden im Anhang ausführlich beschrieben.

Es wird gezeigt, dass die moderne Portfoliotheorie bei Anwendung als Risikomanagementansatz bei Investitionen in Windparks erhebliche Beschränkungen aufweist. Ihr Kernthema, die Definition einer Effizienzgrenze, die effiziente von ineffizienten Portfolios abgrenzt und Investoren bei ihrem Investment-Analyseprozess unterstützen soll, ist für Windparks weitgehend irrelevant. Die Diversifizierung kann jedoch eine wirkungsvolle Strategie zur Erhöhung des Erfolgs von Investitionen in Windparks sein. Gleichwohl ist die gründliche Kenntnis aller bei einem Projekt vorhandenen Risiken und deren Minimierung im Rahmen eines Portfolios der entscheidende Aspekt bei der Diversifizierung.

1. Introduction

1.1. Motivation

According to a detailed analysis of several global energy demand scenarios published by the Renewable Energy Network (REN 21), a global policy network that provides a forum for international leadership on renewable energy, global energy demand will continue to grow and is expected to increase by approximately 50% to 60% by 2030 unless major conservation and efficiency programmes are effectively undertaken (REN 21, 2006). In parallel to that, in the past two or three decades, the issue of anthropogenic climate change has emerged from a debate in closed scientific circles to a global topic of highest importance.

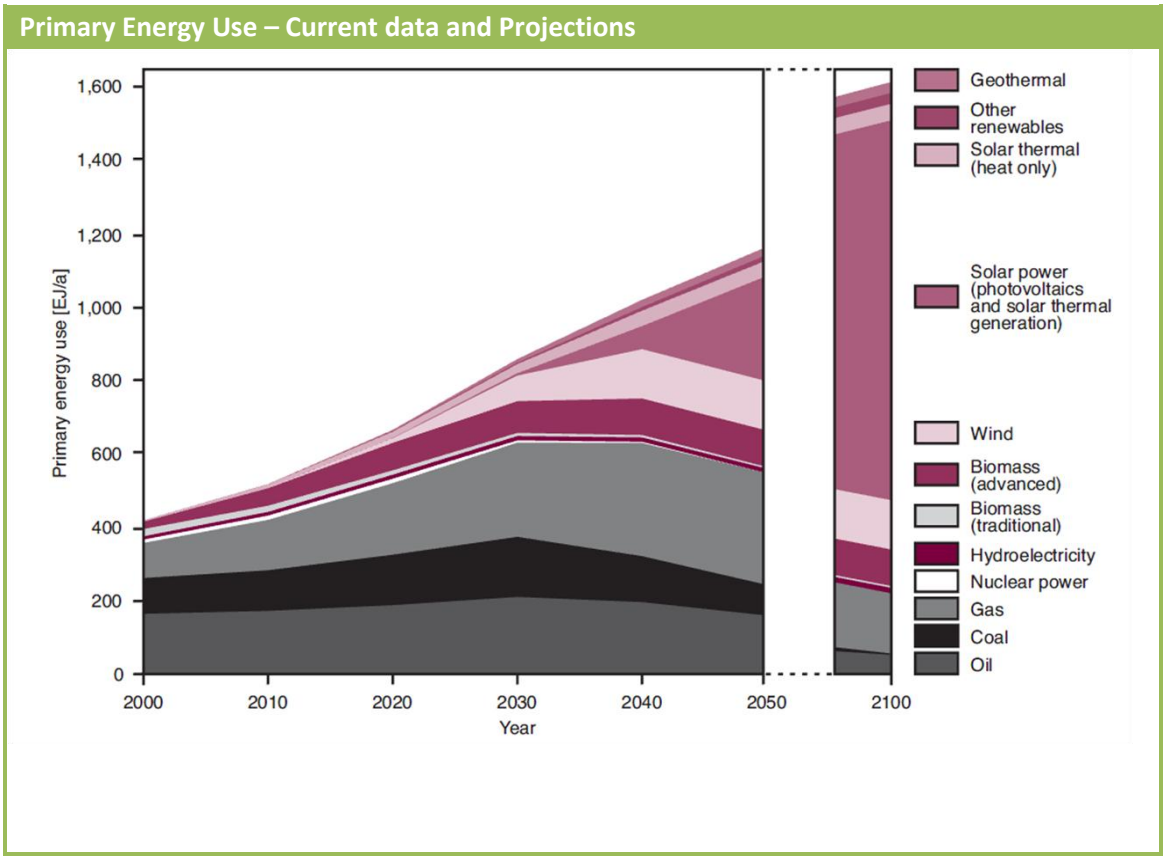
The International Panel on Climate Change, a scientific body established by the United Nations Environmental Programme (UNEP) and the World Meteorological Organization (WMO), came to the conclusion that the atmospheric concentration of greenhouse gases (GHG) has grown significantly since pre-industrial times, increasing by about 31% for CO_2, 150% for methane and 16% for nitrous oxide (IPCC, 2001). Also according to the IPCC, the majority of greenhouse gas emissions, the main cause of climate change, come from the use of fossil fuels to power a growing US$ 60 trillion world economy (REN 21, 2006). These facts have established a challeging task for the next generations: ***How to supply growing energy demand while controlling emissions of greenhouse gases and combating climate change.*** Today, the promotion of renewable energy technologies is seen as the key measure to achieve this task.

Since 1998, the world has seen a rapid and continuous expansion of renewable energy technologies. Despite the headwinds imposed by the global financial crisis, lower oil prices and slow progress with climate policy, the year 2009 was unprecedented in the history of renewable energy. As other economic sectors declined worldwide, the existing renewable capacity continued to grow at great rates. For several years, more renewable power capacity has been installed than any other conventional source of power (coal, gas and nuclear). In 2011 71% of the total European Union new electricity supply capacity installed was renewable energy (REN 21, 2012). At the end of 2011, the total amount of renewable energy capacity installed worldwide, not including hydropower, reached 390 GW. Considering the total amount of hydropower installed globaly, the total renewable energy capacity amounts more than 1300 GW (REN 21, 2012). Another positive aspect of the expansion of renewables in recent years is that the growth is no longer limited to industrialized countries.

Low carbon emission technologies are getting more and more space also in developing countries, especially in countries like China, where energy demand has been steadily increasing in recent years. China ended 2011 with more renewable power capacity than any other country.

However, as the graph from the German Advisory Council on Global Change shows, (graph 1.1), there is still much to be done.

In order to stabilize the concentrations of CO_2 in the atmosphere at acceptable limits, the graph shows an exemplary path of what the distribuiton of primary energy use would have to look like over this century. As the graph also illustrates, the scientific community involved on the climate change debate agrees that the leading role of fossil fuels in the energy supply is likely to continue in the next decades, unless renewable energy technologies become more cost competitive (REN21, 2006).



Graph 1.1. Primary Energy Use actual rates and projection up to 2100. (Source: WGBU, 2003)

Renewable energy technologies still have to overcome a number of barriers to effectively achieve the necessary market penetration. Despite cost reductions achieved in the recent past, the largest barrier to the further expansion of renewables is still mainly the generation costs (Wohlgemuth, et al., 2007). On the top of that, market distortions make the development of renewable energy a difficult task. Generally, the pricing structures of energy markets in both industrialized and developing countries do not reflect the full costs of energy production. Furthermore, traditional energy sources like coal, gas and nuclear are still highly subsidized in many countries. In addition to that, costs such as the impact on human health, environmental damage, and

the global impacts of climate change are usually not factored into energy pricing (REN21, 2006). Another difficulty lies in the nature of investments in renewable energy sources.

Renewable energy systems are capital-intensive and require larger up-front investments and longer repayment periods in comparison to traditional sources (Wohlgemuth, et al., 2007). Conventional credit structures are still not adapted to these characteristics which lead investors to prefer projects with shorter payback periods and lower long-term risk exposure.

Generally, larger renewable energy projects are financially structured in the same way as conventional fossil-fuel projects, combining various forms of equity, debt and risk management instruments. Equity is normally sourced from corporate reserves, strategic investors, private equity funds or the capital markets. Although some equity investments are increasingly available for the sector, this capacity is often not available to cover the required equity share that banks usually expect in a project, especially in uncertain markets such as developing countries (REN21, 2006). In this sense, as recognized by for example Wohlgemuth et al.: *"Innovation in financing mechanisms to advance renewable energy technology projects can be as important as technological breakthroughs."* (Wohlgemuth, et al., 2007). In this sense, the expansion of renewable energy urgently needs innovative finance structures.

The statistics on the expansion of renewables in recent years leave no doubt about the dominance of wind energy among all non-hydro renewable sources. According to the Renewable Energy Network, at the end of 2011, the total installed capacity of wind energy amounted 238 GW worldwide (REN 21, 2012). The acknowledgement of this dominance raises two questions: *1) What are wind energy developers doing right?* And *2) In view of the experience gained during the consolidation of the wind energy industry, what are the alternatives for supporting its further expansion?*

As recognized by the European Wind Energy Association, most of the currently operating wind farms have been funded through *project finance* ((EWEA), 2009 b). In project finance, part of the investment necessary to build a wind farm is financed via loans which are solely repaid by the project's cash flow [1]. The growth of the industry has been followed by an increase in the participation of large companies (e.g. electricity utilities) in the projects. With larger companies involved in the projects, *balance sheet finance* becomes an alternative funding strategy ((EWEA), 2009 b).

Short-term experience has shown that companies financing wind farms with balance sheet financing cover the construction costs of the plant with their own cash, financing the remaining costs with a single-term loan. According to the European Wind Energy Association, balance sheet financing is attractive to large companies investing in wind farms. Balance sheet financing gives the investors the chance to group several projects in a portfolio and get one single loan to support all the projects

at a later stage, therefore reducing the management effort in comparison to multiple loans. ((EWEA), 2009 a). The change in the profile of investors – from small companies to large utilities- is only one of the reasons behind the claim for new financing strategies. Another important reason is the continuous depletion of "good" wind sites.

Wind farm sites relying on high average wind speeds, and a consequent higher production capacity (e.g. coastal areas) were the first being explored. In many countries, especially leading countries such as Germany and Denmark, high capacity sites are more and more scarce, causing new wind farm projects to be mostly located on lower-production-capacity sites. This development trend in the characteristics of wind farm investments brings with it the need to improve the economic performance of the projects.

In the light of these issues, the connection between the Modern Portfolio Theory and the financing of wind farms seems to be a natural consequence emerging from the need for new financing alternatives. Portfolio financing starts to play an important role in the discussion of how to raise funds that the urgent, unquestionable and unavoidable promotion of renewable energy needs. However, the general question is *how the Modern Portfolio Theory approach works applied to the management of a particular type of asset such as a wind farm?*

As discusssed later on, the Modern Portfolio Theory is a risk management approach developed to deal with investments in financial assets. Briefly, the goal of an investment analysis according to the Modern Portfolio Theory is to find a group of securities best able to meet an investor's requisite of risk and return. The approach is largely based on the concept of diversification of risks. Diversification works under the assumption that the good outcome of a certain asset will compensate the bad outcome of another one, so that an investor holding the two assets will somehow always meet his/her expectations of return (Elton, et al., 2007, pg.44).

The income of a wind farm is directly proportional to its energy production. Wind is by nature an intermittent and difficult-to-predict resource, so that the energy production of a wind farm is subject to a high level of uncertainty. It is a general consensus that the risk of investing in a wind farm is strongly linked to the lack of wind. The question of *What to do when the wind is not blowing?* is still one of the greatest concerns of wind energy investors.

Wind farms as structured today are long-term investment assets, so that a parallel to a financial asset like a security is an intuitive exercise. Nevertheless, assuming that diversification is an effective strategy against risk, bundling wind farms subject to complementary wind regimes and a variety of technological risks in one portfolio seems to be one possible answer to this question.

In this context, the general objective of this research is to assess the key concepts of the *Modern Portfolio Theory* as an alternative to manage the risks involved in wind farm investments.

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[1] The principles of project finance are discussed in Chapter 6.

1.2. Research Status

The Modern Portfolio Theory linked to the management of electricity supply portfolios has been addressed a few times in the specialized literature. A discussion of some of the most relevant works[2] is part of Chapter 5. All in all, most of the authors focused on the analysis of diversification as a risk management strategy against the uncertainty about the development of fuel prices that energy supply mixes heavily based on fossil fuels have to deal with.

In comparison to the range of available publications on electricity supply portfolios, the investigation of the Modern Portfolio Theory in the domain of renewable energy supply is rather limited. In the case of wind farms, most of the publications are restricted to specialist magazines or conference proceedings. The available literature has been extensively evaluated. Meaningful publications[3] are discussed in Chapter 5. In one of the undoubtely most relevant publications on the issue of Modern Portfolio Theory and wind farm investments, John Dunlop in 2004 analyzed the applicability of the Modern Portfolio Theory and in particular the Capital Asset Pricing Model (CAPM) to investment wind farms. The conclusions were based on an analysis of production data of wind farms operating at complementary local wind regimes. According to Dunlop, geographical diversification is a useful strategy against production risks. Other authors reached similar conclusions in their analyses. Dunlop however went beyond a quantitative analysis of diversification. The difference between his publication and others dealing with the same issue is the approach of the question *"Can a framework designed for stock markets be successfully adopted to an asset like a wind farm?"* (Dunlop, 2004).

Most of the other publications limited the theory to a diversification approach, being therefore mainly focused on the analysis of possible risk diversfication quantification methods. Their analyses leave no doubt that the diversification of wind regimes is a useful strategy to protect wind farm investors from lack of wind. The Modern Portfolio Theory is however more than diversification. Its central goal is the establishment, through diversification, of an efficient frontier of investments which best meet investors' expectations of risk and return. The understanding of the present work is that the analysis of the Modern Portfolio Theory as an alternative framework to manage the risks of wind farm investments is only complete once this central goal is taken into account. Although meaningful, everything else is no more than the analysis of diversification as a risk management practice focused on wind farm projects.

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[2] See for example (Bar-Lev, et al., 1976), (Humphreys, et al., 1998), (Awerbuch, 2000), (Awerbuch, et al., 2003), (DeCarolis, et al., 2004), (Roques, et al., 2008), (Hickey, 2010)

[3] See for example (Hulsch, et al., 2006) (Marco, et al., 2009) (Roques, et al., 2010). Other publications are discussed in Chapter 5.

In this sense, one of the intentions here is to extend and complement Dunlop's brief analysis of the suitability of a financial asset's framework for wind farm projects. The objective is to focus the analysis of the Modern Portfolio Theory not only on the diversification aspect, but also on the general goal investment analysts have in mind when following this theoretical background.

1.3. Research Questions and the Structure of the Work

The Modern Portfolio Theory was developed as an analysis framework to support financial assets investment decisions. A financial asset differs intrisically from a physical asset like a wind farm. This acknowledgement imposes an evaluation of what limits a one-to-one transfer of the Modern Portfolio Theory approach to other assets than financial ones. With this background the present work has been structured to address in the first place the following research questions:

1) ***What limits the application of an approach designed for the risk management of investments in financial assets to a physical asset such as a wind farm?***

Assuming that the existence of limitations on the applicability of the Modern Portfolio Theory to non-financial assets does not misqualify some of its key concepts as valuable risk management and investment analysis strategies, a second question will be addressed:

2) ***Once the limitations of applying an approach designed for financial assets to a physical asset like a wind farm are taken into account, is diversification a relevant strategy to improve the investment conditions of wind farms? If yes, to what extent?***

The analysis of both questions requires a multidisciplinary approach. Following this understanding, and complementing the focus on the Modern Portfolio Theory, this document has been structured to address both the technical and the commercial aspects of wind farm projects.

The first core chapter addresses the current development status of wind energy. The objective is to review the latest statistics and the implementation of further developments of the industry like offshore and repowering. The assessment of the limitations of the Modern Portfolio Theory to assets other than financial ones demands a detailed examination of what "other assets" are about. In this case, the assessment requires a detailed review of wind farm projects. The second chapter is dedicated to this task.

The second chapter introduces the development steps of a state-of-the-art wind farm project. This exercise supports not only the characterization of a wind farm project as an asset, but also the understanding of its investment decision process.

As mentioned above, the income of a wind farm, and consequently its return, is directly proportional to its energy production. A wind farm is a long-term investment asset, with an estimated operational life of 20 or more years. The structuring of its financing however is part of its project development. Important decisions on this matter are usually taken even before a turbine reaches the site. For this reason, the estimation of a reference production level which realistically foresees the long-term potential is a central issue. To tackle this relevance, the third chapter has been structured to review the main aspects of an energy yield assessment.

The estimation of the most likely yearly energy production of a wind farm is mainly linked to three major factors: The first major factor relates to the estimation of long-term wind conditions at the site. The second one is linked to the analysis of the wind flow's behaviour over the whole wind farm area once the site's topographic characteristics and turbine layouts are taken into account. This analysis determines the level of confidence to be given to the determination of how much of the wind's kinetic energy will actually be available to be converted into power. The third major factor concerns the efficiency with which the turbine will convert this power into electricity. These three issues bring a wide range of uncertainties to the overall analysis, and consequently to the reference long-term production level of a wind farm. The analysis of these uncertainties and the understanding of how they determine the risk on the estimation of a wind farm's long-term reference production build the core of the portfolio analysis methodology introduced later on.

The first part of the fourth chapter is dedicated to a review of the Modern Portfolio Theory in its original formulation, namely an investment analysis framework designed for the management of financial assets. As a transition to the analysis of its applicability to assets other than financial ones, the second part of this chapter begins with an examination of the main characteristics of financial and non-financial assets. The discussion of their differences is followed by an analysis of the limitations of the Modern Portfolio Theory framework when applied to non-financial assets. The discussion is supported by the review of different publications dealing with the theory in a context other than the context of securities management.

Based on the understanding that Modern Portfolio Theory assessments are developed under a capital budgeting context, the third part of the chapter reviews the main principles of capital budgeting and investment decisions. The discussion finally focuses on how the Modern Portfolio Theory framework might enhance the decision process of investments in wind farm projects.

The evaluation of the Modern Portfolio Theory as a risk diversification framework applicable to wind farms is based on a quantification analysis. For this purpose, a mathematical model taking into account information on production estimates, their uncertainties, and correlation levels is proposed. The introduction of the proposed model, followed by the analysis of an illustrative example concludes the fourth part of the work.

The general assumption of this work is that the decision to allocate funds to a portfolio of wind farms instead of single wind farms is justified by the improvement of key financing parameters as a consequence from diversification. For this reason, the fifth chapter is dedicated to the assessment of the diversification of energy production risks and its impact on these parameters.

The first part of this chapter reviews the economics of wind farms today. An overview of capital costs, operation and maintenance costs as well as production costs of onshore wind farms is followed by a review of the current tariffs and support mechanisms.

The second part of the chapter examines the state of the art and new trends in wind farm financing. The assessment of the improvement of financing parameters considering a portfolio strategy is based on the analysis of a financial model proposed exclusively for this exercise. The last part of the chapter focuses on the introduction and the discussion of this model.

The work is completed by the analysis of two case studies illustrating the assessment methodology being proposed. The discussion of the case studies is followed by a review of the research questions, and a summary of the main conclusions.

2. Review of Wind Energy Development Worldwide

This chapter reviews the expansion of wind energy technology over the past 20 years. It begins with a summary of the current statistics on installed wind power capacity worldwide, highlighting the leading countries and the overall current status of development today. The intention is to give an idea of the order of growth achieved by this industry over the last few decades.

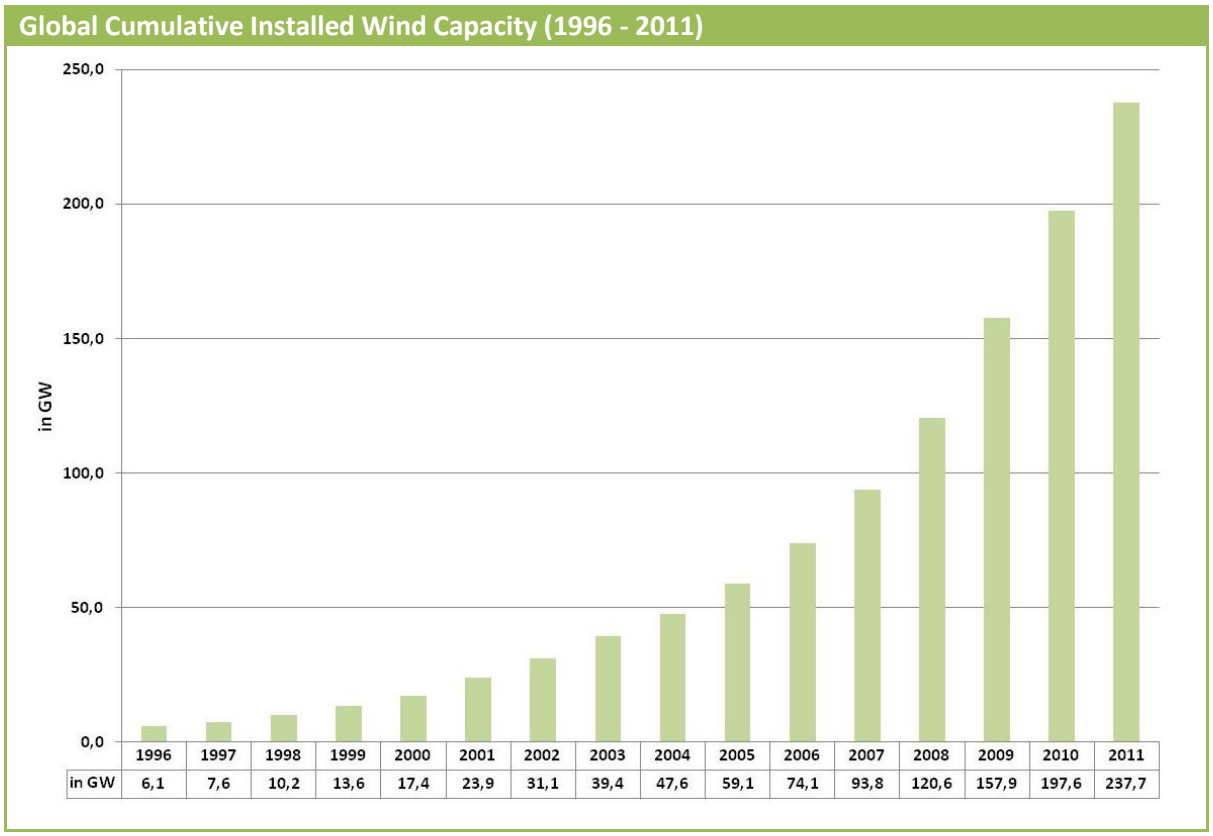
Next, the historical development of the technology will be briefly summarized. This section focuses especially on the state of the art of onshore and offshore technologies. The main reasons for the delay in the promised massive expansion of offshore wind farms are briefly discussed.

The last section is an overview of the research and development activities going on, as well as new technology implementation trends like repowering. The chapter ends with a revision of the penetration level of wind energy in developing countries and the future perspectives for these regions.

2.1. Wind Energy Today: Global Statistics

The participation of wind power in the global energy generation mix has increased significantly in the last two decades. According to the Global Wind Energy Council (GWEC, 2011 b.), the currently accumulated installed capacity worldwide is above 197 GW (graph 2.1). The installed capacity has increased at a rate of almost 25% a year since 2004. In the European Union, wind power installations accounted for 39% of the total of new installations of power generation capacity in 2009, meaning that no other energy generation source has grown more than wind energy[4] (EWEA, 2010). With 48% of the total installed capacity worldwide by the end of 2009, Europe leads the wind power business. European companies have a market share of 66% (EWEA, 2009, pg. 261), and most of the research and technology development activities in recent decades were carried out on this continent.

[4] In 2009, a total of 25,963 MW of new power generation capacity was installed in the European Union. The leader by far is wind energy with 10.163 MW followed by gas with 6,630 MW representing 26% of the new installations, as well as solar photovoltaic with 4,200 MW (16%), 2,406 MW of coal (9%), 581 MW of biomass (2.2%), 573 MW of fuel oil (2.2%), 422 MW of waste (1.7%), 439 MW of nuclear power (1.7%), 338 MW of large hydro (1.3%), 120 MW of concentrated solar power (0.46%), 55 MW of small hydro (0.2%), 12 MW of other gases (0.04%), 3.9 MW (0.01%) of geothermal and 405 kW of ocean power.



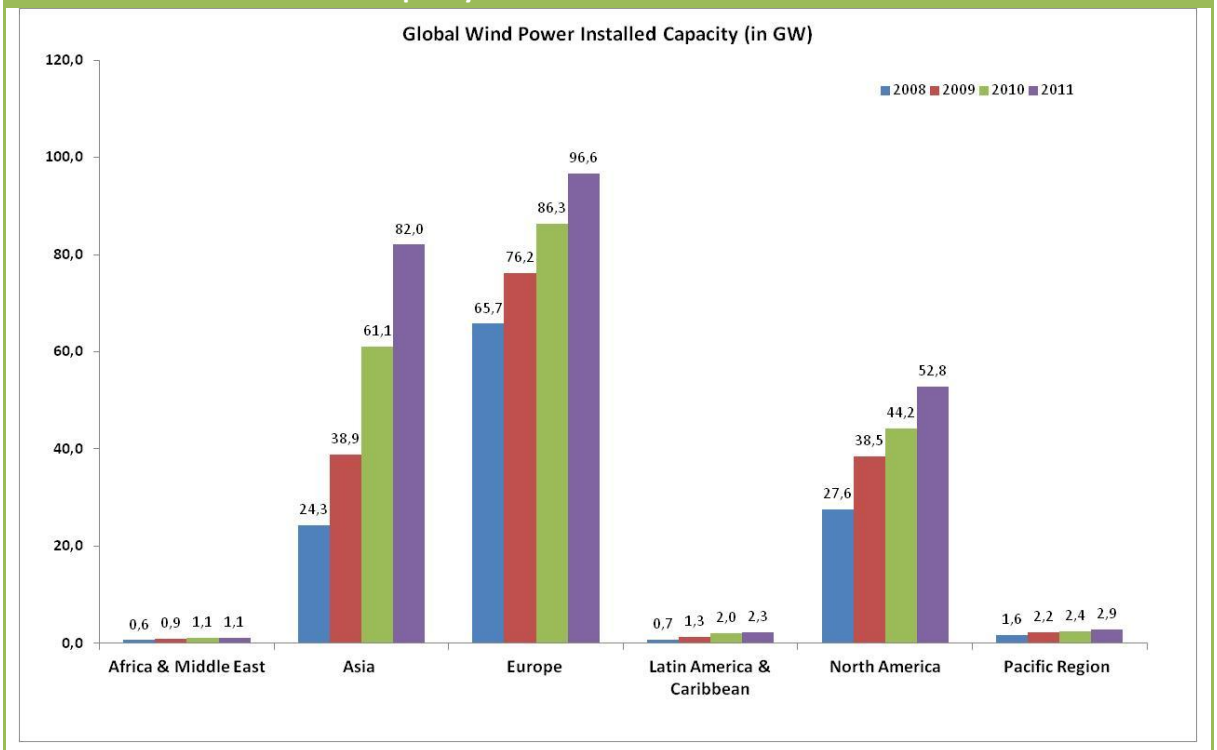
Graph 2.1: Cumulative Installed Capacity at the end of 2011 (Source: (GWEC, 2011 b.)).

Looking at the regional level, the achievements are even more impressive. Today, almost 26% of the total electricity consumption in Denmark is supplied by wind energy (EWEA, 2012). In Germany, the state of Schleswig Holstein alone currently has an installed capacity of almost 3.4 GW, enough to meet 36% of its local demand. The latest predictions indicate that high growth rates are likely to continue, especially due to the expansion of markets in southern and Eastern Europe. The goal is to keep Europe on track to meet the target established by the European Union in 2007 to supply its internal energy demand with 20% of renewable energy by 2020.

Graphs 2.2 and 2.3 show the distribution of the installed capacity worldwide. The imbalance between industrialised regions like Europe and North America in comparison with developing countries is clear. The exceptions are countries like China and India. Today, the installed capacity of wind power in China is more than five times its capacity in 2008[5]. Such numbers support the belief that the more this technology develops, the more accessible it becomes.

[5] In 2008 China had a wind power installed capacity equivalent to 12.1 GW. At the end of 2011 this capacity was equivalent to 62.3 GW (GWEC, 2011 b.).

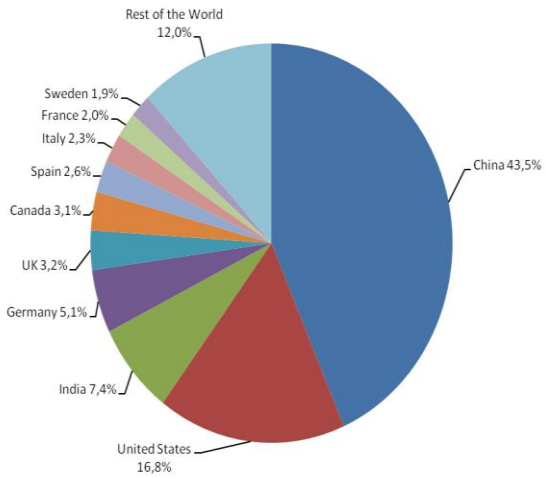
Global Installed Wind Power Capacity – Status at the end of 2011



Graph 2.2: Global Wind Power Installed Capacity by the end of 2011 (Source: (GWEC, 2011 b.)).

New Installed Capacity in 2011 - Worldwide

	In GW	In %
China	17.6	43.5
United States	6.8	16.8
India	3.0	7.4
Germany	2.0	5.1
UK	1.3	3.2
Canada	1.3	3.1
Spain	1.0	2.6
Italy	0.9	2.3
France	0.8	2.0
Sweden	0.7	1.9
Rest of the World	4.8	12.0
Total	40.5	100%



Graph 2.3: New Wind Power installed Capacity worldwide from January to December 2011 (Source: (GWEC, 2011 b.)

The expansion of wind energy observed in the last few years and its continuous growth can be explained by two different reasons: Firstly, the accelerated technological development experienced by the industry increased the efficiency of farms and reduced capital costs. Projects became more attractive to developers and financers over the years.

Secondly, the political support from governmental authorities through climate change mitigation programmes. Policies to diversify energy generation matrixes and improve the participation of renewable energy are today on the agenda of almost every country.

However, it is important to point out that much of this development was possible thanks to the private sector, as the statistics provided by the International Energy Association (IEA) can attest. According to the IEA, between 1974 and 2002 wind power has counted on slightly more than 1% of the total of public funds allocated to energy research among its 24 associated countries. In the same period, nuclear energy received 58% of the total research funds, and fossil fuels 13%. The remaining 29% was split between several other technologies, including renewables. Unfortunately, it seems that this practice will continue in the future. Over the next five years, 54% of the EU budget for energy research will be allocated to nuclear power. The remaining 46% includes research programmes for the so called non-nuclear technologies. At the end of the day, the amount reserved to promote the further development of wind energy will be no more than 3% (EWEA, 2009, pg. 145).

2.2. Historical Development of Wind Energy

2.2.1. Onshore

As illustrated in Figure 2.1, since the middle of the 80's, wind turbines have increased in size by a factor of 100 (from 25 kW to 2,500 kW and beyond). The cost of energy was reduced by a factor of more than five and the industry is no longer an idealistic fringe, but an established branch of the power generation business. The electricity production of a modern 2.0 MW turbine is five times higher than the amount produced by a turbine of the 600 kW class. The horizontal-axis, three-bladed, upwind, variable-speed, pitch-regulated machine is nowadays the state of the art in terms of technology (EWEA, 2009). Apart from a few large-size wind turbines like the Enercon E-126 with a rated power of 6 MW installed in Emden in Germany, the land-based supply, or onshore market, is dominated by turbines in the 1.5 to 2.0 MW range (EWEA, 2009, pg. 73).

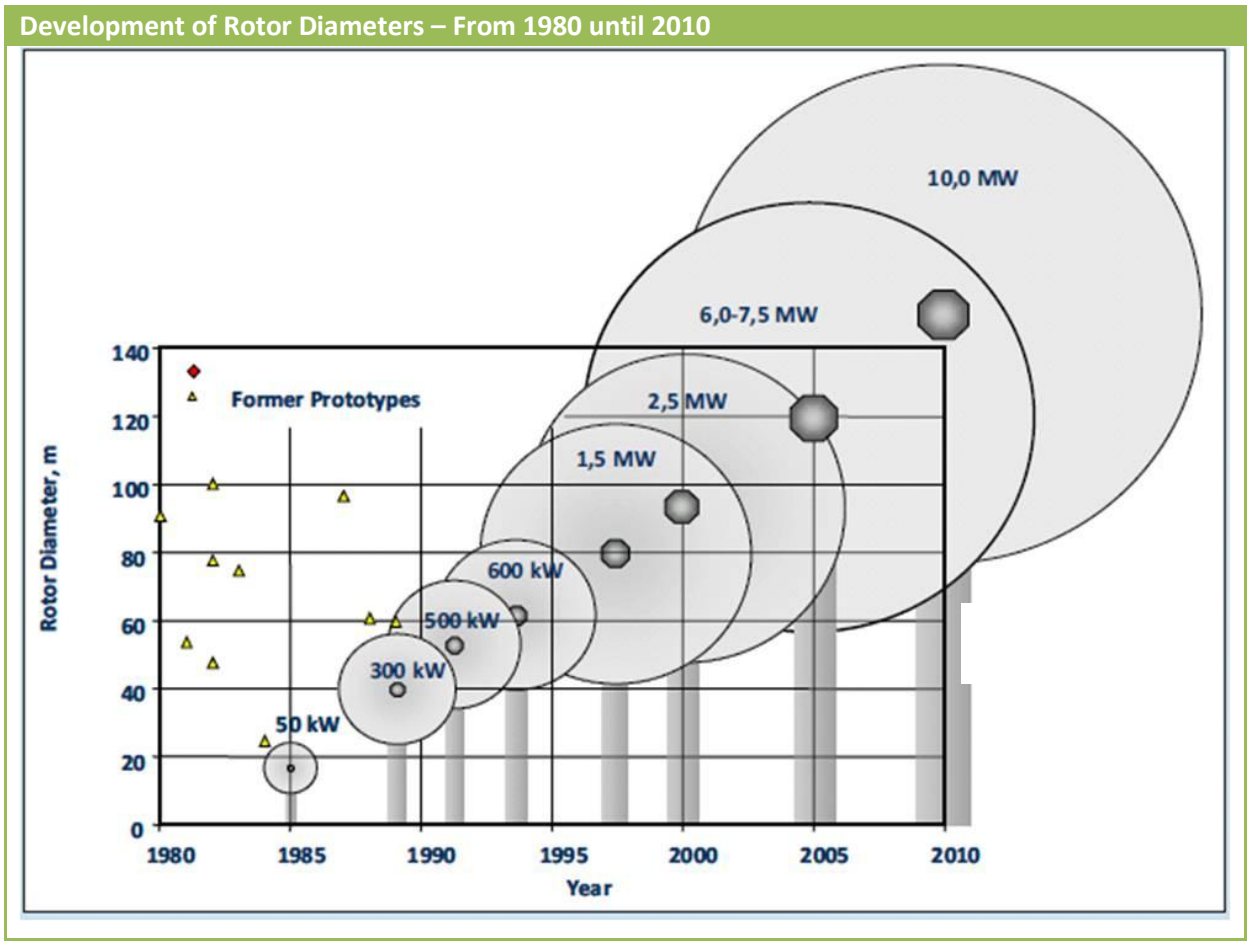


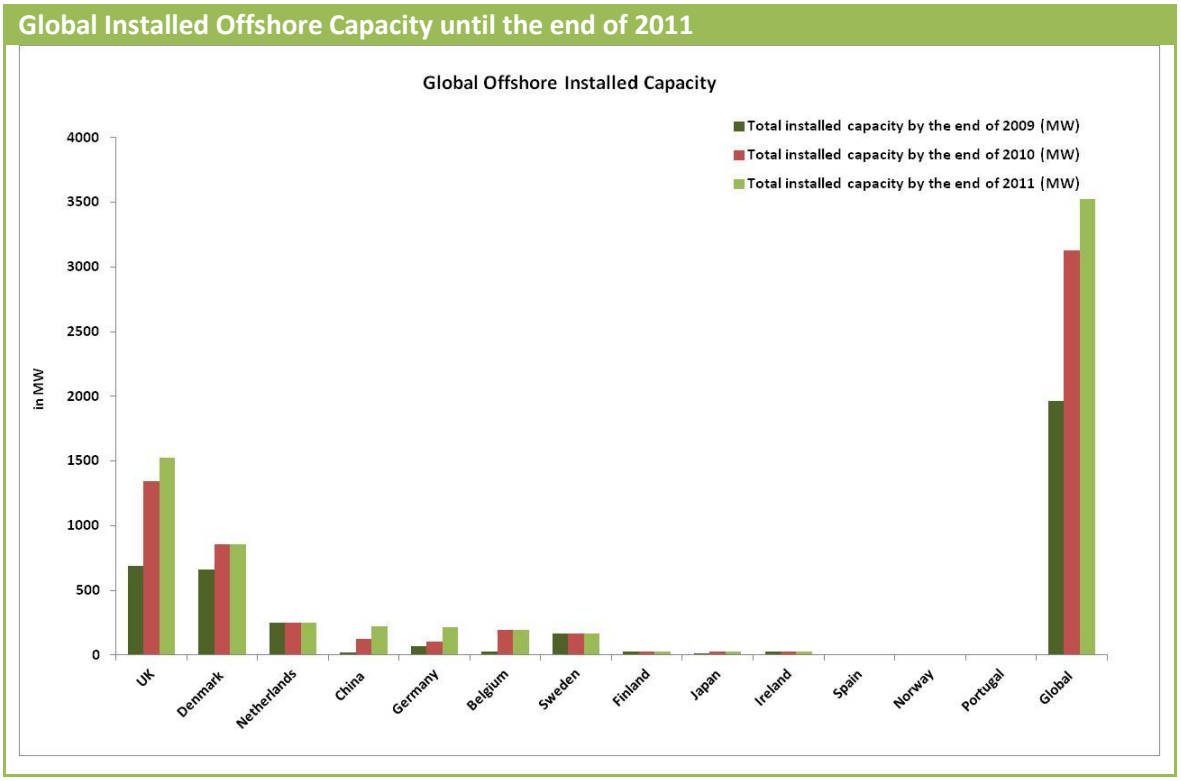
Figure 2.1: Wind Turbine development size from 1980 until today (Source: (Molly, 2009))

Although the growth in the size of wind turbines is the highlight of the technological development achieved by the wind industry, the progress of site assessment techniques, as well as wind forecasting tools also played a relevant rule in the expansion. The improvement of wind atlases and the production of wind maps together with the perfecting of wind measurement techniques upgraded the quality of long-term wind resource assessments. Additionally, the further development of so-called wind farm design tools (WFDTs), as well as the use of Computational Fluid Dynamics (CFD) models, increased the accuracy of the characterization of sites in terms of their energy yield. Today, sites located in interior areas can be assessed with an acceptable level of uncertainty and profitable wind farms are no longer restricted to coastal areas.

The change in the profile of investors in wind farm projects illustrates the industry's scaling up and geographical expansion. From an industry concentrated in Denmark and Germany with single, farmer-owned turbines at the end of the 90's, wind power ownership today includes dozens of multinational players (independent power producers - IPPs). The growing participation of utilities in wind energy projects illustrates the dynamics of the sector towards bigger and bigger investments.

2.2.2. Offshore

With a total of 3522.4 MW of installed capacity by the end of 2011, offshore wind energy accounted for 1.5% of the total wind power installed capacity worldwide (graph 2.4). The market still remains below its forecasted levels and development has proved to be more difficult than previously thought. The potential is huge not only in Europe, but the technical challenges are also great. The capital costs are higher than onshore, the risks are greater, the project sizes are larger, and consequently the costs of mistakes are also greater.



Graph 2.4: Global Installed Offshore Capacity 2009 (Source: (WWEA, 2012)).

The list of barriers holding back the expansion of offshore wind farms is long and includes difficulties in almost every stage of project development (EWEA 2009, pg. 275): Long permit processes, grid constraints, technical issues relating to the construction of farms such as the transport of the equipment, incentive schemes still not in line with the amount of risks involved in the projects, a lack of turbines available on the market as well as a general lack of experience with the technology are some of the main problems.

Offshore wind farms are normally developed by more than one investor. A joint venture between the turbine supplier, a project developer with robust technical know-how and one or more investors with strong financing capabilities is the most common constellation behind offshore projects. In view of their capacity to finance projects on their own balance sheets, there is a general

belief in the industry that the expansion of offshore in the coming years will most likely be driven by large electricity utilities.

In view of the modest development achieved in past years and the eminent targets to be met in the near future, a significant part of the research and development efforts dedicated to wind energy are today concentrated on offshore technology. Mainly five topics are given top priority: Foundations (alternatives to extend the lifetime of the substructures), assembly, installation and decommissioning (how to optimize the logistics necessary to build an offshore plant), electrical infrastructure, larger turbines (increased efficiency) and operation and maintenance (increased reliability of the components to reduce costs).

2.3. Further Development Prognosis

2.3.1. Research and Development

In spite of the significant expansion of wind energy in recent decades, the technology still faces challenges. The high demand for wind turbines worldwide and the price increase of raw materials such as steel and copper in the last three to four years have raised the cost of the turbines. There is an intermittent need to investigate alternative materials and to optimize the reliability of key components.

However, research and development efforts focus not only on the technical improvement of wind turbines. They also address questions relating to the integration of wind plants into the grid, as well as on issues constricting the maximization of wind farm efficiency.

In this sense, programmes mainly deal with four thematic areas: Offshore deployment and operation (as seen in section 2.2.1), wind conditions and energy yield predictability, wind turbine technology, and wind farm integration (EWEA, 2009, pg. 140).

Wind conditions and energy yield predictability: The goal is to improve the current techniques used in long term energy yield assessments in order to reduce the uncertainties of these prognoses. These research projects mainly take the following directions: Siting wind farms in complex terrain, better understanding of wake effects[6], offshore meteorology, extreme wind speeds, investigations and modelling of the wind profile above 100 m as well as short-term forecasting.

[6] The wake effect of a wind turbine is the velocity decrease and turbulence increase downstream of the turbine rotor (see for example (Barthelmie, et al., 2006)). This effect may cause a reduction in the power output and an increase in unsteady and fatigue loads on turbines located downstream. For an analysis of this effect in complex terrain see for example (Berge, et al., 2006). More details are discussed in the 4th chapter.

Wind turbine technology: The biggest challenge is to ensure that in 20 years, wind energy will be the most cost-efficient energy source on the market. In this sense, the research topics relate to issues dealing with the design and operation of wind turbines such as: aerodynamics, materials, electrical and control components, increased system availability and reliability, development of design quality standards in response to the continuous globalization of the market.

Wind farm integration into centralized grids: Since the very beginning of the expansion of wind power, the integration of large-scale wind farms into centralized transmission grids has kept the research community busy. There is a constant need to deal with issues related to limited transmission capacity and inefficient grid operation. One of the goals is to make the operation of wind farms as similar as possible to conventional power. Therefore, "grid management" guides the research. The open questions are related to forecasting errors and the impacts on the power system's short term reserves. There is an urgent need to find solutions on how to manage generation and demand in a more efficient way.

Other topics: Apart from the technical issues, the deployment of wind energy through large-scale wind farms depends also on the support of stable and well-defined markets, therefore efficient support policies and regulatory environments play a central rule. In this context, research and development efforts focus on: Enabling market deployment, cost reduction, adapting policies, optimising administrative procedures, integration of wind farms into the natural environment, and public support.

2.3.2. Repowering

Briefly, repowering is defined as the substitution of old wind turbine types with newer, modern, higher-capacity models. Repowering is obviously still limited to countries with a well developed wind energy market such as Denmark and Germany (Figure 2.2). However, as other markets expand, its dissemination is likely to grow not only in speed but also in scope.

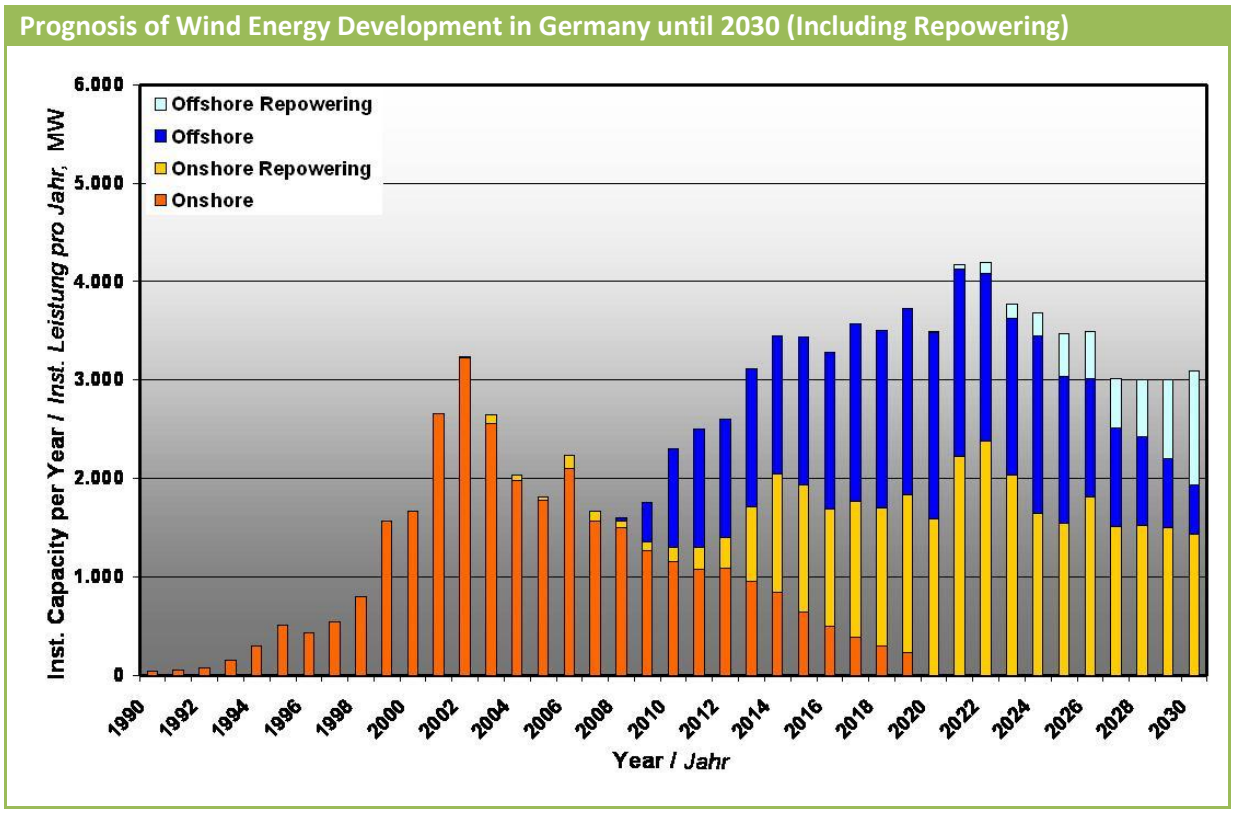


Figure2.2: Prognosis of wind energy development in Germany until 2030 ((Deutscher Städte und Gemeindebund (DStGB), 2009)

The reasons for pursuing a repowering project are diverse, but basically developers take their decisions based on the past performance of the old wind farm. In general, the substitution of an outdated turbine type with a modern type brings a considerable increase in the generation capacity of the wind farm. As a consequence, investors in repowering are motivated by the prospects of better economic performance and financing conditions[7].

Moreover, it has already been recognized that the benefits are not limited to developers. Local communities also gain with the repowering of existing sites.

According to an analysis published by the Association of German Municipalities, the benefits to local communities of repowering are varied. Firstly, new projects are a chance to fix the mistakes of the past. New projects generally improve the landscape characteristics, with fewer turbines and optimised technical performance reducing environmental aspects such as noise emission, shading, etc. Secondly, the increased local income tax revenues[8] (Deutscher Städte und Gemeindebund (DStGB), 2009).

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[7] The energy yield prediction of a wind farm to be repowered involves in general less risk than the prediction of a new one on an unproven site. On an "old" site, the farms or single turbines are under operation over a considerable period of time, so that the wind as a long-term resource can be forecasted reliably. Additionally, technical availability problems can be addressed by substituting poor-performance turbines with new ones. These aspects together lead to a lower overall uncertainty about the effective energy yield to be expected from the new farm, a condition which, in principle, allows better financing conditions.

[8] If applicable, since the exemption from local income taxes is sometimes an incentive

The table below show a comparison of the electricity production and income of a wind farm located in Germany, in its "old" and "repowered" versions. It must be noted however, that the effective economic benefits of a repowering project can only be addressed individually. The economic performance of a repowering project depends on several issues such as the level of the feed-in tariff[9], the financing stage of the original project, the commercial conditions of the new turbines such as price and O&M costs, the permit process to increase site capacity, etc. But in general, the potential gain of additional MW-hours due to a more efficient site employment and allocated technology tends to be worthwhile. Therefore, repowering is today an important variable in the further expansion of wind energy worldwide and decisive in the sustainable development of the technology in the future.

Example: Repowered project in Germany	"Old" Wind Turbines (1996)	New Wind Turbines (2009)
Number of turbines	10	6
Nominal power	600 kW	2 MW
Electricity production	12.82 m kWh per year	44.80 m kWh per year
Feed-in tariff	6.2 ct €/kWh	10.2 ct €/kWh
Revenues per year	856,840.0 Euros	4,596,899.0 Euros

Table 2.1: Example of a repowering project commissioned in Germany in 2009 (Source: Deutscher Städte- und Gemeindebund, 2009).

2.4. The rule of developing countries in the expansion of wind energy

2.4.1. Asia

According to the forecasts of the Global Wind Energy Council, the total installed capacity in wind energy worldwide is expected to reach 240.3 GW by 2012[10] (EWEA, 2009, pg. 291). The leading regions are North America and Asia, specifically the United States[11] and China.

China: China added about 13.000 MW of new wind power capacity in 2009 alone. It was a growth of approx. 52% compared to the installed capacity available in 2008, so that at the end of 2009 China had a total cumulated installed capacity of 25,104 MW (GWEC, 2010) of wind power. At the end of

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[9] In Germany for example, the Renewable Energy Law (EEG) provides a bonus for repowering projects as long as some technical conditions important for improving the quality of the grid are fulfilled (Deutscher Städte-und Gemeindebund, 2009).

[10] According to the latest publication of the Global Wind Energy Council, at the end of 2011 the total installed capacity of wind energy worldwide was equivalent to 238 GW (GWEC, 2011 b.).

[11] The Global Wind Energy Council predicts an addition of 42.6 GW of wind power on the US market in the coming years. The forecasts indicate an installed capacity of 61.3 GW by 2012, representing an average growth of 8.5 GW per year (EWEA, 2009).

2010, this capacity was already equivalent to 44,733 MW – a relative increase of almost 44% between 2009 and 2010. According to the latest statistics, at the end of 2011 the wind power installed capacity of China reached 62,364 MW – a relative increase of 28.3% between 2010 and 2011 (GWEC, 2011 b.). The numbers speak for themselves. The market potential is evident, and experts estimate that this is just the beginning and that the real growth is yet to come. GWEC forecasts an installed capacity of around 200 GW by 2020 (GWEC, 2011 b.).

One of the most important factors behind the expansion of wind energy in China in recent years is the emergence of a significant local manufacturing capacity, composed of both foreign and domestic companies. The manufacturing capacity in 2007 was estimated at something like 5,000 MW and is expected to reach 10 to 12 GW by 2010. However, given the country's substantial coal resources and the still relatively low cost of coal fired generation, reducing the cost of wind power is one of the greatest challenges.

India: India added a total of about 1,200 MW of new wind power capacity in 2009, reaching a total cumulated value of 10,926 MW (GWEC, 2010). At the end of 2010, the installed capacity of wind power was equivalent to 13,065 MW - a growth of more than 16%. At the end of 2011 another 3.0 GW of wind farms were installed in the country so that the current installed capacity is 16 GW (GWEC, 2011 b.). The wind farms are still concentrated in the southern region, but the expansion is beginning to reach other regions and new wind farms can be seen under construction across the whole country. As in many other countries, political support contributed to boosting the implementation of wind farm projects. The first step was the issue of renewable energy purchase obligations, set up by ten of the 29 federal states, requiring utilities to source up to 10% of their power capacity from renewable sources. Additionally, wind energy projects in India rely on fiscal incentives such as 80% depreciation in the first year of installation, ten-year tax holidays and no income tax to be paid on power sales to local utilities.

Furthermore, India has a solid domestic manufacturing base including important global players like Suzlon[12] and Vestas. Other international companies have already set up production facilities on Indian territory, including Enercon, Repower and Siemens.

2.4.2. Latin America

The GWEC also predicts an expansion of the market in Latin America. The development will be mainly driven by Brazil, Mexico and Chile and a total installed capacity of around 4.5 GW is

[12] Suzlon supplies over half the local Indian market alone (EWEA, 2009).

expected to be reached by 2012 (GWEC, 2010). However, Latin America is likely to remain a small market progressing towards a more significant development in later decades.

Brazil: According to data from the GWEC, Brazil had a total wind power installed capacity of 606 MW at the end of 2009, reached with 264 MW of new capacity added during that year. In 2010, this total has been increased by another 325 MW so that at the end of that year, the total wind power installed capacity was equivalent to 931 MW. At the end of 2011 Brazil reached the GW mark. The latest statistics report a current installed capacity slightly over 1.5 GW (GWEC, 2011 b.). The expansion of the market is supported from time to time by the government with direct incentives like the Proinfa programme[13] and specific invitations to bid for contracts for reserve and continuous capacity. A summary of the latest invitations to bid for wind energy contracts indicates that by the end of 2016 Brazil will probably rely on more than 8.0 GW of wind power (Chaves-Schwinteck, 2012).

Local production plants of several international turbine manufacturers such as Enercon, Vestas, Alstom, etc. are already operating in the country. In parallel to other market consolidation signs like the development of local expertise, Brazil has seen a tremendous expansion of its local manufacturing capacity in recent years. Nevertheless the country still has a long way to go before it can draw on sufficient local technological and operational know-how. Therefore, to achieve the forecast expansion, top priority must be given to challenges such as a review of the high import duties and taxes.

Mexico: Despite the huge wind potential in Mexico, the development of wind energy has been very modest. According to GWEC statistics, Mexico had an installed capacity of 202 MW of wind power by the end of 2009 (GWEC, 2010). At the end of 2011, the installed capacity was in the range of 520 MW (GWEC, 2011 b.). The main obstacle is the state monopoly in electricity supply and the consequent very low kWh prices. Further obstacles to the development of a local wind energy industry are a lack of favourable building and planning legislation as well as experienced developers and experts.

In an initiative to stimulate the development of wind energy in the country, the World Bank, through the Global Environment Facility (GEF), has launched a programme to subsidise the electricity cost of wind farms and to promote projects currently under planning. As for the private sector, a few

[13] A renewable energy promotion program, introduced by law in 2002. According to this program, the biggest utility company (Eletrobrás S.A.) was intended to place contracts for energy from biomass, small hydro and wind plants over a period of 20 years, to guarantee the construction of the projects. In its first phase, 3.300 MW should have been contracted, representing a total of 1.100 MW of wind power. However, the obligation to use a minimum of 60% locally manufactured equipment jeopardized the success of the program. For more, see (GWEC, 2011 a.)

international players like Gamesa, EDF and Iberdrola have participated in wind energy developments so far (EWEA, 2009, pg. 294).

2.4.3. Africa and the Middle East

Like Latin America, Africa and the Middle East still have to overcome obstacles to the expansion of renewable energy technologies in general - not only wind power. The small or non-existent local manufacturing industry causes a high dependency on imports and consequently high costs. This is just one of the problems holding back the overall development of renewables.

The lack of expertise at executive and governmental levels is another difficulty in the implementation of wind energy projects. Problems are found at all development stages. They start with poor-quality wind capacity estimations[14], continue with deficiencies in the assessment of environmental impacts[15], and end with a general lack of sufficient grid capacity.

Africa and the Middle East will remain regions with the lowest wind energy development worldwide. An increase in the total installed capacity of 500 MW to 3.0 GW is expected by 2012, mainly due to the expansions forecasted for Egypt and Morocco (EWEA, 2009, pg. 295).

Egypt: Egypt relies on excellent wind regimes, particularly in the Suez Gulf, where average wind speeds reach over 10 m/s. At the end of 2009, Egypt had a total wind power installed capacity of 430 MW. In April 2007, Egypt's Supreme Council of Energy announced an ambitious plan to generate 20% of the country's total electricity demand from renewable sources. 12% of the total is projected to come from wind power. In this context, over 3,000 MW of wind energy distributed over different projects along the Gulf of Suez coast are currently under planning (EWEA, 2009, pg. 295).

Morocco: At the end of 2009, Morocco had a total installed capacity of 253 MW of wind power. According to the Global Wind Energy Council, in 2007 the country generated a total of 450 GWh of electricity from wind, covering 2% of its total domestic consumption. Following the example of other countries, the government established specific measures to raise the contribution of renewable energies in the electricity generation matrix to 20% by 2012. This amount is equivalent to 10% of the total primary energy supply portfolio.

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[14] Developing countries have a general lack of reliable long-term data from regional meteorological stations. These data are necessary to verify and extend the measurements taken at the site. As it will be seen in more detail in Chapter 4, poor-quality long-term meteorological data result in energy yield assessments with a pretty high overall uncertainty, compromising the financing of the projects.

[15] One of the main steps in the licensing process of a wind farm is the assessment of its environmental impacts. A lack of experience in the assessment, verification and establishment of measures to compensate the impacts results in very long permit processes, full of bureaucracy, and in many cases causes investors to postpone or even give up investment plans.

With 3,000 km of coastline and high average wind speeds, wind power is the most promising technology to meet government targets. In 2008 the government initiated a programme to increase the total installed capacity of wind power to 600 MW by the end of 2010 (EWEA, 2009, pg. 295). Apparently this was an over-optimistic goal, since by the end of 2011 the total installed capacity of wind power in Morocco was equivalent to 291 MW (GWEC, 2011 b.).

2.5. Summary

As seen in the previous sections, until the middle of this decade the expansion of wind energy was mainly concentrated in Europe (Denmark, Germany, UK, and Spain). With an installed capacity of over 97 GW, onshore wind energy is definitely an established technology in Europe. In coming years, the expansion will be mainly driven by the further development of offshore and repowering projects and the growth of southern and eastern Europe markets. Outside Europe, the expansion of wind energy is likely to be led by the US and China, whose markets have shown a continuous and significant growth in the last couple of years.

In terms of technology development, much has been achieved thanks to advances in the design and material of wind turbines. Wind farms today are more efficient and cheaper than in the 90's. The current trend in research and development indicates that more attention is being given to issues like wind condition assessments, energy yield prediction techniques, as well as integration of large-scale wind farms into centralized transmission grids. Furthermore, the research agenda is strongly dedicated to issues compromising the further expansion of the offshore technology. Issues such as the technical challenges (transport, foundations, reliability, etc) and high costs will keep researchers, turbine manufacturers and developers busy over the years to come. Apart from China and India, the deployment of wind power in Asian, African, Latin American and Middle East countries has been very modest up to now. Many of these countries can count on good to very good wind resources, but the expansion of wind energy is blocked by the typical problems of developing regions: A general lack of technical expertise, insufficient local industries, a high dependence on imports, high costs, bureaucracy, and an insecure financing environment are only a few of them.

This chapter was an overview on the development of wind energy technology worldwide. The next chapter will sharpen the focus on the use of wind power, thereby introducing the different aspects involved in the planning and implementation of wind farms.

3. Introduction to Wind Farms

The following chapter is divided into two complementary parts. The first section briefly summarizes the physical aspects of wind as a primary energy resource and its conversion into power (Section 3.1). The second part (Section 3.2) deals with the application of wind energy to generate electricity in large scale wind farms. The objective is to review the development of wind farm projects, from the initial plan to mature operation.

As will be seen, the scope of work involved in the implementation of wind farms depends to a large extent on specific physical, legal and economic local characteristics, which may vary considerably from country to country, region to region. For this reason, the review here has a general character. The goal is to provide an overview of the scope of work involved in the planning, execution and construction phases of wind farm projects, while discussing their interdependencies and specific contribution to a long and efficient operational life.

3.1. Physical Principles of Wind Energy

According to Manwell (Manwell, et al., 2009, pg. 24) global winds are caused by pressure differences across the Earth's surface due to the uneven heating by solar radiation and the Earth's rotation. The variation in incoming energy from the sun sets up connective cells in the lower layers of the atmosphere. As shown in Figure 3.1, the spatial variations in heat transferred to the Earth's atmosphere create differences in the atmospheric pressure field that cause air to move from high to low pressure areas. There is a pressure gradient force in the vertical direction, but this force is cancelled out by the downward gravitational force, so that the wind blows predominantly in the horizontal plane.

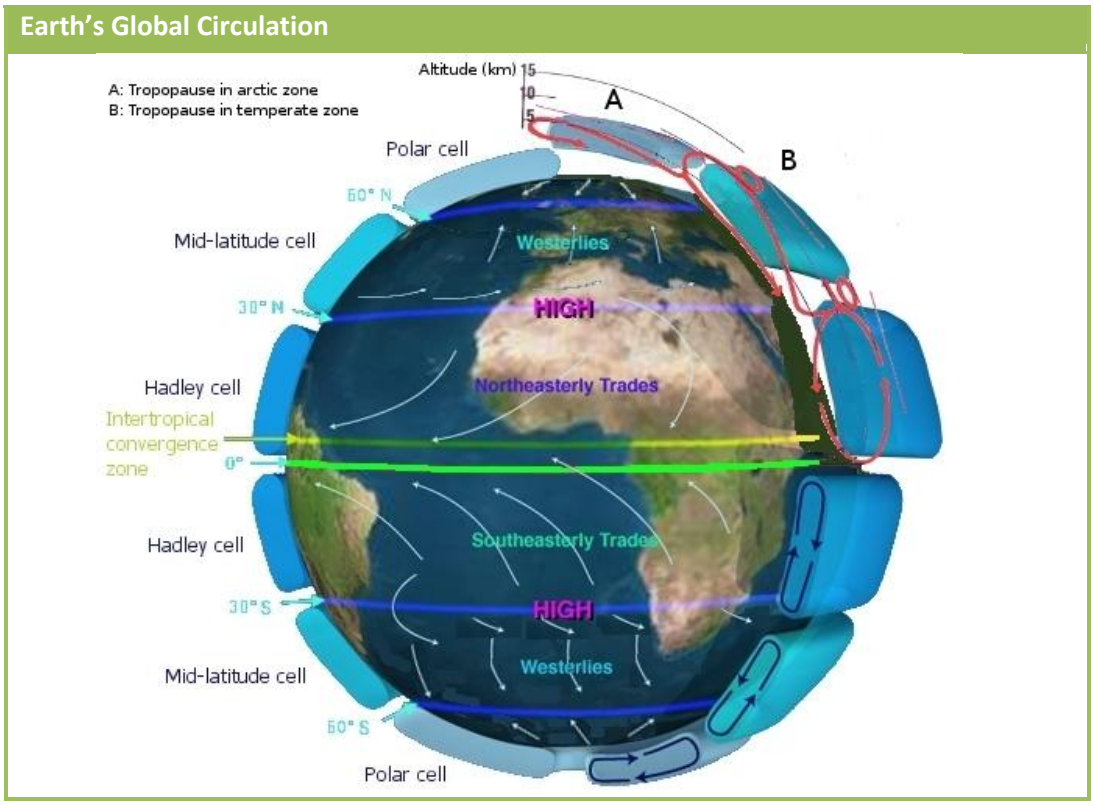

Figure 3.1: Earth's global Circulation. (Source: California Institute of Technology - http://sealevel.jpl.nasa.gov)

A simple model to describe the atmospheric wind motion considers four different forces acting simultaneously: The pressure forces, the Coriolis force (Earth's rotation), inertial forces due to large circular motion, and the frictional forces at the Earth's surface. The result of the interaction of the pressure and Coriolis forces is the geostrophic wind. The interaction of the geostrophic wind and frictional forces at the Earth's surface produces the surface wind, which is the component that can be transformed into power, as described in the following section.

As the solar radiation reaching the Earth's surface varies according to its rotation and position in reference to the sun, the wind also varies in time and space. The variations in time are classified in inter-annual, annual, diurnal and short-term (mainly due to turbulence and short burst of high wind speeds).

Furthermore, the surface wind is strongly influenced by the local topography and ground structure. Over a long-term period, the differences in the mean average wind speed between two sites even close to each other can be significant (Manwell, et al., 2009, pg. 32).

3.2. Power Generation Potential of the Wind Resource

In general terms, wind energy can be defined as the conversion of the kinetic energy of the wind flow into mechanical energy. The mechanical energy can be directly used, for example in a windmill, or further converted into electricity by a *wind turbine generator (WTG)* or *wind energy converter (WEC)*.

The classic mechanical definition of kinetic energy says that a body of mass "*m*" moving at a velocity "*v*" has the capacity to perform work (***energy "E"***) in accordance with the following equation (Molly 1990, pg. 2):

$$E = \frac{1}{2} \cdot m \cdot v^2 \, (Nm) \qquad \text{(Eq. 3.1)}$$

Additionally, ***power*** is the capacity to perform work during a determined period of time *dt*:

$$P = \frac{dE}{dt} \, (W) \qquad \text{(Eq. 3.2)}$$

If one re-writes the eq. 3.1 in 3.2, the following results (Manwell 2009, pg. 33):

$$P = \frac{1}{2} \cdot \frac{dm}{dt} \cdot v^2 \, (W) \qquad \text{(Eq. 3.3)}$$

Where $\frac{dm}{dt}$ can be re-written according to the continuity equation of fluid mechanics, which says that a mass of flow with density "ρ" passing through a rotor of area "*A*" with a speed "*v*" (assumed to be uniform) is given by:

$$\frac{dm}{dt} = \rho \cdot A \cdot v \qquad \text{(Eq. 3.4)}$$

Finally, the capacity of the wind to generate ***power*** is described as:

$$P = \frac{1}{2} \cdot \rho \cdot A \cdot v^3 \, (W) \qquad \text{(Eq. 3.5)}$$

However, not all the power of the wind flow passing through the rotor of a wind turbine can be converted into electricity. The ***capacity factor*** "c_p" of a wind turbine expresses the efficiency of this conversion. It is the ratio between the effective power extracted from the rotor and the theoretical power available in the wind:

$$C_p = \frac{P_{effective}}{P_{teoretical}} \qquad \text{(Eq. 3.6)}$$

Considering the capacity factor, the general equation 3.3 shall be finally re-written as:

$$P = \frac{1}{2} \cdot C_P \cdot \rho \cdot A \cdot v^3 \, (W) \qquad \text{(Eq. 3.7)}$$

From the equation 3.7, two conclusions are relevant:

1) The power produced by wind turbines is proportional to the area of the rotor. This explains why modern turbines with a higher rotor diameter are more efficient.

2) The power extracted from the wind is proportional to the cube of its speed. This means that the power output of a wind turbine is extremely sensitive to changes in the wind speed.

3.3. Wind Farm Projects – an Overview

The definition of *wind farm* depends on legal, political or geographical aspects, and it may vary considerably depending on the country and region where it is developed[16]. From a technical point of view, a wind farm is a group of wind turbines erected on a site, whose simultaneous operation generates electricity. The majority of wind farms in operation worldwide are connected to the local distribution grid, being part of a centralised generation system. However, depending on the size and status of the local grid, wind farms can be designed to supply decentralised generation systems.

Like its definition, the necessary planning work, as well as the implementation time of a wind farm will depend strongly on local issues. But typically, from the initial plan to the mature operation, a wind farm passes through four development phases (Figure 3.2): The preliminary assessment, the project development, the construction, and finally the operational phase.

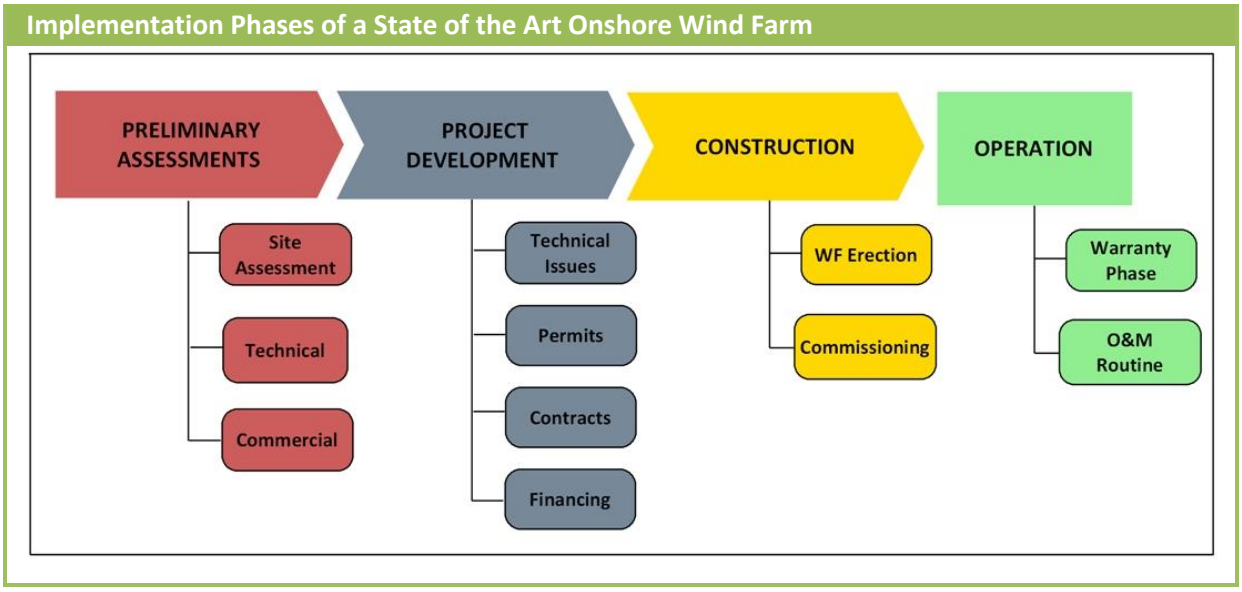

Figure 3.2: Wind Farm Projects - implementation Phases. (Source: the author)

[16] In Germany, the Federal Administrative Court (Bundesverwaltungsgericht) in 2004 defined what a wind farm is for permit purposes. According to this definition, a wind farm is a conglomerate of at least three wind turbines whose layout is designed so that its areas of influence overlap each other (Source: Bundesverwaltungsgericht, decision BVerwG 4 C 9.03, of 30.06.2004).

3.3.1. Preliminary Assessment

The objective of the preliminary assessment is to define the wind farm's potentials and constraints. The preliminary assessment is dedicated to the investigation of the physical characteristics of the site, as well as the technical and commercial issues of the project.

The first task of the site assessment is the definition of the area available for the installation of the wind farm. Factors like the site's boundaries to other properties, environmental protection areas, the capacity of the local grid as well as its constraints, the access to the site, and its topographical characteristics define the limits of the wind farm's area and consequently its maximum capacity.

The assessment of the technical issues of the project is concerned with the investigation of the local wind resource and the energy-production capacity of the site. It includes the installation of measurement masts at the site, the analysis of available meteorological data from the region as well as wind maps. As soon as enough measurement data is available (normally one year) and the area constraints are defined, a preliminary layout assessment is the following step.

A preliminary layout is developed based on "generic" turbine design data, defined in terms of a range of rotor diameters and a range of hub heights. The purpose of a preliminary layout is to limit the power capacity of the farm, investigate the applicable losses and provide a first rough estimate of its energy-production potential. The selection of a specific turbine model is often best left to a more advanced design phase, when the commercial terms of eventual suppliers are known (EWEA 2009, pg.94). For this reason, in the preliminary assessment the project is investigated assuming different conditions of turbine supply.

The assessment of the commercial aspects under which the wind farm will be developed focuses basically on three different, but interdependent issues: Permits, contracts and financing.

The permits will regulate the installation and operation of the wind farm. The preliminary assessment phase evaluates all the efforts in connection with the issue of the necessary permits. The costs and the duration of the permit process are relevant to define the length of the project implementation. Furthermore, in the preliminary assessment, developers have the chance to clarify and regulate eventual operation restrictions leading to a limitation of the overall production capacity of the wind farm. These restrictions are in general linked to environmental issues like noise emission regulations, or bird protection programs.

An overview of the equipment supply and construction contracting conditions, as well as an analysis of the local energy market including the assessment of possible tax benefits and the tariff to be paid for the energy, together with an initial estimation of the energy-production capacity of the wind farm define most of the inputs of the project's economic analysis. Additionally, the estimation of financing conditions such as the amount of the total investment costs to be financed by a loan will

determine the economic feasibility of the project, supporting the decision on whether to go ahead with the development or not.

3.3.2. Project Development

As soon as the constraints on the implementation of the wind farm are removed and the decision to proceed with the project has been taken, the effective development of the project starts. Over the project development phase, the findings of the preliminary assessment will be incorporated into the planning and what was before preliminary now acquires a definitive character. As Figure 3.4 shows, the project development includes the establishment of the final layout, the issue of the permits, the signing of the contracts, and the approval of the financing.

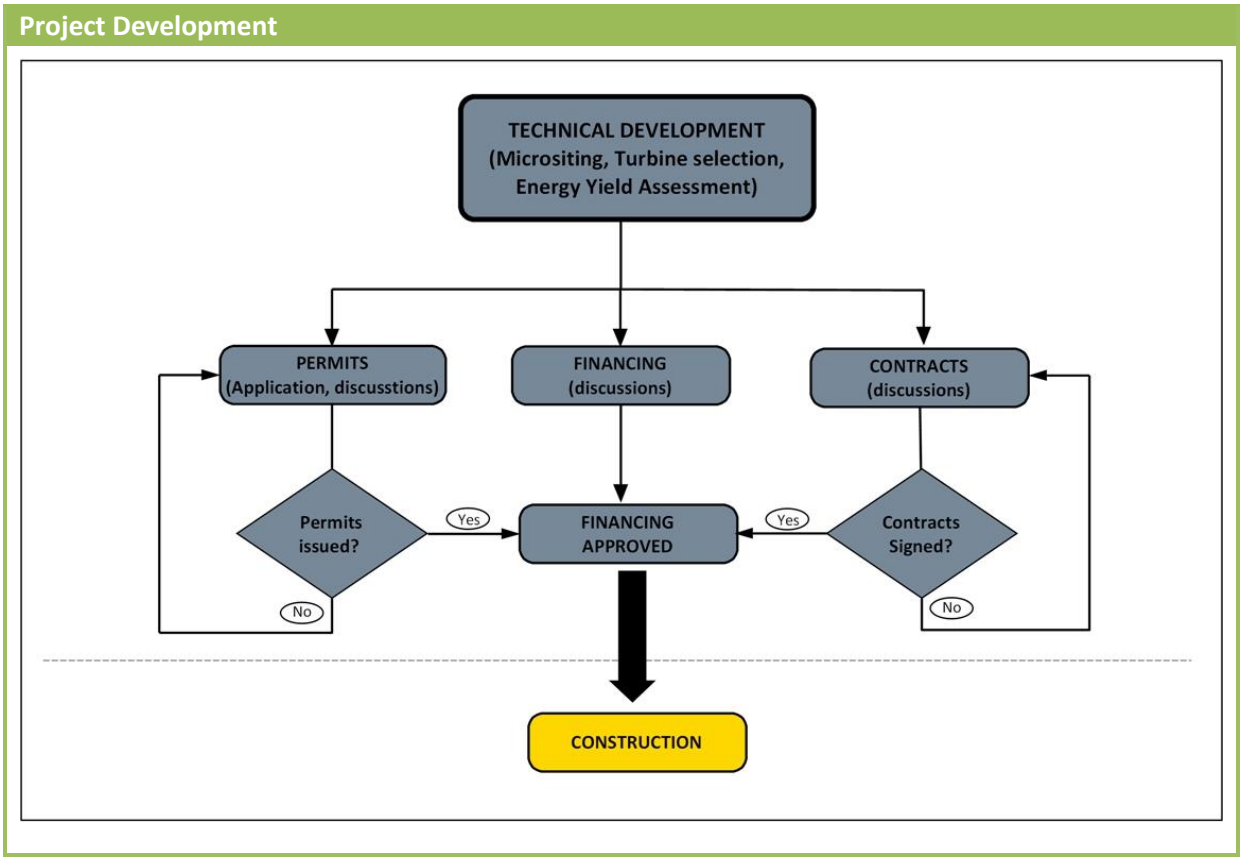

Figure 3.3: Wind Farm projects - Project Development. (Source: the author)

The development of the technical aspects is composed by three complementary processes: Micrositing, turbine selection and energy yield assessment.

Once the wind farm constraints[17] are defined, the layout of the wind farm can be optimized by means of the investigation of different turbine models and design configurations in a so-called

[17] The definition of a list of constraints faced by wind farms is limited by specific local issues. But in general, constraints are typically: Electrical grid limitations, temporary operation restrictions in connection with

micrositing (EWEA 2009, pg.95). The general goal of a micrositing project is to maximize the theoretical energy production of the wind farm while minimizing its infrastructure and operational costs. The outcome of the micrositing, combined with the commercial aspects evaluated in the preliminary assessment phase will then support the selection of the turbines. Once these have been defined, the installed capacity and the energy production potential of the wind farm acquire a definitive character.

With the wind farm dimensioned, the next step in the development process is the issue of the permits, the signing of the contracts and the approval of the financing. Work on these three issues runs in parallel, since they are interdependent and constantly re-organized to account for new conditions.

The dependency of the financing on the conditions agreed in the turbine supply and construction contracts is explained by the fact that the economic performance of the project, for example its ability to cover the debt, is a direct function of the capital and operational costs. In addition, the economic performance of the project is defined by the income from the sale of power, generally defined in the PPA[18]. The dependency of the financing on the permits has to do with the understanding that once all the permits are in place, the parties involved (the local community, local government, etc.) have no objections to the operation of the wind farm. In this case, the issue of the permits is a sort of protection to developers and finance providers against future disputes causing a risk to the full operation of the wind farm.

As soon as the permits have been issued, the equipment and additional works are contracted, and the financing is approved, the construction of the wind farm gets the green light. The final implementation phase starts.

3.3.3. Construction

The construction of a wind farm is relatively simple in comparison to other energy generation facilities. It usually begins with site preparation: the site needs to be cleared for delivery, assembly and erection of the turbines; power lines need to be installed and foundations must be built (Manwell, et al., 2009, pg. 416). Depending on the turbine size and transport conditions, the turbines are delivered ready-assembled or must be fully mounted on site. The towers are lifted with the help of cranes, then the rotor, rotor blades, nacelle and generator are mounted. Then cables and control

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environmental issues, limitations of space imposed by land property issues or protection areas, etc. For more on this issue see for example: (Manwell, et al., 2009, pg. 416)

[18] PPA stands for Power Purchase Agreement and is the contract establishing the remuneration and the supply conditions between the wind farm special purpose company and the power off-taker.

systems are connected so that the initial tests can begin. The final step is the connection of the units to the local grid, and the overall commissioning of the farm.

The construction time of wind farms is also very short compared to a conventional power plant. A 10 MW wind farm can be easily built within a couple of months (EWEA 2009, pg.104). In general, the construction time is determined by specific terrain characteristics like soil properties which can make foundation construction difficult, access constraints challenging the transport of heavy equipment, weather conditions, etc.

Once the turbines are installed, the commissioning of the wind farm takes place. Its scope is not standardized, but generally consists of (Manwell, et al., 2009, pg. 47):

1) Appropriate tests to ensure correct turbine operation and
2) Training of the operation and maintenance staff.

The extent of the commissioning process depends on the technical complexity of the turbines and the degree to which the design has been proven in previous installations. According to the European Wind Energy Association, the commissioning of an individual turbine can take a little more than two days with experienced staff (EWEA 2009, pg. 105). After commissioning, the wind farm is handed over to the company responsible for its operation and maintenance. It must be noted however, that all the steps between the arrival of the equipment at the site and the handover of the operation of the turbines to the O&M team are in general defined in the supply and the construction agreements. These steps normally include the scope and duration of all the necessary acceptance tests, the remedy of faults, the duration of the warranty period, etc.

3.3.4. Operation

The successful operation of a wind farm requires constant monitoring of the performance of the turbines.

Today, wind farms can be operated remotely. Automatic turbine operation requires an oversight system that provides operation information to the operation and maintenance personnel. Remote oversight systems (like SCADA[19]) receive data from the individual turbines and display it on computer screens for system operators. This data is then used to evaluate the turbine energy production and availability (Manwell, et al., 2009, pg. 418).

In view of the technological development of the wind energy industry experienced in recent years, the goal of turbine manufacturers and O&M providers today is to achieve and sustain an operational availability of a minimum of 97%. The technical availability of a wind turbine is contractually defined. In general terms, in a normally structured supply contract manufacturers

guarantee that their turbines will be available to generate during a certain number of hours per month. In case of an availability of 97%, this number of hours is defined as 97% of the total hours in a month. Experience has shown that the achievement of these contractual guarantees depends not only on the quality of the O&M services, but also on the conditions of the site. A wind farm achieves full, mature commercial operation after a period of approximately six months. During this time, the turbines are adjusted to the conditions of the site and the O&M routine adapted so that an availability increase from 80% or 90% to levels even above 97% is often observed.

The provision of an operational warranty of between two to five years is common practice among turbine manufacturers. This warranty, in the form of liquidated damages, covers revenue losses caused by downtimes to correct faults and/or possible performance problems. (EWEA, 2009, pg. 105).

The components of a wind turbine require regular maintenance. The goal of regular maintenance is to ensure the parts operate under the conditions specified by the manufacturers. The provision of predictive maintenance is important to guarantee that components subject to normal wear processes which need to be replaced can be identified in good time. In this way, the procurement of spare parts is efficient enough to avoid unnecessary downtimes (Manwell, et al., 2009, pg.418).

The typical routine maintenance time for a modern wind turbine is 40 hours per year. However, non-routine maintenance might be required. In general, the problems identified via supervisory systems need immediate action. That is why a fixed crew consisting of two people per 20 to 30 wind turbines is the normal manpower available for the operation of a wind farm (EWEA, 2009, pg.105).

Other issues apart from the technical operation of the turbines are managed in the operational phase of a wind farm project. These include for example compliance with environmental conditions imposed by the permit authorities, such as the monitoring of noise, aviation activities or flora and fauna. The commercial management of a wind farm is in general also responsible for the relationship with the local grid operator, for reporting the wind farm's performance to the lenders, etc. (EWEA, 2009, pg. 106).

As discussed later on, the operation phase of a wind farm is no longer the end of its financing process. The re-structuring of the financing of a wind farm after a few months of operation, or in connection with a transfer of a project's rights is becoming the norm.

3.4. Summary

The first part of this chapter briefly reviewed the physical principles behind the generation of electricity by wind power. The physical relations between energy and power were outlined, and the

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[19] SCADA stands for: Supervisory Control And Data Acquisition System.

general equation relating to wind speed and the efficiency of the conversion of kinetic energy into power was discussed.

The second part summarized the typical implementation process of a wind farm. As seen, initial investigations of an available area to install the turbines, the necessary permits and the magnitude of the costs are part of a preliminary assessment phase. In the project development, the final layout and consequently the production estimation of the wind farm are defined. Further goals of the project development are the procurement of the permits, the procurement of the equipment and the finalization of the financing. Finally, the construction of the wind farm and its subsequent operation were briefly summarized.

The next chapter focuses on one of the key issues of the assessment of Modern Portfolio Theory as a risk management framework for wind farms. This is the assessment of the long-term energy production capacity of a wind farm and its related uncertainties.

4. Energy Yield Assessments and their Uncertainties

This chapter addresses the energy yield assessments (EYA) of wind farms and their related uncertainties. An energy yield assessment includes firstly a detailed investigation of the wind resource characteristics at a selected site. An analysis of the local wind resource includes not only the determination of local wind speeds and direction, but also the assessment of other physical characteristics such as turbulence intensity at the site, wind shear profile[20], etc. These investigations are necessary, among other things, to correctly determine the wind turbine type best fitting to the site characteristics.

The assessment of the local wind resource is then followed by the determination of the reference annual energy production of the wind farm. An accurate estimation of the annual energy production of a wind farm relies on the information about the wind resource at the site combined with the power output characteristic of the turbine type. Wind farms as built today are designed to operate over at least 20 years. However, the measurement of the wind characteristics at the site provides only short-term reference information so that the application of this reference information is surrounded by a range of uncertainties.

One of these uncertainties is whether the short term reference information on the wind resource is representative of the long term or not. In other words: *Are the measurements representative of a "good" or a "bad" wind year? Were the measurements taken in a period of unusually high or unusually low wind speeds? Will the local wind suffer any consequences from global climate change?*

Besides the uncertainties about the determination of the long-term local wind resource, the uncertainties about the long-term physical characteristics of the site and the layout of the wind farm challenge the accuracy of the calculation of the annual energy production of wind farm projects. Questions like: *Will the roughness of the site be the same in 10 years as today? Will the layout of the wind farm be the same in 10 years as today, or is it likely that other wind turbines will be installed in the surroundings in the future?* Most of these questions are related to future events of different natures; events which are extremely difficult, if not impossible, to predict. Beyond these "future" character uncertainties, the estimation of the annual energy production of a wind farm has to deal with the uncertainties about the performance of the turbine at the site. Some of the uncertainties

[20] Turbulence has been defined in fluid dynamics literature as a flow regime characterized by chaotic or stochastic property changes. In the case of wind energy, turbulence changes in properties such as pressure and speed are relevant. Wind shear has been defined as differences of wind speed and direction over short distances. Wind shear is composed by two components: vertical and horizontal. Both the turbulence and wind shear local characteristics are important parameters on the analysis of the mechanical suitability of a determined wind turbine type for the site. For more, see for example (Molly J.-P. , 1990).

about the performance of the turbine at the site naturally have a *"future"* character (e.g. *How much will the performance of the turbines change with the wear of their components?*), but others not.

The information on the power output characteristics of a wind turbine (power curves) is based on theoretical calculations, or on measurements. The theoretical calculations are based on general parameters. Being general, these parameters will not always be accurately related to the reality of the wind farm site. Similarly, the measurements of the power output characteristics of a specific wind turbine type are taken under conditions not always comparable to the real conditions under which the turbines will operate at the wind farm site. Therefore, the correspondence of any reference power output characteristic of wind turbines to the real characteristics once these turbines are operating at the site is surrounded by uncertainties of a different nature to the uncertainties about the long-term wind resource. This uncertainty, of a more technical character, creates an additional lack of confidence in the accuracy of annual energy production estimations.

Nevertheless, one of the key issues determining the success of a wind farm project is the quality of its energy yield assessment. The outcomes of this analysis will be the guideline for all the following economical analyses and respective investment and financing decisions. Two slightly different EYA approaches regarding the establishment of the meteorological input data will be addressed here.

The first approach outlined here is described in the details in Version 1 of the MEASNET[21] procedure "Evaluation of Site Specific Wind Conditions" released in November 2009 (Measnet, 2009). The EYA of the wind farms addressed in the second case study to be discussed in the last chapter was developed according to this procedure.

The second approach refers to the 7th revision of the technical guidelines for the determination of the wind potential and energy yield defined by the FGW[22] released in September 2007. The estimations of the annual energy production (AEP), and its related overall uncertainty, of the wind farms discussed in the first case study were developed basically following this procedure.

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[21] MEASNET is a network of measurement institutes which were established to harmonize wind energy related measurement procedures. The institutes of MEASNET all actively perform wind-energy-related measurements and evaluations. The MEASNET procedures are all unanimous among their members and are developed in accordance with the standards established by the International Electrotechnical Commission (IEC).

[22] The Fordergesellschaft Windenergie e.V. (FGW) is a non-profit platform made up of companies, organizations and individuals engaged in research, development, production and application of wind energy. It is a forum for politicians, science and the wind industry. It members are organizations in Germany and the European Community (www.wind-fgw.de).

4.1. Overview

An accurate assessment of the wind resource and the potential energy yield of a wind farm under analysis is the basis for any investment decision in the wind energy business. The diagram illustrated in Figure 4.1 is an overview of what an energy yield assessment is about.

The process addressed here, from the analysis of the local wind resource through to the risk assessement of the most probable annual energy production of the wind farm, is divided into four complementary steps: First, the estimation of the long-term wind resource. Second, the modelling of the wind flow at the site considering its topographic characteristics. Third, the assessment of the wind farm losses and its net energy output. The fourth milestone is the quantification of the uncertainties related to the annual energy production estimation results, and the determination of the probability of occurrence of these results.

The first task, the prediction of the long-term wind regime at the site (meteorological input data) is the key element of an energy yield assessment (EWEA 2009, pg. 46). As described in equation 3.7, the power output of a wind turbine is proportional to the cube of the wind speed. It means that a variaton of 1 to 2% in the wind speed corresponds to 3 to 5 % variation in the energy yield (Strack, et al., 2003). The commercial value of a wind farm is highly dependent on its energy yield, which in turn is highly sensitive to the wind speed. A change of wind speed of a few percent thus significantly impacts the wind farm's cash flow. In this sense, when assessing the long-term wind resource, every effort should be made to maximise its scope, quality and geographical representativeness across the whole wind farm site. In view of this relevance, the next section will be dedicated to the assessment of the meteorological data of energy production potential calculations.

The second step concerns the determination of the gross energy output to be expected from the site considering its topographic characteristics, the layout of the turbines within the area and the site constraints. As will be discussed in more detail in Section 4.3, the process is based on computational models simulating the behavior of the wind flow at the turbine's hub height considering the site's roughness and orography, as well as flow disturbances caused by the interaction between the turbines.

The third milestone will consider the typical losses estimated in the previous step in the determination of the net energy yield most likely to be achieved by the wind farm on a yearly basis. The last milestone is the analysis of the uncertainties around this value. As demonstrated over the discussion, this result is the main input into the subsequent financial calculations, so that the analysis of the uncertainties surrounding this mean value is a relevant (and demanding) task of energy yield assessments. Section 4.4 then addresses the quantification of the uncertainties. Finally, the frequency distribution of the annual energy production will be discussed.

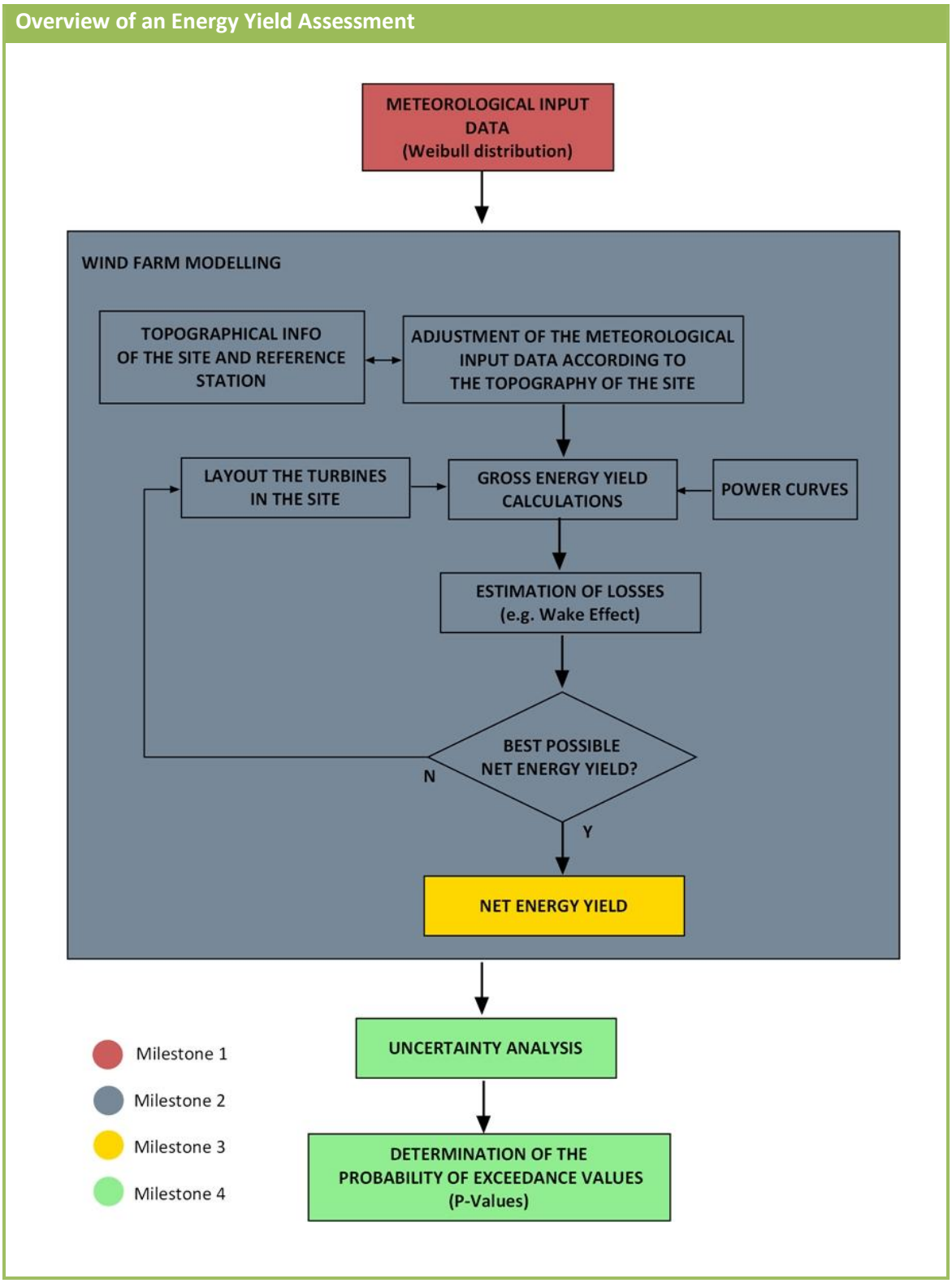

Figure 4.1: Overview of an Energy Yield Assessment. (Reference: EWEA, 2009, pg. 37)

4.2. Meteorological Input Data

Landberg describes eight different ways to estimate the local wind resource (Landberg, et al., 2003):

1. Folklore
2. Measurements Only
3. Measure-Correlate-Predict
4. Global Databases
5. Wind Atlas Methodology
6. Site Data-based Modelling
7. Mesoscale Modelling
8. Combined Meso/Microscale Modelling

The European Wind Energy Association (EWEA) goes one step further and limits the options to two methods that can be used for the prediction of the long-term wind resource at a site where on-site measurements are available (EWEA, 2009, pg. 47):

a) Correlate on-site wind data with wind data recorded at a long-term reference station
b) Use only on-site wind data

A detailed description of these methods is beyond the scope of this paper. For this reason, the review of the establishment of the meteorological input data will be restricted to two different but similar approaches. The approaches are based on the general assumption that a stable long-term mean value of the wind conditions exists and can be derived from historic data, and that this mean value represents the best estimation of the future wind conditions. Nevertheless, the derived values cannot take into account future changes like systematic climate change, being therefore subject to uncertainties (Measnet, 2009, pg. 18).

The first approach is a long-term correlation applying a *measure correlate predict* (MCP) method which compares the wind data measured at the site with the wind data of a long-term reference station. The next section (4.2.1) revises the characteristics and requisites of the site and reference data. Finally, the MCP method will be shortly discussed.

In the second approach (Section 4.2.2), the long-term correlation is based on a *long-term scaling* method, which applies as reference data the energy yield from an operational wind turbine (or turbines) located in the surroundings of the site under investigation corrected to the long term by a local energy yield index.

The difference between both long-term correlation approaches is that the MCP method requires a strong statistical data basis for the determination of the relationships. This data consists of a high resolution time series of wind speed and wind direction measurements. The long-term scaling method can be applied also to data with lower resolution (e.g. monthly data).

4.2.1. Assessment of the Meteorological Input Data Based on On-Site Measurements

***On-Site Wind Measurments*:** The accuracy of the meteorological input data is highly dependent on the quality of the wind data measured at the site. The MEASNET recommends taking the on-site measurements following the IEC standards (IEC 61400-12-1). This includes an appropriate calibration of the anemometers (to measure wind speed), as well as sufficiently sturdy mounting of the wind vane (to measure wind direction) to minimize flow distortion effects due to the interaction of the measurement structure with the wind. As the wind speed tends to increase with height (shear effect), it is important to take the measurements as near as possible to the hub height of the proposed turbines. If a measurement at the hub height is not possible, a reasonable compromise is to ensure that the height of the measurement masts is not less than 75% of the proposed turbine's hub height (EWEA, 2009, pg. 39).

For a small flat wind farm site, one single mast is likely sufficient to provide an accurate assessment of the wind resource. For medium-size wind farms (above 20MW), located in complex terrain, more than one mast will be required to provide an adequate definition of the wind resource across the whole area. For large projects (above 100MW) also located in complex terrain, it is particularly important to take care in "designing" a monitoring campaign which will likely require several measurement masts (EWEA, 2009, pg.38).

Meteorologists have found that the Weibull distribution best approximates the distribution of wind speeds over time (Gipe, 1995, pg. 146). The Weibull distribution is a probability density distribution function described by two parameters: the Weibull "scale" parameter (A), which is closely related to the mean wind speed, and the "shape" parameter (k), which is a measurement of the width of the distribution (EWEA, 2009, pg. 42).

Figure 4.2 presents the wind speed distribution at four different sites, as well as their "Weibull fits". From the Weibull distribution function, it can be concluded that, considering the same scale parameter (e.g. A=1), the higher the shape parameter, the lower will be the amount of different observed values, and with this the higher the frequency of occurrence of values close to the mean value of the distribution. The Weibull fit of the wind speed distribution can provide a general overview of the wind potential of a specific site. Nevertheless, care must be taken when interpreting it. For many sites it may provide a good picture of the real wind speed distribution, but there are some sites where differences may be significant (EWEA, 2009, pg. 42).

For example, in Figure 4.2 the Weibull fit of the distribution of wind speeds observed at the site Snaefell in the UK (Graph 2) is very close to the real format of the distribution, so that the information from the Weibull distribution allows a correct interpretation of the wind conditions at the site. However, if one looks at the distribution of wind speeds measured on a site in Fuerteventura, Canary Islands, Spain (Figure 4.2 – Graph 1), the results can be easily misinterpreted. The median of the Weibull fit is equal to 6.3 m/s. This means that in one half of the observed time the wind speed was higher than 6.3 m/s and in the other half below 6.3 m/s - theoretically a good result. But when looking at the measured data (the bars), it will be noticed that the frequency of occurrence of values lower than 1m/s is quite high. In other words, during a considerable amount of the time the site was windless.

Wind Speed Statistics and the Weibull Distribution – An Example

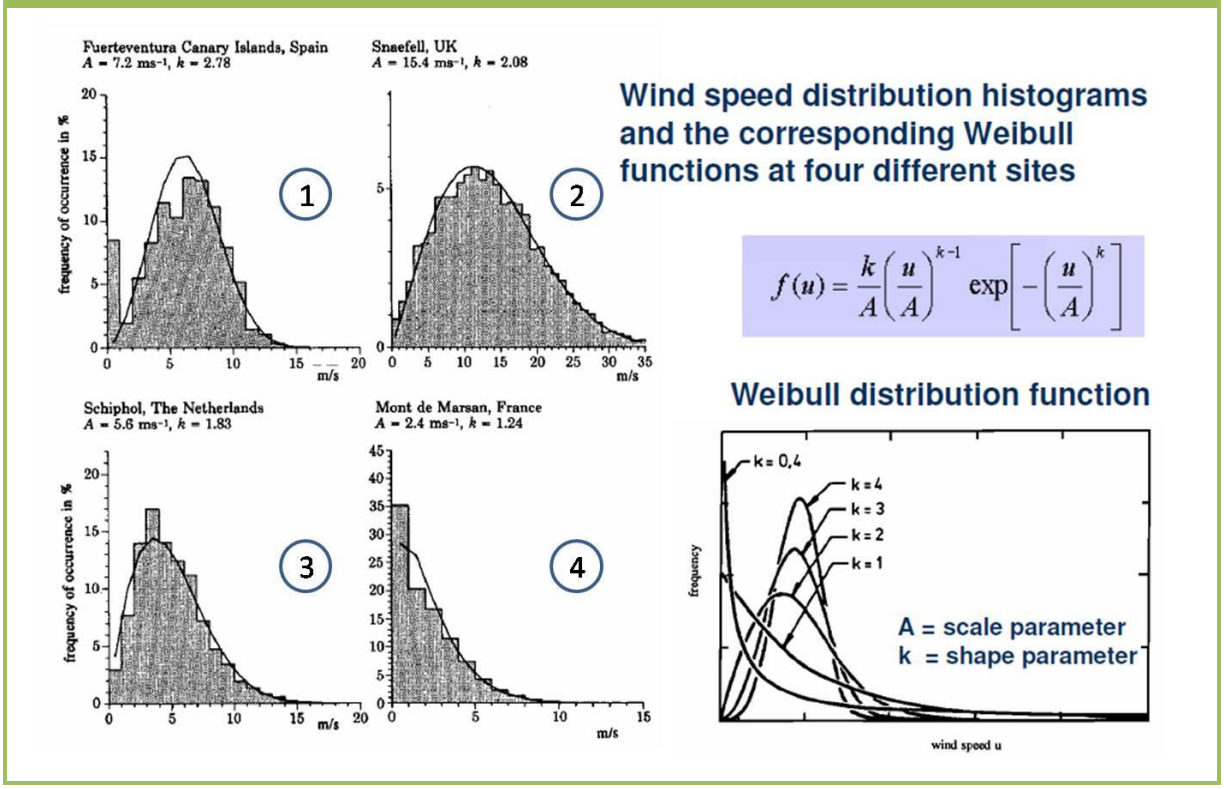

Figure 4.2: Wind Speeds Statistics and the Weibull Distribution – an Example. (Source: DEWI GmbH)

The information on the frequency of the wind directions taken in the measurements is usually shown in a wind rose. For wind energy purposes, the wind rose is divided into 12 sectors, one for each 30 degrees of the horizon. Figure 4.3 is an example of a wind rose representing the frequency distribution of the wind directions of a determined site. In this example it can be seen that the predominant wind direction for the same site can vary considerably between summer and winter.

Frequency Distribution of Wind Directions – An Example

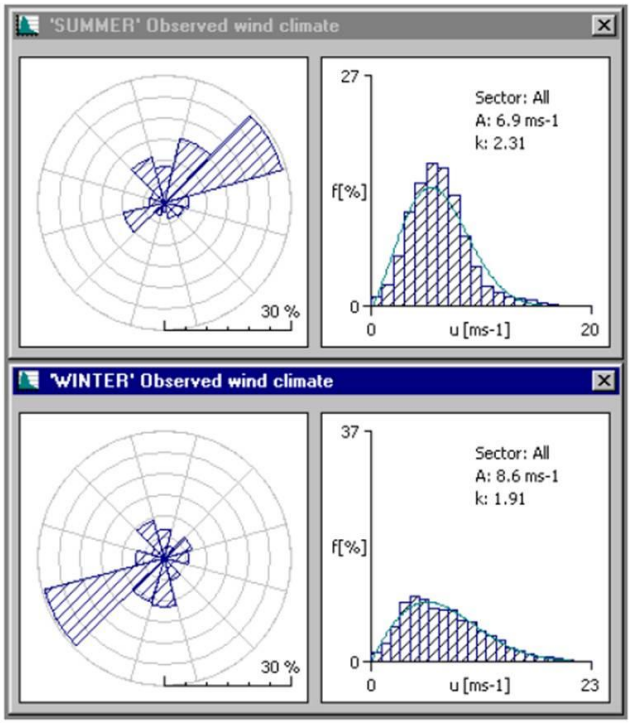

Figure 4.3: Frequency Distribution of measured wind directions – an Example. (Source: DEWI GmbH)

Long-Term Reference Meteorological Data: Generally, the results of a wind measurement campaign at a wind farm site are valid for the measurement period only. Usually this is a short term period of one or a few years only. Due to the fact that wind speed and wind direction distributions can show distinct inter-annual and seasonal variations, a database of many years is required to perform a reliable determination of the typical wind-speed-related site parameters and the consequent long-term annual energy yields (Measnet, 2009, pg. 18).

In practice, long-term reference data on the regional wind conditions is usually provided by a meteorological station located in the same area as the site (up to 100 km distance in flat, a few kilometres in complex terrain), so that the wind conditions at high heights are comparable.

The European Wind Energy Association in its latest publication (EWEA, 2009) has set out some further quality requisites for the long-term data from meteorological stations to be used as reference data. In the first place, the amount and quality of the data overlaping with the data measured at the site is relevant for the accuracy of the final results and the uncertainty related to the whole long-term correlation. Additionally, it is important to be sure that the data has been collected appropriately and that information on the position and height of the masts, as well as potential changes in the exposure of the masts, are accurate. It has been often observed that a decreasing trend in long-term data is caused by changes in the surroundings of the measurement, such as new buildings, growth of trees, etc.

If a meteorological station with data of sufficient quality cannot be found, the long-term correlation can still be made using data from numerical weather models like *Reanalysis or Merra* (EWEA, 2009, pg. 47). The *Reanalysis,* as well as the *Merra* data sets, are the results of a global climate computational model which uses a large number of filtered and converted climatic data. The databases were developed by the US National Centres for Environmental Prediction and the National Centre for Atmospheric Research (NCEP/NCAR). *Reanalysis* and *Merra* data comprise various parameters and are available worldwide with a grid division of 2.5° latitude/longitude and different altitudes. Being free from local influences, geotropic data (like Reanalysis) is understood as representative for larger areas. For this reason, the use of this kind of data for energy yield assessment purposes is common practice, but not always without problems. As argued for example by Winkler et al., in areas where local, e.g. thermal, effects significantly influence the wind conditions near the ground, the use of *Reanalysis* data might be a issue of concern. (Winkler, et al., 2003).

Long-Term Correlation: As illustrated in Figure 4.4, in a measure-correlate-predict (MCP) process, the site data is extrapolated to a longer term by comparison with the long-term reference data. (EWEA, 2009, pg. 48).

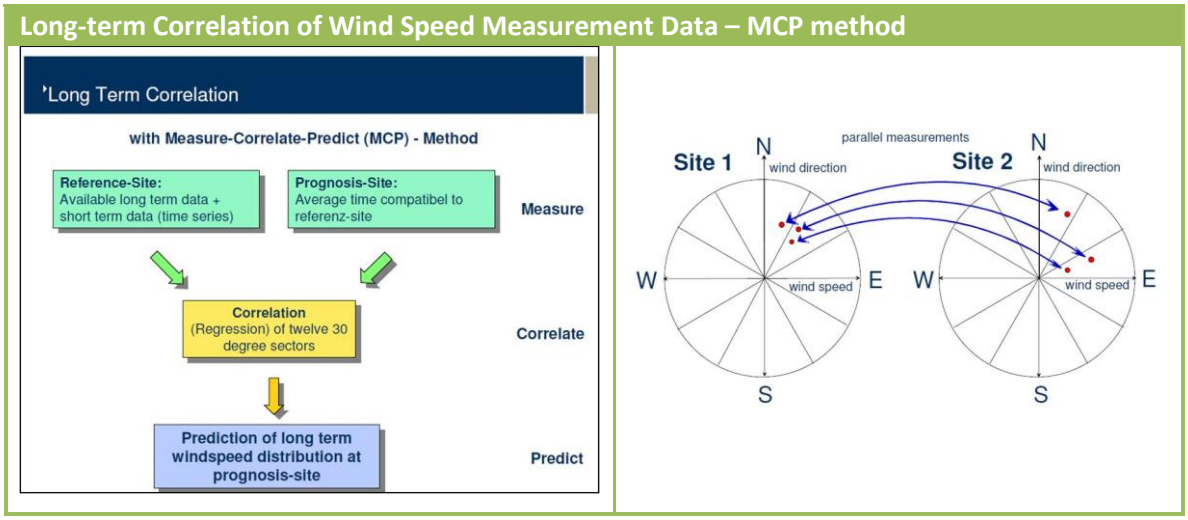

Figure 4.4: Long-term Correlation of Wind Speed Measurement Data Applying the MCP Method. (Source:DEWI GmbH)

A sectoral regression MCP approach following the MEASNET procedures (Measnet, 2009, pg.21) was applied to determine the meteorological input data of the energy yield assessments of the wind farms analysed in the second case study introduced later on.

As detailed by Riedel et al. in a MCP, the concurrent data in different wind direction sectors is analysed with regard to their linear or non-linear relationships (regression analysis). The wind direction deviation between the data is handled independently or implicitly. The definition of the

sectors can be organized in a flexible way, and the way of determining the relationship between the data can be oriented to the deviation of the wind distributions. A prerequisite for the sectoral regression MCP is that a clear relationship between the data exists in the chosen sectors. The relationship is evaluated in the form of the coefficient of determination (R^2) of the wind speed values for each sector considered. Furthermore, it must be verified if the range of occurring wind speeds is sufficient to perform the regression in each sector (Riedel, et al., 2001). For this reason, to choose the most suitable long-term reference set of data, a robust long-term correlation procedure requires the evaluation of different sets of meteorological stations as well as *Reanalysis* or *Merra* data.

As an example, Figure 4.5 illustrates the results of an MCP performed between on-site measurement data (green) taken over a period of approximately one year, and 11 years of data from a meteorological station (red) in the surroundings of the measurement site. The graph in blue is the site data predicted based on the correlation of the short-term data from the measurements taken at the site and the long-term data of the meteorological reference station.

The outcomes of the correlation procedure are a Weibull distribution and a wind rose representing the estimated long-term wind conditions at the site. These parameters then define the meteorological input data of a state-of-the-art energy yield assessment.

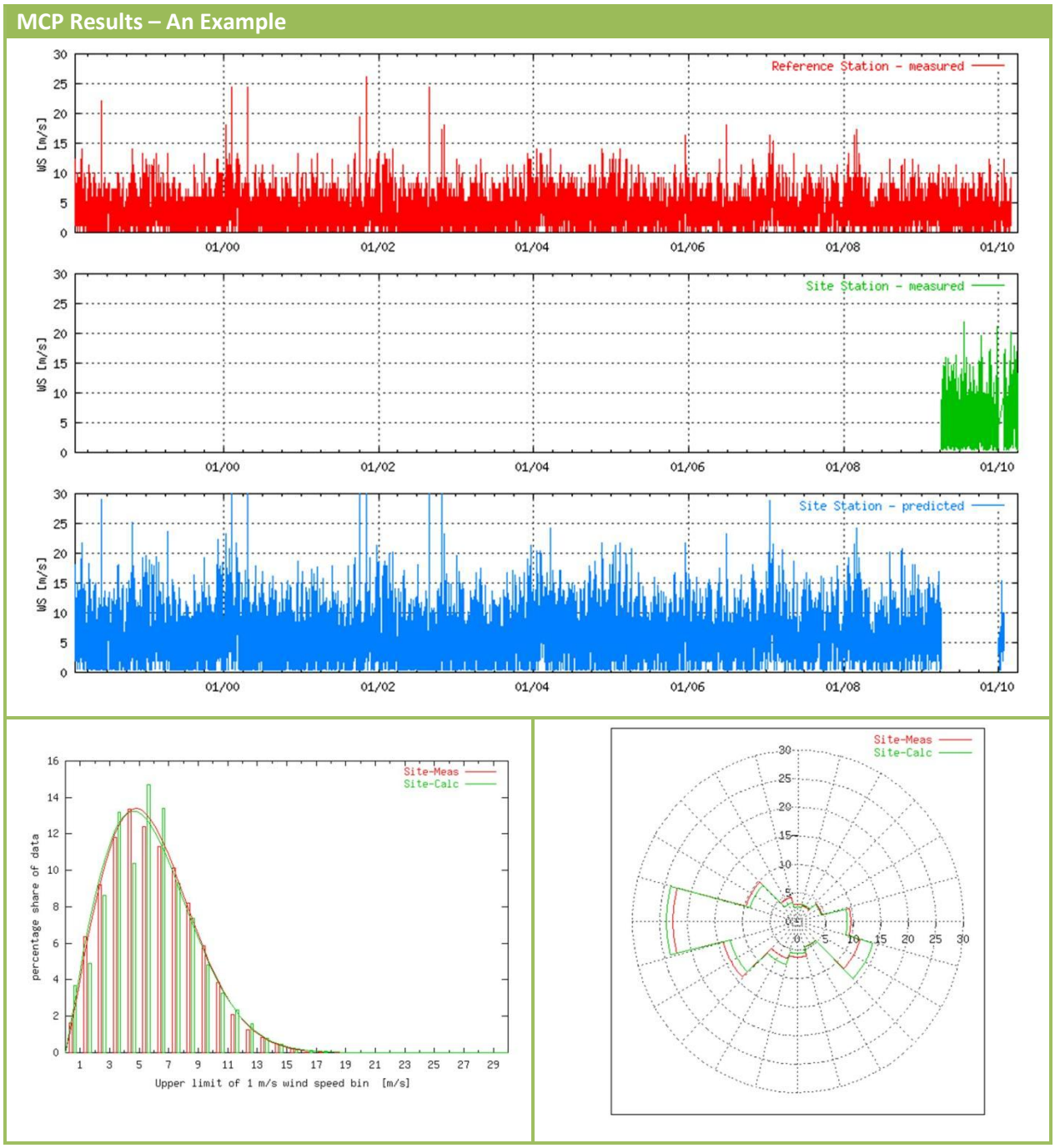

Figure 4.5: MCP results – An Example. (Source: DEWI GmbH)

4.2.2. Assessment of the Meteorological Input Data Based on the Analysis of Operational Data

As described by Winkler (Winkler, et al., 2003) the meteorological input data of energy yield assessments can also be estimated based on the analysis of the energy yield performance of existing wind turbines at the site itself or at wind farms located in the surroundings (short-term reference data). Like the analysis based on local measurements, to be representative over the long term, this reference short-term data must be corrected for the long term. Figure 4.6 illustrates the procedure.

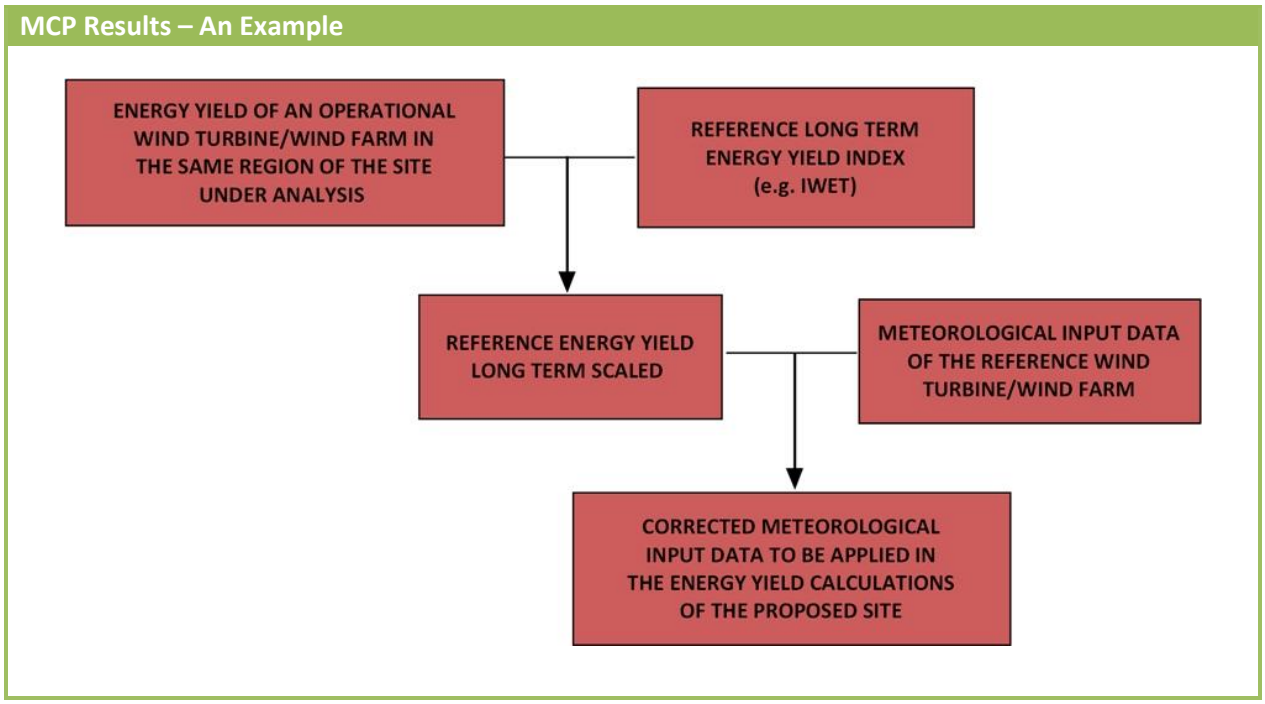

Figure 4.6: Meteorological input data generated with the analysis of operational data of nearby wind turbines/wind farms. (Source: the author)

At first, the availability of operational data of different wind turbines located in the surroundings of the proposed site is checked. Only data with an appropriate amount of monthly energy yields in which the availability of the turbine showed acceptable limits (e.g. above 90%) is used.

As already mentioned, the wind speeds and therefore the energy yields of wind turbines are subject to temporal fluctuations. If energy-yield data of an operational turbine or wind farm is available only for a limited period, the discrete values generally differ from the long-term average. The deviations of discrete monthly values from the long-term average might reach 20% or more (Winkler, et al., 2003). For this reason, the operational data to be used as reference must first be scaled to a longer term according to a local wind index[23] (e.g. BDB Index in Germany). In short, a long-term energy yield index reflects the monthly fluctuations in the energy yield of wind turbines operating in a specific region. Assuming that the energy yield is directly proportional to the wind speed, a long-term reference index can also be created with data from meteorological stations or other references like *reanalysis* and *Merra* data.

[23] Local wind indexes like the IWET in Germany (to be further detailed in the 7th chapter) or the DK Index in Denmark are regional indices which refer to the monthly mean values of energy yields of wind turbines operating in a specific region. The local wind index is a statistical average which specifies how much the monthly energy yield of a wind turbine in a specific region deviates from the long-term average of all turbines included in the index.

Similarly to measured wind data, a scale factor is determined with the comparison of a reference set of short-term energy yield data (e.g. from neighboring wind turbines) to the long-term reference index. The long-term representative meteorology of the site is estimated once this scale factor is applied to the original meteorology (Weibull parameters) of the short-term reference data.

The outcomes of both methods (on-site measurement and energy yield from operating neighboring wind farms) are the parameters describing the long-term meteorological characteristics of the site. This information, however, is solely related to the measurement spots, does not take account of wind speed or energy yield measurements, and does not take into account the overall topographic characteristics of the site. Up to now, nothing is known about the distribution of the wind speed across the site, or the efficiency with which the wind will be converted into energy turbine by turbine. These analyses are the subject of the next section.

4.3. Wind Farm Modelling

For spatial extrapolation of the wind data measured at specific points at the wind farm area to the position and hub heights of the prospected wind turbines, a modelling of the wind farm is required. The wind farm modelling consists of the application of appropriate flow-modelling methods that apply the determined long-term meteorology and the topographic description of the site area (Measnet, 2009, pg. 24). The European Wind Atlas method (WAsP) is the most frequently used method, and has been widely used by the wind industry over recent decades (EWEA, 2009, pg. 49).

It is a general consensus that the European Wind Atlas method has its limitations in complex terrain[24]. As an alternative to WAsP, computational fluid dynamics (CFD) has become popular in the last few years. But in complex sites, CFD tools are still typically used in addition to and not instead of more simple tools like WAsP (EWEA, 2009, pg. 49).

The European Wind Atlas method, schematically presented in Figure 4.7, corrects site-specific measurement data according to the influences of the topography and extrapolates this data to a general non-site-specific, regional wind climate. To calculate the wind climate at another site from this general wind climate, the same procedure is applied in the opposite way, taking into account the site-specific topography. The model is based on the physical principles of flows in atmospheric boundary layers and takes into account effects such as the reduction of wind speed caused by vegetation and other surface roughness, shadow effects of buildings and other obstacles, and changes in wind speed as well as wind direction caused by orographic effects (mountains, valleys).

[24] See for example (Berge, et al., 2006)

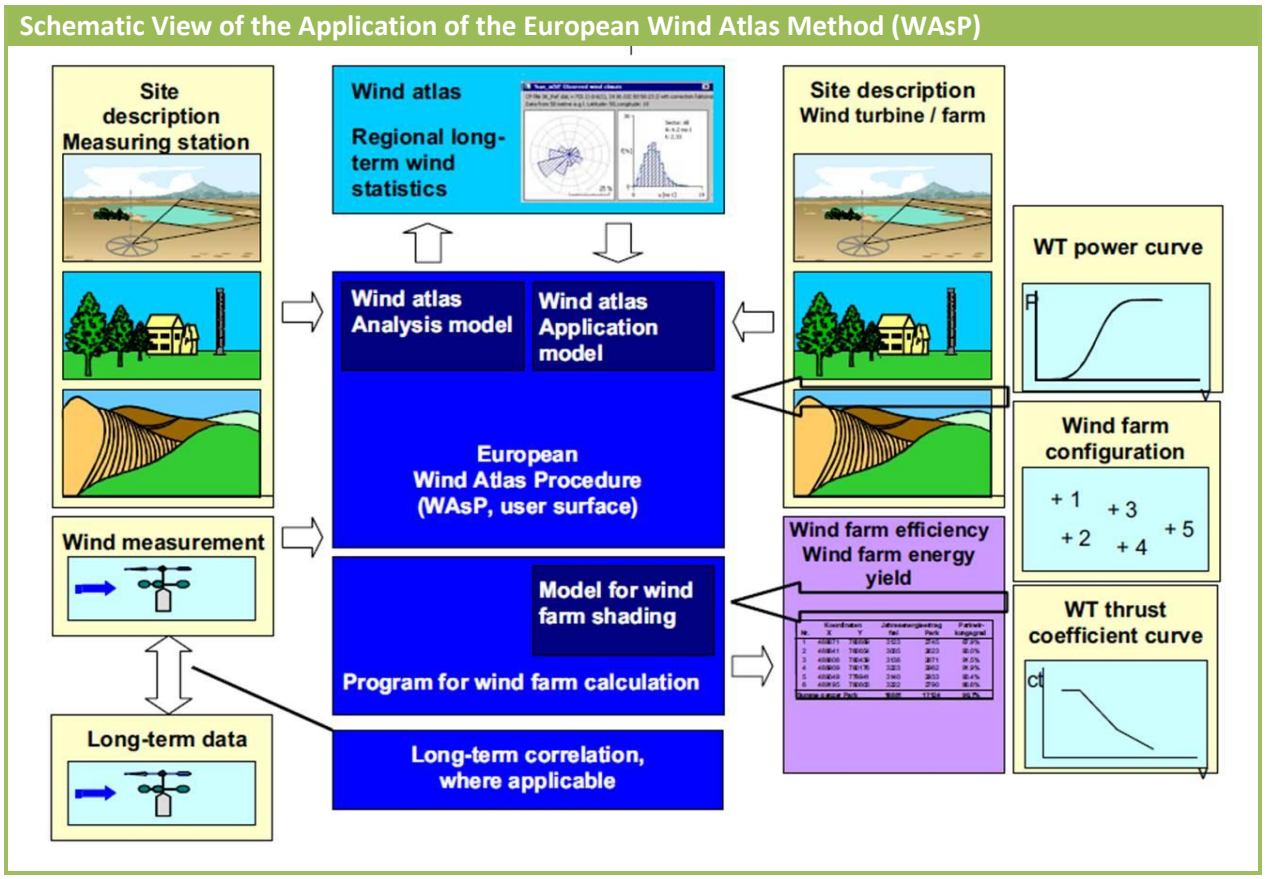

Figure 4.7: Schematic view of the application of the European Wind Atlas method. (Source: DEWI GmbH)

Before applying the model, the surroundings of the site under investigation, as well as the surroundings the meterological reference data comes from are described by the assignment of roughness lengths according to the surface characteristics. Based on this site description, the average wind speed and wind statistics at the site can be calculated from the regional wind climate. In detail, for a specific height, the frequency distribution of the wind speed (Weibull distribution) is calculated for each of the 12 wind direction sectors. With the site-specific wind distribution, the power curve[25] of each single wind turbine, and their planned position at the site (coordinates), the average gross annual energy yield potential of the site is then calculated.

Once the topographical effects on the flow have been estimated, the next step is to determine how the individual turbines affect one another – the wake effects[26]. The losses of power in the wind due to the operation of one turbine downstream of another can be significant. They depend in general on the wind farm design, the wind distribution at the site and its topographical

[25] Power curve is the curve which plots the power output of a turbine corresponding to different bins of wind speed. For more details see for example (Molly J.-P. , 1990).

[26] Defined in Chapter 2. For more details see for example (Sathyajith, 2006)

characteristics. The models estimating these losses are known as "wake models". Strack et al. cite as an example the "Park Model" developed by Riso National Laboratory in Denmark (Strack, et al., 2003). The basic input data of wake calculations are the frequency distributions of the wind speed at each wind turbine position, the thrust coefficient[27] (c_t) of the turbine, and the turbine positions.

Once the calculation models are set up, different layout, turbine type and hub height options are tested in a optimization process. The final results of the wind farm calculations are the annual energy yield and the wind farm efficiency, of each turbine and the whole farm. The total farm efficiency is the ratio between the total energy of the farm (taking into account the wake losses) and the sum of the energy of all single wind turbines on the assumption of an undisturbed flow (gross energy yield).

The net annual energy production of a wind farm includes not only the wake losses but other losses connected to its operation such as the technical availability of the turbines[28], the electrical losses, environmental losses (caused for example by icing), curtailments, losses in connection with the wear of components (e.g. blade degradation), turbine performance, etc. (EWEA, 2009, pg. 51).

The estimation of the losses is based on likely values averaged over the whole project's lifetime. The availability losses are related to the availability of the turbine itself, the balance of the plant (civil and electrical infrastructure of the wind farm), and the grid availability. The electrical losses are related to voltage losses between the terminals of the turbines and the point of connection. These losses are due to cabling as well as non-operational internal consumption of the farm (electrical equipment within the turbine and substation). Losses in connection with the turbine performance are a central issue.

The importance is due to the fact that the energy yield calculations are dependent on the input of the power curves, which are determined assuming standard site conditions like flat terrain or average roughness and air density. Although not state-of-the-art, an alternative to this problem is measurement of the power curves directly at the site. Furthermore, the provision of contractually-agreed performance guarantees is becoming an efficient practice[29].

The environmental losses are connected to downtimes due to icing, high ambient temperatures, or high wind speeds. Curtailment losses are linked to the shut down of some or all turbines in the wind

[27] The thrust curve of a wind turbine plots the force applied by the wind on the turbine's rotor to different bins of wind speed. For more see for example (Réthoré, 2006).

[28] The technical availability determines the amount of hours a wind turbine has been technically available to produce energy. The technical availability is in general contractually defined and takes into account downtimes related to scheduled maintenance as part of the total operational hours. For this reason, the technical availability is the parameter reflecting the technical performance of the turbine. For more see (IEC, 2011).

[29] This issue will be discussed in more detail in the next chapter.

farm due to local environmental regulations (e.g. management of noise emissions or shadow flicker) (EWEA, 2009, pg. 55).

Finally, it is important to emphasize that all the steps involved in a state-of-the-art energy yield assessment - meteorological input data, wind flow modelling, power curves, etc. are linked to uncertainties. The next section is dedicated to the analysis of these uncertainties.

4.4. Uncertainty Analysis

The impact of the energy yield assessment uncertainties on the economics of a wind farm project is discussed in detail in the next chapter. The objective here is to briefly review them from a more technical perspective.

The uncertainties in the analysis of the expected performance of a wind farm have mainly two origins: First, the natural variability of the wind, and second, the uncertainty inherent in the long-term wind and energy yield prediction methodologies (Fontaine, et al., 2007). The natural variability is outside the control of any risk management strategy and cannot be effectively mitigated (Raftery, et al., 1999). On the other hand, the uncertainties related to the prediction of the long-term wind resource and wind farm energy yield are to a certain extent manageable. The first step is a detailed uncertainty analysis.

4.4.1. Uncertainty Components

Not much has been written on the issue of uncertainties of energy yield assessments. Most of the available literature on the topic is based on the experience of developers or consultants[30]. In 2009, a guideline to the quantification of the uncertainties of energy yield assessments performed based on local wind measurements was published by MEASNET. In this guideline, the MEASNET group highlights that the analysis of the different uncertainty components contributing to the overall uncertainty regarding the estimation of the annual energy production of a wind farm should be treated as a site-specific issue. These uncertainties were classified in five groups: wind measurements, correlation and long-term extrapolation, flow modelling, and wake models and power curves (Measnet, 2009, pg.27). These are briefly reviewed below:

Wind Measurements: As seen in the meteorological input data section, the meteorological data used in energy yield calculations comes from short-term onsite measurements, extended to the long term with the analysis of a long-term reference source of local meteorological data. Apart from the natural variabilty of the wind, the uncertainties of onsite short-term measurements are mainly connected to the measurement set up (calibration of the equipment, mounting of the towers, etc.), the

[30] See for example: (Bastide C., 2007) (Fontaine et al., 2007) (Strack et al., 2003)

completeness of the data and the filling of gaps, the representativeness of these measurements to the complete wind farm area, and the measurement period.

Raftery et.al argues that the uncertainty related to anemometer calibrations is often the largest single element contribuiting to the uncertainties in the prediction of wind speeds at a site. (Raftery, et al., 1999). Therefore, a high-quality wind measurement campaign designed in accordance with the exisiting quality standards can significantly contribute to the reduction of the overall uncertainties of energy yield assessments.

Long-Term Extrapolation of Measurement Data: As discussed previously, on-site measurements cover short periods of time, so this data must be extrapolated to a long-term period. Achieving this as well as filling in gaps in the short-term measurement relies on data from a long term-reference such as a nearby meteorological station or *reanalysis / Merra* data. The data from meteorological stations is typically gathered in measurements at a height of 10 m in surroundings strongly influenced by obstacles and vegetation. Furthermore, the data acquisition rate and its completeness, as well as the poor quality of the equipment, which is usually not calibrated according to the applicable quality standards, contribute to its inaccuracy. The uncertainty of the data from long-term reference sources is then estimated taking into account the measurement conditions, the extension of data gaps over the whole measurement period, and the consistency of the values compared to other sources.

According to MEASNET, the assessment of uncertainties on the methodolgy applied to long term extrapolations of onsite measurement data (e.g. MCP) must take into account the coefficients of determination (R^2) and the grade of coverage of relevant wind speed ranges (relevant seasonal information) (Measnet, 2009). The shorter the overlapping period between both short and long-term data, the higher the demands on the MCP, and the greater the uncertainty of the method. This applies particularly to on-site measurement periods under one year. Therefore, the length and the quality of onsite data are relevant to the overall uncertainty of the long-term correlation procedure.

Flow Modelling: The uncertainty of the wind flow modelling is related to the process of adjusting site-specific influences on the measurement data to the turbine positions and hub heights (horizontal and vertical extrapolations). The flow models are very sensitive to the topographic information provided by the maps and the surface roughness description. The uncertainties related to topographic maps as well as the surface roughness description are very subjective. They depend on the accuracy of the maps, as well as on the experience of the model user in his/her interpretation of roughness. Therefore, these uncertainties are difficult to assess and quantify.

The situation is even more difficult in topographically complex areas. Strong terrain-induced influences cannot be completely corrected by models like WAsP. The shorter the measurement heights, the lower the representativeness of the measurements to the full wind farm area and the terrain structure, the higher the uncertainties on whether the model will precisely "clean" the data from surface influences.

Wake Models: The models traditionally used to estimate wind farm losses caused by wake effects are based on simple, empirical assumptions. Additionally, these models are verified and adjusted to small wind farms. Their application to large wind farms is therefore highly innacurate[31]. Furthermore, the models are adjusted to near-neutral stratification conditions, and have larger deviations if the site conditions are different to neutral stratification (Measnet, 2009).

Power Curves: The performance of wind turbines accounts for a considerable part of the overall energy yield uncertainty. The provision of performance guarantees is a contractual alternative to deal with these uncertainties, but still not common practice. Refrence power curves are calculated based on standard assumptions of air density and terrain structure. Most of the turbine types available on the market rely not only on theoretically calculated, but also on measured power curves. Although lower than the uncertainty of a theoretical power curve, the uncertainty of measured power curves is not neglegible, being mostly related to the measurement procedure (calibration of the anemometers, etc.). Depending on the wind conditions, the uncertainty of a power curve measured following IEC standards[32] amounts to 6 to 8%[33]. On top of that, the measurement conditions will always differ from the real operating conditions at the site.

The uncertainty analysis of energy yield assessments based on operational data from neigboring turbines/wind farms has a slightly different character to the uncertainy analysis of energy yield assessments based on wind data measurements. Uncertainties in connection with the wind measurements are replaced by uncertainties about the accuracy of the operational data.

A good guideline has been issued by the "*Fordergesellschaft Windenergie e.V.*" (FGW). In its technical guideline, the FGW recommends considering the reliability of the reference operational data and the long-term energy index in the estimation of the overall uncertainty of the energy yield (FGW, 2007). In general, the uncertainty assessments must take into account the length of the

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[31] The higher the number of turbines and their distances, e.g. wind farms offshore, the stronger the wake effects over the whole site (Strack et al., 2003).

[32] See (IEC, 2005)

[33] Theoretical power curves have a standard uncertainty of 10%.

reference operational period, the distance between the reference turbines and the turbines under assessment, as well as the correlation of the operational data to the long-term energy yield index.

4.4.2. Quantification of the Uncertainties

Acccording to MEASNET, the uncertainties analysis of energy yield assessments should be performed under ISO (International Organization for Standardization) guidelines. These are discussed in the "Guide to the Expression of Uncertainty in Measurement"[34] and the IEC 61400-12-1 Annexes D and E[35] (Measnet, 2009).

According to these documents, the overall uncertainty is quantified as a combination of its individual components. When combining different sources of uncertainty, a central issue is the analysis of independencies and interdependencies. If the components are independent from each other, the combined standard uncertainty is the square root of the summed squares of the uncertainty components. Alternatively, the uncertainty components can be fully correlated, leading to a linear summation of the individual uncertainty components. When there is a dependence between the different uncertainties, a coefficient factor must be determined and considered in the calculations.

Another approach is based on a more complex method, namely the Monte Carlo Simulation. The Monte Carlo method for estimating energy uncertainties is a stochastic method simulating the behaviour of a physical system several times[36]. In an energy yield assessment uncertainty analysis, these simulations produce wind farm outputs while randomly varying the uncertainties according to a defined probability distribution. The final uncertainty is then determined according to the distribution of the several outputs. This method takes into account the non-linear relationships between different uncertainty sources, but is extremely complicated (Fontaine, et al., 2007). Several scientific works (e.g. (Fontaine, et al., 2007), (Raftery, et al., 1999)) compared the results of uncertainty analyses following the IEC method and the Monte Carlo simulation principles. The results of the comparisons show that the use of an uncertainty analysis with a number of simplifying assumptions is as valuable as the Monte Carlo simulation method. The main simplifying assumption is that it is reasonable to assume that the several sources of uncertainty behind determining the most probable annual energy production of a wind farm are independent of each other. Therefore, the IEC method is a safe approach to the estimation of the overall standard uncertainty in the energy yield prediction of a wind farm.

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[34] See (ISO/IEC, 2008)

[35] See (IEC, 2005)

[36] See for example (Schlittgen, 2003)

The FGW also endorses this assumption and recommends assuming that the uncertainties related to the wind data, the modelling, the determination of wake effects, and the inputs from the power curves are independent of each other[37].

According to MEASNET, the uncertainties of the energy yield assessment of a wind farm should be estimated in two parts. The first part takes into account the uncertainties about the long-term wind resource (site-specific uncertainties). As indicated in Equation 4.1, these are estimated considering the uncertainties in the wind measurements, the uncertainties about the long-term extrapolation of site wind measurements, and the uncertainties in the wind flow modelling (horizontal and vertical extrapolation).

$$\textbf{\textit{Uncertainty in the Long-Term Wind Resource}} = \sqrt{\sigma^2_{Windmeas.} + \sigma^2_{LTscaling} + \sigma^2_{H\&Vextrap.}} \qquad \text{(Eq. 4.1)}$$

The second part of the uncertainty analysis estimates the overall uncertainty in the energy yield prediction. The uncertainty in the long-term wind resource is converted into wind energy uncertainty by a calculated sensitivity factor determining the dependency between energy yield and wind speed (dE/dv).

The sensitivity factor is determined taking into account the topographical characteristics of the site (how the wind flow will be affected by topographic effects), and the rotor area and hub height of the turbines. A sensitivity of e.g. 2.18 means that a variation of 10% in the wind speed leads to a variation of 21.8% in the energy yield. The uncertainty of the long-term wind resource corrected by the sensitivity factor is then combined with the uncertainty of the wind farm efficiency calculations (wake losses) and the uncertainty of the reference power curve (Eq. 4.2). The result is the overall uncertainty in estimation of the annual energy production (AEP) of the wind farm under analysis. Table 4.1 shows an example of how the uncertainty analysis of an energy yield assessment is presented in practice.

[37] See (FGW, 2007)

$$\textit{Uncertainty in the AEP} = \sqrt{\sigma^2_{LTwindresource} + \sigma^2_{EfficiencyCalc.} + \sigma^2_{Powercurve.}} \quad \text{(Eq. 4.2)}$$

Overall Uncertainty in Long-term Wind Resources (Standard Uncertainty)	
Wind Measurement	5%
Long-Term Scaling	4%
Horizontal and Vertical Extrapolation	5%
Resulting Overall Uncertainty in the Long-Term Wind Resource	***8%***
Uncertainty in the Annual Energy Production (AEP)	
Overall uncertainties of the wind climate related to the site	18%[38]
Uncertainty of farm efficiency	1%
Uncertainty in power curve	7%
Overall Uncertainty	***20%***

Table 4.1: Example of how the uncertainty analysis is presented in an energy yield assessment (EYA)

4.4.3. Exceedance Probability Curve

The Annual Energy Production estimation of wind farms is normally presented as a distribution curve of exceedance probabilities. The exceedance probability distribution relates a determined range of energy yields according to their probability of occurrence and/or exceedance. The determined average annual energy yield (AEP – annual energy production) is the mean value of the distribution and the overall uncertainty around this value is the standard deviation. The mean value is the so-called P50, and represents the annual energy yield likely to occur with a probability of 50:50. The P75 is the annual energy production likely to be exceeded with a probability of 75%. The P90 is the annual energy production with a probability of exceedance of 90% (Klug, 2006).

As discussed in more detail in the following chapter, traditionally, the income scenarios of wind farm projects are developed based on the P50, P75 and P90 values of the probability distribution. The P50 represents a base case scenario of production, while the P75 and P90 are worst-case scenarios (Klug, 2006).

As seen in the graph below, the shape of a normal distribution is determined by the standard deviation of the distribution – in this case the overall uncertainty of the annual energy production estimation. The higher the uncertainty, the wider the curve and the lower the P90 in terms of Megawatt-hours per year.

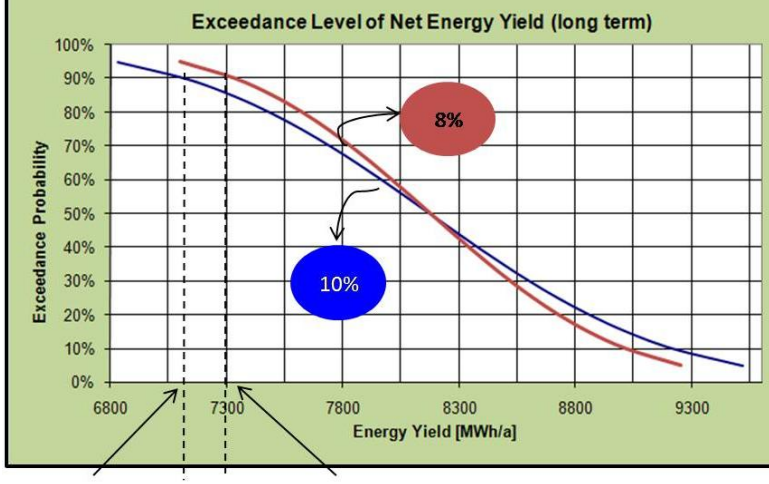
The central issue of the portfolio analysis introduced in the next chapter is the understanding gained with the analysis of the curve below. When comparing the curves in blue and red it can be seen that a reduction in the uncertainty around the reference production value (P50) causes an

[38] Resulting overall uncertainty in the wind speed x sensitivity. (e.g.: 8% x 2.18 ≈ 18%)

increase in the P90[39] , normally taken as the worst-case scenario of production. An increase in the reference worst-case scenario of production means an increase on the projected income of the wind farm – a ground condition to improve its financing conditions as discussed in detail later on.

Exceedance Probability Distribution – P Values

Exceedance Probabilities	Uncertainty in the AEP = 10%	Uncertainty in the AEP = 8%
Long term AEP (P50) [MWh/a]	8176,0	8176,0
AEP exceeded with a probability of 75% (P75) [MWh/a]	7624,5	7734,8
AEP exceeded with a probability of 90% (P90) [MWh/a]	7128,2	7337,8



Energy Yield [MWh/a]	Exceedance Level	Energy Yield [MWh/a]	Exceedance Level
9520,8	5%	9251,9	5%
9223,8	10%	9014,2	10%
9023,4	15%	8853,9	15%
8864,1	20%	8726,5	20%
8727,5	25%	8617,2	25%
8604,7	30%	8519,0	30%
8491,0	35%	8428,0	35%
8383,1	40%	8341,7	40%
8278,7	45%	8258,2	45%
8176,0	50%	8176,0	50%
8073,3	55%	8093,8	55%
7968,9	60%	8010,3	60%
7861,0	65%	7924,0	65%
7747,3	70%	7833,0	70%
7624,5	75%	7734,8	75%
7487,9	80%	7625,5	80%
7328,6	85%	7498,1	85%
7128,2	90%	7337,8	90%
6831,2	95%	7100,1	95%

P90 value @ 10% uncertainty P90 value @ 8% uncertainty

Figure 4.8: Exceedance Probability Distribution and the P-values, an Example (Source: The author).

4.5. Summary

This chapter provided an overview of how energy yield assessments are developed. It began with an overview of the whole process, followed by a discussion of how the meteorological input data is assessed- the key parameter of energy yield assessments.

Two different meteorological input data assessment approaches were discussed. The first approach is when long-term data is generated based on a long-term scaling of short-term data measured directly at the wind farm's site and long-term data from a meteorological reference station, or data from global weather databanks like *reanalysis* data. The second approach is based on the analysis of energy yield data from operational turbines or wind farms located in the surroundings of the site under investigation. The outcomes of the meteorological input data analysis are relevant to the following step of the EYA, specifically to the modeling of the wind flow at the site.

The modeling of the wind flow at the site quantifies the effective kinetic energy of the wind at the turbine's hub height. The quantification is developed considering the wind speed and direction

[39] As a rule of the thumb, an uncertainty reduction of 1% means an increase of about 1.5% in the P90 value.

distributions for the site (Weibull distribution), as well as specific topographical characteristics like surface roughness, orography and presence of obstacles. Further on, the section discussed how the typical energy losses due to the simultaneous operation of several wind turbines are determined (wake effects). Moreover, other typical wind farm losses were introduced, and with this all elements considered in the net energy yield calculations.

The last part of the chapter focused on the analysis of the uncertainties connected with the energy yield assessment. It was seen that the two most important factors contributing to the overall uncertainty in the EYA are the uncertainties related to the wind resource and the turbine power curves. An overview of the quantification of the uncertainties was provided, considering specifically the EYA approach followed in the case studies discussed further. The chapter ends with an introduction to the exceedance probability distribution, a risk assessment approach that displays a wide range of energy yields considering their probabilities of occurrence.

Considering the interdisciplinary characteristic of this work, which involves technical and financial aspects of wind farm projects, the present chapter concludes the overview of the technical concepts necessary for the understanding of the research methodology and its results. The next chapter will change the focus to the financial issues. It is a revision of the principles of the Modern Portfolio Theory and its approach to the analysis of investments in wind farms.

5. The Modern Portfolio Theory and Wind Farm Investments

5.1. Introduction to the Modern Portfolio Theory

The Modern Portfolio Theory (MPT) as known today is the further development of the classic Portfolio Theory first published in the fifties by Harry Markowitz, who won a Nobel Prize for his contributions to the field of Economics. Markowitz's work on the Modern Portfolio Theory is concerned with rational investment decisions under uncertainty. Markowitz's greatest achievement with the Modern Portfolio Theory can be summarized as a way to formalize the behaviour of investors when dealing with risk. In his own words:

"…My work on portfolio theory considers how an optimizing investor would behave, whereas the work by Sharpe and Litner on the Capital Asset Pricing Model (CAPM for short) is concerned with economic equilibrium assuming all investors optimize in the particular manner I proposed…" (Markowitz, 1991 a., pg.1)

Since its origin, the work of Markowitz on the Modern Portfolio Theory has been reviewed by a wide variety of authors. One of them, A.B. Wallingford, provided a succinct but very comprehensive description of Markowitz's background when developing the Modern Portfolio Theory*: "Investors like return and dislike risk"* (Wallingford, 1967). Markowitz defines his basic assumption with the conclusion that two objectives are common to all investors (Markowitz, 1991, pg.6):

1) They want "return" to be as high as possible.

2) They want this return to be stable, not subject to "uncertainty".

As observed for example by Elton et al., these two objectives imply that investors behaving rationally don't hold single assets. Instead, guided by the principle "Don't put all your eggs in one basket", investors hold groups or portfolios of assets (Elton, et al., 2007, pg. 44). Because of that, an investor deciding on where to invest his money would seek out a portfolio of investments which provides the maximum return for a given level of risk, or the minimum risk for a given level of return. Since preferences of return and risk vary from investor to investor indeterminately, the goal of an investment analysis following the principles of the Modern Portfolio Theory is to determine a set of portfolios providing the maximum return for every possible level of risk – the "efficient" set of portfolios.

The uncertainty on the returns of a determined asset requires these to be described by a set of possible outcomes, each of them associated with a probability of occurrence - frequency distribution or return distribution. The two most frequently employed attributes of such a distribution are the expected return and the standard deviation. The expected return is a measure of

central tendency and the standard deviation is the measure of risk or dispersion around this central value (Markowitz, 1991).

On a presentation of his conclusions on the theory and practice of asset management and the behaviour of investors, Renwick differentiates single assets to portfolios of assets according to their return and risk characteristics:

"…Individual assets are characterized by an ex-ante probability distribution of possible returns along with a covariance matrix indicating the magnitude (and sign) of correlation of these possible returns with ex-ante returns from other available risky assets. Portfolios, on the other hand, are characterized by an expected return, ex-ante, and a variance of that return. The objective of optimal asset management is to identify and hold a portfolio which offers the minimum possible dispersion (minimum deviation) for a given or desired ex-ante expected return. Therefore, in the classic Markowitz sense of portfolio selection, ***diversification*** *becomes a search for a set of assets whose expected returns are high and whose co-variances of return are low, or negative, thereby tending to produce a portfolio which promises to be both profitable and unlikely to deviate far from expectations…" (Renwick, 1968, pg. 184).*

In this sense, the central message of what Markowitz defines as the first *"part"of* the portfolio theory is that the diversification of the returns of a portfolio of assets brings an overall reduction of the risk of an investor holding it. However, as discussed in more detail later, diversification reduces the part of the overall risk on the return of a determined asset which is in connection with the activity originating this asset's return – the so called specific risk. The risk remaining even after extensive diversification or *"non-diversifiable"* risk is then the central issue of the second *"part"* of the portfolio theory.

The Modern Portfolio Theory was developed in the context of the management of investments in financial assets (Markowitz, 1952). More specifically, securities like bonds or stocks. Its principles were not developed directly relating to the management of investments in physical assets (e.g.: a wind farm).

Therefore, applying the Modern Portfolio Theory approach to the management of risk of investments in capital assets rather than financial ones is not a "1 to 1" exercise. The principles of diversification and capital asset pricing models have found their place in budgeting practices, but not before several adaptations to key differences between financial and real assets have been taken into account. These will be addressed in the second part of this chapter.

The first part of this chapter addresses the mathematics of diversification. The objective is to review the Markowitz approach on how the return distribution of different single assets contributes to the reduction of the overall variance of a portfolio of these assets. The introduction of the theoretical background on how diversification reduces risk is followed by an examination of the

discussion on why diversification is limited to specific risks. The review of the Modern Portfolio Theory is concluded with an introduction to the Capital Asset Pricing Model and the discussion of how it is complementary to the original work of Markowitz.

The second part of this chapter begins with a discussion of the applicability of an approach developed to manage the risk of investments in securities to the management of risk in investments in other capital assets than financial ones. Based on the understanding that the assessment of risk under the background of the Modern Portfolio Theory is part of a capital budgeting and investment analysis process, the examination of the characteristics of physical and non-tangible assets is followed by a review of the theoretical principles of capital budgeting and investment selection.

The last part is then dedicated to the analysis of how the Markowitz principle of diversification might be applied to wind farm portfolios. A review of the relevant literature on the topic is followed by the introduction of an assessment model developed to address how diversification reduces the uncertainty of the annual energy production of wind farms, and consequently of the income of the projects.

5.2. The Markowitz model of Diversification

The first general assumption of the MPT is that the return of a single risky asset can be described as a normally distributed random variable, where the best single estimate of the actual return from this asset is the mean of this probability distribution. The uncertainty of the return of an asset has been traditionally described as the standard deviation of this mean return value. The higher the uncertainty of an asset's return, the higher the possible outcomes will spread around the mean (Markowitz, 1991, pg.49). In general, risk has been defined in the Portfolio Theory literature as equivalent to uncertainty[40].

Both the assumption that the return of an asset can be approximated by a normal distribution, as well as the assumption that risk is equivalent to the standard deviation of this distribution have been largely discussed in the Portfolio Theory literature[41]. Elton et al. summarized Markowitz's approach to the return of a portfolio as:

"The MPT models an asset's return as a normally distributed random variable, defines risk as the standard deviation of return, and models a portfolio as a weighted combination of assets, so that the

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[40] A review of the main risk measures in connection with the portfolio theory can be found for example in (Rachev, et al., 2008)

[41] For a discussion on the Markowitz approach, when return does not fit to normal distribution, see (Elton, et al., 1974), (Bawa, et al., 1977) or (Sornette, et al., 2000). A contribution to the discussion on whether the standard deviation, or variance is a correct approximation to risk can be found in (Wallingford, 1967), (Samuelson, 1970), (McCord, et al., 1977), (Seitz, et al., 1995) and (Biglova, et al., 2004). For a theoretical differentiation between uncertainty measures and risk measures, see (Ortobelli, et al., 2005).

average return of a portfolio is the weighted combination of the asset's returns. Elton mathematically writes this definition as follows" (Elton, et al., 2007, pg. 53):

$$\overline{\boldsymbol{R}}_{(Portfolio)} = \sum_{i=1}^{N} (X_i \overline{R_i}) \qquad \text{(Eq. 5.1)}$$

Where $\overline{R}_{(Portfolio)}$ is the expected return of the portfolio and $\overline{R_i}$ is the expected return of the asset "*i*".

The variance (σ^2) of a portfolio or its standard deviation (σ) is a little more complex than the expected return. Not only the variance of a single asset must be known, but also the amount by which the returns of two assets co-vary. As recognized by Markowitz himself, modeling the co-variances of inter-security returns is one of the most important aspects of portfolio analysis, especially for large numbers of assets (Markowitz, et al., 1981).

The covariance (σ_{ij}) is a measure of how returns on assets move together. A convenient way of defining the covariance is $\underline{\sigma_{ij}=\sigma_i\ \sigma_j\rho_{ij}}$, where σ_i is the standard deviation of the ith asset of the portfolio, σ_j the standard deviation of the jth asset of the portfolio and ρ_{ij} is the ***correlation coefficient*** between the return of these two assets. (Wallingford, 1967). Elton et al. mathematically defined the correlation coefficient as (Elton, et al., 2007, pg. 54):

$$\boldsymbol{\rho_{ij}} = \frac{\sigma_{ij}}{\sigma_i \sigma_j} \qquad \text{(Eq.5.2)}$$

The "correlation coefficient" measures the extent to which two series of numbers tend to move up and down together. If they move up or down in perfect unison, the correlation coefficient is "1". If the return of one asset moves up and the other down in the same proportion, the correlation coefficient is "-1" and these are said to be uncorrelated. If the returns of two assets move independently – that is if one goes up, the other may go up or down or may not move at all, the correlation coefficient is "0". The more the two series of numbers tend to move up and down together, the greater is their correlation coefficient[42].

Following this understanding, the portfolio's standard deviation is determined by (Markowitz, 1991, pg. 19):

a) The standard deviation of each asset.
b) The correlation between each pair of assets.
c) The amount invested in each asset, or the asset's weight in the portfolio.

[42] In financial portfolio analysis, the correlation coefficient is traditionally determined with the regression analysis of historical return data from the assets under assessment. Problems with this approach have been discussed for example in (Friend, et al., 1965), (Wallingford, 1967), (Blume , 1970), (Frankfurter, et al., 1971), (Kalymon, 1971) (Alexander, et al., 1985) and (Christou, 2008).

Assuming a portfolio composed of two different assets, the portfolio's variance is mathematically expressed as (Elton, et al., 2007, pg. 54):

$$\boldsymbol{\sigma_P^2} = X_i^2\sigma_i^2 + X_j^2\sigma_j^2 + 2X_iX_j\sigma_{ij} \qquad \text{(Eq.5.3)}$$

Where X_i is the participation of asset "*i*" and X_j is the participation of asset "*j*" in the portfolio. σ_i^2 is the variance of asset "*i*" and σ_j^2 the variance of asset "*j*". The covariance of the assets "*i*" and "*j*" is given by σ_{ij}. This formula can be extended to a large number of assets. In this case, the general expression of a portfolio's variance becomes (Elton, et al., 2007, pg. 54):

$$\boldsymbol{\sigma_P^2} = \sum_{j=1}^{N}(X_j^2\sigma_j^2) + \sum_{j=1}^{N}\sum_{\substack{i=1\\ i\neq j}}(X_jX_i\sigma_{ji}) \qquad \text{(Eq. 5.4)}$$

As discussed by Elton, the contribution to the portfolio variance (σ_P^2) of the variance of the individual securities (X_j^2) tends to zero as N gets very large, while the contribution of the covariance terms σ_{ij} approaches the average covariance of all assets. Therefore, for a large number of assets, the portfolio variance becomes (Elton, et al., 2007, pg. 55):

$$\boldsymbol{\sigma_P^2} = \sum_{j=1}^{N}\sum_{\substack{i=1\\ i\neq j}}(X_jX_i\sigma_{ji}) \qquad \text{(Eq.5.5)}$$

The simplification of Equation 5.4 to Equation 5.5 illustrates mathematically what diversification is about. As the number of assets on a portfolio increases, the influence of the individual risk of a determined asset on the portfolio's variance decreases. As the number of assets increases, the portfolio variance becomes dominated by the co-variance between the returns of the assets.

The co-variance can be expressed as a function of the correlation coefficient, which quantifies how much of the variation of one variable can be explained by the variation of the other variable. In other words, the correlation coefficient measures how much the return of one asset is connected to the return of a concurrent asset, reflecting in this sense the risk common to either asset - or the risk that remains after diversification. The risk remaining even after diversification is known as **market risk** (Litner, 1965 a.). A definition of diversifiable (unsystematic) and non-diversifiable (systematic) risks in line with this understanding was given for example by Swamy et al. on their discussions of how portfolio risks should be defined.

"…The risk that remains even after extensive diversification is called non diversifiable (or systematic) and the risk that can be eliminated by diversification is called diversifiable (or non-systematic)…" (Swamy, et al., 1997)

Elton graphically illustrates a portfolio's systematic and unsystematic risk components as shown below:

Number of Assets in a Portfolio and its Variance

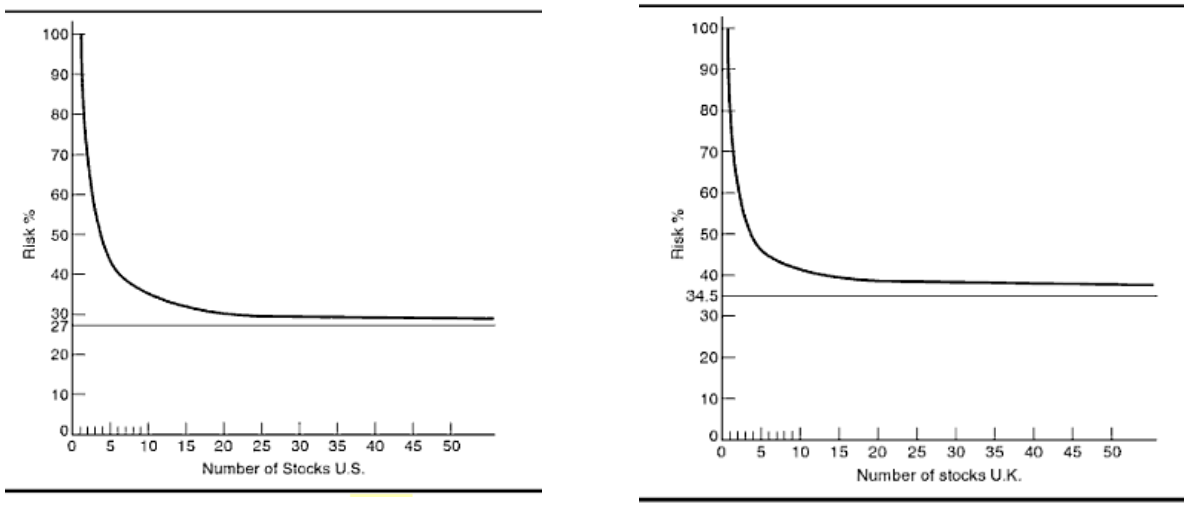

Figure 5.1: Effect of the number of assets on the risk of market portfolios in the United States (left) and in the U.K. (right) (Elton, et al., 2007, pg. 60)

The graphs shown in Figure 5.1 illustrate the effect of an increase in the number of securities in U.S. and U.K. market portfolios. As the number of assets composing the portfolios increases, the risk is gradually reduced to the co-variance of the returns of all these assets. After a certain number of assets, the portfolios reach their maximum diversification. In other words: The specific risks of the single assets have been mutually canceled out. What remains is the systematic risk, or the market risk (Elton, et al., 2007, pg.61).

There is extensive literature on the discussion of systematic and unsystematic risks of financial asset portfolios. Especially William Sharp and John Litner, two of Markowitz's contemporaries, dedicated much of their work to this topic[43]. The central message is that *systematic risks, or market risks,* are related to the risks coming from conditions in the general economy which affect capital markets in total such as business cycles, inflation rates, interest rates, exchange rates, strong financial market crises, etc. These are risks that are present and influence the return of all securities being negotiated in financial markets. Seitz et al. for example argue that *"… none of these macroeconomic variables can be exactly predicted and all affect the rates of returns on assets…"* (Seitz, et al., 1995 pg. 387).

[43] See (Litner, 1965 a.), (Litner, 1965 b.), (Sharpe, 1963) and (Sharpe, 1964)

On the other hand, unsystematic risks are connected to the specific activity generating the return of an asset. For example: a lack of raw materials in the case of a security from the steel industry, or a lack of wind in the case of wind farms. In this sense, the central message of Markowitz is that diversification in financial markets is all about allocating investment to assets whose returns are, as much as possible, independent from each other[44].

Brealey et. al. have summarized this concept in a few words: *"… the gain from diversification depend on how highly the stocks are correlated"* (Brealey, et al., 2010, pg. 216). Litner summarized the diversification principle as:

"…apart from negative correlations, all the gains from diversification come from "averaging over" the independent components of the returns and riks of individual stocks" (Litner, 1965 a.).

In Markowitz's own words:

"A portfolio of sixty different railway securities, for example, would not be as well diversified as the same size portfolio with some railroad, some public utility, mining, various sort of manufacturing, etc. The reason is that it is generally more likely for firms within the same industry to do poorly at the same time than for firms in dissimilar industries. Similarly in trying to make variance small it is not enough to invest in many securities. It is necessary to avoid investing in securities with high covariances among themselves. We should diversify across industries because firms in different industries, especialy industries with different economic characteristcs, have lower covariances than firms within an industry." (Markowitz, 1952).

Markowitz's original assumption on investor behavior - *"Investors like return and dislike risk"* goes beyond the literal meaning of this sentence. He has not only recognized the fact that investors have different expectations of return, but also that investors have different willingness to bear risk. In the words of another contemporaneous author, Fred Renwick:

"Investment policy and portfolio behaviour, logically and rationally depend upon subjective risk-preferences of the investing public." (Renwick, 1968).

Therefore, an investment analysis following the principles of the Modern Portfolio Theory is not concerned with determining one exact portfolio which meets the best conditions of risk x return. In general, investors are guided by the principles of utility maximization when deciding on a determined investment strategy[45]. However, investors have not only different expectations of return, but also different tolerance to risk. Therefore, the overall goal of a financial investment analysis

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[44] For an illustrative example see for example (Bowen, et al., 1998 pg. 44)

[45] Sharp argued that investment decisions are linked to the concept of utility maximization: *"The model of investor behavior considers the investor as choosing from a set of investment opportunities that one which maximizes his utility."* (Sharpe, 1964). For more on the concept of utility maximization, see for example (Seitz, et al., 1995)

following Markowitz is to define a set of asset combinations best able to meet an investor's expectations. Elton et. al, guided by this understanding, defined a portfolio analysis as: *"… the analysis of combinations of all possible risky assets…".* The product of this analysis is what they've called a *"… Subset of portfolios that will be preferred by all investors who exhibit risk avoidance and who prefer more return to less. This set is usually called the efficient set or efficient frontier." (Elton, et al., 2007, pg. 68).*

Mathematically, the way to delineate this frontier is the determination of the risk and return conditions of all possible combinations of individual assets that are part of the portfolio (see Equation 5.5). Possible combinations are determined by attributing all possible weights to the single assets under analysis in the portfolio[46]. By numerical simulations, for example a Monte Carlo Simulation[47], all possible portfolios are calculated and plotted in the so called E-V space (expected return x variance). A line limiting the plotted possible combinatios in the upper left part of the risk x return space is the so-called efficient frontier (see figure below). According to Markowitz, portfolios lying on this line offer the lowest risk for a given level of return[48].

The Efficient Frontier

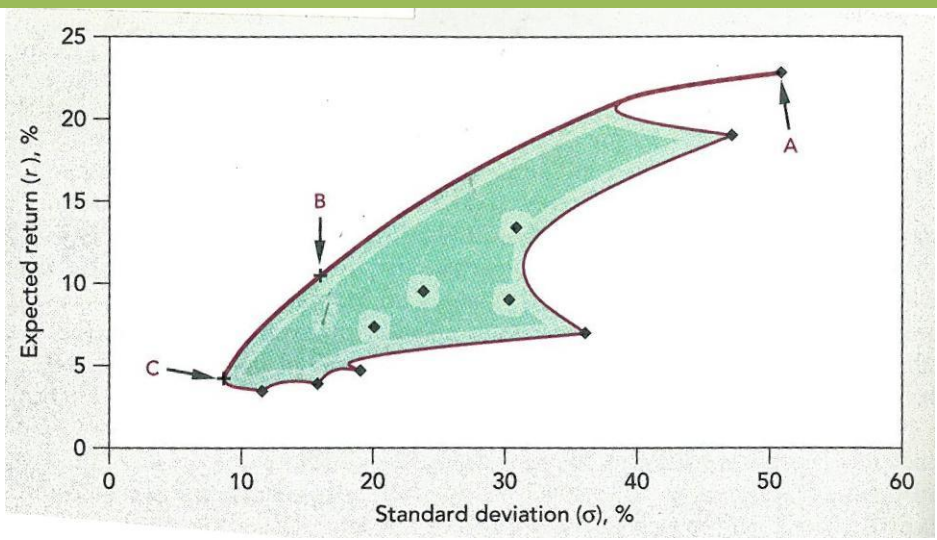

Figure 5.2: Efficient Frontier of Portfolios (Source: (Brealey et.al, 2010, pg. 218)[49]

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[46] For example: Suppose two different assets, say A and B, are under analysis. The variance of a portfolio with these two assets is determined according to the eq. 5.4. The goal is to determine the set of variances correspondent to all possible combinations of X_A and X_B, given the condition that $X_A + X_B$ is always equal to 1 (or 100%).

[47] For an example of Monte Carlo simulations in portfolio analysis, see: (Maier, et al., 1977). Other computational models to derive the efficient frontier are analysed in (Sharpe, 1963), (Sharpe, 1967), (Sharpe, 1971) and (Wallingford, 1967), (Elton, et al., 2007).

[48] More on the geometries behind the definition of an efficient frontier can be found in (Markowitz, 1952)

[49] The graph shows all possible portfolios plotted in the green area and a few exemplary efficient portfolios lying on the efficient curve (portfolios A, B and C).

As summarized for example by Gosch (Gosch, 2010), in practice the goal of the analysis of a portfolio of financial assets following the Modern Portfolio Theory approach is to find the combination of assets leading to the best conditions of risk and return[50] - *the optimal weight structure*.

In the determination of the optimal weight structure of a portfolio of financial assets, the necessary inputs to the analysis are basically the information on historical returns of the considered assets, their variance and the co-variances between these returns. As largely demonstrated in the literature on the management of financial assets following Markowitz, the availability of data[51] as well as the mathematical problems[52] of dealing with a large amount of data are the greatest challenges[53] in portfolio analysis.

The problems connected with the need for a large amount of input data in portfolio analysis originated two alternative models[54]. The *Single Index Model*, also known as the Diagonal Model, introduced by William Sharpe in 1963, and the *Multi-Index Model* introduced by Kalman Cohen and Jerry Pogue in 1967.

Sharp's model assumes that the various securities included in a portfolio analysis are related singularly to a general market performance index. In a single index analysis, only the covariance between one asset and this general market index is necessary (Sharpe, 1963). The Multi-Index Model uses a number of classes of industrial indexes instead of a general market index. In dealing with different classes of securities, such as prefered stocks, common stocks, bonds, etc., a special index is defined for the different classes of securities (Cohen, et al., 1967).

The drawback of both models is the risk of oversimplification. In the original Markowitz approach, the co-variance between every pair of securities included in the portfolio has to be

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[50] For more on the optimal weight structure, see (Hadar, et al., 1988), (Jacobsen, 2010)

[51] Friend for example has shown how the use of historical data might lead to wrong decisions (Friend, et al., 1965). A strategy on how to deal with lack of data on portfolio analysis has been discussed by Gennote (Gennote, 1986). Other discussions related to the problems of availability and accuracy of data can be followed for example in (Blume , 1970), (Frankfurter, et al., 1971), (Kalymon, 1971), (Alexander, et al., 1985).

[52] Examples where the mathematics of portfolio analysis have been discussed: (Dalal, 1983), (Daskin, 1995), (Fisher, 1975), (Chen, et al., 1983), (Kwan, 1984), (Sengupta, et al., 1985) and (Courakis, 1988). The problems deriving from a wrong estimation of the co-variance matrixes were recently addressed by Zhidong and can be found in (Zhidong, et al., 2009).

[53] Apart from the availability of data and the mathematical efforts connected with the large amount of data, other problematic issues such as the costs related to the management of portfolio funds have been discussed in the literature. See (Black , et al., 1974)

[54] Other alternative models are discussed in (Elton, et al., 2007)

estimated and taken into consideration in the determination of the overall portfolio variances. On the one hand, this approach makes the necessary amount of input data enormous, but on the other hand it reflects the covariance between these two specific assets accurately[55]. In the Single Index Model and the Multi-Index Model, the co-variances are no longer estimated in pairs but between one specific security and the respective index, which dramatically reduces the necessary amount of input data. Whether the obtained co-variance is precise enough is the main concern of these two simplification approaches[56].

Irrespective of the discussion on the pros and the limitations of the Markowitz approach and index models, it is important to highlight that these were developed to determine efficient portfolios of investments benefiting from diversification. However, as previously discussed, diversification is limited to unsystematic risks.

The management of systematic risks complements the theoretical background of the Modern Portfolio Theory. The valuation of systematic risks is addressed in the following section within a review of the Capital Asset Price Model.

5.3. The Capital Asset Price Model (CAPM)

As seen in the previous section, investors behaving under the principles of the Modern Portfolio Theory eliminate the specific risk of a single asset in a portfolio of multiple assets by *diversification*. However, diversification cannot eliminate the market risks which are common to all securities in capital markets. In view of market risks, the goal of investment analysis is to find the rate of return of an asset that justifies its exposure to market risks. Put in another way, the objective of investment analysis is to quantify a ***risk premium*** that justifies a determined investment. Elton et al. argue that the construction of an *equilibrium model* allows investors to determine the relevant measure of risk for any asset and the relationship between expected return and risk for any asset when markets are in equilibrium (Elton, et al., 2007, pg. 282). The Capital Asset Price Model is the simplest of all equilibrium models.

Sharpe and Litner demonstrated that in competitive markets, the expected risk premium varies in direct proportion to a variable quantifying the sensitivity of the return of a specific security

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[55] Assuming that the past data is not only accurate, but can be used with an acceptable uncertainty on the prediction of future performances.

[56] Results on the testing of the three models (Markowitz, the Single and the Multi-Index Model) performed by Cohen & Plogue can be found in (Cohen, et al., 1967). A similar comparison can be found in (Wallingford, 1967). Elton and others have developed much of the work initiated by Cohen&Pogue on the Multi-Index Model applied in the analysis of multiple assets. For an overview of their work, see (Elton, et al., 1977), (Elton, et al., 1978). Additional analysis of the multi-index approach can be found in (Markowitz, et al., 1981) and (McEntire, 1984).

to general movements of the market (Sharpe, 1964), (Litner, 1965 b.). Sharpe argues that since diversification allows the reduction of the specific risks of an asset, only the responses of its returns to market conditions (systematical risks) are relevant. He concluded that in capital markets, security prices will be linearly adjusted according to these responses and the expected return. Assets not sensitive to the movements of the market will normally return the free interest rate, while sensitive assets, due to their higher exposure to risk, will provide higher rates of return. In his own words:

"… Diversification enables the investor to escape all but the risk resulting from swings in economic activity – this type of risk remains even in efficient combinations. And, since all other types can be avoided by diversification, only the responsiveness of an asset's rate of return to the level of economic activity is relevant in assessing the risk. Prices will adjust until there is a linear relationship between the magnitude of such responsiveness and expected return. Assets which are unaffected by changes in economic activity will return the pure interest rate, those which move with economic activity will promise appropriately higher expected rates of return". (Sharpe, 1964)

This conclusion is the essence of the CAPM. The linear relation demonstrated by Sharpe is graphically represented by the *capital market line*, also knows as the *security market line,* (as shown in the figure below), which describes the relation between expected return and systematic risk.

The Security Market Line

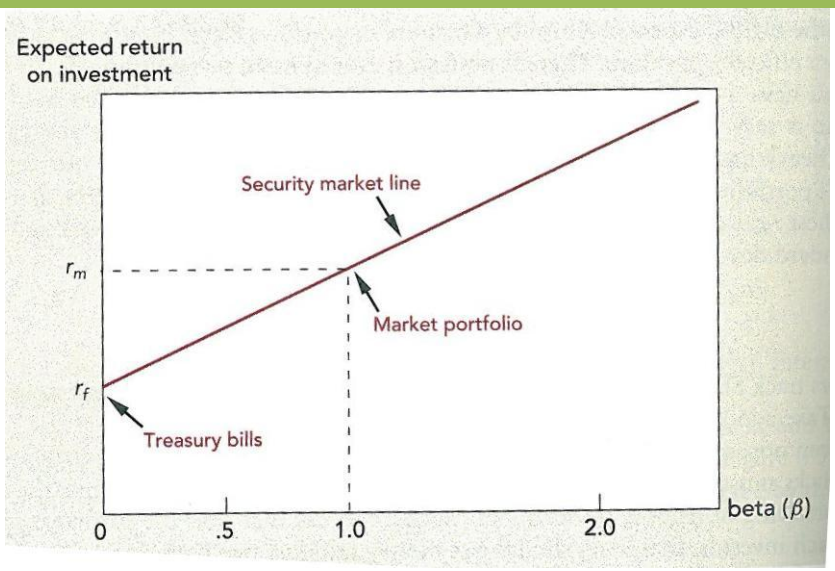

Figure 5.3: Security Market Line (Source: (Brealey et al., 2010, pg. 220)

Mathematically the capital market line describes the following function:

$$\boldsymbol{E(R_i)} = R_f + \beta_i(E(R_m) - R_f) \qquad \text{(Eq. 5.6)}$$

Where, $E(R_i)$ is the expected rate of return of an asset "*i*", R_f[57] is the risk-free rate of interest, R_m[58] is the expected return on the market, and β_i the sensitivity of the asset "*i*" to market movements. The difference between both terms is the *expected risk premium on the market* ($R_m - R_f$). Statistically, beta is defined as (Brealey, et al., 2010, pg. 204):

$$\boldsymbol{\beta}_i = \frac{\sigma_{im}}{\sigma_m^2} \qquad \text{(Eq. 5.7)}$$

Where "σ_{im}" is the covariance between the stock returns and the market returns and "σ_m^2" is the variance of the returns of the market. Similarly, the beta relative to any portfolio can be estimated by dividing the covariance of its return to the portfolio's return to the portfolio's variance. The beta of an asset provides relevant information on its expected return. Brealey et al. briefly summarizes the significance of Beta as:

"The expected risk premium on an investment with a beta of 0.5 is, therefore, half the expected risk on the market, the expected risk premium on an investment with a beta of 2 is twice the expected risk premium on the market." (Brealey, et al., 2010 pg. 221)

Summarizing, the CAPM says that within the market portfolio, beta measures the contribution of each security to the overall market portfolio risk. Therefore, the risk premium demanded by an investor operating in the market portfolio is proportional to beta.

However, apart from its tremendous significance, the CAPM assumes away several complications typical of capital markets. The *"exclusion"* of transaction costs[59], taxes, an infinite divisibility of assets, etc. gave the theory its simplified character (Elton, et al., 2007, pg. 282). Part of these *simplifications* have been addressed by other models, such as for example the Arbitrage Pricing Theory[60], which takes into account *macroeconomic factors* influencing a specific class of asset (Brealey, et al., 2010 pg. 228).

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[57] The risk-free rate is the theoretical rate of return of a risk-free investment. Traditionally, risk-free investments are governmental bonds (e.g.: US Treasury bills) offering a low rate of return in exchange for a low risk of default. The average risk-free rate is estimated with historical data on the return paid by those kinds of assets. For more on the risk-free rate, see (Brealey, et al., 2010, pg. 184)

[58] The expected rate of return on the market is usually estimated by measuring the average of the historical returns of a market portfolio (e.g.: S&P 500). According to Brealey et al., between 1900 and 2008 the average return of all common stocks negotiated in the U.S. was equivalent to 11.1%, while treasury bills provided 4.0%. In this sense, the average risk premium paid to investors trading in these portfolios had an average of 7.1%. For more, see (Brealey, et al., 2010, pg. 186)

[59] For a discussion on the CAPM and transaction costs, see (Black , et al., 1974).

[60] For a connection between the Modern Portfolio Theory and other Asset Pricing Theories, see for example (Fabozzi, et al., 2002)

Nevertheless, the CAPM status as the *"most widely used theory in investment analysis"* (Brealey, et al., 2010, pg. 213) is attribuited to its capacity for dealing with two basic understandings: 1) Investors require extra expected return for taking on risk, and 2) Investors are predominantly concerned with the risks that they cannot eliminate by diversification.

The CAPM is a model largely applied in the decision on investments not only in financial assets but capital assets in general. The principles of diversification, however, are grounded in the management of investments in securities. For this reason, part of the analysis on how the Modern Portfolio Theory has been associated with capital budgeting in investment selection processes is concerned with the limitations of diversification in the practice of risk management of non-financial assets.

After a general review of the main differences and similarities between financial and non-financial assets, these limitations are discussed in the first part of the following section. The second part reviews the theory on capital budgeting.

5.3.1. Capital Investments and the Limitations of Markowitz's Diversification

Capital investment is the process of investing money into something under an expectation of gain. Investments are made in physical, financial or intangible assets. Intangible assets differ from physical asset in the sense that they are not material, are not "*touchable*" or made of "*concrete and iron*" but are also able to generate income. Examples of intangible assets are Research and Development programs (Brealey, et al., 2010, pg. 30), special training programs (Seitz, et al., 1995, pg. 13), etc.. Physical assets like a factory, a machine or a power plant, similarly to intangible assets, must be primarily financed before generating any kind of income.

To finance physical or intangible assets, companies sell claims on these assets and/or on the cash flow that they will generate. These claims are financial assets (Brealey, et al., 2010, pg. 30). Examples of financial assets are bank loans, bonds, shares of a stock, etc. Apart from bank loans, which are not tradable in financial markets, bonds, shares of stocks and other specialized instruments are known as securities. In financial markets, only securities are negotiated. As discussed in the previous sections, the Modern Portfolio Theory was originally conceived to manage investment in securities. However, its principles are largely applicable to the management of investments in other assets rather than only securities.

Nevertheless, as recognized by many authors[61], the principles of the Modern Portfolio Theory, a model designed to optimize investment in securities, cannot be applied to physical and/or

[61] See for example (Litner, 1965 b.), (Lubatkin, et al., 1994), (Mao, et al., 1969)

intangible assets without adaptations. Firstly, the characteristics of risk and return of physical assets must be distinguished from the risk and return characteristics of financial assets.

Seitz (Seitz, et al., 1995, pg. 395) highlighted some of the aspects limiting the application of the portfolio theory in the analysis of investments in physical assets. One of these aspects is simply the fact that an investment in a physical asset is integer in nature. This means investments are either accepted or rejected entirely and rarely fractioned[62]. The same aspect has been discussed by Baum et al. (Baum, et al., 1978).

Baum et al. demonstrated that investments in physical assets are traditionally a discrete variable, while securities such as bonds or stocks are continuous variables. The authors demonstrated how the disregard of this characteristic leads to the wrong decisions[63]. Investors must decide to *invest or not to invest* in a physical asset in its entirety. Investors do evaluate the opportunity of investing in more than one physical asset simultaneously. However, an investor is unlikely to be able to commit solely with a parcel of several different investment opportunities which in theory would build him the most efficient portfolio of assets, in other words, the portfolio of assets that exactly matches his expectations of risk and return. Investors are rarely able to commit to investments in several physical or intangible assets simultaneously, mainly because these are mostly long-term investments.

Black demonstrated that the analysis of year-on-year return fluctuations as part of the decision process makes a direct comparison between the yield of investments in physical assets and securities challenging. Unlike securities, physical assets are generally not held for a short time like securities (Black, et al., 1973), (Black , et al., 1974). Much of the securities portfolio analysis discussion involves either explicitly or implicitly the possibility of “short sales”[64].

In this sense, one of the limitations of the Modern Portfolio Theory as an analysis approach to investments in non-financial assets is the definition of an efficient frontier. A portfolio analysis of the allocation of funds to physical or intangible assets has a different focus than a portfolio analysis for securities. An efficient allocation of available funds is still the main issue. However, portfolio analyses with other capital assets than securities have been generally focused on the contribution of a specific asset to the entire portfolio of assets of a company.

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[62] The issue of the indivisibility of assets limiting a risk management approach in accordance with Markowitz principles has been discussed by several authors. See for example: (Devinney, et al., 1985), (Helfat, 1988), (Herbst, 1990, pg. 303), (Springer, 2003),.

[63] The authors discussed a modified Markowitz approach, in which the capital budgeting problem is reformulated as a parametric programming problem. The reformulation is presented as an alternative approach to the Markowitz model in view of the difficulties presented by discrete variables. See (Baum, et al., 1978).

[64] See for example (Elton, et al., 1978).

Sharp justifies this difference with the recognition that in a portfolio analysis of investment in securities, the market of securities is the environment that indicates whether a certain security shall be added to a portfolio of other securities or not. The criterion is the contribution to the relation risk x return as described by Markowitz. Decisions on long-term investments, even when guided by the same principles, are taken in view of all other assets of a company willing to invest. The criterion is the contribution of a certain investment to the overall company's value. In his own words:

"… As suggested earlier, the complexity of the relationship between the characteristics of individual assets and the location of the investment opportunity curve makes it difficult to provide a simple rule for assessing the desirability of individual assets, since the effect of an asset on an investor's overall investment opportunity curve depends not only on its expected rate of return and risk, but also on its correlation with the other available opportunities..". (Sharpe, 1964)

Renwick formulated this understanding with the conclusion that a capital investment is worth undertaking if this investment increases the so called *shareholder's value*, or the company's value increase associated with the decision of undertaking a determined investment. In this context, the decision on a specific asset is guided by three criteria: 1) the new asset increases the expected return of the company's portfolio, 2) the new asset reduces the total risk exposure of the company's portfolio and 3) there will be an acceptable tradeoff between the change in total risk and the expected return on the portfolio as whole (Renwick, 1968). In other words, for acceptance an investment must offer a risk-return combination such that the new portfolio has either a lower risk, a higher return with the same risk, or a lower risk and higher return compared to the original portfolio.

In his discussion on the principles of the portfolio theory applied to capital budgeting decisions, Litner has shown how the condition imposed by mutually exclusive investment projects is quantified in a decision criterion. According to him, the minimum expected return justifying the allocation of funds to a project is an increasing function of four different factors: 1) the risk-free rate, 2) the market price of risk, 3) the variance in the project's own present value return and 4) its total co-variance with other projects already included in the capital budget (Litner, 1965 b.).

In summary, the decision on a capital investment, no matter if in a physical or intangible asset, is not limited only to the analysis of the investment itself, but to the contribution of this specific investment to the overall value of a company undertaking it. Since the overall value of a company is determined not only by its physical and intangilbe assets but also by its financial assets and liabilities, the decision on a specific capital investment also involves the decision on the right or the best way to finance it.

Therefore, the objective of the next section is not only to review investment analysis practices and the most important theories justifying why one specific investment is prefered instead of another, but also to highlight the importance of efficient financing decisions.

5.3.2. Capital Budgeting and Investment Selection

At this point, it is important to review and differentiate between the concepts of investment decision and financing decision. According to Brealey et al., an investment decision is concerned with the question *"What investments should the corporation make?"* Traditionally, investment decisions are referred as ***capital budgeting*** or ***capital expenditure (CAPEX)*** decisions. A financing decision is related to the question of how to raise cash today as well as how to meet obligations to banks, stockholders, etc.

A company can obtain cash from lenders or shareholders to finance the investments they have decided to make within their capital budgeting decisions. The lenders contribute with cash, which has to be paid back at a fixed rate of interest. Shareholders are called equity investors. They don't get a fixed return, but they own shares of stock which guarantee participation in future profits and cash flows. The capital decision is the choice between debt and equity financing (Brealey, et al., 2010, pg. 32).

Much of the discussion and the findings on capital budgeting and capital decision are credited to Franco Modigliani and Morton Miller. In one of their most important contributions to this topic, they synthesized the process of rational decision making as being guided by two basic criteria: First, the maximization of profits followed by the maximization of market value.

According to Modigliani and Miller:

"…an asset is worth acquiring if it will increase the net profit of the owner of the firm. But net profit will increase only if the expected rate of return, or yield of the asset exceeds the rate of interest. According to the second criterion, an asset is worth acquiring if it increases the value of the owner's equity, i.e., if it adds more to the market value of the firm than the costs of acquisition.." (Modigliani, et al., 1958).

Seitz et al. describe the same proposition as stockholder's wealth maximization. An investment is worth acquiring or performing if it maximizes stockholder's wealth (Seitz, et al., 1995). Renwick goes beyond this and defines stockholder's wealth maximization in accordance with the following three criteria:

"… (1) the new asset can cause a net increase in total present expected return on the portfolio of assets of a company, (2) the new asset can cause a net decline in total risk exposure on the entire portfolio of assets of a company, or (3) there can be some subjectively acceptable tradeoff between change in total risk and change in total expected return on the portfolio…" (Renwick, 1968).

Under conditions of certainty, these two criteria - net profit increase and rate of return exceeding rate of interest are equivalent. However, investment decisions under uncertainty involve rather complex conditions.

Conditions of uncertainty cause investments to be characterized by a diversity of possible outcomes[65]. Put simply, profit is said to be a random variable. Its expected value is affected by specific decisions, for instance financing decisions which also affect its dispersion and other characteristics of the distribution (Modigliani, et al., 1958).

Efficiency variables like the net present value (NPV), the interest rate of return (IRR), etc. are the reference parameters analysts have to use to understand how a certain investment responds to different underlying conditions influencing the distribution of possible outcomes.

Put simply, an investment is worth undertaking if the net present value[66] of the cash inflows (C_0, C_1, ... C_n) is higher than the initial investment. A mathematical description of the net present value has been given by Brealey (Brealey, et al., 2010, pg.51).:

$$\textbf{\textit{Net Present Value}} = C_0 + \frac{C_1 + \ldots + C_n}{(1+r)} \qquad \text{(Eq.5.8)}$$

Where "*r*" is the rate of return, discount rate or ***opportunity cost of capital***.

The internal rate of return is the discount rate which gives a project a zero net present value. Opportunity cost of capital is the minimum rate a determined investment must have to be more attractive than simple investment in financial markets.

Seitz et al. summarize the concept of opportunity cost of capital as:

"…For a capital investment to be justified, the return on money used must be at least as great as the return from alternate opportunities of equal risk. In most situations, money invested by a company must be raised from investors who could invest elsewhere. The cost of capital – the minimum acceptable rate of return - is the return that investors could earn in opportunities of equal risk..." (Seitz, et al., 1995, pg. 494)

According to this understanding, there are mainly two equivalent decision rules in project analysis. These have been summarized by Bradley et al. as follows:

"1) Net present value rule: Accept investments with a positive net present value.

2) Rate of return rule: Accept investments that offer rates of return above the opportunity cost of capital"[67] *(Brealey, et al., 2010,pg. 53).*

These investment analysis fundamentals were formalized by Modigliani and Miller in the so called **preposition III**: "If a firm in class k is acting in the best interest of the stockholders at the time

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[65] See for example M0ao, et al., 1969

[66] Seitz et al.: *"The net present value is the amount of money investors would be willing to supply in exchange for the future cash flows from the investment, less the initial outlay"* (Seitz, et al., 1995 pg. 495).

[67] Arguments questioning the correctness of this "rule" can be found in (Litner, 1965 b.)

of the decision, it will exploit an investment opportunity if and only if the rate of return on the investment, say ρ* is as large as or larger than ρk", where ρ_k is previously defined as the market rate of return of a share of an asset of class k (Modigliani, et al., 1958).

The work of Modigliani and Miller caused a redefinition of the investment decision question. Baron summarizes the question in his discussion of default risk and the Modigliani-Miller theorem. According to the MM criterion, to be carried through an investment must pass only the following test: Will the project, as financed, raise the market value of the firm's shares? If so, it is worth undertaking, if not, its return is less than the marginal cost of capital of the firm (Baron, 1976).

Under the understanding that in a private company profitability and its impact on the market value of the company provide the principle criterion for the acceptability of a determined investment, Herbst defined the **cost of capital** as the minimum profitability rate that project returns must have to cause an increase in the market value of the company (Herbst, 1990, pg. 10). The company cost of capital is estimated as the average rate of return demanded by investors in the company's debt and equity. The rate of return on the debt is denominated as the cost of debt and the rate of return on the equity is the cost of equity. Considering the company's capital structure[68], the weighted-average cost of capital (WACC) is an average of the required return for the various financing sources, weighted according to the proportion of total capital raised from each source.

Brealey et al. define the WACC, or the company cost of capital, as (Brealey, et al., 2010, pg. 242):

$$\boldsymbol{WACC(\%)} = r_D \cdot \frac{D}{V} + r_E \cdot \frac{E}{V} \qquad \text{(Eq.5.9)}$$

Where *"r_D"* is the cost of debt or the desired rate of return on the parcel of the debt (given by the ratio D/V, where V is the total value of the company), and *"r_E"* the cost of equity, or the rate of return on the parcel of the equity.

The cost of debt is the interest rate on the debts that the company has to finance itself. Considering new investments, the cost of debt can be estimated with the help of potential lenders or investment banks. Furthermore, an estimation of the cost of debt can be based on observation of market interest rates on debts financing investments of similar risk (Seitz, et al., 1995, pg. 498).

The cost of equity is the expected rate of return demanded by investors from the company's common or preferred stocks (equity claims). Therefore, the complex part of determining the weighted-average cost of capital of an investment is the determination of the company cost of equity.

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[68] A company capital structure is the mix of long term financing sources, including debt, common stock, and preferred stock. See Seitz et al. pg. 494

Traditionally the Capital Asset Pricing Model (CAPM) discussed previously is a reference approach in the determination of a company's cost of equity. Briefly, the CAPM states that the expected rate of return equals the risk-free interest rate plus a risk premium determined according to the beta of the asset, or risk class in comparison to overall market risks (Brealey, et al., 2010, pg. 241), (Seitz, et al., 1995, pg. 418)[69]. For this reason, companies acting in different businesses have different costs of equity. The cost of equity is linked to the class of the assets corresponding to a determined activity.

Today, the company cost of capital is the benchmark used by several companies as a reference rate to discount new investments. However, the company cost of capital is the right discount rate only for investments under the same level of risk as the company's overall business. Riskier projects have a higher opportunity cost of capital than the company's cost of capital, while safer projects are discounted at lower rates than the company's cost of capital. Furthermore, the condition for the use of the WACC as a reliable reference in investment analysis is the efficiency of the capital structure.

As seen in Equation 5.9, the weighted average cost of capital is linked to the parcels of debt and equity in the overall value (market value, not book value[70]) of a company, or the company's capital structure. A great part of the Modigliani and Miller work on capital budgeting is dedicated to the capital structure question – what is the combination of debt and equity that maximizes the total value of a company's securities?

Modigliani and Miller argue that the capital structure of a company is irrelevant to its value. The irrelevance of capital structure was the subject of their first proposition. According to Modigliani and Miller:

"…The market value of any firm is independent of its capital structure and is given by capitalizing its expected return at the rate k appropriate to its class…". In other words: "The average cost of capital to any firm is completely independent of its capital structure and is equal to the capitalization rate of a pure equity stream of its class…" (Modigliani, et al., 1958).

Herbst summarizes MM proposition 1 as:

"The firms's cost of capital is invariant with respect of its capital structure, depending only on the risk class to which the firm belongs" (Herbst, 1990, pg. 54).

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[69] Mathematically defined, the cost of equity says that:

$$\text{Expected Return on the Equity} = r_f + \beta \bullet (r_m - r_f)$$

where r_f is the risk-free interest rate; r_m is the market rate and β the beta of the asset, estimated according to the CAPM principles (Brealey, et al., 2010, pg. 245)

[70] See Brealey et al. pg. 244

Brealey et al. interpreted the proposition 1 by concluding that, highly levered or not, at the end of the day *"the value of a company is determined by its real assets and not by the proportions of debt and equity issued to buy these assets*[71]". Furthermore, they drew a parallel between the MM proposition 1 and the law of conservation of value in the following example: *"We can slice a cash-flow into as many parts as we like; the values of the parts will always sum back to the value of the unsliced stream"*- In this sense, debt and equity are irrelevant to the company's cost of capital, what matters are their assets and not how they were financed. Modigliani and Miller justify the understanding of capital structure irrelevance with the conclusion that actually "*…physical assets aggregate value to a company, not financing decisions" (Modigliani, et al., 1958).*

The principle of independency between the capital structure of a company and its cost of capital is complemented by the second theorem proposed by Modigliani and Miller, which deals with the effect of debt in the weighted average cost of capital of a company:

"…The expected yield of a share of stock is equal to the appropriate capitalization rate k for a pure equity stream in the class, plus a premium related to financial risk equal to the debt-to-equity ratio times the spread between k and r…" (Modigliani, et al., 1958)

Where *"r"* is the required rate of return. In other words, the proposition 2 says that to keep the company's cost of capital constant, the rate of return an investor requires from its shares increases proportionally to the debt-to-equity ratio of the firm. The higher the risk of default caused by a higher proportion of its capital being financed through debt, the higher the required rate of return of investors. Brealey et al. summarize the principle behind the second proposition of the MM theorem as:

"…any increase in expected return is exactly offset by an increase in risk and therefore in shareholder's required rate of return…" (Brealey, et al., 2010, pg. 453).

Several authors have been discussing the work of Modigliani and Miller on capital budgeting since its appearance at the end of the fifties[72]. Especially the main conclusion that *"Capital structure doesn't matter in well-functioning capital markets"* has been broadly reviewed.

In general it has been concluded that the Modigliani Miller theorem assumes away several complications[73], as commented by Litner:

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[71] See Brealey et al. pg. 449

[72] A collection of articles reviewing the Modigliani and Miller propositions can be found in the *Journal of Economic Perspectives*, Fall 1988 as well as three more articles in the *Financial Management* edition of summer 1989. Furthermore, the theorem has been reviewed by Miller in the article "*The Modigliani-Miller Propositions after Thirty Years"*, M.H. Miller, published in the Spring edition of 1989 of *the Journal of Applied Corporate Finance* pages 6-18. For further reading see Brealey et al. pg. 462.

[73] Seitz et al. listed some of the assumptions to which the MM theorem holds (Seitz, et al., 1995, pg. 531).

"It has been developed under severely idealized conditions" (Litner, 1965 b.). MM assumed away several imperfections typical of capital markets. Seitz et al argued that if a capital structure matters it is because of market imperfections. In this sense, the selection of an optimal capital structure would be the response to those imperfections (Seitz, et al., 1995).

The influence of several market complications like taxes, bankruptcy costs, agency problems as well as information asymmetry have been addressed in the discussions on Modigliani and Miller arguments supporting the irrelevance of capital structure[74]. In general, the conclusion of several discussions on capital structure is that in real life all market complications as well as dividend payout policies have their place in capital structure decisions. However, taxes seem to be one of the most relevant issues in efficient financing decisions.

As Herbst summarizes:

"…The original M and M theory did not take taxes into account, particularly the tax deductibility of interest payments on debt. Subsequent modifications of the M and M theory to include tax effects weakened their original conclusions…" (Herbst, 1990, pg. 54).

Seitz et al. comment on the exception that taxes impose to the principles of the MM's proposition 1 with the following argument:

"…The value of a company can be affected by financial leverage only if financial leverage changes the total cash flow that can be paid to investors. In the absence of taxes, the total stream of cash flow is not affected…" (Seitz, et al., 1995 pg. 532).

Considering the income tax system of several countries in which interest is a tax-deductible expense, debt finance has an important advantage in comparison to equity finance. The parcel deductible from the income subject to taxes, or *tax shield* is equivalent to the corporate tax rate multiplied by the debt interest. The higher the expenses with interest, the lower the taxable amount[75]. Brealey et al. illustrate the effect of taxes on a company's value with the following example:

"…MM's proposition 1 amounts to saying that the value of a pie does not depend on how it is sliced. The pie is the firm's assets, and the debt and equity claims. If we hold the pie constant, then a dollar more of debt means a dollar less of equity value. But there is really a third slice, the government's..."therefore, "...anything the firm can do to reduce the size of the government's slice obviously make stockholders better off…" (Brealey, et al., 2010, pg. 470).

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[74] An analysis of relaxing certain key assumptions like taxes and capital structure in capital budgeting practices can be found in Litner, 1965 b. Arditti has discussed the influence of a company's dividend payout policy as well as high leverage into the shareholder's required return (Arditti, 1967).

[75] An illustrative example can be found in Brealey et al. pg. 471.

Within several examples, Brealey et al. have also demonstrated that the total income to be repaid to debt and stockholders is added by the tax shield. In other words, the after-tax market value of a firm is added to by the tax shield.

Considering taxes, the weighted average cost of capital shall be adjusted. Equation 5.9 shall be re-written to (Brealey, et al., 2010, pg. 500):

$$\textit{After Tax WACC(\%)} = r_D \cdot (1 - T_c) \cdot \frac{D}{V} + r_E \cdot \frac{E}{V} \qquad \text{(Eq.5.10)}$$

Where "T_c" is the corporate tax rate.

In the presence of taxes, the key management issue is to define the capital structure that maximizes the value of future cash flows after income tax. Renwick analyzed how debt financing can be relevant to the financial risk of companies and therefore to the market value of expected income. He concluded that additional debt financing tends to increase the net income under the premise that the rate of return on corporate assets exceeds the rate of interest paid on debts, (Renwick, 1968). In a similar approach, Seitz et al. demonstrated, with the help of conclusive examples, that financing with a higher parcel of debt increases the total cash flow, therefore increasing value (Seitz, et al., 1995 pg. 539).

Based on the positive effects of a tax shield, the first impulse would be to convert the capital to 100% debt finance. However, debt finance alone is rarely seen in practice. High leverage has also negative effects like a higher risk of default. The risk of bankruptcy is increased and various problems come with it such as the impact on the company's creditworthiness, legal costs, indirect costs linked to the management of a company under liquidation, key employees *"leaving the boat"*, etc. Turnbull argues that the existence of a maximum amount of credit that lenders are willing to extend to a company provides a natural definition of debt capacity[76]. He has further demonstrated that a capital structure which leads to maximization of a company's value does not fully explore the maximum debt capacity. Instead, this is achieved when the debt financing stays shortly below its maximal capacity (Turnbull, 1979).

Therefore, the best debt finance rate considers not only tax shields but also the costs of financial distress – the principle of the *Trade-off Theory* (Brealey, et al., 2010, pg. 486).

According to the Trade-off Theory, a company should increase debt until the market value of the company is offset by increases in the costs of financial distress. In general words, the Trade-off Theory recognizes that debt ratios vary with the overall characteristic of a company. Companies with

[76] According to Turnbull, the maximum amount of credit lenders will be willing to provide to the company is determined by finding the point at which, if the firm increases its promised level of repayment, the amount of credit outstanding does not increase. For details see (Turnbull, 1979)

safe, tangible assets and a high parcel of taxable income tend to have higher debt ratios, while companies with risky and intangible assets rely primarily on equity financing. This is one of the arguments justifying why infrastructure projects like wind farms tend to be heavily financed through private loans[77].

Seitz et al. demonstrated that the way companies finance new investments is not always the same. Adjustments in the capital structure are part of the investment decision process. Furthermore, it has been seen how capital structure is connected to the company's risk and the minimum required rate of return by equity investors. Changes in the capital structure connected to financing decisions influence the risk perception of investors which means unavoidable changes in the weighted average cost of capital (Seitz, et al., 1995).

Brealey et al. commented on the impact of financing decisions on the WACC and what to observe when using the WACC as a benchmark for investment analysis. According to them, there are basically two ways of evaluating (or valuating) a project in view of financing decisions: The first way is to estimate the net present value of a project, discounting the *after-tax weighted cost of capital*.

The problem of this first approach is that the WACC is calculated considering the market values of debt and equity of the company investigating the project. Therefore, in order to work, the project under analysis must have characteristics as close as possible to the core business of the company. Due to this effect, the WACC is be used in practice as a reference or benchmark to evaluate a specific project to be adjusted considering possible capital structure adjustments in connection to the way it will be financed. In practice, these adjustments are behind the general understanding that riskier projects will have a cost of capital above the reference WACC while the cost of capital of lower-risk projects can be below this reference.

The second way (named adjusted present value or APV) is to discount at the *opportunity cost of capital* considering the present value of financing side effects. Financing side effects then include tax shields, special financing advantages, etc. The present value of these effects should then be added or subtracted from the NPV discounted at the opportunity cost of capital calculated assuming that the capital structure doesn't matter[78] (Brealey, et al., 2010, pg. 494).

To sum up, much of the principles guiding investment decisions or capital budgeting are credited to Modigliani and Miller, who formalized the understanding that capital investments are justified by wealth maximization. In practice, investors adjust their requests of return to their perception of risk. Riskier investments require a higher rate of return, while lower risk is

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[77] Further reasons why wind farm projects tend to be highly leveraged are discussed in more detail in the next chapter.

78 Seitz et al. have dedicated one full chapter to the analysis of NPV adjustment practices considering capital structure adjustments imposed by financing decisions (See Seitz, et al., 1995, chapter 18).

compensated by lower rates of return. How much a specific investment is likely to contribute to stockholder's wealth is normally quantified by its weighted average cost of capital, which takes into account the necessary capital structure (debt to equity ratios) linked to the investment. In general, investments made of tangible assets with a high parcel of taxable income tend, typically, to be highly financed via debt mechanisms, like for example *project finance*, one of the subjects of the next chapter.

5.4. The Modern Portfolio Theory applied to Capital Assets

After discussing the principles of the Modern Portfolio Theory as developed in the context of financial assets management and capital budgeting, this section addresses some examples of how the Modern Portfolio Theory has been used in practice as a risk analysis tool in decisions on investments in non-financial assets.

The principle of diversification as a strategy to reduce risk, as well as the CAPM approach to quantify the return on investments as a decision parameter, have been used in the analysis of investments in many different types of assets. From real estate properties to fishing[79], through customer management, electricity generation, climate change mitigation[80] and others, the particularities of the MPT have been discussed with a focus on a variety of aspects in connection with the different areas in which its capacity as a risk management tool has been assessed.

In the assessment of the potentialities of the MPT in the management of the risks linked to investments in real estate properties, Penny for example concluded that besides the indivisibility characteristic of real estate properties, the lack of a market organization comparable to a stock exchange limits the portfolio theory approach as a risk management tool. Furthermore, the high transaction costs involved in real estate transactions as well as the long development periods connected with this kind of asset represent a difficulty in the implementation of the principles of the MPT as they were originally developed. (Penny, 1982).

In another approach to the management of real estate assets, Kangari et. al analysed the fundamentals of the MPT in the management of the risks connected with construction assets. Beyond the limitations linked to the indivisible character of these assets, the estimation of the risks associated with different projects and the estimation of the correlation coefficient between the return on these different projects are barriers to the implementation of Markowitz's principles as a risk management practice for this kind of business. (Kangari , et al., 1988)

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79 See (Baldursson, et al., 1997)

80 See (Springer, 2003)

In the context of customer management, Nenonen discussed some problems of applying the mean variance diversification approach as well as the CAPM as a management strategy in the field of marketing. The author summarizes the main differences between key concepts of the MPT and interconnections between specific companies' decisions in view of their relationship to individual customers, the basic definition of risk and return, the correlation between risk and return and resource allocation (Nenonen, 2009). Another example of portfolio theory applied in the domain of marketing was given by Dhar (Dhar, et al., 2003).

The core idea of these two assessments is that a company can maximize the returns from its overall customer portfolio by acquiring or retaining particular customers on the basis of how their spending and cost patterns are likely to contribute to the diversification of segments and a consequent diversification of cash flows. In this sense, the spending characteristics of specific customers, as well as the costs associated with these outcomes are viewed as assets which, when strategically combined, can diversify the cash flows of the companies following this strategy.

Still in the field of customer management, but this time focused on credit analysis, Inossa et al. presented the idea behind an "active" or "structured" credit portfolio management. The approach is to price loans to finance energy projects within a project finance alternative, designed to take into account possible diversification effects that these projects would bring to the bank's overall portfolio. The stronger a specific project contributes to the overall risk reduction of the bank's portfolio risk, the lower the rate of the loan. (Inoussa, et al., 2004)

A very particular application of the MPT to non-financial assets has been presented by Krysiak in an article titled *"Sustainability and its Relation to Efficiency under Uncertainty"*. Krysiak discusses the assessment of the diversification of uncertainties associated with sustainability projects. Krysiak argues that most sustainability projects are burdened with uncertainties related to the concept of "well-being" which is directly linked to sustainability. The concept is not only uncertain regarding individual preferences, but also regarding the question of whether a momentary preference will be the same in the future. Krysiak employs the portfolio approach to address the diversification achieved by combining actions towards sustainability (Krysiak, 2009).

In one of the first assessments linking the Portfolio Theory to the diversification of the risks of electricity generation assets, Ben Lev and Steven Katz addressed the definition of an efficient frontier of generation portfolios combining different sources of fossil fuels. In their assessment, the authors saw the uncertainties of fuel prices as the main risk component of the U.S. electricity generation matrix. The approach considers the return of electricity utilities to be connected with the costs of fuel and the risk to the variation of these costs. By mixing coal, oil and gas in very different combinations determined according to the operational experience of the utilities, Ben Lev and Steven Katz developed a portfolio approach able to define what would be an efficient mix of

generation sources (Bar-Lev, et al., 1976). A similar approach was addressed by Humphreys et al. at the end of the 90's.

Humphreys et al. demonstrated that generation portfolios heavily based on coal would reduce the volatility of energy prices in the U.S., as long as external generation costs associated with this source are disregarded from the analysis. Once these are included in the analysis, portfolios with a stronger participation of natural gas dominate the efficient frontier. The interesting aspect of the Humphreys et al. analysis is the evaluation of the changes in the efficient frontier in relation to the changes in the correlation matrix. They show how the correlation matrix varies in view of the high volatility of fossil fuel prices in the U.S. (Humphreys, et al., 1998).

In 2003, Awerbuch and Berger published an assessment of the Portfolio Theory approach in the establishment of an efficient electricity generation portfolio in the European Union. In this work, an extension of a similar approach developed on the U.S. generation market[81], Awerbuch and Berger focused on the fuel, operation and maintenance (O&M), and construction period costs in the evaluation of the return and risk characteristics of generation portfolios in the EU. Contrary to other analyses on the same issue, Awerbuch and Berger demonstrated that the inclusion of renewable generation sources like wind power in portfolios traditionally composed of nuclear, coal and other fossil fuel alternatives would under some circumstances reduce the associated risks and the overall costs of electricity generation portfolios. The basis of the analysis is the evaluation of the impact of a "*risk-free*" asset like wind power[82] in the assessment of the portfolio risk connected to the uncertainty on the fuel prices of traditional generation assets. The inclusion of "*practical constraints*" in the analysis, such as the long construction periods associated with new alternatives, as well as the decomissioning periods of existing nuclear power plants, gave the assessment a realistic character. All in all, Awerbuch and Berger demonstrated that the benefits of the inclusion of renewable sources in the EU electricity generation mix would be considerable enough to justify a review of some of the local energy polices strongly based on the expansion of natural gas generation (Awerbuch, et al., 2003).

In 2008, a new assessment of fuel mix diversification based on the principles of the Portfolio Theory was published by Roques et. al. This analysis had a different focus in comparision to past analyses such as the analysis of Bar-Lev and Katz, Humphreys et. al and Awerbuch and Berger. Roques et al. argue that these previous analyses were developed in a context in which electricity generation matrixes are exclusively managed by regulated utilities. Under this assumption, the core of the assessments was always the evaluation of diversity in *production costs*. Roques et. al argued

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[81] See (Awerbuch, 2000)

[82] *"Risk-free"* in the sense that wind power is a *"fuel-free"* electricity generation alternative.

however that in the context of liberalized markets, where the decision on investments taken by private investors sets the course of the expansion and the consequent generation mix, the production costs of the different technologies are not the main issue in the assessment of generation portfolios developed following the principles of Markowitz. The authors argue that private investors base their analysis strongly on the expected returns and on the risks of specific technologies. That being so, the production costs play a secondary rule. In their analysis, developed to reflect the newly liberalized United Kingdom electricity market, Roques et al. included the risks related to the electricity prices and CO_2 prices in an analysis based on portfolios of fossil fuels like coal, oil and gas as well as on nuclear generation (Roques, et al., 2008).

In a new assessment of the Portfolio Theory applied to the optimization of electricity generation mixes, Delarue et al. analyzed portfolios of generation using wind power, conventional fossil fuel generation (oil, coal and gas), and nuclear power. Due to its variable character, wind power is treated as a negative load[83] to the system, being subtracted from demand when available. The approach assumes the costs associated with every type of capacity as a measure of return, and the uncertainty of these costs as the measure of risk. The results have shown that a generation mix heavily based on conventional generation is associated with higher risks. More wind power in the generation portfolios contributed to a significant reduction of the risks connected with the generation costs (Delarue, et al., 2009).

Some arguments against the Portfolio Theory as an assessment approach of electricity generation diversification were discussed by Hickey et al. In their analysis, the authors discussed the optimization of electricity generation portfolios considering that optimization criteria are in reality constraints imposed by reliability of supply, security of supply, flexibility of supply, environmental considerations, social acceptability, and the existing generation capacity. In the authors' point of view, these constraints impose a condition of uncertainty in the diversity capacity of generation matrixes which is more connected to the concept of "ignorance" (people don't know what will be possible) than the concept of "risk" as defined by Markowitz[84] (Hickey, 2010).

Other aspects regarding the uncertainty aspects of electricity generation planning and the limits of the Portfolio Theory were discussed by Fuss et al.. In this analysis, a portfolio approach was designed to provide the most efficient mix of generation under several scenarios of uncertainty on costs (e.g. technology, carbon emissions, etc.) and social economical constraints (population increase, etc.) (Fuss, et al., 2010).

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[83] For another example of generation portfolio analysis where wind generation is treated as a negative load, see (Stoft, 2008).

[84] The problems of allocating uncertainty in electricity supply to risk or ignorance and the consequences for the applicability of the portfolio theory as a risk management approach are discussed in depth in (Stirling, 1994).

The analysis of several works linking the Modern Portfolio Theory to the management of risks in capital asset investments (other then securities), leads to the following general conclusions:

1) The return distribution of assets other than securities can not be always described by a normal gaussian distribution. Different types of assets have different return distributions.
2) The correlation analysis of returns of capital assets other than securities is one of the greatest challenges of portfolio analyses following the principles of Markowitz.
3) The indivisibility characteristic of physical assets, as well as intangible assets limits the establishment of a frontier of efficient portfolios. Rather then the determination of an efficient frontier, the goal of investment analyses applying the principles of the Modern Portfolio Theory is the assessment of how the inclusion of diversification aspects in the analyses contributes to investment decision processes.

Following these conclusions, the next sections address some of the aspects of the application the Modern Portfolio Theory as a risk management approach suitable to the analysis of investments in wind farms.

The first part of the analysis reviews the characteristics of a wind farm as a capital asset. The general objective is to provide an answer to the question to which extend investment analysis practices developed to traditional physical assets are applicable to wind farms. This initial review is then followed by an assessment of the risk diversification potential of wind farm projects bundled to a portfolio. Finally, the concluding section presents an approach developed under the basic principles of the Modern Portfolio Theory to assess the risk reduction capacity of the "simple" strategy of allocating wind farms located in different wind regimes, operating under different technical risks to investment portfolios.

5.4.1. A Wind Farm as a Capital Asset

According to Brealey et al. *Real Assets* are *Tangible* and *Intangible* assets used to carry on business. *Tangible assets* are physical assets such as a plant, machinery and offices for example. *Intangible assets* are non material assets such as a technical expertise, a trademark or a patent (Brealey, et al., 2010, pg. 923). Following this understanding, a wind farm is a tangible asset, which energy production generates a cash flow.

Hulsch and Strack defined a wind farm as:

"… long term and capital intensive real asset-investment under uncertainty which regularly require leverage through debt to meet the return expectations of equity investors. These returns are i) uncertain and furthermore ii) volatile…" (Hulsch, et al., 2006).

Uncertainty and volatility regarding the returns of wind farm projects are mainly imposed by technical specific characteristics like the wind regime at the sites and the performance of the wind

turbines, combined with commercial aspects such as the price at which the energy is sold and the running costs of a wind farm. (Raftery, et al., 1999).

Mostly due to these reasons, in the early days of wind energy expansion, wind farms were seen as a pretty risky capital investment. However, the urgency of the implementation of alternatives to fossil fuel generation, as one of the immediate consequences of the climate change discussion, imposed the development of strategies to deal with the unattractiveness of wind farms as an electricity generation capital asset.

As suggested by, for example, Brower et al., by the end of the nineties the establishment of market premiums or direct subsidies was still seen as the most effective, or even the only effective way, to promote the expansion of wind energy. Brower et al. examined the costs and risks of wind farms in comparison to gas-fired combined cycle power plants. The authors concluded that besides the fluctuations of fuel prices and the risks linked to environmental regulations, gas fired generation was still more attractive to utilities than wind power. This conclusion was based on the understanding within the analysis that the benefits of wind power depended strongly on the assumed distribution of risks and other market conditions. Under traditional regulation schemes, where most of the risks are shifted to end consumers, little incentive was perceived by utilities willing to invest in wind power. (Brower, et al., 1997).

As time passed and experience with the expansion of wind energy increased, other alternatives to deal with the risks of investments than governmental incentives provided in the form of *special premiums* gained importance. Aspects like efficient contracting enriched the investment analysis practices[85].

Today, tighter supply contracts for example give investors the possibility of dealing with the uncertainties on the performance of wind turbines. Supply contracts with a guaranted power curve[86] agreed between both parties became state of the art in the wind energy business. The same applies to commercial risks like the power offtake and the running costs.

In practice, the power offtake of a wind farm can be guaranteed within Power Purchase Agreements (PPA) concluded between the wind farm company and the utility or any other offtaker. Different countries have different models regulating the supply of electricity from wind farms. Some countries have adopted a feed-in tariff, others leave the tariff to be defined according to normal

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[85] Even with the increase of evidence that wind power can be competitive on its own, the attractiveness of wind farms is still linked to the loss of competitiveness of thermal generation due to issues like for example CO_2 credit prices. For a discussion, see for example (Boccard, 2010).

[86] A power curve lists the active power production of a turbine according to the different levels of wind speed. These power curves can be generated within theoretical calculations or measurements. For more on this issue, see (Strack, et al., 2003).

demand x supply dynamics[87]. However, power purchase agreements are there to guarantee, among other commercial issues, the price to be paid for the electricity generated. Therefore, like the risk relating to the performance of the turbines, the risk of the income of a wind farm project related to the tariff ($/MWh) has been generaly managed in a contractual way. The same applies to the risks regarding the running costs.

Running costs of wind farms are associated with expenses for their operation and maintenance. These are in general related to repair works, insurance, land lease agreements, technical and commercial operation, etc. In general, expenses for insurance, land use or technical and commercial operation are contractually defined as early as the development phase of the projects. Their dimension and the risk to the future cash flows of the projects can to a certain extent be quantifed and managed with accurate planning. Repair costs are generally defined within service agreements regulating the provision of scheduled and unscheduled maintenance works, including expenses with spare parts. Service contracts can be established to last over the financing period of the project or even over the whole operational life of a wind farm (Böttcher, 2012, pg. 232).

Like the uncertainties about the performance of the turbines, or the uncertainty on the tariff to be paid when the power generated is sold, the uncertainties about the running costs of a wind farm are manageble in the same way as some of the uncertainties in the future cash flow of traditional generation assets like a coal or a gas fired power plant. Adequate contracting shifts the risks to the parties best able to manage them, supporting the forecast of project cash flows.

As discussed in the first chapter, the significant expansion of wind energy observed in the last 20 years gave this form of electricity generation the status of the most competive of all the *"fuel-free"* alternatives[88]. However, if one hand wind farm investors are spared from the risks of future fossil fuel prices, they must on the other hand deal with the intermittency and the high uncertainty of the predicability of a natural primary ressource like wind. After a few decades of continuous expansion of wind energy, investors largely agree that the most challenging risk of wind farms is still the uncertainty about energy production in connection with the availability of wind[89].

In hydro power plants, nucelar power plants, and in other traditional generation sources, powering fuel can be stored. This possibility provides operators with the flexibility to coordinate supply with periods of higher or lower demand. Put briefly, in periods of higher demand more fuel is converted into electricity, while in periods of lower demand fuel (whether water, coal, etc.) is stored.

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87 An overview of different models regulating the supply of electricity by wind farms is given in the next chapter.

88 For a detailed analysis supporting this statement, see ((EWEA), 2009 b)

89 See for example (Raftery, et al., 1999), (Borod, 2005), (Harman, et al., 2005) and (Caporin , et al., 2009)

A wind farm does not provide operators such flexibility. Roughly speaking, wind farms produce electricity when there is wind - higher wind speeds mean more power, lower wind speeds mean less power. Periods of higher or lower wind speeds do not necessarily coincide with actual demand.

In view of that, and assuming that less volatility leads to lower uncertainties in predicting future cash flows, which in theory alleviates the risk perception of investors and financing agents, the current challenge is to find a way of "smoothing" the cash flow of investors deciding on wind farm projects.

One of the strategies and the object of different assessments over recent years, is geographical diversification[90]. The basic understanding, commonly justified by the principles of the Modern Portfolio Theory, is that the risk regarding the production of wind farms due to the availability/variability of wind can be managed, or partly managed, with a strategy of bundling single wind farms located in different, complementary wind regimes in a portfolio of assets[91]. The next section reviews some of the existing literature linking the Modern Portfolio Theory to wind farms.

5.4.2. Review of the Modern Portfolio Theory in association with Wind Farms

In one of the first analyses linking wind farm projects to the Modern Portfolio Theory, John Dunlop quantified the total risk of wind farm portfolios following the principles of the CAPM. Guided by the questions: *"1) Can the frameworks of the Modern Portfolio Theory be successfully adapted to fit the wind farm market rather than the stock market, and 2) If so, how much production risk can be diversified away using these tools to build wind farm portfolios?" (Dunlop, 2004),* the object of Dunlop's analysis was portfolios of wind farms located in different European countries and in the United States.

In his approach, Dunlop created a wind farm market index with production data from wind farms in the EU and US, weighted according to the size of the wind power market of the countries considered in the analysis. Countries with larger markets had higher weights on the index and vice-versa. The risk of a single wind farm included in the analysis was defined as the standard deviation of its mean production. The variance of the index (or coefficient of variation) was the standard deviation of the weighted production of all the wind farms included in the index divided by the mean of this value. The correlation of the individual wind farm against the index gives the amount of

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[90] The analysis of geographical diversification as a strategy to reduce the risk of energy production of wind farms has not always been automatically linked to the Modern Portfolio Theory. See for example: (DeCarolis, et al., 2004)

[91] Dunlop summarizes this risk management approach with the following sentence: "…Instead of owning one large 100MW wind farm in the U.K. we might be better off owning a 50MW wind farm in the U.K. and a 50MW wind farm in Spain…" (Dunlop, 2004)

market risk not being diversified away. The beta of each wind farm is its single risk divided by the coefficient of variation of the index.

Portfolio variances were estimated for three different combination approaches (or three different portfolios). Wind farms located solely in northern Europe, wind farms located in northern and southern Europe, and a mix of wind farms located in Europe and in the US. Due to geographical diversification, or independency of local wind regimes the portfolio composed by wind farms in Europe and the US had the lowest variance. In his analysis, Dunlop demonstrated that up to 30% of the production risks of wind farm portfolios could be reduced solely by geographical diversification. Geographical diversification has also been addressed by Drake et al. (Drake, et al., 2007) in a rather simpler approach.

Drake et al. used hourly data from meteorological stations on the UK coast and theoretical power curves to determine the energy potential of wind farms. The correlation of the applied meteorological data was used in the definition of an "efficient frontier" defining the average energy production (MWh) of the considered sites of an optimal portfolio. The authors found out that reductions of about 36% in the *"wind power variability"* were achievable through geographical dispersion of the sites. However, Drake et al. ignored the existence of other constraints than the wind regime that limit the energy production of wind farms. Some of them were discussed by Roques et al. (Roques, et al., 2010) in an analysis of the deployment of wind power in Europe following a portfolio approach.

Roques et al. used historical hourly production data from wind farms located in five different countries in Europe to develop an efficient frontier of portfolios with a minimized production variance. The portfolio assessment was developed on a country basis, with the objective of assessing the level of wind power development country by country leading to an increase in the adequacy[92] of the wind energy supply. The assessment considered at first unconstrained conditions of development. In a second phase, technical constraints like the local wind potential and grid capacities were taken into account.

Unlike Drake et al., Roques et al. recognized that the presence of constraints in the development of a portfolio analysis (e.g. local grid capacities) raises the question of whether the development of an efficient frontier of wind farm portfolios is meaningful. This was also one of Dunlop's conclusions when answering the question of whether the frameworks of the Modern Portfolio Theory fit assets like wind farms.

Dunlop's arguments against the definition of an efficient frontier of wind farm portfolios in accordance with the mean variance approach is based on the recognition that, unlike stocks, wind farms are not a liquid investment. In his own words: *"Wind farms come onto the market sequentially*

and do not stay on the market for long. In other words, you cannot see all the wind farms that will be available over the next several years and run them through a mean variance program" (Dunlop, 2004).

In parallel to that, with the conclusion that *"wind power output is more predictable than the share prices movements" (Dunlop, 2004)*, Dunlop limits a portfolio approach to the determination of how much production risk can be diversified by geographical diversification. He argues that in the case of wind farms, future returns are to a great extent connected to seasonal effects (differences in the wind pattern between summer and winter). For this reason, investors considering the past performance of the sites under analysis in the estimation of future returns are able to know in which periods higher or lower returns are likely to occur. Therefore, it is not relevant to determine a theoretical portfolio of wind farms with the best possible risk x return conditions, but to estimate how much of the market risk of determined sites can be reduced by diversification with other sites.

Although following different paths, Dunlop (Dunlop, 2004) and Roques (Roques, et al., 2010) reach conclusions on the particularities of the Modern Portfolio Theory framework applied to an asset like a wind farm that are comparable to the conclusions of Seitz (Seitz, et al., 1995) and Baum (Baum, et al., 1978) on the differences between physical and financial assets.

A wind farm, like other physical assets, is an integer investment. In theory it is possible to determine that the most efficient 100 MW wind generation portfolio in terms of wind regime complementarity is one composed of a 50 MW wind farm in the U.K., 30 MW in Spain and 20 MW in France. The key issues is that, although playing an important rule, the decision on where to build a wind farm is not solely based on the wind regime.

Other factors beyond the local wind resource conditions determine the feasibility of the projects. At the end of the day, even with the best wind conditions, factors like the availability of the sites, access to the local grid, environmental restrictions, offtake conditions, etc. are extremely relevant in the investment analysis process.

Summing up, wind farms are long-term, capital-intensive investment assets. Their returns are conditioned to uncertainties imposed by commercial and energy production risks under which they are developed and operated. Commercial risks are mostly related to the guarantee of the technical performance of the turbines, conditions of power off-take and expenses from operation and maintenance. Energy production risks are largely dominated by uncertainty about the estimation of future wind speeds and their variability.

The analysis of previous publications dealing with the financing of wind farms suggests that commercial risks are to a certain extent manageable with efficient contracting, while energy production risks could be reduced by geographical diversification. Previous assessments of the

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[92] For an overview of the concept of "adequacy" in electricity generation supply systems, see (Boccard, 2010).

Modern Portfolio Theory applied to wind farms have shown that a framework designed for financial assets like securities cannot be entirely applied to a physical asset like a wind farm without adaptations. The main differences in the nature of financial assets and wind farms which impose these adaptations are shortly summarized below:

Financial Assets (Securities in General)	Wind Farms
Returns are conditioned to systematic risks related to the economy in general (e.g. interest rates, etc.), as well as unsystematic risks, or specific risks connected with the primary activity generating income and expenses (e.g.: lack of raw materials, changes in customer preferences, etc.)	Apart from the repayment of initial capital expenditures, the returns are conditioned to the energy production of the turbines, the costs with their maintenance, as well as other operational expenses (e.g. insurance, land rent, etc.), and the tariff paid by the off-taker.
Securities are short-term, liquid investments.	Wind farms are long-term investments. Their feasibility is determined by a bunch of physical and commercial aspects (e.g.: local wind regime, energy off-take conditions, electrical grid availability, site availability, equipment supply availability, etc.)

Table 5.1: Financial Assets x Wind farms (Source: the author)

Assuming that some of the energy production risks of wind farms are unsystematic risks, which can be reduced by diversification, the main task of this work is to develop a portfolio assessment model based on Markowitz's framework which respects the basic, intrinsic differences between financial assets and a capital asset like a wind farm. The model introduced in the following sections is an attempt to do this.

5.5. The Diversification Effect of Wind Farms: Proposing a new Quantification Approach

5.5.1. Introduction

According to Markowitz, the Modern Portfolio Theory is applicable to assets whose returns are described by a set of outcomes associated with a probability of occurrence in the form of a frequency distribution, characterized by a mean value and a standard deviation (Markowitz, 1991, pg.17). As discussed previously, in the case of single securities, the returns from and the variance of these are estimated with the analysis of their past performance.

The return from a single wind farm is directly proportional to its energy production (or energy yield), which in turn is mainly proportional to the wind speed at the site. The annual average mean wind speed at one site is mainly estimated with the analysis of historical wind speed

measurement data[93]. The variance in the energy production of a wind farm is determined by uncertainties[94] involved in the determination of the long-term mean wind speed at the sites, the modeling of the wind flow at the turbine's hub-height in view of the topographical characteristics of the site, and the uncertainty on whether the reference power curve used in the reference calculations is comparable to the real power curve of the turbines once these are in operation at the site.

In this sense, the following analogy between return and variance from securities and wind farm projects is drawn:

	Securities	**Wind Farms**
Return	Determined based on the analysis of past performance	A direct function of energy production. In a pre-construction phase, the energy production of a wind farm is estimated mainly with wind speed measurements and standard, reference power curves. When operating, the return is estimated on the analysis of available past production data
Variance	Standard deviation of past returns	Uncertainty about the long-term determination of the wind regime at the site according to pre-construction measurements, as well as the uncertainties about the wind flow modeling at the site and uncertainties about the reference power curve. For operating wind farms, the uncertainty on the return is linked to the general question on whether the production of the first operational periods will be kept constant over the overall operational life of the turbines or influenced by wind regime variations and turbine performance problems.

Table 5.2: Return and Variance characteristics of securities and wind farms (Source: the author)

[93] For more on how measurement data is used in the estimation of the local wind resource, see for example (Justus, et al., 1979) and (Landberg, et al., 2003)

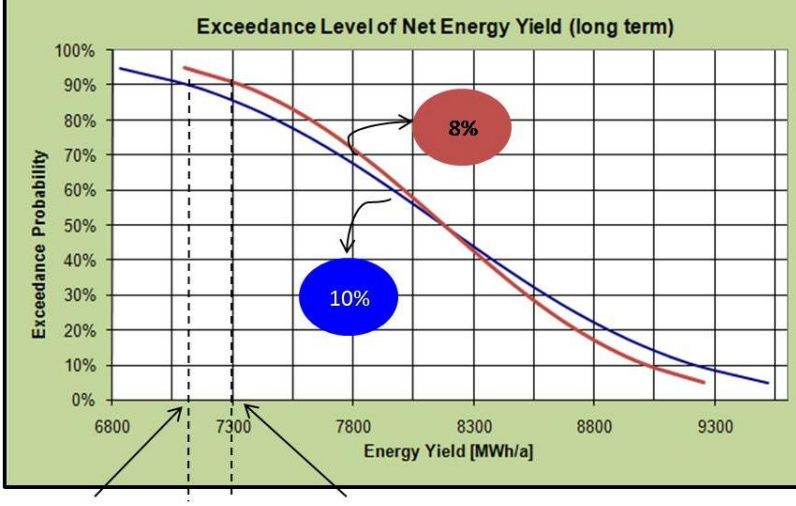
[94] For more on the uncertainties in the prediction of the energy production of wind farms, see for example (Albers, 2003), (Strack, et al., 2003), (Bastide C., 2007), (Fontaine, et al., 2007).

Similar to securities, the set of energy production outcomes and consequently returns associated with a determined probability of occurrence are obtained with basis on the exceedance probability distribution[95].

As discussed by Klug (Klug, 2006), the mean of the exceedance probability distribution is the estimated annual average energy production of the wind farm. The standard deviation is the overall uncertainty of this estimation. The P75 value is the annual average energy production with a probability of 75% of being exceeded. Similarly, an annual average energy production with 90% probability of being exceeded corresponds to the P90 value of the distribution. As seen in the graph below, the higher the standard deviation of the distribution, the greater the P75 and the P90 values deviate from the mean. In other words: ***The higher the standard deviation, the lower the energy production associated with the P75 or the P90 value.***

The Exceedance Probability Curve

Exceedance Probabilities	Uncertainty in the AEP = 10%	Uncertainty in the AEP = 8%
Long term AEP (P50) [MWh/a]	8176,0	8176,0
AEP exceeded with a probability of 75% (P75) [MWh/a]	7624,5	7734,8
AEP exceeded with a probability of 90% (P90) [MWh/a]	7128,2	7337,8



Energy Yield [MWh/a]	Exceedance Level	Energy Yield [MWh/a]	Exceedance Level
9520,8	5%	9251,9	5%
9223,8	10%	9014,2	10%
9023,4	15%	8853,9	15%
8864,1	20%	8726,5	20%
8727,5	25%	8617,2	25%
8604,7	30%	8519,0	30%
8491,0	35%	8428,0	35%
8383,1	40%	8341,7	40%
8278,7	45%	8258,2	45%
8176,0	50%	8176,0	50%
8073,3	55%	8093,8	55%
7968,9	60%	8010,3	60%
7861,0	65%	7924,0	65%
7747,3	70%	7833,0	70%
7624,5	75%	7734,8	75%
7487,9	80%	7625,5	80%
7328,6	85%	7498,1	85%
7128,2	90%	7337,8	90%
6831,2	95%	7100,1	95%

P90 value @ 10% uncertainty P90 value @ 8% uncertainty

Figure 5.4: Exceedance Probability Curves[96]. (Source: the author)

The relevance of the P75 and P90 values to a wind farm investment analysis has been addressed by a number of authors. According to Borod (Borod, 2005), as well as Hulsch et al. (Hulsch, et al., 2006), investors analyze the performance of investments in wind farms based on different confidence levels of return, determined according to the energy production probability curve. This means that in the analysis of investments in wind farms, less conservative scenarios of return are

[95] For more on the characteristics of an Exceedance Probability Distribution, see for example (Kunreuther, 2001), or (Alexander, 2009).

normally associated with the P75 value of the distribution, while more conservative scenarios are based on the P90.

Since the level of annual energy production associated with the P75 and/or the P90 are determined by the overall uncertainty of the production estimation, any attempt to reduce this uncertainty contributes to an increase in these reference production levels and consequently an increase in income. Here is where the Markowitz principle of diversification of unsystematic risks comes into play.

The objective of the portfolio analysis approach described in the following sections is to quantify how much of the overall uncertainty in the estimation of the energy production of wind farms can be reduced once these are viewed as part of a portfolio of different projects, operating under different wind regimes subject to different specific technical uncertainties.

5.5.2. Expected Return and the Portfolio's Variance

Similarly to securities, the expected return of a portfolio of wind farms is described by the MPT general equation. It equals the sum of the expected return of all single farms:

$$\overline{\boldsymbol{R}}_{(Portfolio)} = \sum_{i=1}^{N} (X_i \overline{R_i}) \qquad \text{(Eq. 5.11)}$$

Where $\overline{R}_{(Portfolio)}$ is the expected return of the portfolio and $\overline{R_i}$ is the expected return of the wind farms *"i"* to *"N"*.

Since in the case of wind farms, return is a direct function of energy production, the annual energy production of a portfolio of wind farms becomes:

$$\boldsymbol{Portfolio's\ AEP\ (MWh/a)} = \sum AEP_{WF"A"} + AEP_{WF"B"} + \ldots + AEP_{WF"N"} \qquad \text{(Eq.5.12)}$$

The overall risk or portfolio variance, described by the general equation below, comprises not only the sum of the variance on the return of single wind farms but also the covariance of returns, which quantifies the risk that the return of all the single farms develops into the same direction.

$$\boldsymbol{\sigma_P^2} = \sum_{j=1}^{N} (X_j^2 \sigma_j^2) + \sum_{j=1}^{N} \sum_{\substack{k=1 \\ k \neq j}} (X_j X_k \sigma_{jk}) \qquad \text{(Eq.5.13)}$$

[96] AEP means annual energy production

Where X_j is the participation of the wind farm "*j*" and X_k is the participation of the wind farm "*k*" in the portfolio. σ^2_j is the variance of returns of the wind farm "*j*" and σ^2_k the variance of the returns of the wind farm "*k*". The covariance of the returns of "*j*" and "*k*" is given by σ_{jk}.

Like financial assets, as the number of wind farms in the portfolio increases, the overall portfolio's variance depends less on the cumulated single variances of each single farm. It becomes dominated by the covariance-risk (Hulsch, et al., 2006). In this sense the general portfolio variance expression according to Markowitz becomes:

$$\boldsymbol{\sigma_P^2} = \sum_{j=1}^{N} \sum_{\substack{k=1 \\ k \neq j}} (X_j X_k \sigma_{jk}) \qquad \text{(Eq. 5.14)}$$

Raftery et at. summarized the risks involved in the financing and operation of wind farms in the following categories (Raftery, et al., 1999):

- ✓ Sponsor/completion risk
- ✓ Technology risk
- ✓ Energy production risk
- ✓ Offtake/sales risk
- ✓ Regulatory risk
- ✓ Insurance risk
- ✓ Financial risk
- ✓ Country risk

As discussed previously, some of these risks, such as sponsor, offtake, regulatory, and country risks are manageable mostly within qualitative analyses (e.g. efficient contracting, insurance, etc). The same applies to part of the technological and financial risks. However, *Energy production risk* can be statistically quantified, which makes a quantitative risk diversification approach like the Modern Portfolio Theory a feasible alternative[97].

As proposed by Klug (Klug, et al., 2001), as well as Marco et al. (Marco, et al., 2009), energy production risks are in general a combination of the uncertainties related to the determination of the long-term wind resource, the modelling of the wind flow reaching the hub height of the turbines, and the accuracy of reference power curves.

Therefore, the estimation of the variance of a portfolio of wind farms discussed here is generally based on the analysis of the correlation of returns in respect to the individual uncertainties in connection with the estimation of the long-term wind resource, the wind flow modelling, and the applied reference power curves.

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[97] Please note that diversification (the focus here) is only one of several hedging strategies of risk management theory. See for example (Copeland, et al., 2004)

Following this assumption, the general equation on the variance of a portfolio of wind farms considering this approach would be[98]:

$$\sigma^2_{portfolio(overall)} = \sqrt{\sigma^2_{wind\ climate\ (portfolio)} + \sigma^2_{modeling\ \ (portfolio)} + \sigma^2_{Power\ Curves\ (portfolio)}} \qquad \text{(Eq. 5.15)}$$

The portfolio variance due to the correlation of the energy production of the wind farms in respect to their predicted meteorology (long-term wind resource) following the MPT general equation would be (supposing two wind farms "A" and "B"):

$$\sigma^2_{Wind\ Climate\ (portfolio)} = X_A^2\sigma_A^2 + X_B^2\sigma_B^2 + 2X_A X_B \sigma_{AB} \qquad \text{(Eq. 5.16)}$$

Where X_A and X_B is the respective participation of the wind farms A and B in the portfolio, σ_A^2 and σ_B^2 are the variances of the energy production of the farms A and B regarding their predicted long-term wind resource, and σ_{AB} is the covariance between the predicted long-term wind resources.

The same equation could be re-written for the estimation of the portfolio variance due to the correlation of the uncertainties in the reference power curves, and the wind flow modeling. However, decisive is the question of whether all these uncertainties are in reality diversifiable or not. In other words, whether they are systematic or unsystematic uncertainties:

a) Uncertainties in the overall production of a portfolio of wind farms in connection with local wind regimes:

As discussed in Chapter 4, pre-construction wind farm energy yield assessments are developed based on the estimation of the long-term wind resource at the site. Since the energy production of a wind farm is mainly proportional to the wind speed, the general assumption here is that the correlation of the return of the wind farms analyzed in the portfolio can be approximated to the correlation of their correspondent long-term wind resources.

As with financial assets, the estimation of the correlation coefficient between the predicted individual long-term wind resources of the single wind farms is based on the analysis of the time series of these data. According to Moon et al., the coefficient of determination (R^2) obtained through

[98] As discussed in Chapter 4, the single sources of uncertainties determining the overall uncertainty of the annual energy production estimation of a wind farm are assumed to be independent from each other. In the

a linear regression between two sets of wind speed data is a wide measure of the degree of correlation between these datasets (Moon, et al., 2006). As in the prediction of the long-term meteorology of one site developed according to these sets of data, it is assumed[99] that the trend of seasonal behaviors will be kept in the future. Therefore, it is assumed that the energy production correlation coefficients applied in the estimation of the portfolio variance are representative of the long term.

Graph 5.1 shows an exemplary scatter plot of the monthly mean wind speeds of two different sites. The data range is between June 1998 and December 2007. In the example, the correlation coefficient (R^2) is equal to 0.19 and represents the proportion of common variation in the two compared sets of data. The portfolio assessment approach introduced here assumes then that the correlation between the wind speeds obtained with the regression analysis of two sets of data can be approximated to the correlation of the energy production potential of these two sites.

Graph 5.2 shows the curve of the variation of the wind speed at the sites over the considered period. It can be seen that wind farm site “A” has a long-term mean wind speed higher than the wind speed at site “B”. Furthermore, during the analyzed period, it could be observed that in several months a positive peak of wind speed at one site coincides with a negative peak of wind speed at the other site, like for example in August 2003. This effect clearly characterizes the independency of the wind regimes, evidencing the complementary nature of local wind regimes. Being so, the uncertainties about the estimations of the energy production of single wind farms bundled in a portfolio are understood as unsystematic ones, or as discussed previously, diversifiable ones.

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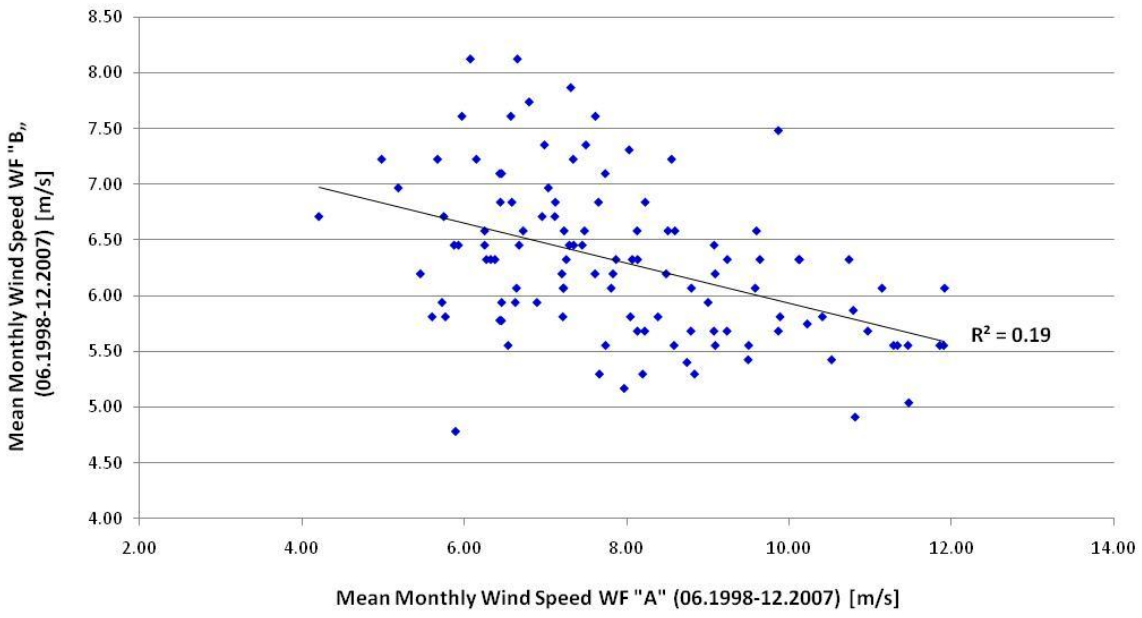
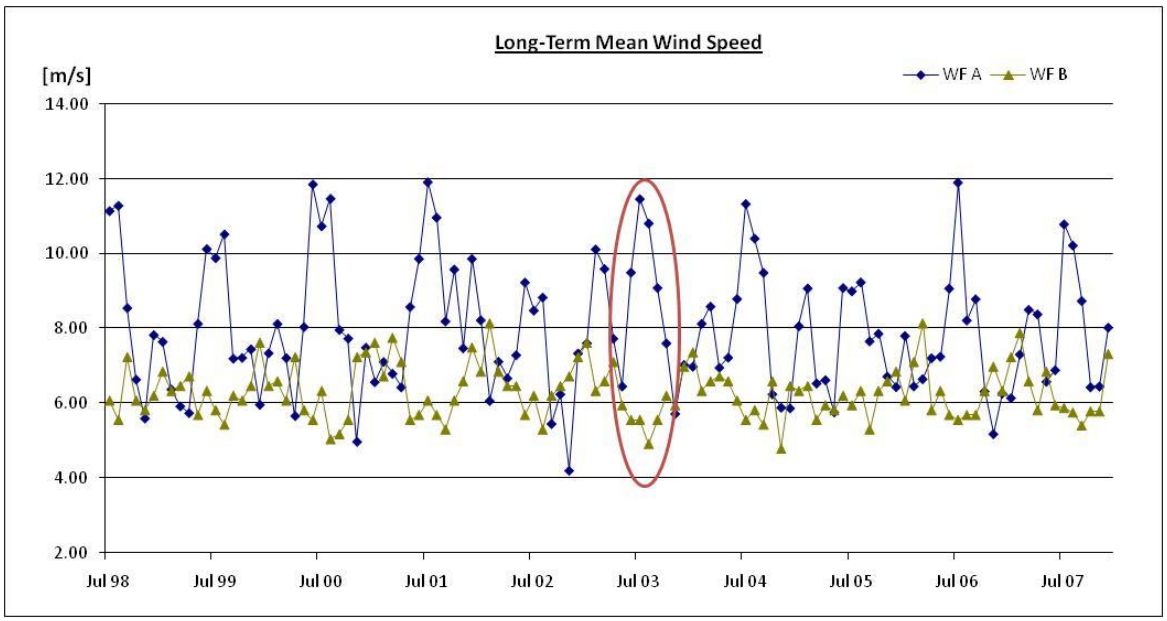
determination of the portfolio variance the same assumption is followed. For more, see: (FGW, 2007), (Measnet, 2009), as well as (Marco, et al., 2009).

Correlation of Wind Climate Data for Two Exemplary Wind Farm Sites (WF "A" and WF "B")



Graph 5.1: Correlation of the long-term wind data of wind farms "A" and "B".

Long-Term Wind Speeds (WF "A" and WF "B")



Graph 5.2: Long-term mean wind speed, wind farms "A" and "B".

[99] In this assumption lies actually most of the uncertainty in the estimation of the annual energy production of wind farms. It is however state of the art. For more, see (Measnet, 2009)

b) Uncertainties in the overall production of a portfolio of wind farms in connection with wind flow simulation models:

The uncertainty on the estimation of the annual energy production of wind farms caused by the modeling of the wind flow at the sites is assumed to be a systematic one. This assumption can be justified by the fact that what determines this uncertainty is the accuracy of the models used in the estimation of the wind flow at the sites. This accuracy is mainly determined by the input parameters of the applied models, specifically the topographic characteristics (terrain complexity and roughness) of the area being simulated and the wind farm layout[100]. In general the modeling uncertainties in the estimation of the energy production of complex sites tend to be higher than the uncertainties of production estimations in flat areas (Strack, et al., 2003). However, because the topographic characteristics of a site, as well as its layout, are likely to remain constant over the operational life of a wind farm, these uncertainties do not contribute to the variation of energy production of the farms[101] in the same way the uncertainties in the estimation of the long-term wind resources do.

In terms of a portfolio of wind farms, the individual uncertainty about the production of one farm regarding its wind flow modeling will add up to the same uncertainty of another wind farm - simply because they follow the same trend, being not complementary and therefore not diversifiable. The only difference is the level of contribution of the individual modeling uncertainties to the overall portfolio variance.

Being a systematic uncertainty, the correlation coefficient between the uncertainties of the energy production of the different wind farms as part of a portfolio caused by the accuracy on the wind flow modeling is “1”.

b) Uncertainties in the overall production of a portfolio of wind farms in connection with power curves:

The uncertainty on the estimation of the energy production of wind farms in connection with the technical performance of the turbines is determined by the uncertainty on the reference power curves. In other words, the uncertainty is related to the question on whether the power curve used in the pre-construction estimations of energy yields will be confirmed by the real power curve of the

[100] In general, the models tend to be more accurate in flat areas with low roughness characteristics than in areas of high roughness and a rather complex terrain structure. The wind farm layout is relevant to determination of the production losses caused by wake effects in connection with the mutual operation of several turbines in the site area.

[101] In reality, production losses caused by effects like turbulence and wind shear (see for example (Ray, et al., 2006)) are related to wind conditions. Therefore, variations of wind conditions do impose variation of these effects, and consequently the production losses in connection to them. However, these losses are estimated in the pre-operational analysis and assumed to be representative of the long term.

turbines once these are operative at the sites. As state of the art[102], if for one determined turbine type no measured power curves are available, energy yield calculations are based on theoretically calculated power curves. The uncertainty of measured power curves is in general lower than the uncertainty from theoretical power curves. Nevertheless, due to differences in the measurement conditions to the operational conditions (site topography, air density, wind direction distribution, etc.), these uncertainties are not negligible (Albers, 2003).

Because all the turbines parts of a portfolio are subject to the same level of technical performance uncertainties, this kind of uncertainty is by assumption systematic. Similarly to the part of the portfolio variance in connection to the uncertainties in the energy production estimation caused by modeling limitations, the part of the portfolio variance linked to power curve uncertainties is by definition the cumulative variance of the energy production of the individual wind farms due to these uncertainties.

A comment to the portfolio variance estimation approach in case of energy production assessments based on the analysis of production data (operational wind farms):

In the case of a portfolio analysis performed on the basis of a long term correction of the production data from wind farms already in operation, the correlation of this past production data gives direct information on how the return of the single farms co-vary. This data includes not only information on the past wind behavior at the site, but also on the technical and the energetic availability[103] of the turbines – two of the main parameters on their technical performance. The information on the real production of the turbines includes losses caused by wake effects, as well as other effects in connection with the topography of the site such as turbulence and wind shear. Once a portfolio of wind farms relies on enough production data, the portfolio variance might be determined straightforwardly:

$$\boldsymbol{\sigma^2_{portfolio(overall)}} = \sqrt{\sigma^2_{\text{production data}}} \qquad \text{(Eq. 5.17)}$$

[102] See (Measnet, 2009)

[103] The technical availability is the information on how many hours the turbines were available for generation. The technical availability is in general obtained with the formula:

$$\boldsymbol{Tech.Avail}.(\%) = \left(\frac{\text{total of hours in a month} - \text{hours of scheduled maintenance}}{\text{total of hours in a month}} \right)$$

The energetic availability is related to losses of production in connection with scheduled and non-scheduled maintenance (stops to correct technical problems), as well as differences between the energy production estimated with a reference power curve and the real meteorology of the site over the reference period (theoretical energy production) and the real production of the turbines. For more, see ((IEC), 2011).

Nevertheless, it must be noticed that if the turbines are under-performing due to technical problems (which is often the case in the first operational months) the information on the past production data does not reflect the real annual energy production of the wind farm, once technical performance issues are solved. In this sense, this kind of approach should be followed once the technical performance of the turbines is as close as possible to the contractually guaranteed performance.

Furthermore, the long-term representativeness of this data in terms of future wind behavior should be taken into account. The last chapter discusses a case study developed with the analysis of production data.

5.5.3. Estimation of the Diversification Effect – The Quantification Model

The portfolio effect quantification approach introduced here was modeled in *Excel* 2007. The figure presented in Annex A is an overview of how the spreadsheet was structured. The original spreadsheet was designed to calculate the portfolio effect considering 20 different wind farms, but it can be easily updated to run simulations for more or fewer wind farms. In total the model has basically three tables:

Table 1: The first table was designed to show the input of the relevant information of the single wind farms addressed in the portfolio: wind turbine types, number of wind turbines, nominal power, etc., as well as the predicted long-term annual energy yields (P50) and the respective exceedance probability values (P75 and P90), systematic losses, and the uncertainties. The objective is to provide a global overview of all farms included in the assessment, and concentrate all the necessary calculation input data in one place.

Table 2: The second sheet is the core of the quantification model. This sheet contains the matrixes necessary for the estimation of the portfolio variances[104]. Every correlation of energy production addressed in the calculation has its own set of matrixes.

Table 3: In the third table, the overall portfolio variance is determined considering the partial portfolio variances in respect to the uncertainties about the wind regimes, the wind flow modeling and the power curves. The portfolio variance takes into account the weighting of the wind farms in the portfolio. In a second step, the exceedance probability values (P75 and P90) respective to the determined portfolio variance are estimated. Finally, the P75 and the P90 values of the portfolio are compared to the sum of the P75 and P90 values of the single wind farms. The results can be expressed in two ways:

[104] The matrix approach used in the determination of the portfolio variance is a parallel to a similar approach introduced by Frankfurter et al. for portfolio analyses with securities. For more, see (Frankfurter, et al., 1971).

a) Expression of the portfolio effect in terms of additional energy: The portfolio effect is the difference in MWh/a between the P90 (or the P75) value of the portfolio considering the portfolio effect (P90') and the P90 value without the portfolio effect (merely a weighted sum of all P90 values (P90)).

$$\textit{Portfolio Effect (MWh/a)} = P90' - P90 \qquad \text{(Eq.5.18)}$$

b) Once the portfolio effect is expressed as energy, this additional amount of energy can be transformed into "virtual turbines"[105], according to the following expressions:

$$\textit{Average Energy Yield of the Portfolio (MWh/a/turbine)} = \frac{\sum \text{P90 of all turbines}}{\text{N}^{\circ}\text{ of turbines}} \qquad \text{(Eq.5.19)}$$

$$\textit{Virtual Turbines} = \frac{\text{Average Energy Yield of the Portfolio (MWh/a/turbine)}}{\text{N}^{\circ}\text{ of turbines}} \qquad \text{(Eq.5.20)}$$

The following example illustrates the portfolio assessment approach introduced here:

Wind farm "A" located on the west coast of Turkey
Wind farm "B" located on the north of Poland
Wind farm "C" located on the central west coast of France

Table 5.3 summarizes the profile of the wind farms. The information is merely illustrative and not connected to any existing project. Table 5.4 details the uncertainties in the long-term wind resource, as well as the uncertainties in the predicted annual energy production of the wind farms individually and in the portfolio, considering the sum of the variances of the single wind farms (without portfolio effect).

[105] Virtual because physically the turbines do not exist. However, once the portfolio effect is expressed as energy (MWh/a), the conversion is possible. It is just another way of expressing the benefits of the diversification effect, or the energy gain in connection to the reduction of the overall uncertainties.

Portfolio Wind Farms "A", "B" and "C" – Overview				
	WF "A"	WF "B"	WF "C"	Portfolio
Location	Turkey	Poland	France	
WT Type	Nordex N90	REPower MM92	Gamesa G90	
N° of Units	36	22	9	67
MW/unit	2.5	2.0	2.0	
Nominal Power (MW)	90.0	44.0	18.0	152.0
P50 (MWh/a)	316.1	119.7	50.9	486.7
P75 (MWh/a)	294.9	109.3	46.7	450.9
P90 (MWh/a)	278.8	99.8	42.8	418.4
Participation in the portfolio (%)	64.9	24.6	10.5	100
Average Energy Yield of the Portfolio (MWh/a)				**7.264**

Table 5.3: Overview of the input of the input information – Portfolio of Wind Farms "A", "B" and "C".

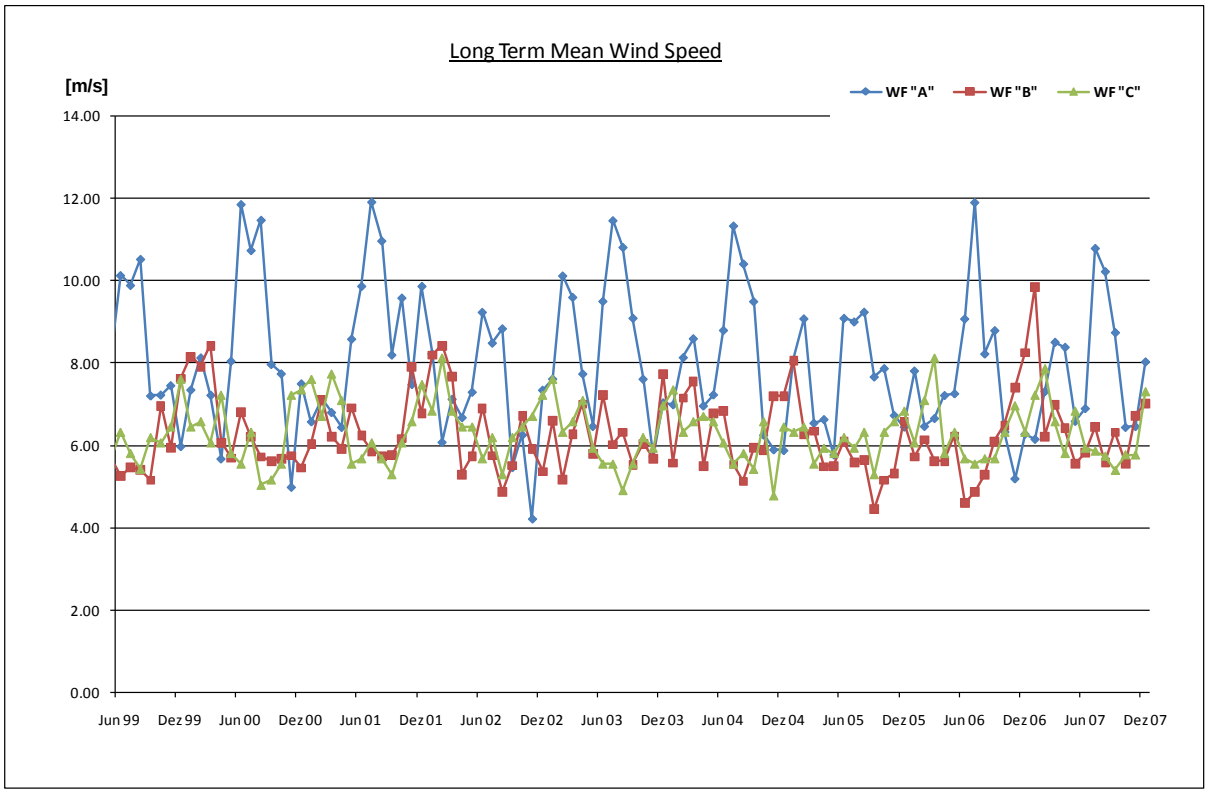
Portfolio Wind Farms "A", "B" and "C" – Energy Yield Assessment Uncertainties				
	WF "A"	WF "B"	WF "C"	Portfolio (Weighted)
Overall Uncertainty in the long-term wind resource				
Wind Measurement	3%	2%	2%	2.6%
Long-Term Scaling	4%	3%	4%	3.8%
H&V Extrapolation	6%	4%	3%	5.2%
Overall Uncertainty in the Wind Speed	8.5%	5.5%	5.4%	6.9%
Sensitivity Factor	1.0	2.2	2.0	
Overall Uncertainty in the Annual Energy Production				
Wind Regime of the site	8.5%	11.0%	10.8%	9.3%
Power Curves	6.0%	7.0%	6.0%	6.2%
Farm Efficiency Calculations (flow models)	0.6%	3.0%	1.0%	1.2%
Overall Uncertainty in the Energy Yield	10.4%	13.4%	12.4%	11.3%

Table 5.4: Uncertainties of the Energy Yield Assessment – Portfolio of Wind Farms "A", "B" and "C".

The correlation of the energy yield regarding the wind climate related to the sites was determined correlating the monthly average wind speeds of the three sites over a period of approximately 9 years (102 months). The wind data is the same as that used in the energy yield assessment calculations. As described in the 4th chapter, the measured data at the site was long term correlated with data from a local meteorological station. As usual, data from several meteorological stations were tested in order to select the best station to be used in the long-term correlation. Graph

5.3 shows the monthly correlation of the wind data over the full period of analysis (from February 1999 until the end of December 2007). Table 5.5 presents the correlation coefficients.

Monthly Average Wind Speed Correlation



Graph 5.3: Monthly average wind speed of the three wind farm sites considered in the example.

Correlation Coefficients

	WF "A"	WF "B"	WF "C"
WF "A"	1.0		
WF "B"	0.047	1.0	
WF "C"	0.198	0.114	1.0

Table 5.5: Correlation Coefficients of the long term mean wind speed of Wind farms "A", "B" and "C".

Based on the given correlation coefficients, the portfolio variance considering the variability of the wind climate was estimated:

$$\sigma^2_{\text{wind regime (portfolio)}} = 0.0043$$

The uncertainty (standard deviation) in the energy yield of the portfolio due to the correlation of the wind climate is then:

$$\sigma_{\text{wind regime (portfolio)}} = 0.0658 \approx 6.6\%$$

The uncertainty of the wind climate of the portfolio was estimated at ***6.6%***, a reduction of 29.4% in comparison to the sum of this uncertainty wind farm by wind farm (9.3%).

The variance in the power curves of the portfolio (technical performance) was estimated considering a correlation coefficient of 1. Therefore, it is just the weighted sum of the uncertainties of every wind farm part of the portfolio:

$$\boldsymbol{\sigma^2_{\text{power curves (portfolio)}} = 0.004 * 0.649 + 0.005 * 0.246 + 0.004 * 0.105 = 0.0039}$$

The uncertainty (standard deviation) of the power curves of the portfolio is then:

$$\boldsymbol{\sigma_{\text{power curves (portfolio)}}} \approx 6.2\%$$

The variance in the farm efficiency calculations of the portfolio (wind flow calculation models) was estimated considering a correlation coefficient of 1. Like in the uncertainty of the power curves, it is just the weighted sum of the uncertainties of every wind farm contained in the portfolio:

$$\sigma^2_{\text{calc. models (portfolio)}} = 0.00004 * 0.649 + 0.0009 * 0.246 + 0.0001 * 0.105 = 0.0002$$

The uncertainty (standard deviation) of the power curves of the portfolio is then:

$$\boldsymbol{\sigma_{\text{calc. models (portfolio)}}} \approx 1.2\%$$

The overall uncertainty of the portfolio is then calculated as:

$$\sigma_{\text{Overall Uncertainty (portfolio)}} = \sqrt{0.066^2 + 0.062^2 + 0.012^2} \approx 9.16\%$$

The overall uncertainty in the energy yield of the portfolio was therefore reduced from 11.3% to approximately ***9.2%***, which means a reduction of about 19% taking into account the diversification of the uncertainties in the long-term wind regimes. With the estimated overall uncertainty in the energy production of the portfolio taking into account the diversification aspects, the P values of the portfolio were calculated. The new P90 value, calculated with the overall uncertainty in the portfolio's energy yield of 9.2%, is equal to 429.6 MWh/a. This is an increase of 11.2 MWh/a in comparison to the portfolio's P90 value when no complementarities of the local wind regimes are taken into account (418.4 MWh/a).

Since the overall energy yield of the portfolio per turbine is approximately 7.2 MWh/a, the diversification effect is equivalent to 1.54 "virtual turbines" in the portfolio. In other words, the effect coming from the geographical diversification of the wind farms quantified by the correlation coefficient between the long term wind speeds brings to the bundling of wind farms one additional wind turbine operating at 100% of the average portfolio's operational hours, plus a second wind turbine running at 54% of this time. Table 5.6 summarizes the results.

Portfolio Wind Farms "A", "B" and "C" – Results					
	WF "A"	**WF "B"**	**WF "C"**	**Portfolio (Weighted)**	**Portfolio (with Diversification Effects)**
AEP – P50 (MWh/a)	316.1	119.7	50.9	486.7	486.7
AEP – P75 (MWh/a)	294.9	109.3	46.7	450.9	456.6
AEP – P90 (MWh/a)	278.8	99.8	42.8	418.4	429.6
Overall Uncertainty in the AEP (Annual Energy Production)					
Wind Regime of the site	8.5%	11.0%	10.8%	9.3%	6.6%
Power Curves	6.0%	7.0%	6.0%	6.2%	6.2%
Farm Efficiency Calculations	0.6%	3.0%	1.0%	1.2%	1.2%
Overall Uncertainty in the Energy Yield	10.4%	13.4%	12.4%	11.3%	9.2%
Portfolio Results					
AEP – P50 (MWh/a)	486.7				
AEP – P75 (MWh/a)	456.6				
AEP – P90 (MWh/a)	429.6				
Portfolio Effect (MWh/a)	11.2				
Portfolio Effect ("Virtual Turbines)"	1.54				

Table 5.6: Summary of the Results – Portfolio Wind Farms "A", "B" and "C".

As seen in the example, the assessment of the diversification potential of the risks involved in the energy production of wind farms enriches the investment analysis of this very specific type of asset. Up to here, the analysis focused on how complementary wind regimes contribute to the increase of the production expectation of a portfolio of wind farms. As discussed, it is safe to assume that the return on investments in wind farms is directly connected to their energy production. Nevertheless, return is not exclusively dependent on energy production.

In view of that, the following chapter discusses other aspects of a wind farm project's cash flow. At first, the economics of wind farms will be reviewed with a focus on capital and operational expenditures. In a second step, a review of the financing decision aspects in line with the previous discussions on capital budgeting intends to complement the analysis of wind farm portfolios introduced here.

6. Wind Farm Investments and Diversification

6.1. Economics of Wind Farms

In general, it can be said that the economics of wind farms are characterized by high capital costs and relatively stable and low operational costs in comparison to traditional generation sources. According to the European Wind Energy Association (EWEA), approximately 75 to 80% of the total power production costs of a wind turbine are related to capital expenditure – that is, the costs of the turbine itself and its erection, grid connection, foundation, land, electrical works, access (roads), control (supervision systems), planning (including consultancy), and expenses with financing ((EWEA), 2009 b, pg.57).

A wind turbine is more capital-intensive in comparison to conventional fossil-fuel-fired technologies, such as natural gas power plants. However, because the *"fuel is free"*, the operation and maintenance costs (O&M costs) of wind farms are significantly lower than the same costs of conventional fossil fuel generation, where as much as 40% to 60% of the total generation costs are related to fuel, operation, maintenance, and repair costs ((EWEA), 2009 b, pg. 57).

As a capital-intensive electricity generation alternative, the financing costs of wind farms are a large variable in the projects. Furthermore, being a relatively new technology in comparison to traditional generation sources, lenders financing wind farms offer in general less favourable terms, while demanding a higher return on the investments in comparison to traditional power generation projects (International, 2005).

The next section reviews the typical investment and O&M costs of wind farm projects. Then the production costs will be introduced, together with an overview of wind energy tariffs and the existing support mechanisms.

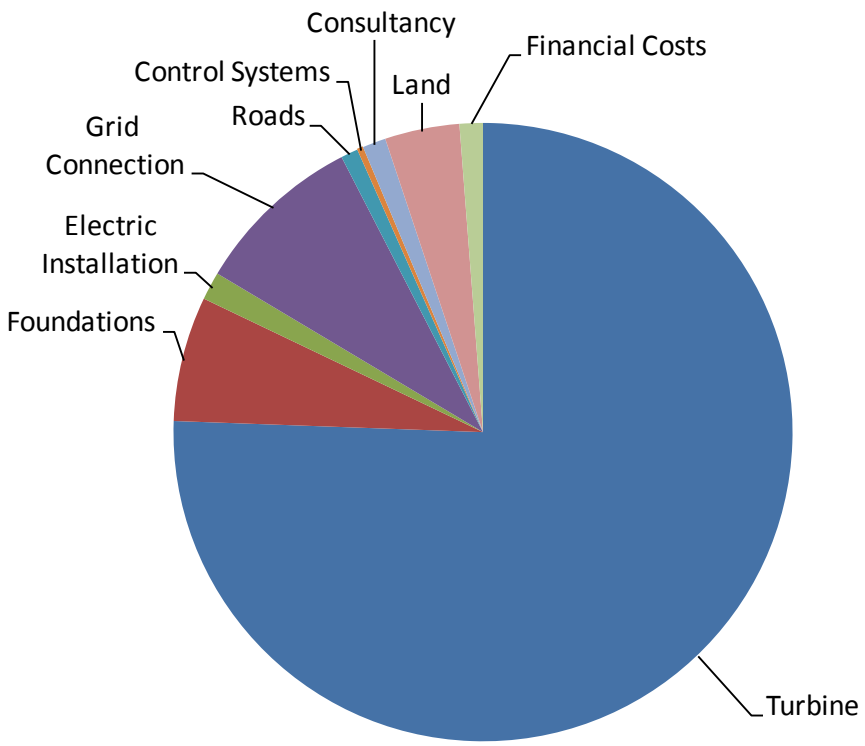
Since financing is one of the key issues determining the attractiveness of a wind farm project, the first part of this chapter is followed by a review of the current wind farm financing state of the art. The last part discusses how the diversification effects discussed in the previous chapter impact relevant economic and financing parameters of wind farm projects.

6.1.1. Capital Costs

As shown in the graph below, the investment costs of wind energy projects are dominated by the cost of the wind turbine itself. The table shows the typical cost distribution of a 2.0 MW turbine erected in Europe. The total cost per kW of installed capacity differs significantly from country to country, being in a range between 1000€/kW to 1350€/kW. The differences are in part linked to the

type of terrain (flat or complex areas) which determines the foundation costs, transport costs in view of difficulties related to the transport of large and heavy equipment, grid connection, land use[106], etc.

Wind Farm Investment Costs



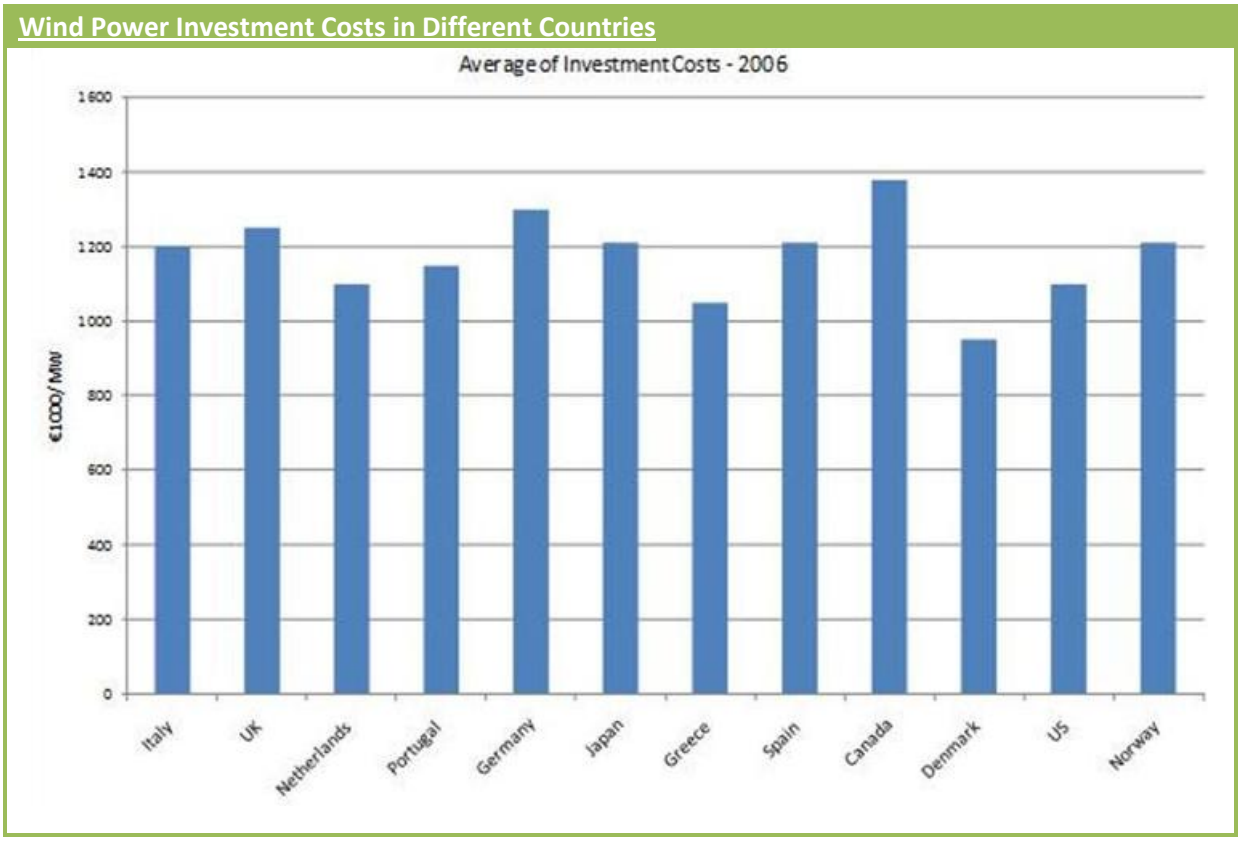
	Investment (€1000/MW)	Share (%)
Turbine	928	75.6
Foundations	80	6.5
Electric Installation	18	1.5
Grid Connection	109	8.9
Roads	11	0.9
Control Systems	4	0.3
Consultancy	15	1.2
Land	48	3.9
Financial Costs	15	1.2
Total	1227	100

Graph 6.1: Investment Costs of a typical 2 MW wind turbine installed in Europe. (Source: ((EWEA), 2009 b))

[106] Costs related to land use constitute a part of the capital costs, once these incur in the development phase of the wind farm project. If a wind farm "rents" the piece of land on which it operates over its lifetime, then land use costs are normally part of the operation and maintenance costs, to be discussed in the next section.

Graph 6.2 shows the average total investment costs of onshore[107] wind turbines according to data collected in 2006 in a survey with project developers and manufacturers by the European Wind Energy Association.

It can be noticed that countries with a more highly-developed wind energy industry, for example Denmark, report lower investment costs than countries with a relatively young market such as Canada.



Graph 6.2: Average of investment costs in different countries – 2006. (Source: ((EWEA), 2009 b))

In recent years, three major trends have been observed in the development of grid-connected onshore wind turbines ((EWEA), 2009 a):

1) Turbines are larger and taller. Therefore the average size of turbines sold on the market has increased.
2) The efficiency of the turbines has increased considerably.

[107] It is important to note that the distribution of capital costs for onshore and offshore wind farms differ significantly. According to a report on the economics of wind farms published by the American Research Reports International in 2005, in offshore wind farms, the turbine costs represent about 51% of the total capital costs. The remaining costs are shared by the expenses for foundations (16% of total capital costs), cabling, and grid connection (25% of total capital costs), and other expenses like planning, financing, etc. (8% of total capital costs). For more, see (International, 2005).

3) Over the first few years of development, an overall decrease in wind turbines capital costs/kW has been observed. However, the last couple of years have shown a trend toward an increase in the costs (around 20% in comparison with figures from 2004[108]).

This increase can be largely justified by a significantly higher demand for wind turbines worldwide, as well as rising commodity prices (specially steel and copper) imposing constraints on the overall supply chain.

6.1.2. Operation and Maintenance Costs

Operation and maintenance costs constitute a sizeable share of the total annual costs of a wind turbine. For a new turbine, O&M costs might easily constitute between 20 and 25% of the total leveled cost per kWh produced over the lifetime of the turbine. If the turbine is new, this share may be 10-15% in the first few operational years and increase to at least 20-35% by the end of the turbine's lifetime ((EWEA), 2009 b).

O&M total costs typically include the costs for regular maintenance, repairs, spare parts, administration (including the technical and commercial management of the wind farms), insurance, and depending on the project structure, land use payments[109]. Although all costs tend to increase with the turbine's lifetime, the costs for repairs and spare parts are particularly influenced by the turbine's age - starting low and increasing over time.

As commented by Böttcher, the industry still does not agree on a common definition of O&M costs (Böttcher, 2012, pg. 242). Additionally, a general lack of wind farms with a long history of operation combined with local market peculiarities make the determination of a robust trend of operational costs over the years extremely difficult. Only a few references on O&M costs are available.

An O&M cost study published by the German Wind Energy Institute (DEWI GmbH) in 2002 is still one of the main references on the topic. The study[110] was based on data from about 400 German projects under development between 1997 and 2001. According to DEWI, in the first two operational years the costs of maintenance (repair and spare parts) of a wind turbine are covered by the manufacturer's warranty. In this way, in the first two years of operation, the total of O&M costs amounted to about 2 to 3% of the total investment costs, being equivalent by that time (2002) to approximately 0.3 to 0.4 Eurocents per kWh. After six years of operation, an increase in O&M costs

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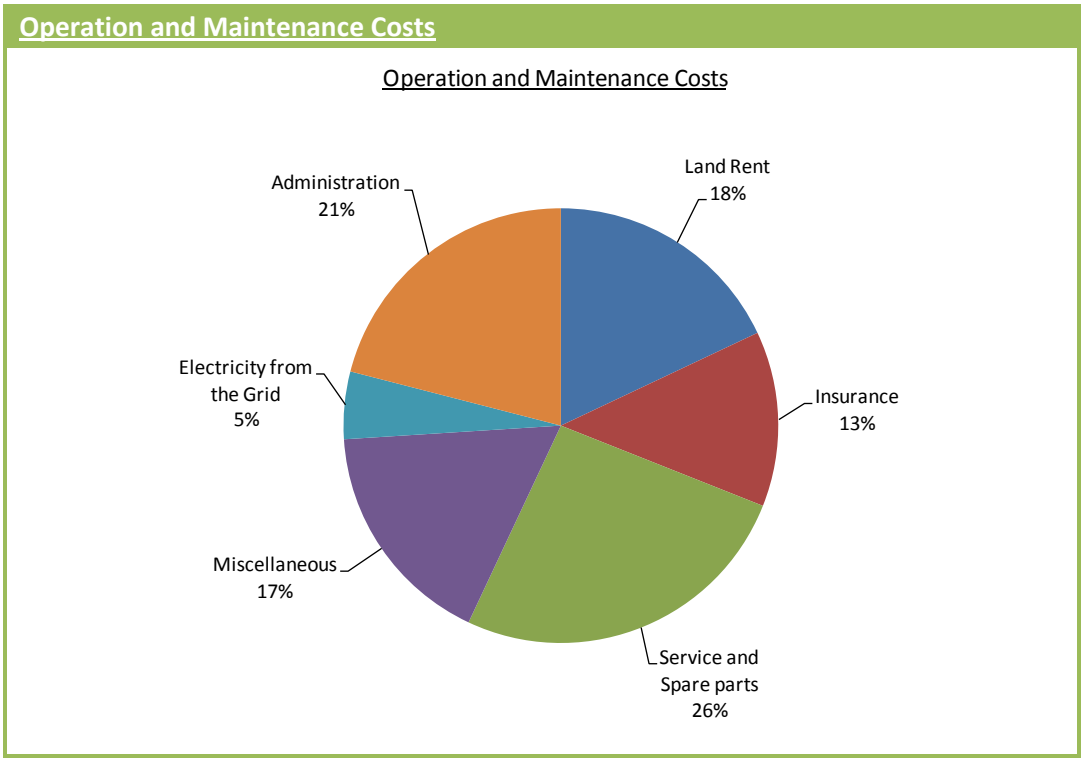
[108] Comparing the same data published by the European Wind Energy Association in 2004 and the most recent data published in 2009 (European Wind Energy Association (EWEA), 2009).

[109] A detailed description of all the works included in each of these parts of O&M costs can be found in (Böttcher, 2012), Chapter 3.

[110] See (DEWI GmbH, 2002).

has been observed so that these costs were equivalent to 5% of the total investment costs, or 0.6 to 0.7 Eurocents per kWh. From this total of O&M costs, the expenses were distributed as shown in Graph 6.2. It is important to note that the distribution of costs reflects the situation in Germany at the beginning of the past decade. It is based therefore on turbines of lower rotor and hub height sizes, and consequently lower generation capacities, as well as different technologies (e.g. a higher predominance of stall regulated models) in comparison to the current state of the art.



Graph 6.3: Distribution of Operation and Maintenance Costs (Source: (DEWI GmbH, 2002)

In 2004, the German Wind Energy Association (BWE – Bundesverband Windenergie e.V.) released the experience of German investors with operational expenses. According to the German association, operational costs viewed as a function of the yearly revenue of a wind farm had the following distribution (Bundesverband Windenergie, 2004):

- ✓ Commercial operation management: 2-3% of the yearly revenues
- ✓ Technical operation management: also 2-3% of the yearly revenues
- ✓ Expenses with land use: 3-8% of the yearly revenues
- ✓ Maintenance, repair, spare parts, insurance: 13-16% of the yearly revenues
- ✓ Expenses from the decommissioning of the turbines: 27.000 -33.000 Euros/MW

More recently, the European Wind Energy Association published data on O&M costs based on the experience of other European countries apart from Germany such as Spain, the UK, and Denmark. According to the EWEA, O&M costs were generally between 1.2 to 1.5 Eurocents per KWh of wind energy produced over the total turbine's lifetime. Around 60% of this total goes completely

to the maintenance of the turbines, and the other 40% is distributed between costs such as insurance, land and administration fees ((EWEA), 2009 b).

The European Wind Energy Association points out that, as with the investment costs, part of the O&M costs of wind turbines has decreased over recent years. The observed decrease of costs is mainly justified by the fact that the operation of wind turbines exhibits economies of scale similar to their investment costs.

As installation costs decreased proportionally to the increase of a turbine's size, the operation costs decreased as the size of the wind farms increased ((EWEA), 2009 b). However, not all costs components decreased. The dynamic of interaction between the several expenses involved in the operation of wind farms is still pretty unclear.

What has been recognized is that O&M costs are in the first place determined by the size of the turbines and the expanse of the wind farms. Furthermore, these costs are to a large extent dependent on the location of the wind farms. If on the one hand the expansion of wind energy and the development of the technology brought with it a general reduction of costs in connection with the increase in reliability, the value of areas suitable for the installation of wind farms has increased considerably[111].

Another conclusion from the relatively short experience with the operation and maintenance of wind farms is that the magnitude of the expenses for unscheduled maintenance and spare parts is normally connected to the wind regime of the sites.

Wind turbines operating on sites with a strong incidence of high wind speeds, where turbines operate a large number of hours under full power, as well as sites with a high tendency to turbulence (e.g. complex terrain and dense forested areas) have notably higher expenses for unplanned maintenance and spare parts. A way to deal with the uncertainty about the costs related to this issue is for example the provision of full service maintenance contracts.

As recognized by Böttcher, O&M costs are extremely dependent on the type of service contract regulating the provision of maintenance and repair work of a wind farm. In general the cash flow of wind farms relying on a full service contract over their full operational lives, or at least over their entire financing period, is rather more robust than the cash flow of wind farms covered by a normal service contract (Böttcher, 2012, pg. 244).

The main difference between the two types of contract lies in the provision of unscheduled and predictive maintenance. A normal service contract regulates the provision of scheduled general maintenance work alone (e.g. checking of bolts, change of oil, etc.). Any unplanned repair

[111] According to Böttcher: If in the past assumptions of expenses related to land use agreements amounting to between 2-5% of the yearly income of a wind farm were realistic, today these will not be lower than 5-10% (Böttcher, 2012, pg. 243).

(manpower + spare parts) is charged separately. A full service contract guarantees that any technical problem will be treated as soon as it occurs. Additionally, the price of a full service contract is normally structured between a fixed part determined in terms of cost/MW installed, and a variable part determined in terms of cost/KWh.

The differentiation between fixed and variable costs allows a certain level of certainty in the determination of the monthly expenses for maintenance. Assuming that higher wind speeds are connected to a higher wear of mechanical parts, it is likely that months with higher wind speeds and a consequent higher production of energy are immediately followed by months with higher unscheduled maintenance expenses.

All in all, it can be summarized that the expenses for maintenance have over recent years shown a general decreasing trend in connection with technology improvement and the increase of manufacturers' and wind farm operators' experience. Contrary to that, operational costs such as land use payments, insurance, electricity supply, etc. have over recent years shown a general increasing trend. Particular market characteristics such as labor costs, manpower specialization, turbine parts, local supply conditions, etc. combined with a general lack of long-term experience imposed difficulties on the development of a clear and robust reference on the O&M costs of wind farms.

6.1.3. Unit Electricity Cost

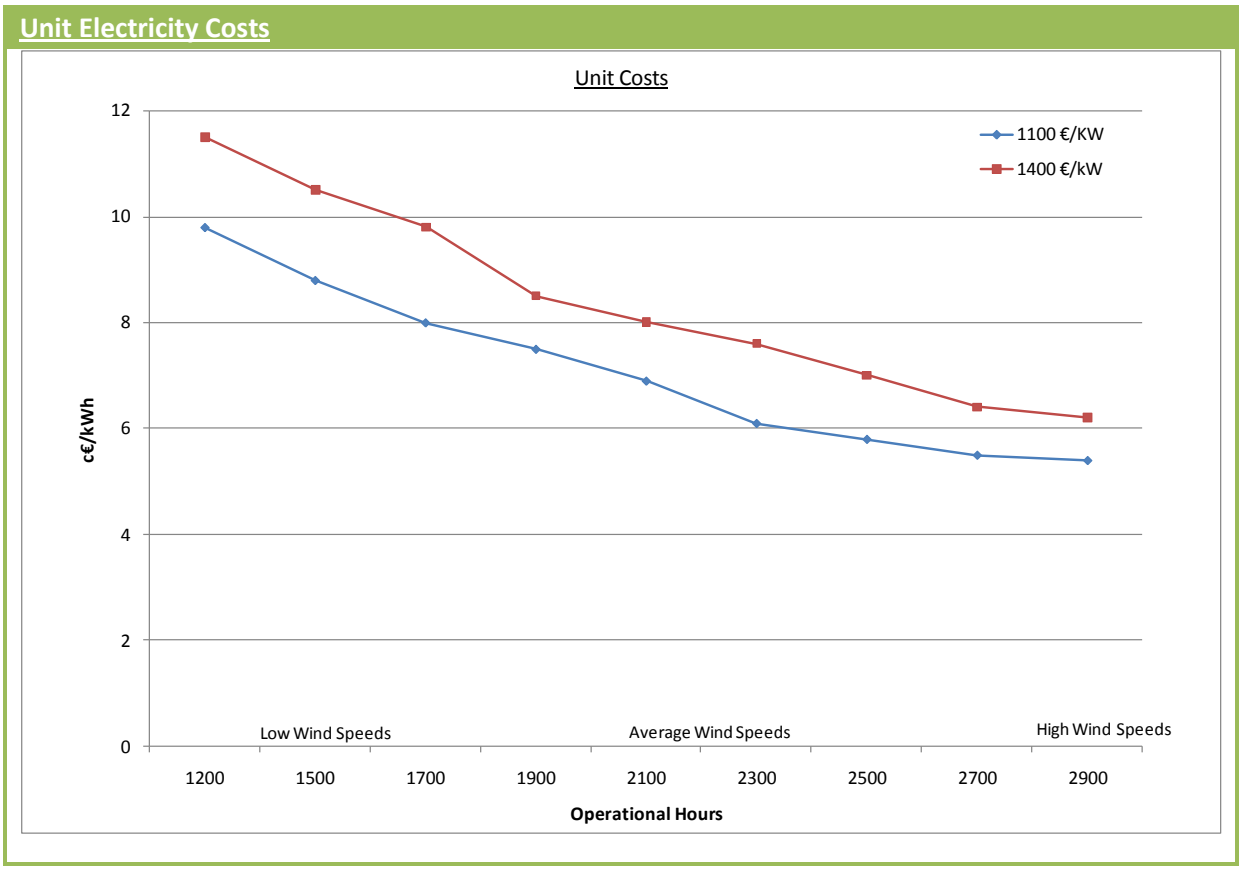
The total cost per kWh produced (unit cost) of a wind farm is given in Equation 6.1.

$$\textbf{\textit{Unit Cost (€/kWh)}} = \frac{\text{Investment Cost(€)} + \text{O \& M Cost(€)}}{\text{Annual Energy Production (kWh)}} \qquad \text{(Eq. 6.1)}$$

Here, the investment and O&M costs are leveled out and discounted over the lifetime of the turbine. Therefore the unit cost of generation of a wind farm is calculated as an average cost over the wind farm's operational life. Due to lower O&M costs in the first few operational years, unit costs are normally lower then, increasing proportionally to the O&M costs over the years. Applying information from the European Wind Energy Association, Graph 6.3 shows an estimation of costs for an average turbine installed in Europe carried out in a simple analysis (without taxes, depreciation, and risk premiums), under the following assumptions ((EWEA), 2009 b):

- ✓ Calculations relate to a new onshore, medium-sized turbine (1.5 – 2 MW);
- ✓ The investment costs are between €1100 – 1400 /kW, with an average of €1225/kW according to Section 6.1.1.

- ✓ The O&M costs are assumed to be 1.45 c€/kWh as an average over the lifetime of the turbine (20 years).
- ✓ A discount rate of 7.5%/a.



Graph 6.4: Unit electricity Costs – Data from the European Wind Energy Council (Source: ((EWEA), 2009 b))

As illustrated, the costs range from approximately 7-10 c€/kWh at sites with low wind speeds. At sites with average wind speed the costs are approximately 7 c€/kWh, and at sites with high wind speeds, costs are between 5 to 6.5 c€/kWh.

The rapid European and global development of wind power capacity has strongly influenced the production prices over the last 20 years. A survey by the EWEA has shown that for wind turbines located in coastal areas, the average cost decreased from around 9.2 c€/kWh for the old 95 kW turbines to around 5.3 c€/kWh for a fairly new 2.0 MW machine, an improvement equivalent to more than 40% over 20 years ((EWEA), 2009 a pg. 209). The same survey indicates that the industry has a learning rate of 0.17 to 0.09. This means that when the total installed capacity of wind energy doubles, the costs per kWh produced for new turbines goes down between 9 and 17%.

Assuming this rate, an average 2.0 MW wind turbine to be erected on a site with an average wind speed of 6.3 m/s in a country with relatively low costs (for example Denmark) would today have a unit cost of 6.1 c€/kWh. If a doubling time of the total installed capacity in the country of three

years is assumed, in 2015 the cost range would be approximately 4.3 to 5.0 c€/kWh. Assuming a doubling time of five years, the cost would stay between 4.8 and 5.5 c€/kWh.

6.1.4. Wind Energy Tariffs and Support Mechanisms

The strategies to support the promotion of renewable energy are mainly based on *investment-focused strategies* or *generation-based strategies*. *Investment-focused strategies* provide financial support in the form of subsidies, soft loans, or tax credits, while *generation-based strategies* provide support in the form of feed-in tariffs, or fixed premium certificates such as green certificates ((EWEA), 2009 a, pg. 227). Many countries adopt both types of strategies with the aim of supporting not only the immediate inclusion of renewable energy generation in their matrix, but also of developing a specialized local industry.

These strategies are further classified in the specialized literature as *quantity-driven* or *price-driven*. *Quantity-driven* strategies are those in which governments, through their regulatory authorities, establish renewable energy quotas that the energy companies are obliged to buy and resell to their end consumers. In *price-driven* strategies, the government defines a remuneration tariff in $/kWh to be paid for the energy provided from renewable sources. For the promotion of wind energy specifically, the main strategies are ((EWEA), 2009 a), pg. 228):

Quantity-Driven Strategies:

1. *Quota obligations based on Tradable Green Certificates (TGCs):* In this system, the government defines targets for wind energy deployment and requires a particular party in the electricity supply chain (generator, distributor, or consumer) to fulfill certain obligations. Once the obligations are defined, a parallel market for certificates is established by itself and the price is set following demand and supply.

2. *Tendering Systems:* This type of financial support can be either investment-focused or generation-based. In the first case, a fixed amount of capacity to be installed is determined and contracts are awarded following a predefined bidding process. Bidding winners receive a set of favorable investment conditions, including investment grants per kW installed. In the case of generation-based tendering systems, the support is provided in the form of a “bid price” per kWh for a determined period.

Price-Driven Strategies:

1. *Feed-in Tariff:* In this system, a price per unit of electricity that a utility, supplier or grid operator is legally obliged to pay for the electricity coming from a wind farm is legally determined by the responsible governmental body. It usually takes the form of either a fixed price to be paid for the wind energy production, or an additional premium on the top of the normal electricity market price to be paid for producers generating wind energy. Besides the level of the tariff, the

government also defines the duration of the payment, so investments can be planned accordingly.

2. *Investment Incentives:* This kind of incentive establishes a determined percentage of the total project costs, or a predefined amount of cash per kW installed to be directly subsided. Therefore, the level of this incentive is technology-specific. In the case of wind farms, this means either onshore or offshore.

3. *Production Tax:* This incentive is provided in the form of exemptions from the normal electricity taxes applied to all producers. In practice, this type of incentive differs from feed-in tariffs only in terms of the cash flow of the projects relying on it. In other words, it represents negative cost instead of additional revenue.

Incentive mechanisms, and the tariffs paid for the generation from wind farms vary considerably from country to country. Furthermore, they are adjusted continuously according to the responses to newly implemented support polices. For this reason, any overview of tariffs and adopted promotion policies are a mere illustration of the current situation, being not in reality representative of the long term. Therefore the table below is a brief example of some incentive mechanisms and their respective onshore wind energy generation tariffs.

Some Examples of Onshore Wind Energy Support Mechanisms and the Corresponding Tariffs		
Country	**Support Mechanism**	**Tariff**
Brazil	Tendering	5.9 c€/kWh[112]
France	Feed-in tariff	Onshore: 8.2 c€/kWh (10 years); 28-82c€/kWh (following 5 years depending on the local wind conditions) Offshore: 13.0 c€/kWh (10 years); 3-13 c€/kWh (following 5 years depending on the local wind conditions)[113]
Germany	Feed-in tariff	Onshore: base tariff 4.87[114] c€/kWh (turbines going into commercial operation in 2012) + 8.93 c€/kWh (during the first 5 operational years) + 0.48 c€/kWh (bonus for ancillary services – SDL bonus[115])
Poland	Quota obligation (TGC) + Tax exemptions	9.0C€/kWh (average 2009)[116]
Sweden	Quota obligation (TGC)	6.9 c€/kWh (average 2007)[117]
Turkey	Feed-in tariff	5.5 c€/kWh (since May 2007)[118]

Table 6.1: Support Mechanisms and Wind Energy Generation Tariffs in the Countries Addressed in the Case Studies.

As seen, different countries apply different policies. However, when considering the volume of installed capacity relating to the incentive strategy, the results clearly indicate that countries with feed-in tariff schemes achieved a higher penetration of wind energy in comparison with countries applying a defined quota or other incentives ((EWEA), 2009 a) pg. 236).

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[112] Reference: EPE – "Empresa de Pesquisa Energética" (Brazilian Energy Reseach Company). The tariff is the average energy price of the projects contracted in the last specific bidding for wind energy, realized in December 2009.

[113] Reference: European Wind Energy Association (EWEA, 2009 pg. 231)

[114] Reference: EEG Novelle 2012 (Renewable Energy Law, 2012), see: http://www.gesetze-im-internet.de/eeg_2009/index.html

[115] Restricted to turbines going into commercial operation by the 1st of January 2015.

[116] Reference: PSEW (Polish Wind Energy Association – www.psew.pl)

[117] Reference: European Wind Energy Association (EWEA, 2009 pg. 231)

[118] Reference: EMRYA - Turkish Energy Market Regulatory Agency (www.epdk.org.tr)

Moreover, the brief experience gained so far has shown that, whether a national or an international support scheme is applied, a single instrument is usually not enough to stimulate the long-term growth of the renewable energy supply matrix. A mix of instruments should be applied accordingly.

Whereas investment grants are normally suitable for supporting immature technologies, feed-in tariffs are appropriate for the interim stage of market introduction of a specific technology. A premium or quota obligation based on TGCs (Tradable Green Certificates) has proved appropriate in mature markets large enough to guaranantee competition not only between different renewable energy sources, but also conventional energy.

After a brief review of the main economic parameters involved in the development and operation of wind farms, the next section addresses their financing.

6.2. Financing of Wind Farms

6.2.1. Overview of the state of the art – Project Finance

According to the European Wind Energy Association, most of the wind farms in operation since the great expansion of wind energy in the last decades have been funded via project finance ((EWEA), 2009 a, pg. 221).

Brealey et al. define project finance as:

"...Project finance is a type of private loan. The loan is tied as closely as possible to the participants of a project that minimizes the exposure of the parent company. Project finance means debt supported by the project, not by the project's sponsoring companies..." (Brealey, et al., 2010, pg. 641).

Peter Newitt and Frank Fabozzi define project finance in a similar way:

"...*Project finance is the financing of a particular economic unit in which a lender is satisfied to look initially to the cash flows and earnings of that economic unit as the source of funds from which a loan will be repaid and to the assets of the economic unit as collateral for the loan...*" ((Nevitt, et al., 2000), pg. 1).

According to Hoffmann (Hoffman, 2007), the term project finance is generally used to define the long- term financing of infrastructure and industrial projects based upon the projected cash flow of the project rather than the project sponsors.

All these definitions give an overview on the essence of project finance: That the repayment of the loan supporting the initial investment is solely guaranteed by the cash flow of the project itself. In nonrecourse project finance, the repayment is solely supported by the cash flow of the project. If a project defaults on repayment, the parent company, or the project participants, bear no liability for the debt. In general, a collateral for payment default is provided by the assets of the projects (Akbiyikli, et al., 2006).

Because lenders have no guarantee of repayment other than the cash flow of the project, a project finance deal involves a tight structure of participants, including customers, suppliers and sometimes local governments. Following the principle *"the risks are borne by the parties best able to manage them"* (Brealey, et al., 2010), the parties are committed over the whole debt period, within a series of contracts and guarantees, to the sucess of the project's cash flow. Some typical characteristics of project finance were listed by Brealey et al. (Brealey, et al., 2010, 642):

- ✓ A special purpose vehicle (SPV) is established as a separate company[119].
- ✓ Equity ownership is privately held by a small group of investors. Normally these are the contractors and the plant manager, who therefore share in the risk of the projects's failure.
- ✓ The project company enters into a complex series of contracts that distribute risk among the contractors, the plant manager, the suppliers, and the customers.
- ✓ Typically about 70% of the capital for the project is provided in the form of bank debt or other privately placed borrowing. This debt is supported by the cash flows; if these flows are insufficient, the lenders do not have any recourse against the parent companies.
- ✓ Banks are happy to lend a high proportion of the cost of the project because they know that once it is up and running, the cash flow is insulated from most of the risks facing normal business.

Akbiyikli justifies this last characteristic with the conclusion that:

"... a physical asset and its respective future cash flows are of little value if the project is abandoned" (Akbiyikli, et al., 2006).

Therefore, project finance debts are normally provided once the project has been built and is running. In the case of a wind farm, this means once the wind farm goes into commercial operation. The development and the construction phases are normally funded by the equity of project investors. By providing a loan only after commercial operation, private lenders avoid the risks related to grid connection, issuance of permits, delays in the delievery of equipment, etc. What remains to be managed are the risks related to the energy production of the wind farm and its related operational expenses.

In order to manage the risks of what Borod calls a *"future flow transaction"* in both the financial and the meteorological sense, lenders assign an investment grade rating in accordance with the cash flow scenarios determined by the P90 or the P95 energy production confidence levels[120] (Borod, 2005).

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[119] In the case of a wind farm, a Wind Farm "XY" Co. is established. The loans are then provided to this special purpose vehicle, which takes responsibility for the re-payments.

[120] As discussed previously, the P90 production level corresponds to the annual energy production of the wind farm that will be exceeded with a probability of 90%. The same definition is applied to the P90 and the P95 levels. These confidence levels are a function of the uncertainty under which the most probable annual energy production has been determined- the higher the uncertainty, the lower the P90 in terms of MWh/y. Traditionally, base-case scenarios are addressed with a P50 confidence level, and worst-case scenarios are

A parallel risk management strategy is the determination of the project's capacity to serve the debt considering that a determined amount of its net income will be saved in a reserve account. In general, the saved amount in the reserve account – the debt service reserve account (DSRA) is equivalent to an established percentage of the debt to be repaid (including interest) in the following period. In the anlysis of the financing practice of wind farms, Böttcher reports the requirement of a DSRA with 50% of the debt obligations of the coming re-payment period as state of the art (Böttcher, 2012, pg. 239).

Another credit analysis strategy followed by lenders providing funds to wind farms is the setting of minium requirements of loan coverage, or debt service capacity ratios (DSCR).

Böttcher reports the DSCR[121] as *"probably the most frequently used reference parameter in project financing".* Further on, he defines the DSCR as (Böttcher, 2012,pg. 305).:

$$\boldsymbol{DSCR} = \frac{\text{Cash Flow of the Period} + \text{Reserve Account}}{\text{Debt Service of the Period}} \qquad \text{(Eq. 6.2)}$$

The DSCR defines how much the future cash flow of the project is over or below the debt to be repaid. In the *"bankability"* evaluation of a project, the DSCR is estimated for every repayment period. However, the overall DSCR estimated as the average of all the financing period, determines the *"credit worthiness"* of a project.

The DSCR definition of Böttcher includes the expenses related to the reserve account. This procedure has the disadvantage of a possible overestimation of the project's capacity of servicing the debt. It has, however, the advantage of reflecting the real capacity of the project's cash flow including the capacity of serving the reserve account.

As discussed by Borod, the establishment of a minimum DSCR is one of the alternatives credit providers have to demonstrate their perception of risk in the analysis of the loan. Riskier projects have higher DSCR requests than lower-risk projects (Borod, 2005). The DSCR is a flexible ratio which reflects the necessary adjustments in the financing profile of the project, such as interest rates, requirement for other sources of external capital, leverage, etc.

An accurate assessment of the risks involved in the provision of the credit is the key to successful project finance. That's because, as discussed by Newitt and Fabozzi, one of the main objectives of project financing is the high leverage of the debt (Nevitt, et al., 2000, pg. 12).

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determined with the P90. Nevertheless, the risk perception of the lenders determines under which confidence level the financing conditions of the project will be set (Borod, 2005).

[121] For more on the background of the DSCR as a project evaluation parameter, see for example (Findlay, et al., 1975).

The high leverage is supported from the lender's point of view basically by two arguments: In the first place, lenders are in general comfortable with the tight contractual structure involving all the project participants[122]. The second argument is that most borrowings from commercial bank lenders for project financing are in the form of a *senior debt* (Nevitt, et al., 2000, pg. 80).

A senior debt[123] is the first to be placed. In case of default, senior lenders have priority over the rights of project assets and/or any available cash left over.

From the equity provider's point of view, high leverage is decisive in an investment analysis not only because equity providers bear most of the risks in case of project failure[124], but also because lower equity is generally connected to higher internal rates of return[125] (Brealey, et al., 2010, pg. 643).

Equity providers have to manage the construction and completion risks, they have the lowest priority in the distribution of the cash flows and have no right to project assets in case of default. Consequently, a way to limit their exposure to these risks is reducing the amount of equity invested (Brealey, et al., 2010, pg. 641).

The decision on how much of the total investment will be funded via private loans and private equity is taken jointly between the banks involved in the deal and the equity investors. Due to the necessary involvement and commitment of the several parties involved in the development and the operation of the projects, a project finance deal is in general a long and complex process mainly supported by financial modelling.

The objective of a financial model is to provide an "abstract" representation of a determined investment opportunity. It focuses mainly on the determination of the value today of a series of cash flows over time (Benninga, 2000, pg. 1). In project finance, a financial model is the tool supporting not only the credit risk analysis and the consequent determination of leverage, but also the equity provider's decision on the investment[126].

In the case of a wind farm project, a financial model focuses on the determination of the series of cash flows over its operational life, considering the different assumptions of income from

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[122] See (Brealey, et al., 2010 pg.641)

[123] For other types of debts in the financing of wind farms, for example mezzanine financing, see (International, 2005)

[124] A list of project financing risks typically borne by lenders and equity investors can be found in (Nevitt, et al., 2000, pg. 43)

[125] For an overview of how the increase in leverage improves the internal rate of return of wind farm projects, see (Böttcher, 2012, chapter 4 section 4.2)

[126] See for example (Kong , et al., 2008)

the sales of energy production[127], the operational costs, taxes, and financing. The main goal of the model is the estimation of typical investment decision parameters such as the internal rate of return, the net present value, etc [128].

To sum up, project financing is mainly characterised by the following: 1) Loans are repaid by the project's cash flow. In case of default, project shareholders are not liable. 2) The debt is carried by the project company. 3) High leverage 4) The risk of lenders is managed within a complex structure of contracts regulating the commitment of all project participants 5) Loans are provided as senior debt. The figure below presents a typical structure of a wind farm financed via project finance.

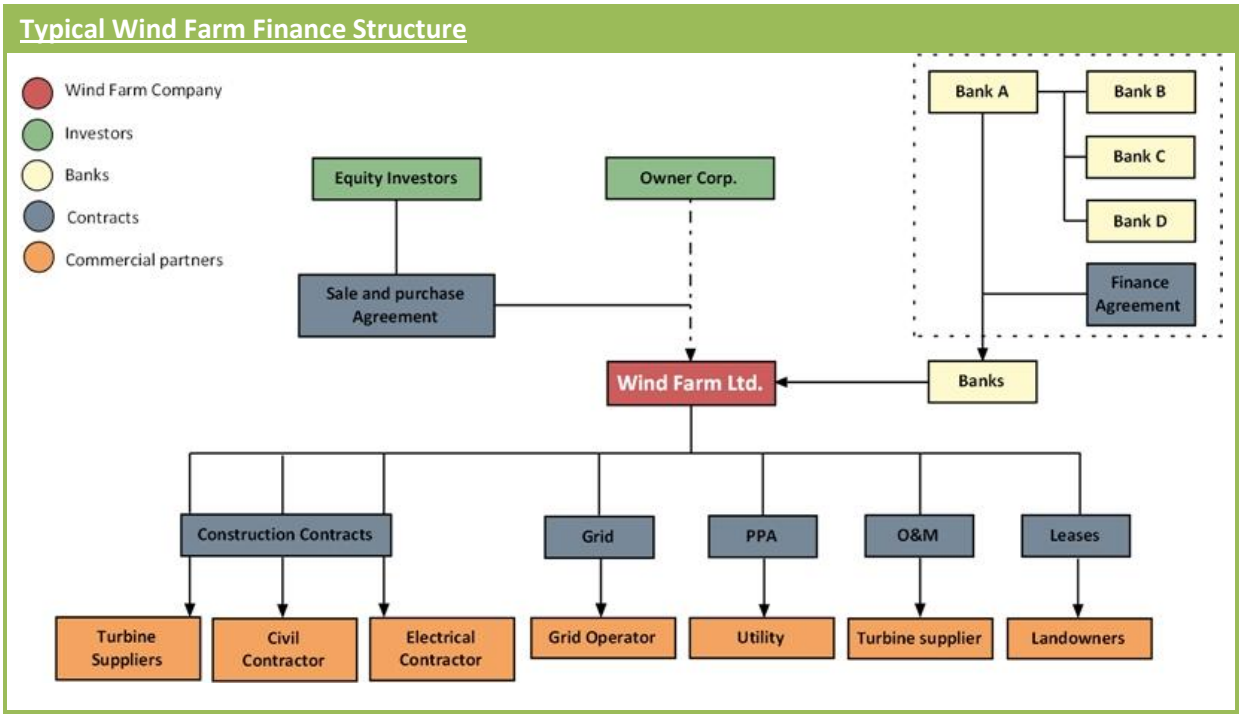

Figure 6.1: Typical Wind Farm Finance Structure. (Source: ((EWEA), 2009 a))

6.2.2. New Developments

According to the European Wind Energy Association, the last five years have seen the emergence of a number of new forms of transactions to finance wind farms, including structured finance, balance sheet financing, and portfolio financing ((EWEA), 2009 a pg. 223).

Much of the interest in structured finance has come from renewable energy funds, long-term investors such as pension funds, and even a network of worthy individuals looking for efficient investment opportunities. The principle of structured finance is very similar to project finance. It is a

[127] As discussed previously, the different assumptions of income from the sales of energy are based on the estimated exceedance probability values (P-values).

[128] An illustrative example is given at the end of the chapter.

term loan of which the return from the invested cash is in the form of interest payments. However, the structures are more varied than project finance loans. For this reason, structured finance deals have proved to be an alternative for project owners considering a refinancing of the project after a few years of operation (EWEA, 2009, pg. 223).

Balance sheet financing became an alternative to project financing once energy utility companies got involved in the implementation of wind energy projects. In balance sheet financing, projects are built solely with the utility's equity. Since utilities are in theory able to finance more than one project simultaneously, portfolio financing approaches are attracting more and more attention.

As discussed in the previous chapter, a portfolio of wind farms will usually include a range of projects located in different regions, which theoretically reduces regulatory risks. Furthermore, different projects are subject to different wind regimes, allowing geographical diversification, which in theory leads to a reduction in the overall income risks, an assumption discussed in more detail in the next section.

Although it is a relatively new financing alternative, the brief experience of banks and investors from the first deals has shown that the risk associated with portfolio financing is indeed significantly lower than that of financing wind farms individually[129]. Additionally, portfolio financing can also be adopted even after the initial financing has been in place for some time, making it an alternative to the refinancing of operational wind farms, or repowering projects.

The next section introduces an approach to investigate the characteristics of portfolio financing.

6.3. Diversification of the Energy Production Risks and the Financing of Wind Farms

The last section introduced the state of the art as well as new trends in wind farm financing. The intention was to provide an overview on how deals have been structured up to now, and present the new alternatives emerging from the lessons learned by credit providers and investors after relatively short experience. This section focuses on a recent development, namely portfolio financing.

The objective now is to introduce a complementary approach to the portfolio assessment approach discussed in the previous chapter. This time the focus of the analysis is the assessment of the impact of the diversification of production risks on wind farm portfolios' key financing parameters. The analysis is supported by a general financial model developed specially for this purpose. The model is a mere reference developed under ordinary assumptions, having no connection to a specific project.

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[129] See ((EWEA), 2009 a, pg.224)

The general question governing the assessment introduced here is: *Under what conditions does it makes sense to go for portfolio finance instead of financing single projects simultaneously?* The goal is to find the break-even point of when portfolio financing makes sense, as well as the conditions delimitating it.

Two case studies presented in the next chapter introduce the assessment approach. As the case studies show, due to the complementary aspects of the uncertainties in the annual energy production of the wind farms bundled in the portfolio, the worst-case production reference value, the P90 determined in terms of MWh/year of the portfolio, is higher than the simple sum of the P90 values of the single wind farms. As discussed, a higher P90 means higher income from the sales of the energy produced and in theory the improvement of key investment decision parameters such as Interest rate of return, etc.

Since the objective is to analyze the performance of portfolio financing in contrast to financing wind farm projects individually, an economic performance parameter has been chosen as a comparison reference – in this case the debt to equity ratio.

The dynamic of the economic analysis is straightforward: Initially a minimum reference DSCR is targeted (e.g. 1.28[130]) for all the single wind farms addressed in the portfolio. Depending on the yearly net income of the wind farm, the minimum equity necessary to provide the debt correspondent to the target DSCR is then determined. The background understanding is that the annual energy production of the portfolio is higher than the sum of the annual energy production of all the farms of the portfolio. A higher annual energy production means a higher cash flow, which increases the DSCR. An increased DSCR allows a higher percentage of the total investment to be funded by debt[131]. Once a larger part of the investment is funded by debt, less equity is required – the desire of most investors (Nevitt, et al., 2000, pg. 23).

The final goal is to understand under which conditions of energy production and related operational expenses (including financing expenses) portfolio financing becames advantageous. Therefore, a sensitive analysis supported by the financial model introduced below is essential.

6.3.1. The Financial Model

A financial model is an investment analysis tool (Benninga, 2000, pg.1). In the application discussed here, the main task of the financial model is to forecast the cash flow of the wind farm

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[130] 1.28 min DSCR is solely a reference value (Böttcher, 2012, pg.300). In practice, the minimum DSCR required by credit providers depends strictly on their perception of risk, which varies with specific project peculiarities such as tax benefits, governmental incentive mechanisms, etc (Böttcher, 2012, pg. 293). For more on the economic analysis of wind farm projects, see for example (Böttcher, 2012), (Borod, 2005) or (International, 2005).

[131] See Equation 6.2

under investigation, enabling the analysis of the economic performance of the project over its complete operational life. In order to simplify the analyses, the cash flows are estimated yearly. However, financial models can be designed to provide results quarterly or half-yearly. The time resolution is normally defined according to the repayment dates of the loans, whether these are to be paid every four months, six months, or once a year respectively. For the construction of the model, an operational life of 20 years was considered.

The topology of the general financial model developed to support the analyses here is shown in the figure below. The spreadsheet is divided into five different parts, which are interconnected in order to calculate the parameters of interest according to key initial assumptions. The following sections are an overview of these single parts. The intention is to highlight the flow of calculations and the interdependencies between the information regarding the production income of the wind farm, its operational costs, the structure of the loans, and the invested equity, as well as its ability to repay the loans, and the distribution of return to the investors.

As in the model developed for the estimation of the portfolio effect, the fields in yellow are for input information, fields in light green hold the interim calculations and dark green fields contain the final results.

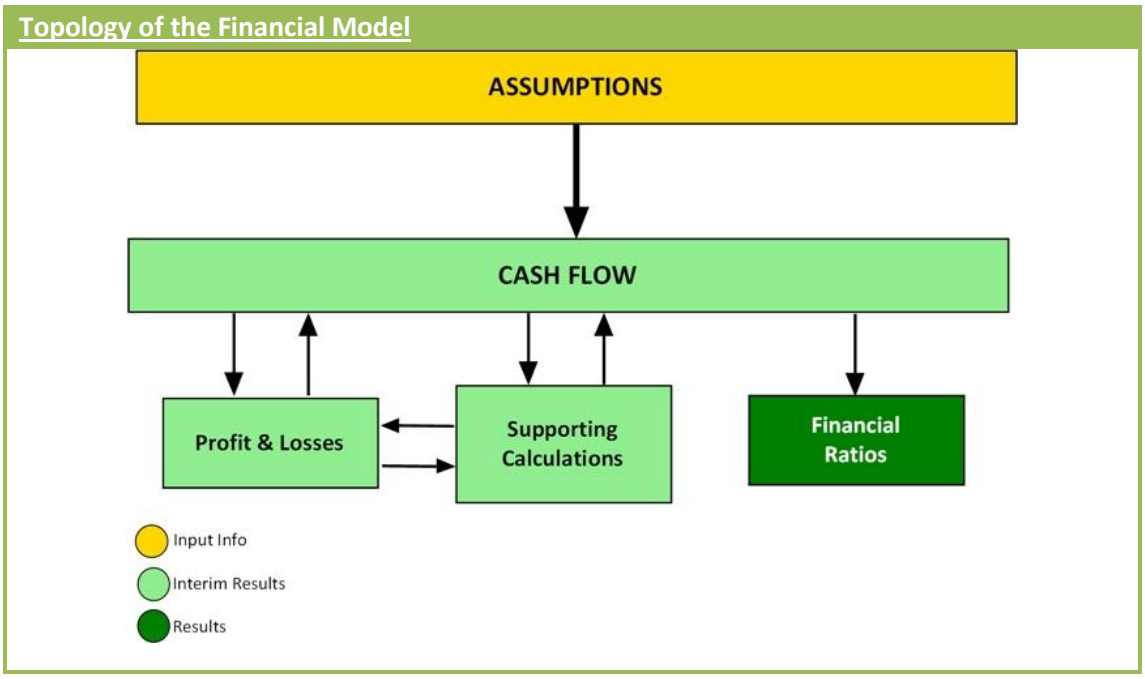


Figure 6.2: Topology of the Financial Model developed to carry out the analysis of the financial performance of the wind farms considered in the portfolio analyses. (Source: the author).

In brief, the model works with the income from the sales of the energy, as well as the interest from existing reserve accounts as total revenues. The expenses are divided between the operational costs (expenses from maintenance, land lease, insurance, etc.), the debt interests, and repayments. Senior debts (e.g. loan from banks) have priority payments, followed by the return

distribution to equity investors. To guarantee that the loan will be fully repaid, two strategies are included:

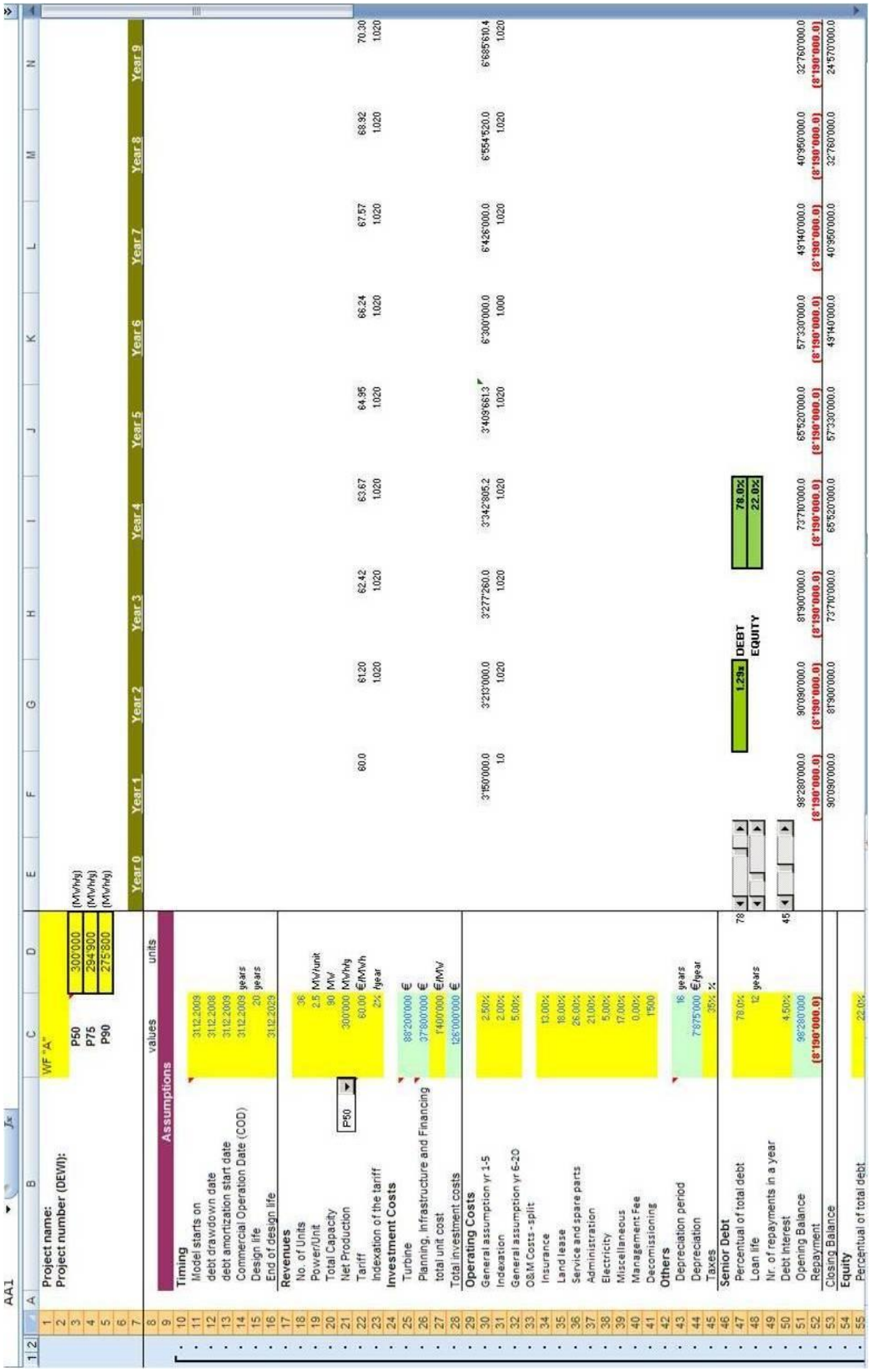
First, a debt service reserve account (DSRA) which is a reserve account containing a determined percentage of the debt to be paid in the next period. In the simulations, the assumed reserve is 50% of the following period's debt (Böttcher, 2012, pg. 239). Depending on the balance of the period, the remaining account's balance is then available for equity repayments. The second strategy is a distribution test.

In the distribution test, a minimum DSCR is imposed to permit the transfer of the cash available to equity repayments. The DSCR of the period is tested and, depending on the result, the cash in the reserve account is transferred to repay the equity invested, or remains in the account to cover the reserve amount.

What happens in practice is that in the first few operational years, the cash available for the payment of the equity usually remains in the account to guarantee the repayment of the next period's loan. As the loan principal and interests get lower, the remaining cash flow starts being transferred to equity providers. A constant equity repayment is in many cases only observed after the debt is completely repaid- in the simulations after 12 operational years or more depending on the length of the debt. However, *"good"* projects, subject to a high energy production (windy sites relying on a good performance of the turbines) are in general able to repay the loan, cover the reserve account and still transfer the remaining cash as a payment for the invested equity. The amount of cash repaid to the equity will determine the level of the internal rate of return.

The figure below is a diagram of a small part of the spreadsheet, since due to its size the full illustration here is not possible. The model is detailed in Annex B of this document.

Partial Illustration of the Financial Model



	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		Project name:	WF "A"											
2		Project number (DEWI):												
3			P50	300'000	(MWh/y)									
4			P75	294'900	(MWh/y)									
5			P90	275'800	(MWh/y)									
6														
7						Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
8			values	units										
9		Assumptions												
10		Timing												
11		Model starts on	31.12.2009											
12		debt drawdown date	31.12.2008											
13		debt amortization start date	31.12.2009											
14		Commercial Operation Date (COD)	31.12.2009	years										
15		Design life	20	years										
16		End of design life	31.12.2029											
17		Revenues												
18		No. of Units	36											
19		Power/Unit	2.5	MW/unit										
20		Total Capacity	90	MW										
21		Net Production	300'000	MWh/y		60.0	61.20	62.42	63.67	64.95	66.24	67.57	68.92	70.30
22		Tariff	60.00	€/MWh	P50		1.020	1.020	1.020	1.020	1.020	1.020	1.020	1.020
23		Indexation of the tariff	2%	/year										
24		Investment Costs												
25		Turbine	88'200'000	€										
26		Planning, Infrastructure and Financing	37'800'000	€										
27		total unit cost	1'400'000	€/MW										
28		Total investment costs	126'000'000	€										
29		Operating Costs												
30		General assumption yr 1-5	2.50%			31'500'000.0	32'310'000.0	33'277'260.0	34'342'805.2	35'409'613	36'300'000.0	37'426'000.0	38'554'520.0	39'685'510.4
31		Indexation	2.00%			1.0	1.020	1.020	1.020	1.020	1.000	1.020	1.020	1.020
32		General assumption yr 6-20	5.00%											
33		O&M Costs - split												
34		Insurance	13.00%											
35		Land lease	18.00%											
36		Service and spare parts	26.00%											
37		Administration	21.00%											
38		Electricity	5.00%											
39		Miscellaneous	17.00%											
40		Management Fee	0.00%											
41		Decomissioning	1'500											
42		Others												
43		Depreciation period	16	years										
44		Depreciation	7'875'000	€/year										
45		Taxes	35%	%										
46		Senior Debt												
47		Percentual of total debt	78.0%		78									
48		Loan life	12	years										
49		Nr. of repayments in a year												
50		Debt Interest	4.50%		45									
51		Opening Balance	98'280'000			98'280'000.0	90'090'000.0	81'900'000.0	73'710'000.0	65'520'000.0	57'330'000.0	49'140'000.0	40'950'000.0	32'760'000.0
52		Repayment	(8'190'000.0)			(8'190'000.0)	(8'190'000.0)	(8'190'000.0)	(8'190'000.0)	(8'190'000.0)	(8'190'000.0)	(8'190'000.0)	(8'190'000.0)	(8'190'000.0)
53		Closing Balance				90'090'000.0	81'900'000.0	73'710'000.0	65'520'000.0	57'330'000.0	49'140'000.0	40'950'000.0	32'760'000.0	24'570'000.0
54		Equity												
55		Percentual of total debt	22.0%											

Figure 6.3: Partial picture of the spreadsheet of the financial model (Source: the author).

6.3.1.1. Sensitivity Analysis and Interpretation of Results

The objective of a sensitivity analysis is to check the response of one or several selected variables to changes in specific assumptions (Brealey, et al., 2010, pg.166). A sensitivity analysis can provide answers to several questions. The choice of parameters addressed depends on the interest of the analyst.

In the analysis of the wind farms and the wind farm portfolios addressed in the case studies discussed at the end of this work, the sensitivity analysis was mainly focused on the behaviour of the DSCR to changes in specific parameters such as the annual energy production, increase of operational costs, financing assumptions, etc. To illustrate the goal of the sensitivity analysis in the evaluation of the characteristics of portfolio financing and the dynamic of the model, a generic example is discussed in Annex B. In this example, where key assumptions are merely illustrative, the response of the DSCR to different loan interest rates is shown in the table below.

As the values show, the DSCR dynamic follows the rule: As the debt percentage increases (i.e. higher loan), the DSCR decreases. As more equity is invested, the debt proportion decreases and the DSCR increases. The breakeven point in the analysis considered is a DSCR of around 1.28x[132]. Higher loan interest rates mean higher debt services, and therefore lower DSCRs.

Sensitivity Analysis Example 1

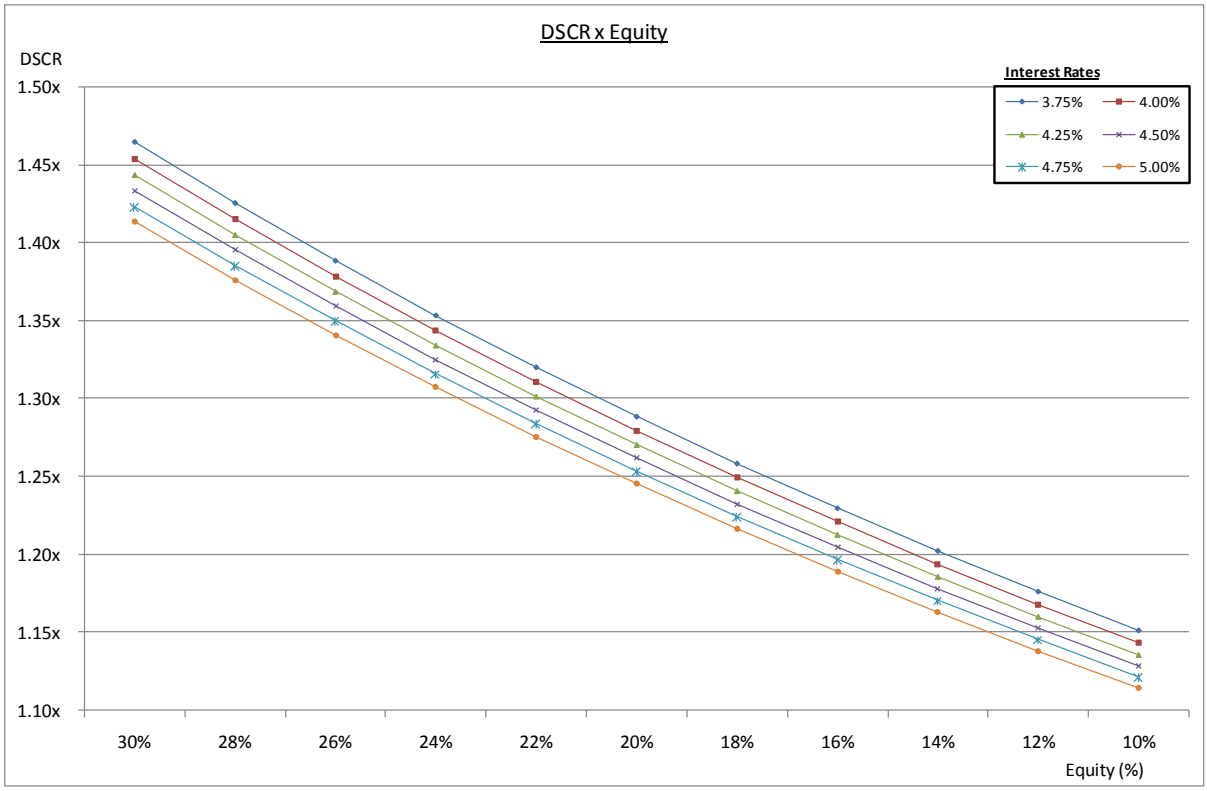
DSCR											
	Debt Finance										
Interest Rate on the Debt	70%	72%	74%	76%	78%	80%	82%	84%	86%	88%	90%
3.75%	1.46x	1.43x	1.39x	1.35x	1.32x	1.29x	1.26x	1.23x	1.20x	1.18x	1.15x
4.00%	1.45x	1.42x	1.38x	1.34x	1.31x	1.28x	1.25x	1.22x	1.19x	1.17x	1.14x
4.25%	1.44x	1.41x	1.37x	1.33x	1.30x	1.27x	1.24x	1.21x	1.19x	1.16x	1.14x
4.50%	1.43x	1.40x	1.36x	1.33x	1.29x	1.26x	1.23x	1.20x	1.18x	1.15x	1.13x
4.75%	1.42x	1.39x	1.35x	1.32x	1.28x	1.25x	1.22x	1.20x	1.17x	1.15x	1.12x
5.00%	1.41x	1.38x	1.34x	1.31x	1.28x	1.25x	1.22x	1.19x	1.16x	1.14x	1.11x
5.25%	1.40x	1.37x	1.33x	1.30x	1.27x	1.24x	1.21x	1.18x	1.16x	1.13x	1.11x
5.50%	1.39x	1.36x	1.32x	1.29x	1.26x	1.23x	1.20x	1.17x	1.15x	1.12x	1.10x

Table 6.2: Sensitivity Analysis example 1: DSCR resulting from different debt finance percentages and applied interest rates (Source: the author).

In the same example, important conclusions can be derived from Graph 6.5. The graph shows the curve of the relation between DSCR x percentage of the equity in the total financing of the investment costs for different interest rates. For a DSCR of around 1.28x, the percentage of equity varies between 21 and 23% of the total debt. In cash, the percentages are equivalent to EUR

26,460,000.0 and EUR 28,980,000.0 - A difference of approximately EUR 2.5 million depending on the loan interest rate applied.

Sensitivity Analysis Example 2



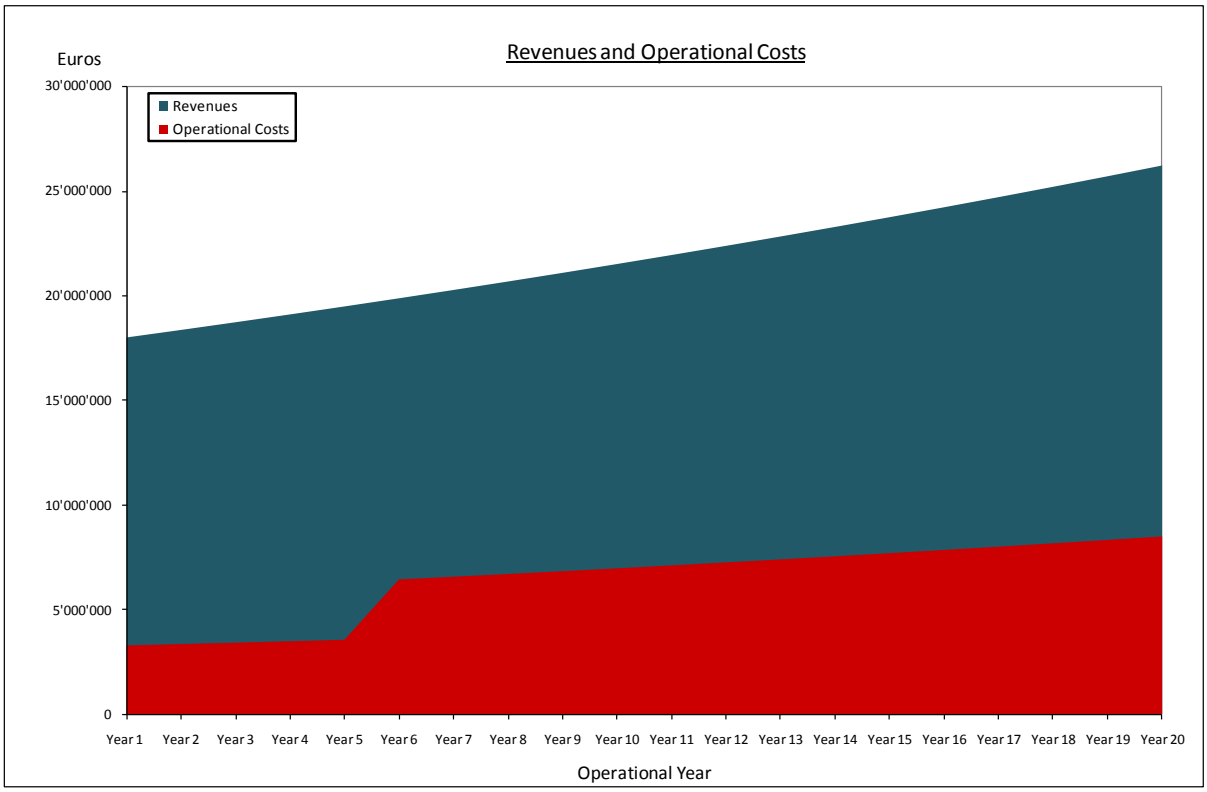
Graph 6.5: Sensitivity Analysis example 2: DSCR x Equity percentage curves for different interest rates applied (Source: the author).

However, other results than financing parameters can be used to illustrate the performance of the projects.

Graph 6.5 shows for example the relation between the production revenues and the operational costs considering the applied assumptions. The area diagram shows a constant increase in revenues solely influenced by the indexation of the tariff, since a constant annual energy production has been assumed. Additionally, an increase in operational costs after the initial 5 operational years is observed.

[132] See for example (Borod, 2005) or (Böttcher, 2012)

Presentation of Results



Graph 6.6: Resulting Revenues x Operational Costs, considering the assumptions presented at the beginning of this section (Source: the author).

To conclude, the best way to compare two wind farm projects from the point of view of their financing performance is through the analysis of the financial models. A financial model is a very powerful tool in risk analysis and investment decisions (Benninga, 2000, pg. 3). As demonstrated, the initial assumptions can be constantly changed so the output of several parameters considering different scenarios is easy to assess. More than that, this exercise provides relevant answers to decisive questions guiding the decision on physical asset investments such as wind farms.

6.4. Summary

The methodology of analysis of the application of the Modern Portfolio Theory to wind farm investments addressed in this work is divided into two different parts: The estimation of the portfolio effect, or the increase in the predicted annual energy production of a group of wind farms subject to diversification effects, and a comparison of investment decision parameters once the financing of the wind farms is treated separately from the financing of the closed portfolio.

In the two last chapters, the quantification approach of both parts was introduced. The next chapter will discuss two case studies applying the methodology discussed up to now. The first case study introduces a portfolio analysis considering wind farms already in operation, to which the risks regarding the estimation of future cash flows are subject to different uncertainties than the

uncertainties about the estimation of future cash flows of new wind farms. In the second case study, the aspect of geographical diversification is in the foreground. All in all, the objective of the case studies is to address the applicability of the portfolio assessment approach developed here in the practice of wind farm investment analysis. Therefore, the general goal is to highlight specific aspects of the methodology, to interpret the results in view of the necessary initial assumptions, and finally to identify the determinants of an efficient portfolio financing.

7. Case Studies

This chapter illustrates the diversification assessment approach developed according to the principles of the Modern Portfolio Theory, as discussed throughout the work. The analysis of the dynamics of the approach and its applicability to wind farm projects is based on the evaluation of two case studies structured for this purpose. Important conclusions regarding the efficiency of diversification as an improvement strategy for investments in wind energy are discussed within a comparison of the case study outcomes. To better evaluate the particularities of a portfolio analysis in view of the project development stage, two different energy yield assessment approaches are taken into account.

The first case study addresses a portfolio of wind farms already in operation. The annual energy production is estimated with an analysis of the available production data of the operating turbines in a procedure detailed in the first section. The second case study analyses a portfolio of wind farms in the pre-operational phase. The estimation of the annual energy production of the wind farms is based on the analysis of the wind data measured at the sites in a procedure detailed in Chapter 4.

The diversification effect is addressed in two complementary steps: The first step focuses on the impact of diversification on the annual energy production of the wind farm portfolios. The second step focuses on the analysis of this impact on some of the project financing conditions of the respective portfolios in comparison to the same conditions once the financing is structured to the single projects.

The case studies are based on existing projects. For confidentiality reasons, part of the information has been modified.

7.1. Case Study 1: Portfolio of 9 Operating Wind Farms in Germany

The wind farms addressed in the first case study are operating in different parts of Germany. The objective of limiting the portfolio to operative wind farms subject to a relatively similar wind regime is to extend the analysis from a mere assessment of geographical diversification to an assessment of performance diversification. This goal is supported by two initial assumptions:

1) The analysis of the production data of wind farms provides a real picture of the local wind regime under which the turbines are operating;
2) The analysis of the production data of wind farms provides a real picture of the technical performance of the turbines.

7.1.1. Location of the Wind Farms

The figure below illustrates the location of the wind farms. Due to confidentiality issues, the exact location will be not disclosed.

Case Study 1: Location of the Wind Farms

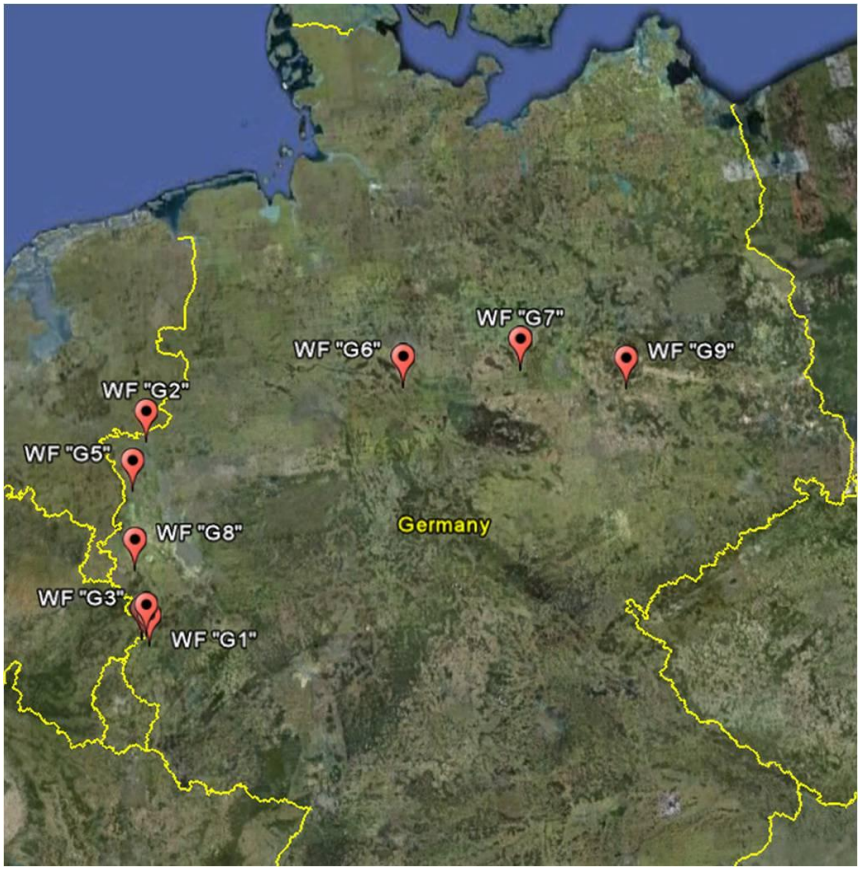


Figure 7.1: Location of the wind farms included in the portfolio analysis (source: the author)

7.1.2. Estimation of the Annual Energy Production and the related Uncertainties

The re-estimation of the annual energy production of the wind farms based on the analysis of their production data is performed based on a local energy yield index - in the case of Germany, the BDB index.

According to the information summarized by the company managing the index, Enveco GmbH[133], the BDB index is established with data from a database (*Betreiber-Datenbasis)* which has since 1988 registered the production data of around 20,000 wind turbines operating in the whole of Germany. The production data of around 4,500 wind turbines located on different sites around the country are analyzed monthly for the establishment of regional energy production indexes. The indexes are statistical monthly average values. An index value describes the relation between the

[133] See http://www.btrdb.de/bdbindex.html

informed monthly energy yield (kWh) of wind turbines located in a specific region and the long-term, average energy yield of the registered wind turbines in this region.

The monthly index refers to a rate of 1/12 of an average year. The following example describes how the index should be interpreted: A monthly index of 63% of a specific region means that in the reference month the energy production of all the wind turbines included in the index was 37% below the average production determined with the long-term data available in the database. The index works as a long-term reference source, used to extrapolate (or to correct) the past information on production data to a longer period. The following expression illustrates the correction procedure:

$$\text{Corrected Energy Yield} = \frac{\text{Production of the Month (kWh)}}{\text{BDB Index}} * 100 \qquad \text{(Eq. 7.1)}$$

The correction procedure can be illustrated by the following example (Enveco GmbH, 2006): Assuming that a wind turbine produced 100,000 kWh in March of a certain year, and that the index of the region where the wind turbine is located is equal to 100% in this month, the corrected energy yield for the month of March would be:

$$\frac{100.000\text{kWh}}{100} * 100 = 100.000\text{kWh} \qquad \text{(Eq. 7.2)}$$

If the production in April is 55,000 kWh and the index equal to 50%, the corrected energy yield for the month of April would be:

$$\frac{55.000\text{kWh}}{50} * 100 = 110.000\text{kWh} \qquad \text{(Eq. 7.3)}$$

From the two months, the most probable annual energy yield would be given by:

$$((100.000 + 110.000)/2\text{months})) * 12\text{months} = 1.260.000\text{kWh} \qquad \text{(Eq. 7.4)}$$

Consequently, the higher the number of months included in the calculations, the higher the accuracy of the long-term corrected annual energy yield.

The BDB version 06, applied to the wind farms discussed here, has a long-term reference period of 30 years (from 1975 to 2004). To respect the local behaviour of the wind, the index has been established to include 25 different regions defined according to their landscape characteristics (e.g. coastal areas, inland). Figure 7.2 shows the latest version of the BDB index regions.

Case Study 1: BDB Index Regions

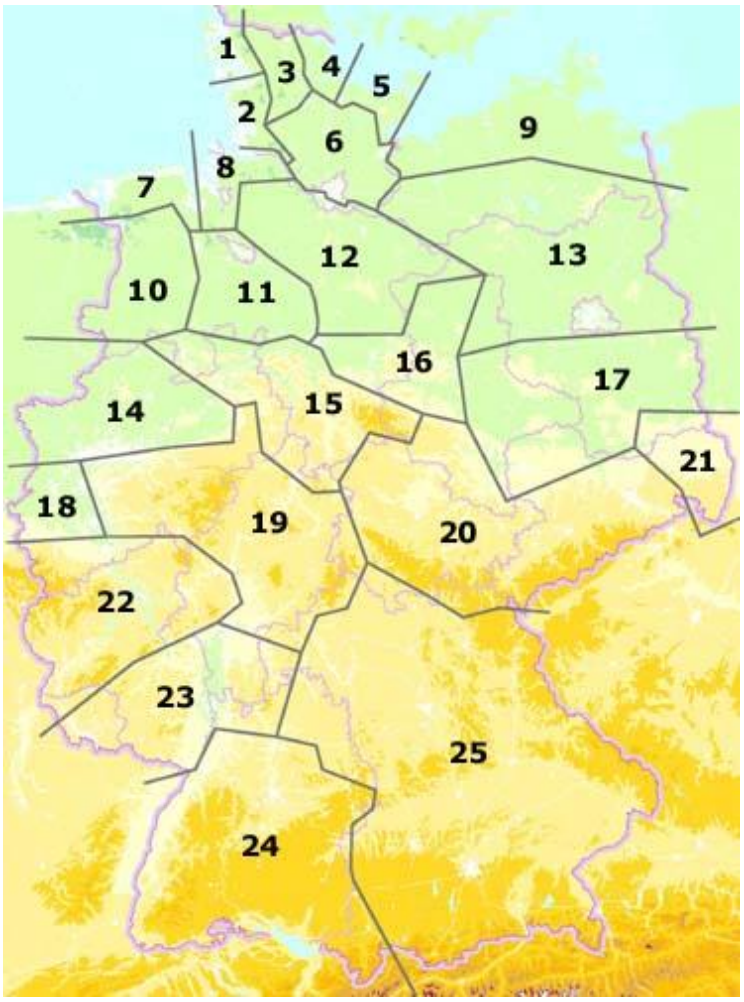


Figure 7.2: Regions of the BDB Index (Source BDB Index Website: http://www.btrdb.de/bdbindex.html)

The accuracy of the index is directly connected to the number of wind turbines registered in a region, which will further determine the level of uncertainty connected to the application of the index.

As shown below, most of the wind turbines operating in Germany by 2007 were concentrated in the northwest of the country. The graph in Figure 7.3 shows the current wind power capacity installed in Germany by federal states. As seen, most of the operating turbines are still concentrated in the federal states of the northern part of the country (e.g. Lower Saxony, Brandenburg, Schleswig-Holstein). For this reason, a long-term extrapolation of production data with a regional index from the northern areas (e.g. region 8) has in theory a lower uncertainty than the uncertainty of a long term extrapolation based on a regional index from the southern areas (e.g. region 25).

Case Study 1: Overview of wind farms operating in Germany until the end of 2007

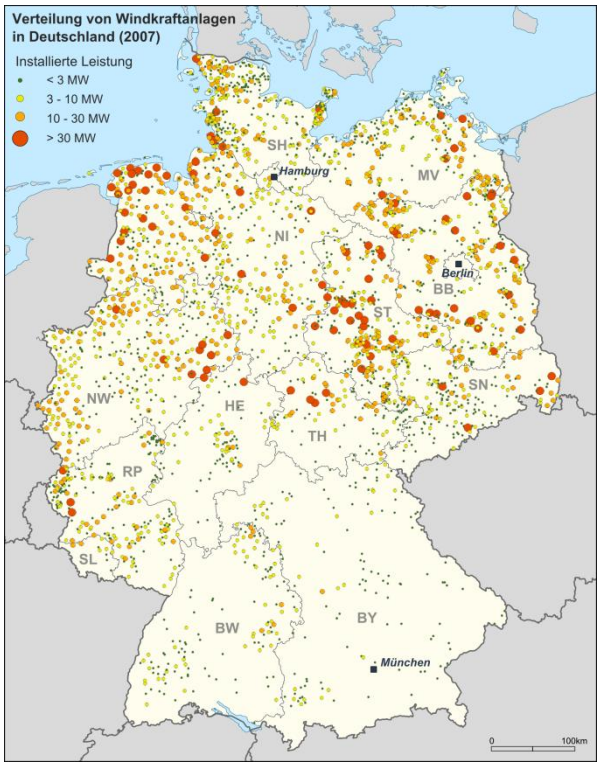


Figure 7.3: Regional distribution of operating wind farms in Germany by the end of 2007 (Source: data from the publication on the §15 paragraph 2 of the German Renewable Energy Law (EEG) issued by the grid operators Vattenfall, E.ON, EnBW und RWE).

Case Study 1: Wind Power installed capacity in Germany – Situation by June 2012

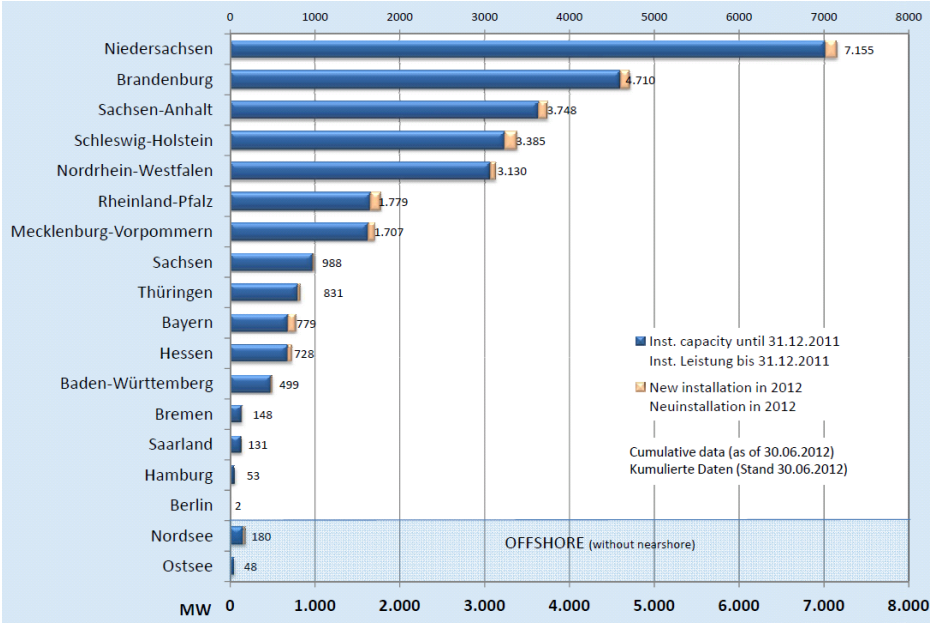


Figure 7.4: Regional distribution of German wind power capacity installed by 2012 (Source: (Ender, 2012)

The estimation of the annual energy production of the wind farms included in the first case study began with a plausibility analysis of the existing monthly production data according to the regional index. Deviating values were identified and not further considered in the analysis. Then the monthly production data was correlated with the regional monthly index to determine a variation coefficient. The variation coefficient is the rate between the effective produced energy and the calculated energy respective to the index. In practice, a variation coefficient of up to 13% is within an acceptable range. In cases where the variation coefficient was above this value, the index of other regions was tested. Finally, the monthly production data was corrected with the applied index in a procedure like the one described in the previous example to determine the long-term energy yield. The procedure was concluded with an uncertainty analysis.

The overall uncertainty of the annual energy production estimated following the described approach is delineated by four different factors:

Uncertainty of the long-term correction: This is the uncertainty related to the long-term representativeness of the index. It has to do mainly with the question of to what extent the future behaviour of the wind resource can be accurately predicted by observations in the past. The uncertainty of the mathematical approach developed to correct the long-term energy yield has also been taken into account (FGW, 2007, pg. 12).

1. ***Uncertainty of the correlation with the applied wind index:*** This is the uncertainty related to the relation between the operational data of the wind farm and the applied index, given by the variation coefficient. The higher the variation coefficient, the higher the uncertainty. In general it can be said that the higher the number of months included in the analysis and the reliability of the

index the lower the uncertainty. The uncertainty of the long-term correction combined with the uncertainty of the correlation with the applied wind index determines the ***combined uncertainty of the wind index***.

2. ***Uncertainty of the Operational Behaviour:*** The uncertainty of the operational behaviour depends mainly on the reported technical availability and the performance deviations of the different turbines. It is related to the uncertainty on whether the operational behaviour of the turbines will be the same in the future: Are the deviations related to a discrete performance disturbance or are they likely to persist?
3. ***Uncertainty of the Production Data:*** This is the statistical uncertainty of the measurement of the data. It is mainly due to deviations in the metering of the energy production. The higher the consistency and reliability of the data, the lower the uncertainty.

Table 7.1 summarizes the main results of the annual energy production re-estimations.

Case Study 1 – Annual Energy Production Estimation: Overview of the Main Results									
Wind Farms	**"G1"**	**"G2"**	**"G3"**	**"G4"**	**"G5"**	**"G6"**	**"G7"**	**"G8"**	**"G9"**
WT Type	Nordex	Nordex	Nordex	Enercon	Nordex	Gamesa	Gamesa	Gamesa	Gamesa
N° of Units	9	5	10	4	8	2	4	2	7
MW/unit	1.5	1.5	1.5	2.0	1.5	0.85	2.0	2.0	0.85
Nominal Power (MW)	13.5	7.5	15.0	8.0	12.0	1.7	8.0	4.0	6.0
Availability of Production Data (months)	47	41	47	47	41	21	15	23	19
Index Region	22	14	22	22	18	15	16	18	17
P50 (MWh/a)	16,488.0	10,882.0	28,951.0	13,242.0	19,355.0	2,948.0	12,547.0	8,846.0	7,186.0
P75 (MWh/a)	15,633.0	10,384.0	27,643.0	12,748.0	18,295.0	2,802.0	11,667.0	8,316.0	6,780.0
P90 (MWh/a)	14,899.0	9,936.0	26,465.0	12,303.0	17,340.0	2,670.0	10,876.0	7,839.0	6,415.0
Participation in the portfolio (%)	13.7%	9.0%	24.0%	11.0%	16.1%	2.4%	10.4%	7.3%	6.0%
Overall Uncertainties									
Combined Uncertainty of the wind index (long-term correction)	5.8%	5.1%	5.4%	5.2%	5.1%	5.8%	7.6%	6.7%	7.2%
Uncertainty of the Operational Behavior	4%	4%	3%	1%	6%	2%	5%	5%	3%
Uncertainty of the Production Data	2%	2%	2%	1%	2%	4%	5%	3%	3%
Overall Uncertainty of the AEP	7.35%	6.78%	6.70%	5.54%	8.12%	7.35%	10.39%	8.98%	8.37%

Table 7.1: Case study 1 - Main results of the annual energy production estimations and their uncertainties.

7.1.3. Correlation of the Uncertainties

The estimation of the portfolio variance was performed considering the co-variance of the predicted annual energy production in view of two aspects: The correlation of the applied wind index used to estimate the long-term wind resource, and the correlation of the technical availability[134].

The premise to evaluate the portfolio variance due to the correlation of the applied wind index is the understanding that the existing historical data series describes the correlation between the wind regimes considered accurately enough to support the assumption that the same trend will continue in the future.

The same understanding applies to the portfolio variance due to the correlation of the operational behaviour. The initial assumption is that the technical performances, described by the technical availability data of the first operational years of the wind farms, are unlikely to suffer considerable changes. Consequently the correlation between the technical performances of the wind farms in the future can be estimated through the analysis of data from the past.

Correlation of the wind index:

The correlation coefficient of the wind index is given by the coefficient of determination (R^2) of the linear regression realized between the available monthly BDB-indexes of the regions where the wind farms considered are located. The next tables summarize the correlation results:

Table 7.2: Overview of the wind index data availability;

Table 7.3: Overview of the correlation periods, wind index region by wind index region;

Table 7.4: Wind index correlation matrix wind farm by wind farm. This table was used in the estimation of the portfolio variance due to the correlation of energy yields with regard to the uncertainty of the wind index. The scatter plots of the correlation of the wind indexes region by region is presented in Annex C.

Graph 7.1: The graph illustrates the results of the correlation of the wind indexes applied in the estimation of the annual energy production of the wind farms addressed in the case study.

[134] See page 54.

Case Study 1 - BDB Wind Index: Overview of Data Availability			
Index Region	Wind Farms	Period of Available Data	Total of Available Months
14	"G2"	10.1990 to 07.2009	225
15	"G6"	12. 1990 to 07.2009	223
16	"G7"	06.1995 to 07.2009	169
17	"G9"	10.1997 to 07.2009	141
18	"G5", "G8"	06.1995 to 07.2009	169
22	"G1", "G3", "G4"	07.1992 to 07.2009	210

Table 7.2: Overview of the BDB index data availability periods.

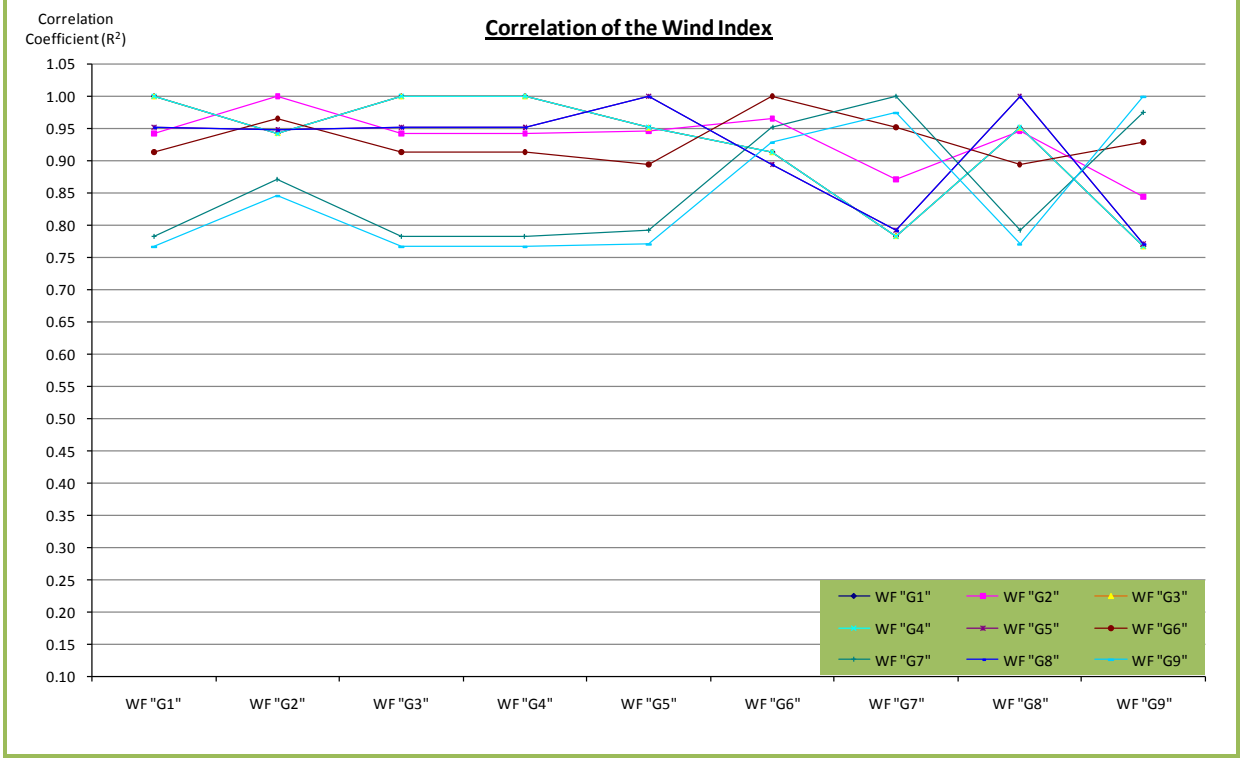
Case Study 1 –Wind Index: Number of correlated months						
Index Region	14	15	16	17	18	22
14	225	223	169	141	169	204
15		223	169	141	169	204
16			169	141	169	169
17				141	141	141
18					169	169
22						204

Table 7.3: Wind Index Correlation – Correlation period (in months).

Case Study 1 – BDB Wind Index Correlation Matrix									
Wind Farms	"G1"	"G2"	"G3"	"G4"	"G5"	"G6"	"G7"	"G8"	"G9"
"G1"	1.00	0.94	1.00	1.00	0.95	0.91	0.78	0.95	0.77
"G2"		1.00	0.94	0.94	0.95	0.97	0.87	0.95	0.84
"G3"			1.00	1.00	0.95	0.91	0.78	0.95	0.77
"G4"				1.00	0.95	0.91	0.78	0.95	0.77
"G5"					1.00	0.89	0.79	1.00	0.77
"G6"						1.00	0.95	0.89	0.93
"G7"							1.00	0.79	0.98
"G8"								1.00	0.77
"G9"									1.00

Table 7.4: Wind Index Matrix of Correlation Coefficients – Wind Farm per Wind Farm.

Case Study 1: BDB Wind Index Correlation – All Wind Farms



Graph 7.1: Correlation of the Wind Index – Wind Farm per Wind Farm.

Correlation of the Technical Availability Data:

The correlation coefficient of the technical availability data from the first operational years of the wind farms is given by the coefficient of determination (R^2) of the linear regression realized between the monthly technical availabilities. The following tables summarize the results:

Table 7.5: Overview of the period of available operational data;

Table 7.6: Overview of the correlation periods, wind farm by wind farm;

Table 7.7: Correlation of the technical availability wind farm by wind farm. This table was used in the estimation of the portfolio variance due to the correlation of energy yields with regard to the uncertainty of the operational data. The scatter plots of the correlation of the available operational data between all wind farms are presented in Annex C.

Graph 7.2: The graph illustrates the technical availability of the wind farms according to the available data.

Graph 7.3: The graph illustrates the results of the correlation of the wind indexes applied in the estimation of the annual energy production of the wind farms addressed in the case study.

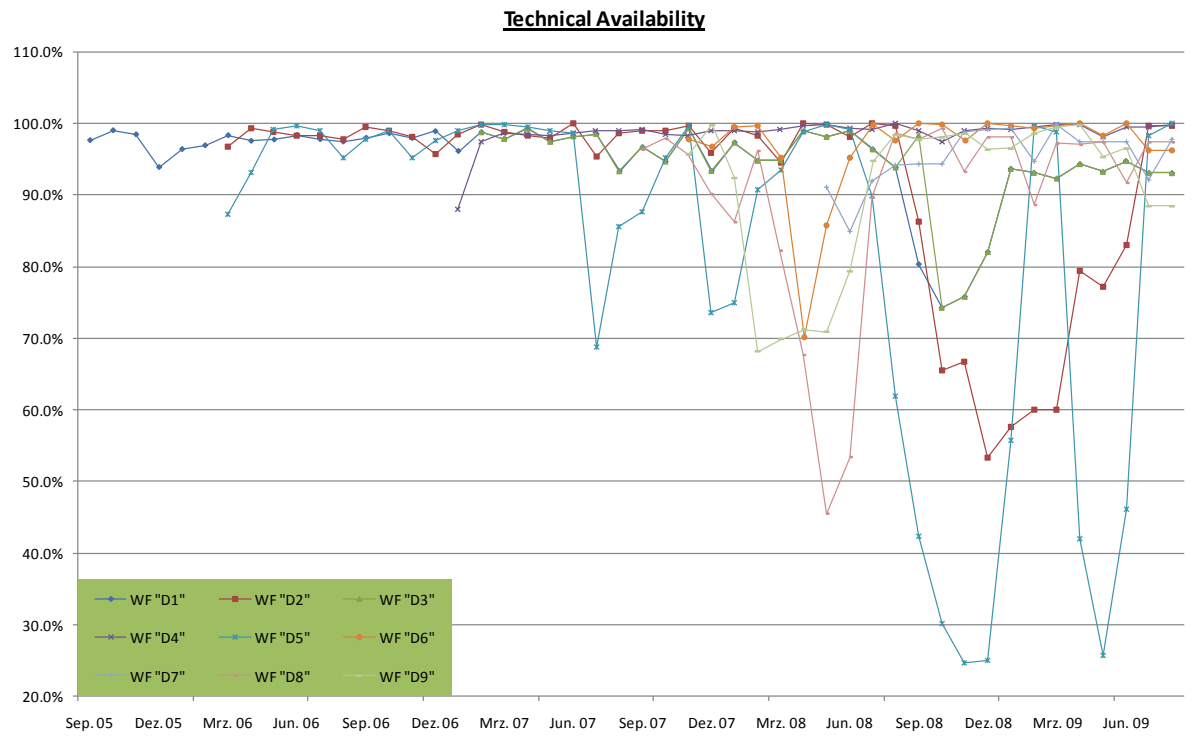
Case Study 1 – Technical Availability: Overview of Data Availability		
Wind Farm	**Period of Available Data**	**Total of Available Months**
"G1"	09.2005 to 08.2009	47
"G2"	03.2006 to 08.2009	41
"G3"	02.2007 to 08.2009	30
"G4"	01.2007 to 08.2009	31
"G5"	03.2006 to 08.2009	41
"G6"	11.2007 to 08.2009	21
"G7"	05.2008 to 08.2009	15
"G8"	09.2007 to 08.2009	23
"G9"	11.2007 08.2009	21

Table 7.5: Overview of the technical availability data available periods.

Case Study 1 – Technical Availability: Number of Correlated Months									
Wind Farms	**"G1"**	**"G2"**	**"G3"**	**"G4"**	**"G5"**	**"G6"**	**"G7"**	**"G8"**	**"G9"**
"G1"	47	41	30	31	41	21	15	23	21
"G2"		41	30	31	41	21	15	23	21
"G3"			30	30	30	21	15	23	21
"G4"				31	31	21	15	23	21
"G5"					41	21	15	23	21
"G6"						21	15	21	21
"G7"							15	15	15
"G8"								23	21
"G9"									21

Table 7.6: Technical Availability Data – Correlation period (in months).

Case Study 1: Technical Availability Data

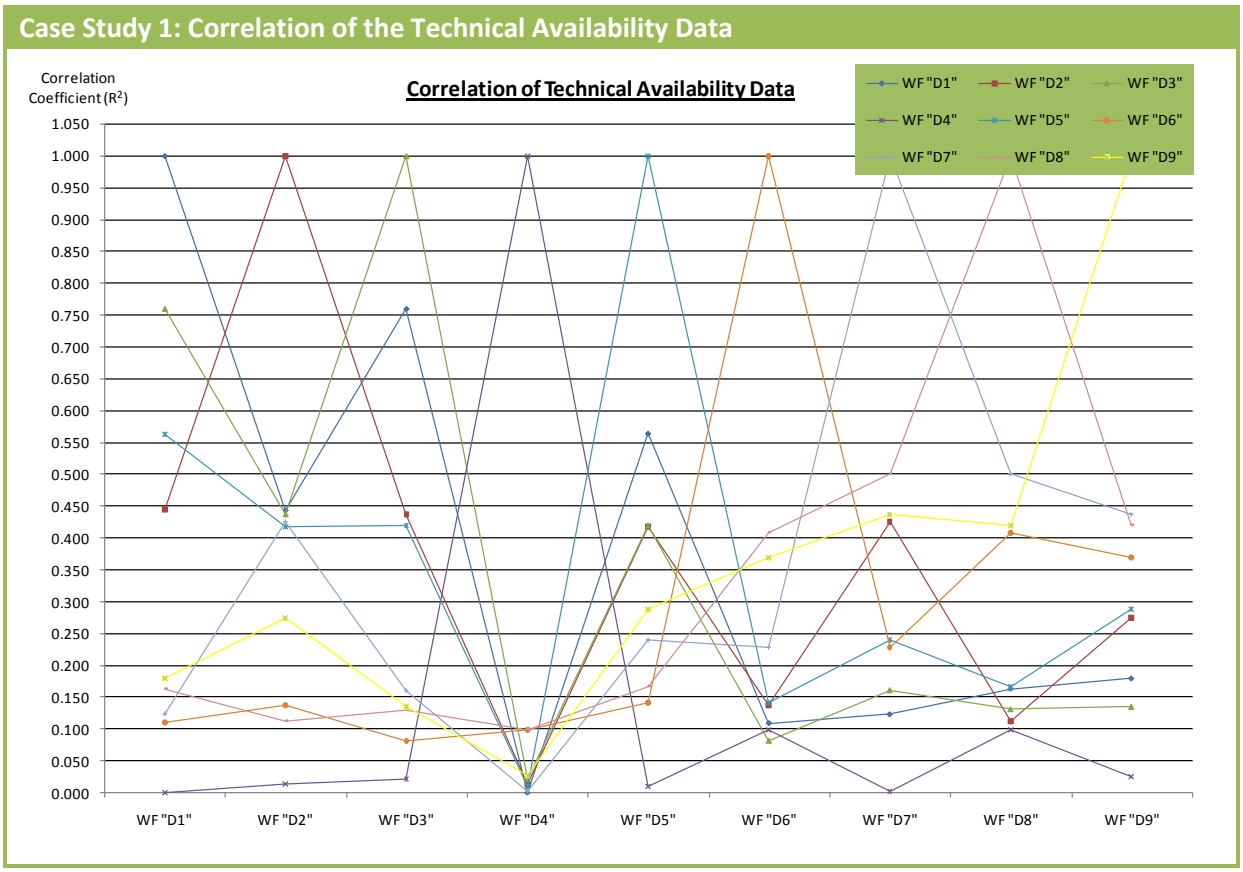


Graph 7.2: Technical Availability historical data.

Case Study 1 – Technical Availability Data Correlation Matrix

Wind Farms	"G1"	"G2"	"G3"	"G4"	"G5"	"G6"	"G7"	"G8"	"G9"
"G1"	1.00	0.44	0.76	0.00	0.56	0.11	0.12	0.16	0.18
"G2"		1.00	0.47	0.01	0.42	0.14	0.42	0.11	0.27
"G3"			1.00	0.02	0.42	0.08	0.16	0.13	0.13
"G4"				1.00	0.01	0.01	0.00	0.01	0.03
"G5"					1.00	0.14	0.24	0.17	0.29
"G6"						1.00	0.23	0.41	0.37
"G7"							1.00	0.50	0.44
"G8"								1.00	0.42
"G9"									1.00

Table 7.7: Technical Availability Matrix of Correlation Coefficients – Wind Farm per Wind Farm.



Graph 7.3: Correlation of the Technical Availability – Wind Farm per Wind Farm.

7.1.4. Estimation of the Portfolio Variances

In the first case study, the portfolio variance was estimated considering the correlation of the wind index and the technical availability data of the first operational years of the wind farm's part of the portfolio. According to the procedure described in Chapter 5, the portfolio variance was estimated following a matrix calculation approach. The matrix with the participation of the wind farms in the portfolio, the uncertainty in the annual energy production estimation due to the long-term correction procedure (wind index) and the operational data were considered, as well as the wind index and the technical availability data correlation coefficient matrixes. The results of the portfolio variances estimation are shown in Tables 7.8 and 7.9 respectively.

Case Study 1 – Portfolio Variance Due to the Correlation of the Applied Wind Index										
Wind Farms	**"G1"**	**"G2"**	**"G3"**	**"G4"**	**"G5"**	**"G6"**	**"G7"**	**"G8"**	**"G9"**	**Sum of all WFs**
Combined Uncertainty of the wind index (long-term correction)	5.8%	5.1%	5.4%	5.2%	5.1%	5.8%	7.6%	6.7%	7.2%	**5.6%**
Diversification effect taken into account:										
Combined Uncertainty of the wind index (long-term correction)					**5.5%**					
Difference					**- 1.2%**					

Table 7.8: Results of the portfolio variance estimation considering the correlation of the applied wind indexes.

Case Study 1 – Portfolio Variance Due to the Correlation of the Technical Availability										
Wind Farms	**"G1"**	**"G2"**	**"G3"**	**"G4"**	**"G5"**	**"G6"**	**"G7"**	**"G8"**	**"G9"**	**Sum of all WFs**
Uncertainty of the Operational Behavior	4.0%	4.0%	3.5%	1.2%	6.0%	2.0%	5.0%	5.0%	3.0%	**3.1%**
Diversification effect taken into account:										
Uncertainty of the Operational Behavior					**2.6%**					
Difference					**- 15.2%**					

Table 7.9: Results of the portfolio variance estimation considering the correlation of the technical availability.

As shown in Graph 7.1, and in compliance with initial expectations, the correlation coefficients regarding the part of the uncertainty on the annual energy production linked to the long-term correction procedure (wind index) are quite high.

This means that the diversification potential due to the geographical complementarities of the local wind resource of the farms is very limited. If all the uncertainties regarding the application of the wind index were simply added, not considering their correlation, the overall portfolio's uncertainty in this regard would be equivalent to 5.6%. Once the correlation coefficients are included, the uncertainty is reduced to 5.5%, a difference of 1.2%. A better result was obtained with the uncertainty of the operational behaviour.

As Graph 7.3 shows, the correlation of the technical availability data, describing the performance of the wind farms, is much lower than the correlation of the wind indexes. Consequently the portfolio variance due to the uncertainty on the operational behaviour of the turbine's part of the portfolio is around 15.2% lower than the simple sum of the uncertainties of the operational behaviour individually, or in other words, not considering the correlation coefficients.

The next section presents the results of the portfolio assessment, including an overview of the overall uncertainties in the annual energy production with and without the diversification assessment.

7.1.5. Portfolio Results

The first table summarizes the overall uncertainties of the annual energy production estimation of all wind farms, as well as the estimation of the portfolio variance. The partial uncertainties of the group of wind farms (e.g. uncertainty of the production data), once the portfolio effects are not considered (sum of all WFs column), were calculated as the weighted sum of the partial uncertainty of each wind farm. The overall uncertainty in the annual energy production of the portfolio was calculated as the square root of the quadrate sum of the partial uncertainties, according to the assumption that they are independent from each other, as detailed in Chapter 4.

As shown in Table 7.9, the overall uncertainty in the annual energy production estimation was reduced from 7.56% to 6.58% - a reduction equivalent to approximately 13%. According to the portfolio assessment approach introduced in Chapter 5, a reduction of the overall uncertainty (portfolio variance) on the annual energy production estimation of the portfolio implies an increase of the production reference values likely to be exceeded with a determined probability (75% “P75” or 90% “P90”).

Table 7.10 shows the annual energy production results. Graph 7.4 shows the diversification effect reflected in the portfolio variance.

Case Study 1 – Portfolio Variance										
Wind Farms	**"G1"**	**"G2"**	**"G3"**	**"G4"**	**"G5"**	**"G6"**	**"G7"**	**"G8"**	**"G9"**	**Sum of all WFs**
Combined Uncertainty of the wind index (long-term correction)	5.8%	5.1%	5.4%	5.2%	5.1%	5.8%	7.6%	6.7%	7.2%	**5.6%**
Uncertainty of the Operational Behavior	4.0%	4.0%	3.5%	1.2%	6.0%	2.0%	5.0%	5.0%	3.0%	**3.1%**
Uncertainty of the Production Data	2.0%	2.0%	2.0%	1.5%	2.0%	4.0%	5.0%	3.0%	3.0%	**2.4%**
Overall Uncertainty of the AEP	**7.3%**	**6.8%**	**6.7%**	**5.5%**	**8.1%**	**7.3%**	**10.4%**	**8.9%**	**8.4%**	**7.6%**

Diversification effect taken into account:	
Combined Uncertainty of the wind index (long-term correction)	5.5%
Uncertainty of the Operational Behavior	2.6%
Uncertainty of the Production Data	2.4%
Overall Uncertainty of the AEP (Portfolio Variance)	**6.6%**

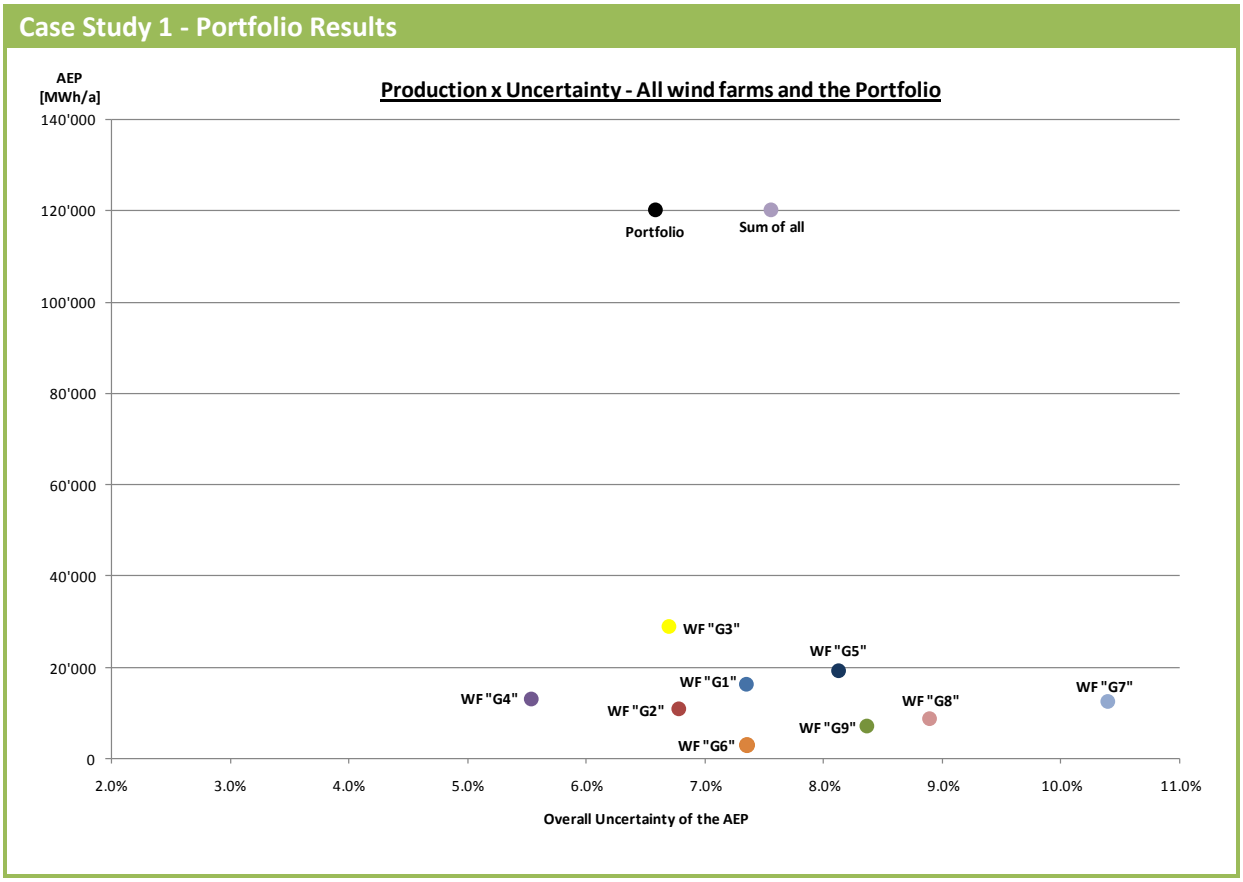
Table 7.10: Summary of the Portfolio Variance.

Case Study 1 – Portfolio Annual Energy Production					
Wind Farms	**Nominal Power (MW)**	**Net AEP (MWh/a)**	**Overall Uncertainty (%)**	**P90 (MWh/a)**	**Participation in the Portfolio (%)**
"G1"	13.5	16,448.0	7.3	14,899.0	13.7%
"G2"	7.5	10,882.0	6.8	9,936.0	9.0%
"G3"	15.0	28,951.0	6.7	26,465.0	24.0%
"G4"	8.0	13,242.0	5.5	12,303.0	11.0%
"G5"	12.0	19,355.0	8.1	17,340.0	16.1%
"G6"	1.7	2,948.0	7.3	2,670.0	2.4%
"G7"	8.0	12,547.0	10.4	10,876.0	10.4%
"G8"	4.0	8,846.0	8.9	7,839.0	7.3%
"G9"	5.95	7,186.0	8.4	6,415.0	6.0%
All Wind Farms	**75.65**	**120,406.0**	**7.6**	**108,743.0**	**100%**
Portfolio	**75.65**	**120,406.0**	**6.6**	**110,249.0**	
Diversification Effect				***1,505.1***	

Table 7.11: Portfolio's annual energy production estimation

Considering that the portfolio has a total of 51 wind turbines, the equivalent P90 value per turbine would be equal to 2,132.0 MWh/a[135]. ***A portfolio effect of 1,505.1 MWh/a (P90 of the portfolio once the diversification effect is taken into account) would be then equivalent to one additional wind turbine operating at 71% of the average portfolio's annual operational hours[136].***

The next section addresses the impact of the additional energy yield in the financing parameters and the respective investment conditions of the portfolio of operational wind farms.



Graph 7.4: Portfolio Results.

7.1.6. Analysis of the Project Financing Parameters – Case Study 1

Once the portfolio effect in terms of energy (MWh/a) has been estimated, the second part of the case study focuses on the analysis of the impact of the additional energy in the financing conditions of the portfolio. The analysis was performed with the support of the financial model

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135 $\frac{\text{P90 not considering the diversification effect: } 108{,}743.0}{51} = 2{,}132.0 \text{ MWh/a/turbine.}$

136 $\frac{1{,}505.1}{2{,}132.0} = 71\%$

described in the last chapter. The model was applied in the determination of the most important financing parameters such as the DSCR and the debt to equity ratios.

The model was initially applied separately for all the wind farms included in the portfolio. The income of the projects considered in the cash flows was based on the P90 value of the single projects, which is equivalent to a worst-case income scenario. In a second step, the parameters of the first portfolio scenario were determined assuming the portfolio income as the simple sum of the P90 of the individual wind farms. The impact of diversification has been addressed with the comparison of this scenario to the P90 of the portfolio respective to the determined portfolio variance.

Since all the projects included in the analysis are in Germany, some key input parameters such as the tariff, applied tax rate, percentage of operational costs, etc. were assumed to be the same for all projects. All the inputs of the financial model are listed in Annex C. An average total unit cost of EUR 1.2 million per installed MW is also assumed for all projects, as well as the applied debt interest rate of 4.5% and a loan life of 12 years. Other project's specific input parameters are listed in Annex C.

7.1.6.1. Financial Model Results

As discussed in Chapter 6, from an investor's point of view, one of the factors determining the economical and financial performance of a wind farm project is the ratio between the debt finance and the private equity. The debt is determined by the DSCR, or the ability of the project's cash flow to cover a certain amount of debt. For this reason, many of the comparisons discussed here assume the DSCR as a central parameter of interest.

The debt to equity ratio was adjusted in the financial models to provide an average DSCR over the loan life of around 1,28x[137]. The DSCR is dependent on the cash flow available for the debt payment CFADS. The CFADS is equivalent to the total project income reduced by the operational expenses. Therefore, the best wind farms from a financing point of view are those located on sites with a high energy production[138]. The parameter indicating the performance of one wind farm site in terms of energy production is the so called *capacity factor*.

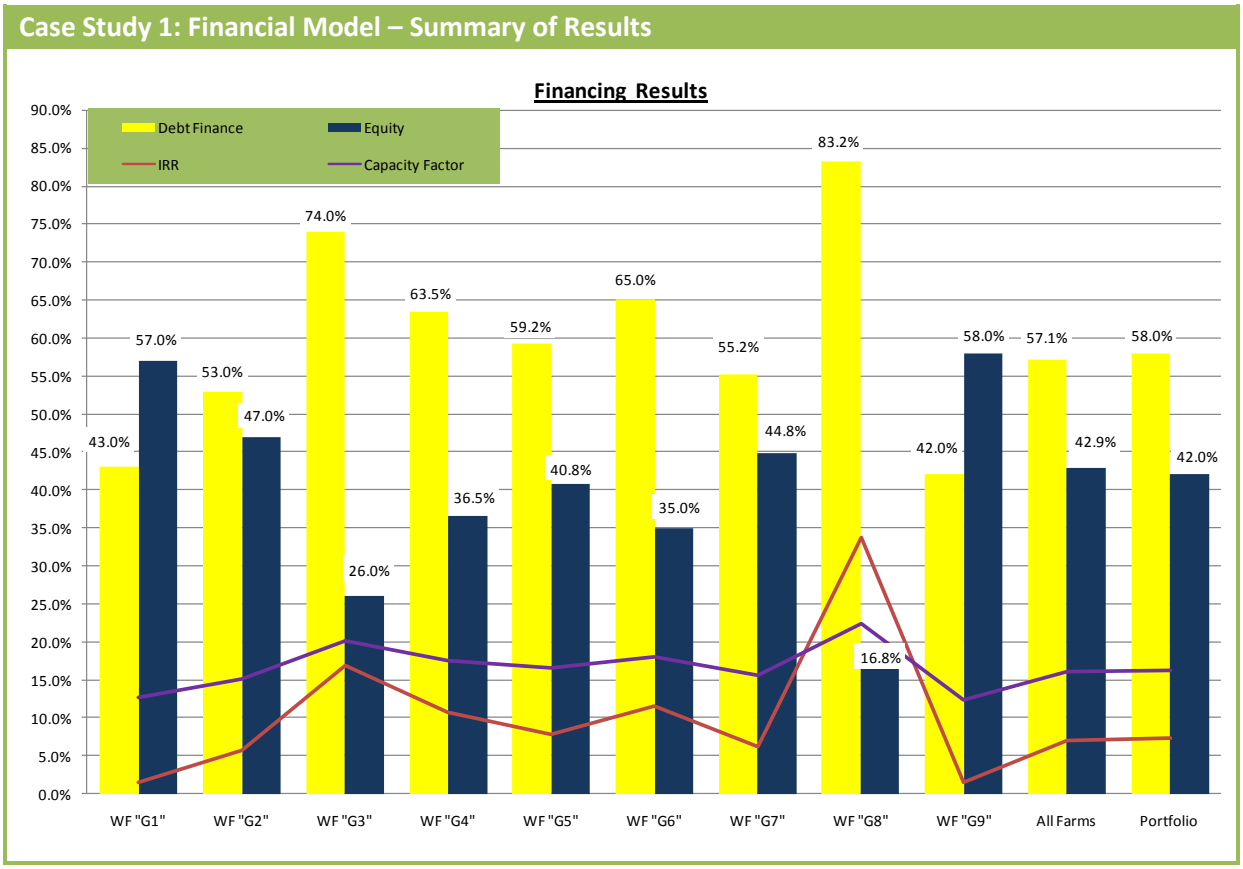
The capacity factor is the ratio between the effectively produced energy and the energy that would be produced assuming full operational hours (i.e. 8760 hours per year). In the case of the

[137] As discussed in the previous chapter, a DSCR of 1.28x is an assumption in line with current practice in the wind energy industry (developers, financiers, etc.).

[138] Considering that the assumptions of operational costs of the wind farms addressed in the case study are the same, the difference between the CFADS levels will be determined by the production income, which is a function of the wind farm's energy production.

projects addressed here, the worst case of annual energy production (P90) is estimated. Therefore, the capacity factors are also an estimation. The initial assumption of the financing assessment presented in the following is that the higher the capacity factors, the better the economical and financial performance of the wind farm. The results of the financial model applied wind farm by wind farm, to the portfolio and the portfolio once diversification is taken into account are detailed in Annex C.

Graph 7.5 illustrates the main financing results of all projects individually, and of the portfolio.



Graph 7.5: Comparison of the Debt to Equity ratios, as well as other decision parameters such as the project's Internal Rate of Return, as estimated with the financial model.

7.1.7. Summary of the Results

The similarity of the wind regimes can be seen in Graph 7.1 which shows the correlation between the long-term corrected wind indexes. The correlation of the long-term data was quite high, with values not lower than 75%. A correlation coefficient of 75% means that over the period considered the wind resource of the correlated sites only differed between sites 25% of the time. In other words, 75% of the time a wind of similar magnitude was blowing at site A and site B. A high correlation coefficient led to a modest reduction of the uncertainty in the long-term correction, from 5.6% to 5.5% - a reduction of approximately 1.2%.

The reduction of the uncertainty regarding the future operational behaviour of the turbines included in the portfolio was in comparison higher. Due to the lower correlation of the existing historical data on technical availability, this uncertainty was reduced from 3.1% to 2.6%.

Once both uncertainties are taken into account in the determination of the portfolio variance, a reduction equivalent to 13% is observed. The overall uncertainty of the portfolio not considering the diversification effect was equivalent to 7.6%. Once the diversification effect is taken into account, the portfolio variance is reduced to 6.6%. The reduced uncertainty increased the P90 value of the portfolio in 1,505.1 MWh/a. The second part of the case study then investigated the increased P90 value and the consequences to the project financing parameters.

The additional annual energy of 1,505.1 MWh meant an increase in the production revenues of the portfolio of about EUR 138,500.0 per year, or 1.4% more revenues in comparison to the sum of the revenues of all wind farms considered in the portfolio, once the diversification is neglected. The increase in the production revenues increased the parcel of the investment costs being financed by a loan from 57% to 58%. An increase in the loan is equivalent to a proportional reduction of the equity - in this case from 42.9% to 42% of the total investment costs, or approximately EUR 844,000.0. Considering that the portfolio's total investment cost is equivalent to EUR 93,160,000.00, a reduction of approx. 0.9% of this total could be achieved once the diversification effect is part of the project evaluation.

The internal rate of return of the investment in the portfolio is equivalent to 7.3%. If the investor decides to finance the wind farms individually, neglecting any sort of diversification effect, his/her total return would be equivalent to 6.9%, or 5.0% less than the portfolio alternative. The relation between the internal rate of return and the proportion of debt to equity is seen in Graph 7.5: The higher the debt, the higher the internal rate of return on the equity (e.g. wind farm "G8").

The results of the financial analysis confirmed the initial assumption that the higher the capacity factor of the wind farm, the better its financing performance. The IRR (red) and capacity factor (violet) lines following the same trend support this conclusion.

The second case study tests the main assumptions from a different perspective, as detailed in the following section.

7.2. Case Study 2: Portfolio of 9 Wind Farms Located in Different Regions Worldwide

The second case study is a portfolio analysis considering nine wind farm projects located in different regions worldwide. The wind farms are in a pre-operational phase, so that the assessment of the annual energy production is based on wind data measured at the sites. As detailed in Chapter 4, the long-term meteorology of the sites was determined within a long term correction of the short-term measured wind data by long-term reference data from meteorological stations near the sites.

The portfolio variance was estimated taking into account the correlation of the long-term meteorology of the sites. To evaluate the relevance of the wind data resolution to the correlation coefficient and therefore to the portfolio variance, two approaches were addressed:

1) At first, the portfolio variance was determined with the correlation coefficients obtained within a regression analysis of the 10-minute sets of local wind measurements accordingly scaled by the factor determined in the long-term correction analysis. As detailed previously, the long term is part of the assessment of the long-term meteorology of the sites – the central issue of estimation of the annual energy production of the wind farms.

2) The monthly average of the same data.

Differently from the first case study, the portfolio assessment of wind farms situated in different regions worldwide is focused on the evaluation of geographical diversification. The objective is to investigate the role a complementarity of wind regimes plays on the overall uncertainty around the energy production estimation of a portfolio of wind farms. As discussed previously, the structuring of the project finance conditions of a wind farm project or a portfolio of wind farm projects is strongly dependent on the energy production estimation of these projects. Therefore, to extrapolate the evaluation of the impact of geographical diversification to project finance parameters, the assessment of the portfolio variance is followed by a comparison of the financing conditions of the single wind farm projects to the financing conditions of the portfolio.

7.2.1. Location of the Wind Farms

The location of the wind farms considered in the analysis is shown below. Due to confidentiality issues, the exact location of the plants will not be further commented.

Case Study 1: Location of the Wind Farms

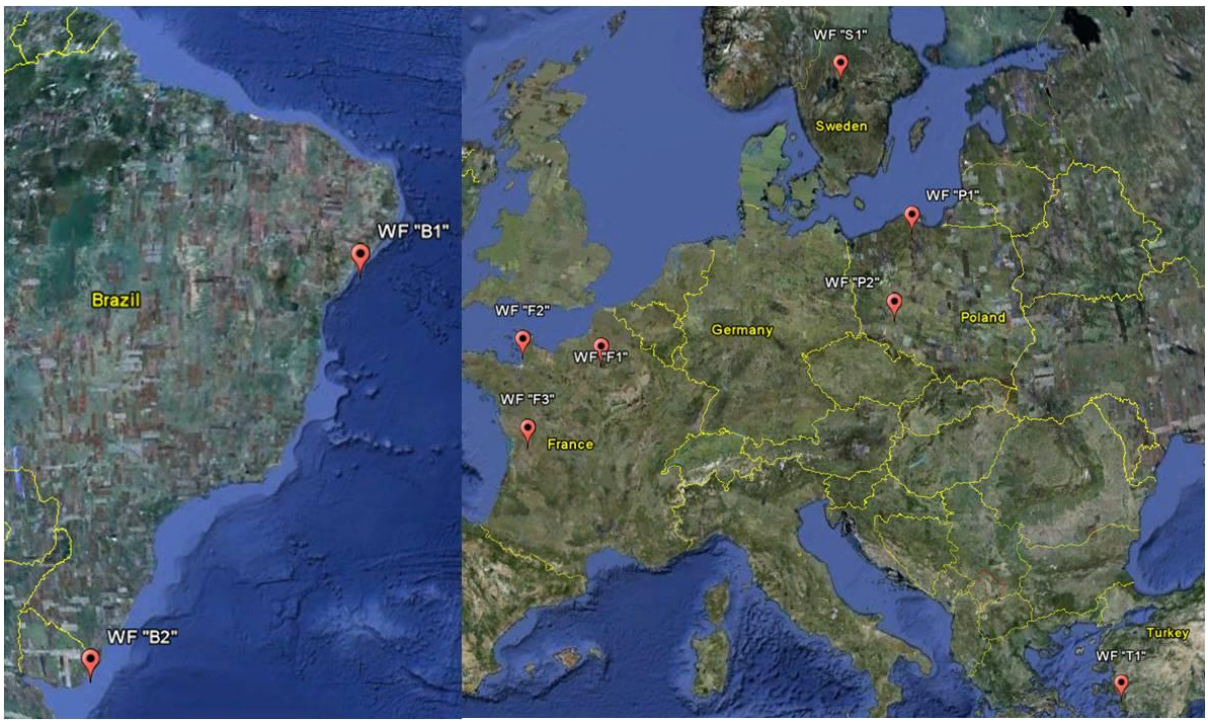


Figure 7.5: Location of the wind farms included in the portfolio analysis of the second case study (source: the author).

7.2.2. Estimation of the Annual Energy Production and the related Uncertainties

The annual energy production of the single wind farms and its related uncertainties were taken from their respective energy yield assessments. In brief:

The meteorological input data was obtained with the long-term scaling of measured wind speed and direction at the sites. The scaling factor was determined within a comparison procedure. The short-term site data was compared with long-term data from a meteorological station in the surroundings of the sites. With the purpose of selecting the best long-term reference source, the data from several meteorological stations was tested regarding its correspondence to the site data, the occurrence of long data gaps and other quality criteria. The result of this analysis is a Weibull distribution which, combined with the layout of the turbines and the topographical description of the sites, builts the input of the wind flow modelling at each turbine position. The annual energy production of the wind farms is estimated based on the output of this modelling and the power generation characteristics of the turbines described by their reference power curves.

The net annual energy production of the wind farms takes into account the losses in connection with the mutual operation of the several turbines, as well as the losses linked to the transmission of the energy from the turbine end to the grid connection point, special operational modes (e.g. noise reduced), etc. The assessment is concluded by the assessment of the uncertainties on the overall procedure. The table below summarizes the main results of the energy yield assessments.

Case Study 1 – Annual Energy Production Estimation: Overview of the main Results									
Wind Farms	**"T1"**	**"S1"**	**"P1"**	**"P2"**	**"F1"**	**"F2"**	**"F3"**	**"B1"**	**"B2"**
Location	Turkey	Sweden	Poland	Poland	France	France	France	Brazil (North)	Brazil (South)
WT Type	Nordex	Enercon	REPower	Nordex	Enercon	Enercon	Gamesa	Führländer	Vestas
N° of Units	36	2	22	17	6	5	9	12	247
MW/unit	2.5	2.0	2.0	2.5	2.0	2.3	2.0	2.5	1.8
Nominal Power (MW)	90.0	4.0	44.0	42.5	12.0	11.5	18.0	30.0	444.6
P50 (MWh/a)	300,295.0	9,975.0	113,715.0	97,280.0	24,320.0	20,235.0	48,355.0	72,960.0	1,436,400.0
P75 (MWh/a)	280,155.0	8,740.0	103,835.0	87,115.0	22,230.0	18,430.0	44,365.0	65,740.0	1,299,980.0
P90 (MWh/a)	262,010.0	7,600.0	94,810.0	77,995.0	20,235.0	16,720.0	40,660.0	59,280.0	1,177,145.0
Participation in the portfolio (%)	14.1%	0.5%	5.4%	4.6%	1.1%	1.0%	2.3%	3.4%	67.6%
Overall Uncertainties									
Wind climate related to the site	7.8%	17.7%	11.0%	11.0%	11.0%	12.0%	10.8%	13.0%	8.0%
Power Curves	6.0%	6.0%	7.0%	10.0%	6.0%	7.0%	6.0%	7.0%	10.0%
Farm Efficiency	0.6%	1.0%	3.0%	3.0%	1.0%	2.0%	1.0%	3.0%	5.0%
Overall Uncertainty of the AEP	9.9%	18.7%	13.4%	15.2%	12.6%	14.0%	12.4%	15.1%	13.7%

Table 7.12: Case study 2 - Main results of the energy yield assessments and their uncertainties.

7.2.3. Correlation of the Uncertainties

The estimation of the portfolio variance was performed considering the co-variance of the predicted annual energy production in view of the estimation of the long-term wind climate at the sites. The uncertainties on the AEP of the wind farms regarding the applied power curves and the farm efficiency calculations are assumed to follow the same trend (i.e. correlation coefficient =1).

This assumption is based on the understanding that the power curves of the wind turbines will be constant over the operational life of the wind farms, as well as the variables influencing the farm efficiency calculations (the topography of the sites, the layout of the turbines, etc.). Following this approach, the portfolio variance regarding these two partial uncertainties is assumed to be the simply weighted sum of these uncertainties wind farm by wind farm.

The premise of the portfolio variance evaluation in view of the correlation of the wind climate related to the sites is that the existing historical series of wind speed and direction data describes the correlation between the wind regimes considered accurately enough to support the assumption that the correlation of the project cash flows will follow the same degree of independency. Furthermore, the general assumption of the analysis is that the trend information described by the past data will remain the same in the future.

The next tables summarizes the period of available data used in the regression analysis determining the correlation coefficients:

Table 7.13: Overview of wind data availability – wind farm by wind farm;

Table 7.14: Overview of the number of correlated months;

Case Study 2 - Overview of Wind Data Availability		
Wind Farms	**Period of Available Data**	**Total of Available Months**
"T1"	01.1994 to 12.2007	168
"S1"	04.1996 to 02.2009	156
"P1"	02.1999 to 02.2009	120
"P2"	06.1999 to 06.2009	120
"F1"	12.1996 to 12.2008	144
"F2"	02.1998 to 02.2009	132
"F3"	06.1998 to 06.2008	120
"B1"	05.1999 to 05.2009	120
"B2"	03.1998 to 03.2009	120

Table 7.13: Overview of wind data availability periods.

Case Study 2 – Wind Data: Number of correlated months									
Wind Farm	**"T1"**	**"S1"**	**"P1"**	**"P2"**	**"F1"**	**"F2"**	**"F3"**	**"B1"**	**"B2"**
"T1"	168	140	106	102	132	118	114	103	117
"S1"		156	120	116	144	132	120	120	120
"P1"			120	120	114	116	108	119	117
"P2"				120	118	120	112	117	120
"F1"					144	130	120	115	120
"F2"						132	120	117	120
"F3"							120	109	120
"B1"								120	118
"B2"									120

Table 7.14: Wind Data Correlation – Correlation period (in months).

The total of data sets correlated in the first approach (10-minute data) can be obtained by multiplying the number of days in the month by 24 hours, and this value by 6, since in one hour (60 minutes), 6 pairs of data were available. For example:

$$30\,\text{days (approx.)} * 24\,\text{hours} = 720\,\text{hours};$$

Since every hour had a total of 6 data sets, in one month a total of 6*720=4320 data sets were included in the regression analysis. For example: Considering wind farms "S1" and "P1", a total of 120 months of wind data was available. Therefore, the correlation coefficient was obtained with the linear regression of 120*4320 data points, or a historical data series of approximately 518,400 values of wind speed.

The correlation coefficient matrix obtained with the correlation of the data with a 10-minute resolution is presented in Table 7.14. Graph 7.6 illustrates the correlation. The correlation coefficient matrix of monthly correlated data is presented in Table 7.15 and its illustration is presented in Graph 7.7. An overview of the monthly wind speeds of all wind farms over the whole correlation period is shown in Graph 7.8. Graph 7.9 is based on the monthly wind speed data for the year 2002 and aims to better illustrate the typical seasonal behaviour of wind speeds on all wind farm sites. The scatter plots of the correlation of the wind data project by project is presented in Annex C.

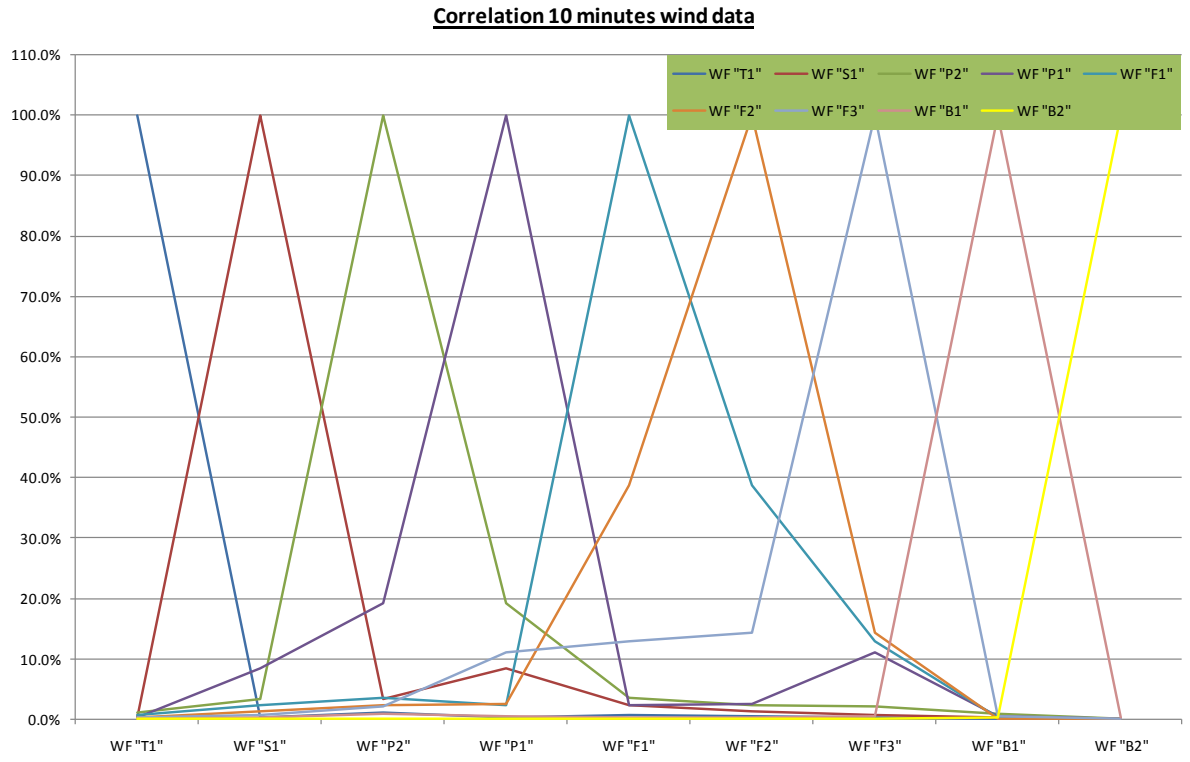
Case Study 2 – Wind data Correlation Matrix – 10-min data									
Wind Farms	**"T1"**	**"S1"**	**"P1"**	**"P2"**	**"F1"**	**"F2"**	**"F3"**	**"B1"**	**"B2"**
"T1"	1.00	0.002	0.01	0.002	0.005	0.003	0.003	0.000	0.001
"S1"		1.00	0.032	0.084	0.023	0.013	0.006	0.002	0.000
"P1"			1.00	0.191	0.034	0.024	0.021	0.008	0.000
"P2"				1.00	0.023	0.025	0.110	0.004	0.000
"F1"					1.00	0.387	0.128	0.003	0.000
"F2"						1.00	0.142	0.002	0.001
"F3"							1.00	0.004	0.000
"B1"								1.00	0.002
"B2"									1.00

Table 7.15: 10-minute resolution wind data Matrix of Correlation Coefficients – Wind Farm by Wind Farm.

Case Study 2 – Wind data Correlation Matrix – Monthly data									
Wind Farms	**"T1"**	**"S1"**	**"P1"**	**"P2"**	**"F1"**	**"F2"**	**"F3"**	**"B1"**	**"B2"**
"T1"	1.00	0.090	0.122	0.047	0.246	0.215	0.198	0.044	0.002
"S1"		1.00	0.483	0.407	0.249	0.275	0.150	0.009	0.023
"P1"			1.00	0.719	0.442	0.457	0.236	0.005	0.001
"P2"				1.00	0.202	0.259	0.114	0.006	0.002
"F1"					1.00	0.753	0.495	0.027	0.004
"F2"						1.00	0.542	0.076	0.022
"F3"							1.00	0.110	0.086
"B1"								1.00	0.322
"B2"									1.00

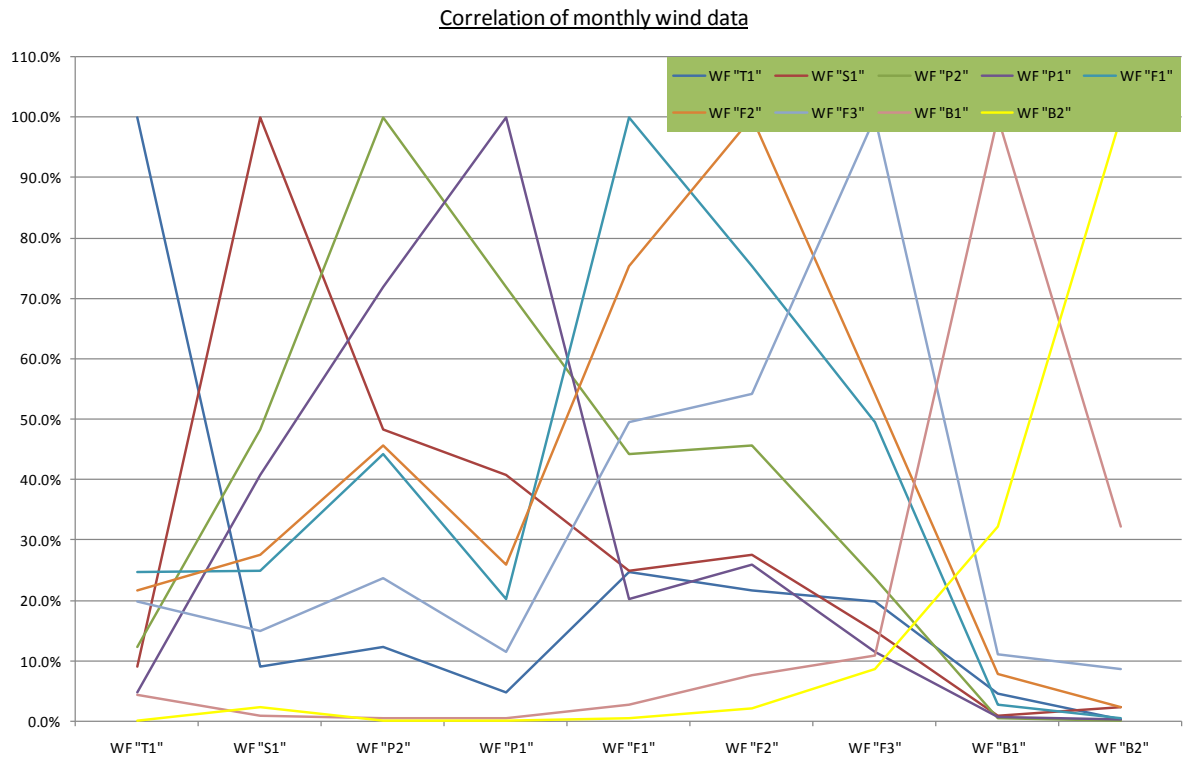
Table 7.16: Monthly averaged wind data Matrix of Correlation Coefficients – Wind Farm by Wind Farm.

Case Study 2: Correlation of 10-Minute Wind Data – All Wind Farms



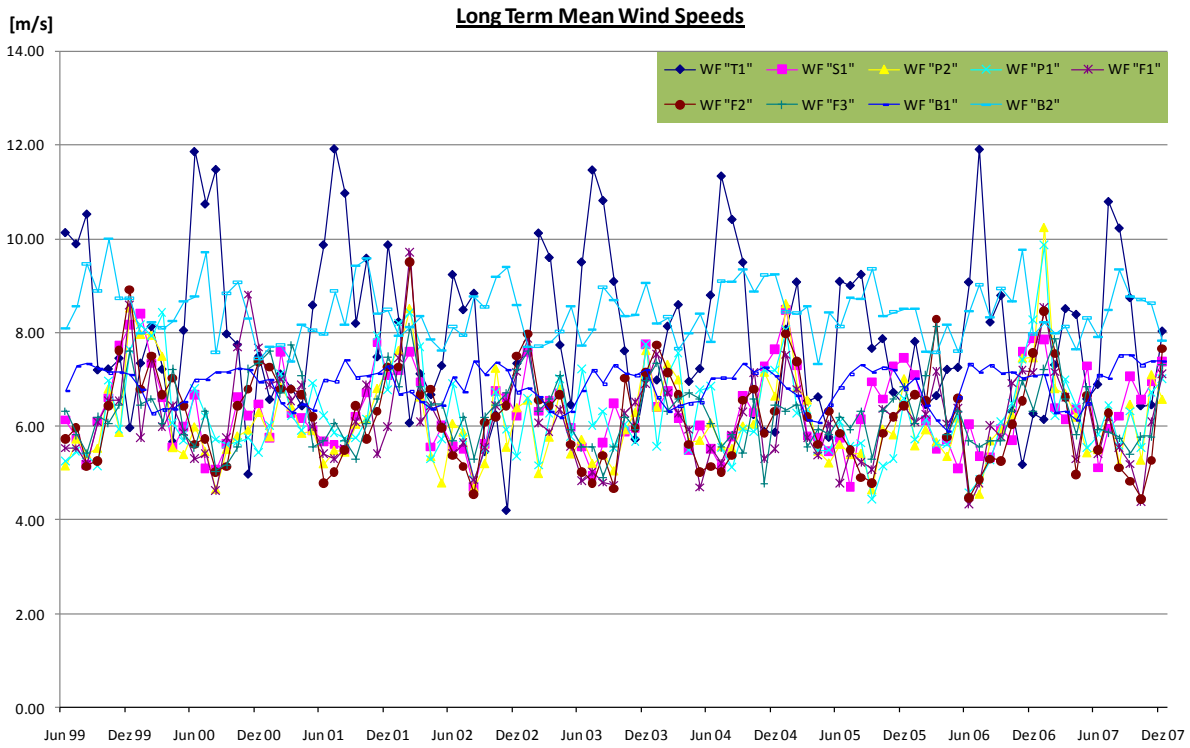
Graph 7.6: Correlation of 10-minute wind data – wind farm by wind farm.

Case Study 2: Correlation of Monthly Wind Data – All Wind Farms



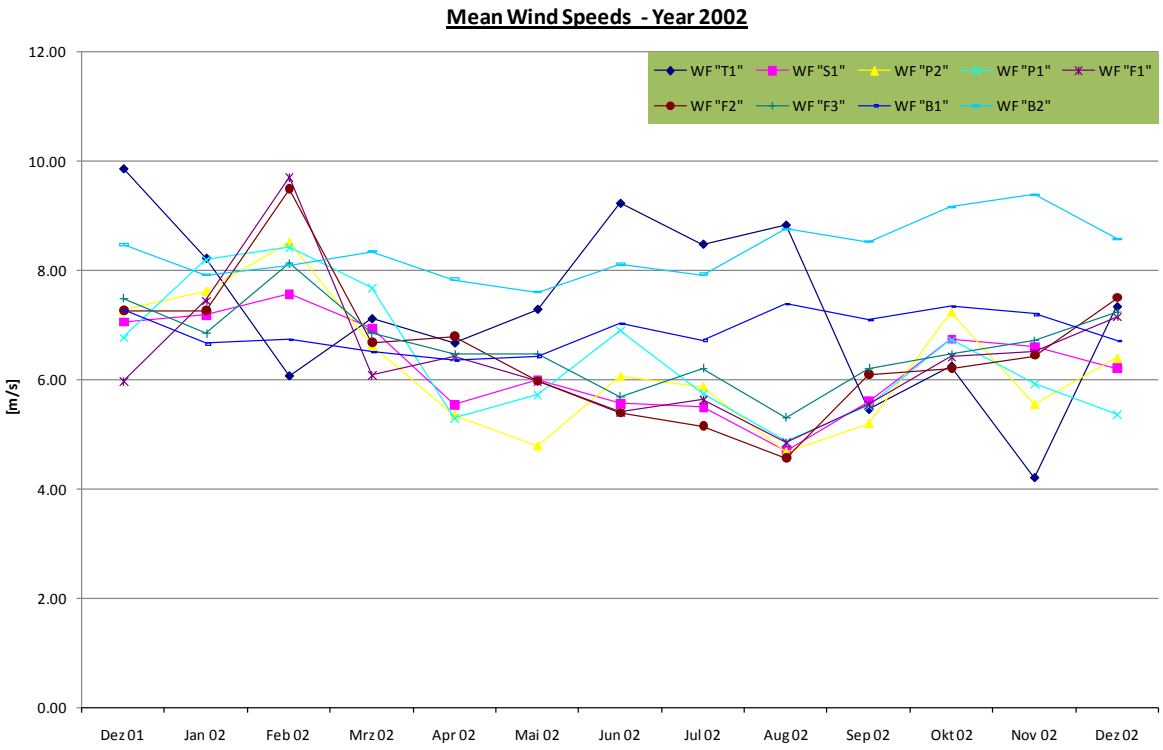
Graph 7.7: Correlation of monthly averaged wind data – wind farm by wind farm.

Case Study 2: Monthly Mean Wind Speeds – All Wind Farms



Graph 7.8: Monthly Mean Wind Speeds of all wind farms – between June 1999 and December 2007.

Case Study 2: Monthly Mean Wind Speeds in the Year 2002 – All Wind Farms



Graph 7.9: Monthly Mean Wind Speeds of all wind farms – year 2002.

As shown in Graph 7.8, the wind speed of wind farm “T1” located on the coast of Turkey presented the higher peaks of wind speeds, and a high average wind speed of around 8 m/s. The higher average wind speed is from wind farm “B2” located on the Brazilian south coast. Wind farm “B1” presented the yearly most constant wind speeds. A typical behaviour of wind speeds of sites located in central Europe can be seen in the data from wind farms “F1”, “F2” and “F3” which shows higher wind speeds in the winter in comparison to summer months.

As shown in Graphs 7.6 and 7.7, the correlation coefficients of the linear regression of data with 10-minute resolution are lower than the correlation coefficients of the linear regression with monthly averaged data.

Additionally, when comparing both graphs to Graph 7.1 (first case study) which shows the correlation of the energy production of different wind farms located in Germany, the rule of geographical diversification on the correlation of local wind speeds becomes evident. The further the wind farms are distant from each other the lower their wind speeds correlate.

7.2.4. Estimation of the Portfolio Variances

Table 7.16 summarizes the uncertainties of all wind farms, as well as the portfolio variance estimated applying the correlation of 10-minute and monthly averaged wind data.

Applying the correlation of 10-minute wind data (Variant 1), the uncertainty on the prediction of the wind climate related to the sites was reduced from 8.6% to 5.6%. The portfolio variance (overall uncertainty on the annual energy production estimation) once the diversification of wind regimes is taken into account was estimated in 11.3%. If this effect is not taken into account, the overall uncertainty on the estimation of the portfolio’s annual energy production was estimated as 13.4%.

Applying the monthly averaged wind data (Variant 2), the uncertainty on the wind climate related to the site was reduced from 8.6% to 5.8%. In this case, the portfolio variance was estimated as 11.4%.

As in case study 1, the column “sum of all WFs” is the weighted sum of the uncertainties of all wind farms, assuming that they are independent from each other. The table below presents the results of the analysis. Graph 7.10 illustrates the diversification effect.

Case Study 2 – Portfolio Variance										
Wind Farms	**"T1"**	**"S1"**	**"P1"**	**"P2"**	**"F1"**	**"F2"**	**"F3"**	**"B1"**	**"B2"**	**Sum of all WFs**
Wind climate related to the site	7.8%	17.7%	11.0%	11.0%	11.0%	12.0%	10.8%	13.0%	8.0%	**8.6%**
Power Curves	6.0%	6.0%	7.0%	10.0%	6.0%	7.0%	6.0%	7.0%	10.0%	**9.0%**
Farm Efficiency	0.6%	1.0%	3.0%	3.0%	1.0%	2.0%	1.0%	3.0%	5.0%	**3.9%**
Overall Uncertainty of the AEP	9.9%	18.7%	13.4%	15.2%	12.6%	14.0%	12.4%	15.1%	13.7%	**13.06%**

Diversification effect taken into account:		
	Correlation of 10-min wind data (Variant 1)	**Correlation of monthly averaged wind data (Variant 2)**
Wind climate related to the site	5.6%	5.9%
Power Curves	9.0%	9.0%
Farm Efficiency	3.9%	3.9%
Overall Uncertainty of the AEP	**11.3%**	**11.4%**

Table 7.17: Summary of the Portfolio Variances.

Case Study 2 – Portfolio Annual Energy Production					
Wind Farms	**Nominal Power (MW)**	**Net AEP (MWh/a)**	**Overall Uncertainty (%)**	**P90 (MWh/a)**	**Participation in the Portfolio (%)**
"T1"	90.0	300,295.0	9.9%	262,010.0	14.1%
"S1"	4.0	9,975.0	18.7%	7,600.0	0.5%
"P1"	44.0	113,715.0	13.4%	94,810.0	5.4%
"P2"	42.5	97,280.0	15.2%	77,995.0	4.6%
"F1"	12.0	24,320.0	12.6%	20,235.0	1.1%
"F2"	11.5	20,235.0	14.0%	16,720.0	1.0%
"F3"	18.0	48,355.0	12.4%	40,660.0	2.3%
"B1"	30.0	72,960.0	15.1%	59,280.0	3.4%
"B2"	444.6	1,436,400.0	13.7%	1,177,145.0	67.6%
All Wind Farms	**696.6**	**2,123,535.0**	**13.06%**	**1,756,455.0**	**100%**
Portfolio AEP – Variant 1					
Portfolio	**696.6**	**2,123,535.0**	**11.3%**	**1,815,850.0**	
Diversification Effect				***59,395.0***	
Portfolio AEP – Variant 2					
Portfolio	**696.6**	**2,123,535.0**	**11.4%**	**1,812,233.0**	
Diversification Effect				***55,778.0***	

Table 7.18: Portfolio's annual energy production estimation results.

7.2.5. Portfolio Results

Considering that the portfolio has a total of 356 wind turbines, the equivalent P90 value per turbine would be equal to 4,934.0 MWh/a[139]. In the first variant, the portfolio effect of 59,395.0 MWh/a (***P90 of the portfolio once the diversification effect is taken into account)*** is equivalent to 12 additional wind turbines running at 100% of the average portfolio's operating hours[140]. In the second variant, the equivalent in additional wind turbines would be 11.3 (11 additional turbines running at 100% of the average portfolio's operating hours and one additional turbine running at 30% of this time[141]). The rule of the period of data series applied in the estimation of the correlation coefficients

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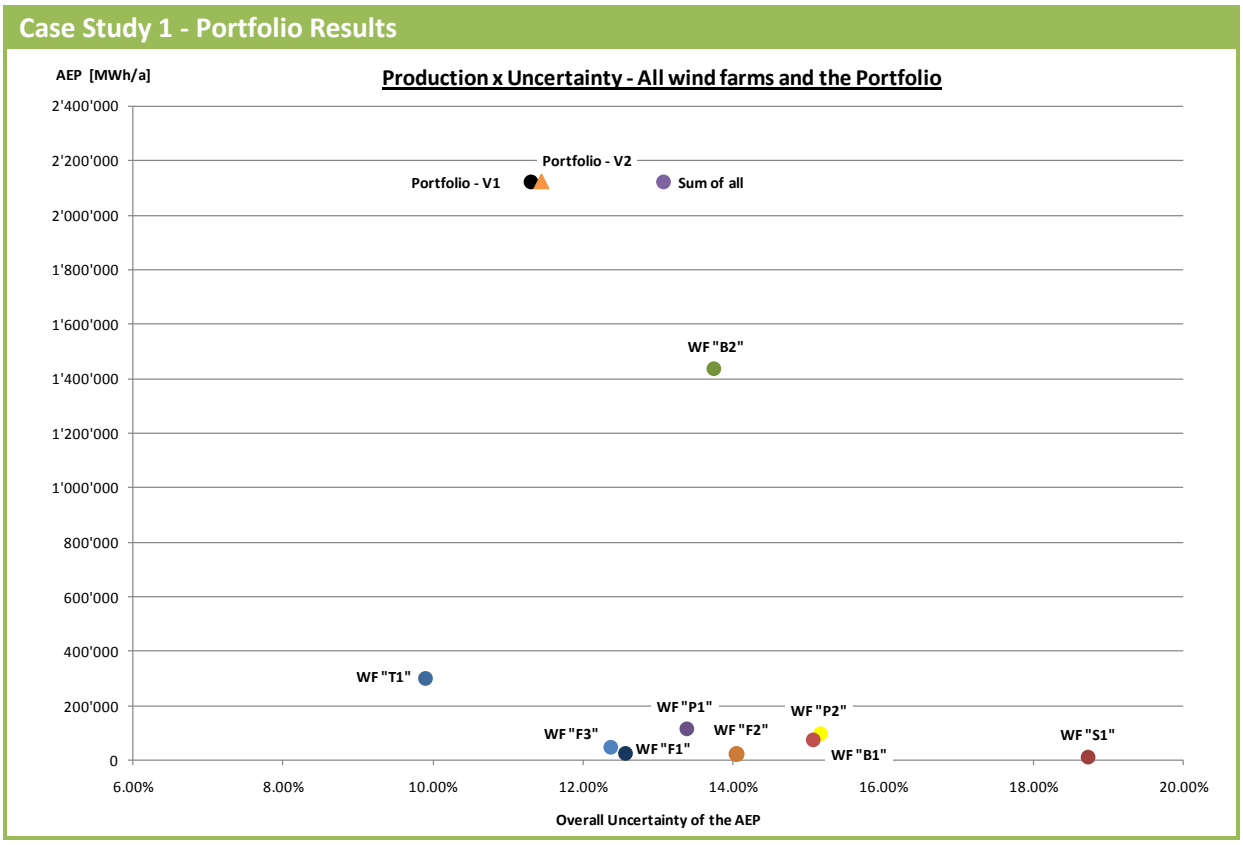
139 $\frac{\text{P90 not considering the diversification effect: } 1{,}756{,}455.0}{356} = 4{,}9340$ MWh/a/turbine

140 $\frac{59{,}395.0}{4{,}934.0} \cong 12$

141 $\frac{55{,}778.0}{4{,}934.0} \cong 11.3$

is reflected in the difference of about 3,617.0 MWh/a between the portfolio effects of variant 1 (10-min resolution wind data) and variant 2 (monthly averaged data).



Graph 7.10: Portfolio Results.

The next section evaluates the impact of the increase in the predicted annual energy production of the portfolio, once diversification is part of the analysis, on the project financing parameters of the portfolio.

7.2.6. Analysis of the Project Financing Parameters – Case Study 2

Similarly to the first case study, the analysis of the portfolio effect considering wind farm projects developed to operate under different wind regimes is complemented by the evaluation of this diversification aspect relating to the financing conditions of a portfolio of these projects.

The analysis approach is very similar to the approach of the first case study. In a first step, the project finance parameters of the individual wind farms were investigated relating to a cash flow respective to an annual energy production equivalent to the P90 of the single projects. In a second step, the same parameters were estimated assuming that the annual energy production of the portfolio is equivalent to the simple sum of the P90 of the single wind farms. The analysis concludes with the assessment of the project financing parameters once diversification is taken into account.

This scenario assumes an income respective to the P90 of the portfolio determined with the variance correspondent to the diversification analysis.

Some Input parameters of the reference financial model such as the O&M cost assumptions, depreciation, taxes, indexation rates, debt interest rate, and loan period are the same as those of the first case study. This simplification assumes that these parameters do not vary considerably from country to country[142]. In addition to that, the objective of the financing parameters analysis is the evaluation of the diversification effect and not a comparison of costs or investment conditions such as interest rate, etc. The financial model inputs are listed in Annex C.

The tariff applied in the estimation of the financing parameters of the portfolio (with and without the inclusion of diversification) is equivalent to the weighted average[143] of the local tariff of the projects. The project's specific input parameters are listed in Annex C as well.

7.2.6.1. Financial Model Results

As in the first case study, the financial model was applied to all wind farms separately, to the portfolio without assumptions of diversification, and to the portfolio once diversification is taken into account. The investigation was based on a debt finance percentage respective to a DSCR of 1.28[144].

The results are detailed in Annex C. The graph below illustrates the main financing results of the individual projects and their respective portfolios.

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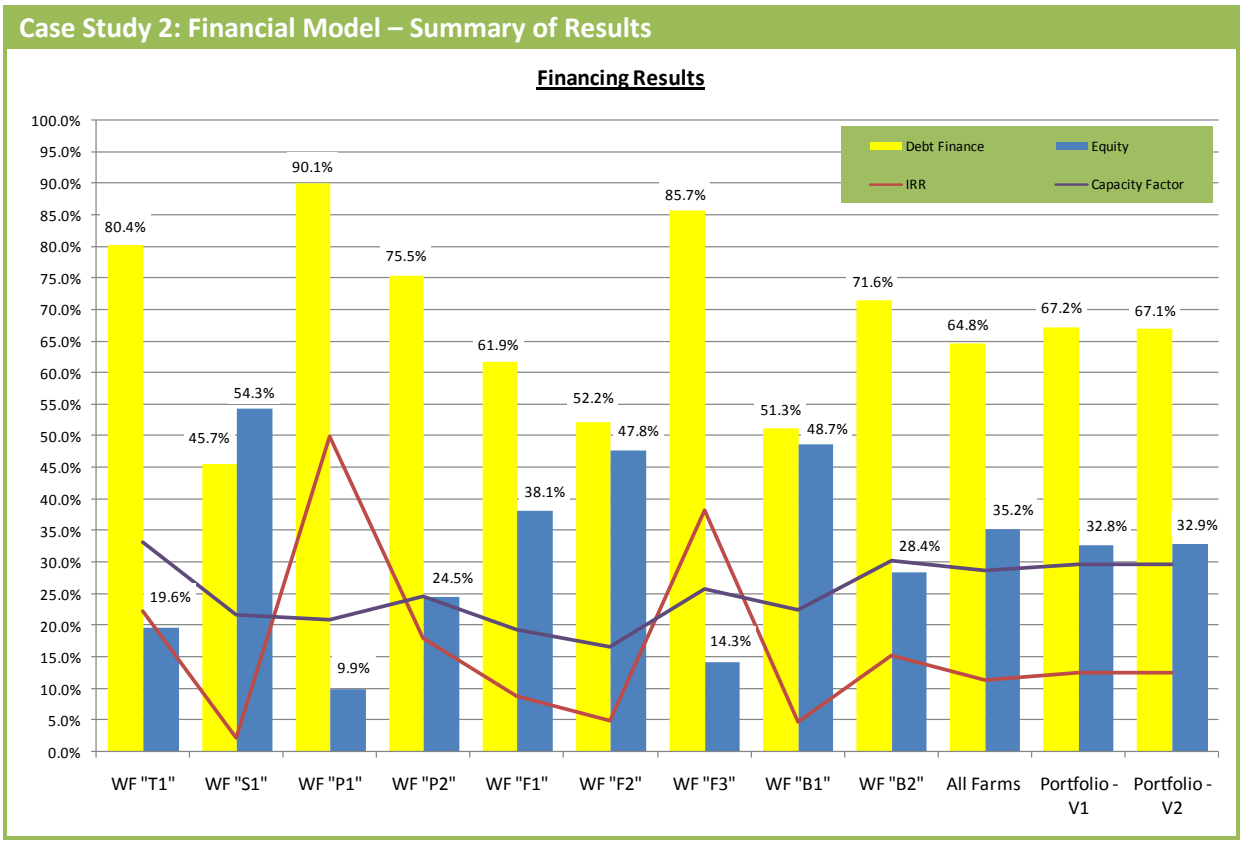
[142] The exceptions are parameters such as the applied energy tariff.

[143] $$\textbf{\textit{Weight(\%)}} = \frac{\textbf{\textit{Installed capacity of the Wind Farm}}}{\textbf{\textit{Installed capacity of the Portfolio}}}$$

[144] See for example (Borod, 2005) or (Böttcher, 2012)



Graph 7.11: Comparison of the Debt and Equity proportions, as well as the Internal Rate of Return estimated with the reference financial model.

7.2.7. Summary of the Results

The second case study assessed the diversification effect within wind farms subject to distinct wind regimes. In comparison to the first case study, where the correlation of production data of wind farms operating in similar wind regimes was addressed, the correlation of historical wind data at the sites subject to different wind regimes is noticeably lower. In both analysis procedures – using data with 10-minute resolution and monthly averaged data, the independency of wind regimes became evident. This is true especially between wind farm “B2”, located in the south of Brazil, and wind farms in central Europe, like “F1”, “F3” and “S1”.

The level of independency between the wind regimes led to significant reductions in the uncertainty of the wind climate predicted for the sites, once these are treated as part of a portfolio. Once the diversification effect is taken into account, the overall uncertainty in the annual energy production of a portfolio of projects including the analyzed wind farms was reduced from about 13% to 11%. The lower portfolio variance increased the worst-case production scenario of the portfolio (P90) in about 60,000.0 MWh. Considering all the turbines building the portfolio, this additional energy is equivalent to 12 additional turbines operating at the average operational hours of the wind farms.

The increase in the prediction of the portfolio's production had a positive impact on its financing parameters. All in all, once the wind farms are included in the portfolio, their diversification potential is reflected in the increase of the parcel of debt necessary to finance the entire capital cost of the projects. Assuming a standard debt coverage ratio of 1.28, the debt increased from 64.8% to 67.2% of the overall capital cost. The higher debt supports a reduction of the necessary equity, in this case of about 7%. From an investor's point of view, this percentage is equivalent to savings in the total investment cost of around 2.5%.

When comparing the results of the portfolio assessment applying the correlation of high resolution wind data (variant 1 – 10 minutes) to the results applying the monthly averaged wind data (variant 2), the differences in terms of energy production are noticeable, but the same cannot be said about the differences in the financing parameters. This fact can be explained by the size of the portfolio. In terms of energy production, the difference between variant 1 and variant 2 is about 3,600.0 MWh/a, which is equivalent to 0.2% of the total portfolio's worst-case annual energy production. This difference is not significant enough to have a considerable impact on the main project financing parameters of the portfolio.

In contrast to the first case study, in the second portfolio analysis the assumption that the economic performance of a wind farm is directly proportional to its capacity factor was not entirely confirmed. As seen in Graph 7.11, for the wind farms located in Poland both curves do not follow the same trend. While for wind farm "P1" the capacity factor is lower than the capacity factor of wind farm "P2", its internal rate of return is considerably higher. Since both wind farms are subject to the same tariff of 90,00 €/MWh, this difference is explained by the operational costs.

The operational costs are directly proportional to rate of total invested/n° of units. While in wind farm "P1", this rate is 2.4 million €/unit, in wind farm "P2" this rate is equal to 3.0 million €/unit. From a financing point of view, lower operational costs are reflected in a higher cash flow over the loan period, which enables an increase in the debt proportion of the capital cost financing. Higher debt leads to lower equity, which in this case is reflected in a better internal rate of return.

The analysis of the second case study has shown that multiple parameters should be taken into account when evaluating the economic performance of an investment in wind farms. The quality of the wind resource, and the level of investment and operational costs play an equally important role in the economic and financial performance of wind farms.

7.3. Comparison of Results: Case Study 1 x Case Study 2

Although the correlation of the uncertainties connected to the wind climate related to the sites was significantly lower in the second case study in comparison to the first one, the reduction of the overall uncertainty on the estimation of the annual energy production of both portfolios was within a comparable range. In the first case study, once the diversification effect is taken into

account, this uncertainty was reduced from 7.6% to 6.6% - in the second case study from about 13% to 11%.

The similar results are justified by the proportion of unsystematic risks, or the risks reducible by diversification, on the overall risk of the portfolio's production. In the first portfolio, these risks are equivalent to 85% of the overall risks, while in the second portfolio these risks are limited to 65% of the overall production risks. The difference is due to the energy yield assessment approach. In the first case study, the annual energy production of the portfolio was estimated based on the analysis of the production data of the wind farms. This data reveals not only the characteristics of the local wind regimes but also the technical performance of the turbines. In the second case study, the energy yield assessment is based on estimations of wind regime as well as estimations of technical performance, since the calculations are based on reference power curves.

The uncertainties on the applied power curves, as well as the uncertainties on the wind flow modelling and the estimations of farm efficiency represent 35% of the overall uncertainty in the annual energy production estimations. These uncertainties are by definition systematic ones. Because this is the case, the diversification potential is limited to risks in connection to the wind resource.

The limitation of diversification to unsystematic risks has been summarized by Elton in the following sentence: *"The contribution to the portfolio variance of the variance of the individual assets goes to zero as N (number of assets in the portfolio) gets very large. However, the contribution of the co-variance terms approaches the average co-variance as N gets large. The individual risk of the securities can be diversified away, but the contribution to the total risk caused by the co-variance terms cannot be diversified away."* (Elton, et al., 2007, pg.58). In the second case study, the co-variance between the risk related to the power curves, the wind flow modelling and the farm efficiency calculations is equal to 1[145], so that these terms will always be present in the estimation of the portfolio variance.

Nevertheless, the size of the portfolio of international wind farms boosted the gains from diversification.

The diversification of the wind climates related to the sites was reflected in an increase in the worst-case scenario of annual energy production (P90) of about 3%. In the first case study, the diversification of the wind regime combined with the diversification of the performance of the wind turbines was reflected in an increase of about 2% on the same yield parameter. The increase in the prediction of production led to improvements in the financing conditions of both portfolios.

[145] Since no operational information is available, the same assumption is applied to all the wind farms.

In the first case study, the reduction of the equity percentage necessary to finance the projects was limited to 0.9% of the total investment costs. The estimated internal rate of return of the portfolio of projects increased by 5%. In the second case study, the equity was reduced by 3.7%. This amount is equivalent to 2.5% lower investment costs. The lower costs resulted on an increase in the predicted internal rate of return of about 10%.

Summarizing the results of the analysis, the general conclusion is that the proportion of unsystematic risks to systematic risks is decisive to the reduction of the overall uncertainties on the estimation of annual energy production of a wind farm. As demonstrated, the level of unsystematic risk on the overall uncertainty of the annual energy production of a portfolio of wind farms is what determines the diversification's potential. The higher the availability of historical data about the inter-dependency of the several variables influencing the production of the wind farms (wind availability, performance of the wind turbines, farm efficiency data, etc.), the higher the accuracy of a diversification analysis. Where technical performance data is available, a portfolio assessment might be an important strategy to improve the financing conditions of a portfolio of operating wind farms. In parallel to that, once single wind farm projects subject to complementary wind regimes are treated as part of a portfolio of projects, geographical diversification has proved to be a valuable strategy against the production risks linked to the question *"What happens when the wind is not blowing?"*.

Finally it is important to remark that the analysis discussed here is based on assumptions not always applicable in *"real life"*. One of the most important ones is the assumption that the projects have no other potential drawbacks than the wind potential of the sites - Issues such as grid connection availability, permits, commercial bottlenecks, etc. were intentionally ignored. Further on, the assessment of financing parameters such as the internal rate of return of the projects serves solely for comparison purposes. All the assumptions necessary to illustrate the results (O&M costs, insurance, interest rate, DSCR, etc.) are mere assumptions that do not necessarily reflect the real current situation of wind farm projects.

8. Conclusion

8.1. Review of the Chapters

As discussed in the second chapter, the wind energy industry has been facing tremendous growth over the last 20 years. According to the latest statistics, the expansion is still strongly concentrated in developed countries – especially European countries. The exception to this rule is China, which showed impressive numbers in the last two years. The challenge now is not only to maintain the ascending curve in more mature markets but also, and mainly, to penetrate weak and immature markets. These markets, typically distinguished from developed markets by a great need for infrastructure investments, are characterized by a wide range of economic risks, which combined with a general lack of local capacity to adapt the technology imposes extra barriers to the development of a self-sustaining industry – a basic condition to guarantee the competitiveness of a relatively young technology such as wind energy.

To limit the success risks of a project to these risks, priority has been given to projects located at sites relying on the best possible wind resources. The current reality in leading countries shows that a strategy to improve the economic and financial performance of projects at sites with a fairly limited production capacity is the key to maintain (and increase) expansion. In addition to that, large utility companies now joining the industry are changing the profile of investors. In comparison to the traditional small to medium size wind energy investor, large utility companies with a stronger self-financing capacity are bringing alternatives, for instance portfolio financing, to traditional project financing strategy. In this context, this work focused on the analysis of the Modern Portfolio Theory as a risk management strategy applicable to investments in wind farm projects.

The analysis of the few publications dealing with this topic revealed the need for a deeper investigation of the question of whether a theory developed for the management of investments in securities is valuable for a physical asset such as a wind farm. Throughout the analysis, diversification was recognized as a meaningful strategy against the production risks involved in the operation of wind farms. Under these circumstances, the analysis went beyond a technical assessment to gain a multidisciplinary character.

In view of this multidisciplinary character, the work consisted of six main chapters. After a general introduction to the research subject, the following chapter reviewed the statistics around the expansion of wind energy worldwide, as well as recent technological developments like offshore wind farms and repowering. The objective was to examine the current status and the trend of development while highlighting the bottlenecks and the issues requiring further attention.

The third chapter focused mainly on the state-of-the-art dynamic of wind farm projects. A brief review of the physical background of the conversion of wind into power was followed by an introduction to the implementation steps of a wind farm project.

A wind farm project is typically divided into three complementary phases. A preliminary assessment deals with the assessment of the physical, legal, and commercial constraints of the site, and the project itself. Once these are interpreted as "manageable", the project goes ahead to reach a development phase.

In the development phase, the project "leaves the paper" to reach the necessary construction and operation conditions. Since many of these conditions are determined by the energy production potential of the sites, special attention was given to the assessment of this potential.

Energy yield assessments were the main focus of the fourth chapter. This part of the work reviewed two different but state-of-the-art estimation approaches. As discussed, energy yield assessments are surrounded by a wide range of uncertainties, which together determine a large part of the risky character of wind farm investments. The most relevant source of uncertainty is linked to the variable and difficult-to-predict attribute of the wind resource, which imposes volatility and insecurity to the cash flow of the projects. One strategy to deal with this uncertainty is the assignment of a probability of occurrence to determined levels of annual production.

In practice, the energy yield assessment determines the most probable annual energy production of a specific site and the overall uncertainty around this value. The most probable annual energy production builds the mean and the overall uncertainty the standard deviation of a normal distribution function. This practice allows the analysis of the projects according to different income scenarios. As recognized by different authors[146], diversification may contribute to a reduction of the overall uncertainty (standard deviation of the distribution) and the increase of the several reference production levels associated with their respective probability of occurrence. To understand how diversification works and explore its capacity to improve investments in wind farms, the fifth chapter was dedicated to the Modern Portfolio Theory.

The fifth chapter began with the review of Modern Portfolio Theory in its original concept, namely a risk assessment and management strategy to investments in financial assets. The first part addressed the mathematical relation behind the co-variances of the return of assets bundled in a portfolio and the reduction of the risk in connection to these co-variances. The Markowitz model of diversification and the characteristics of unsystematic and systematic risks were discussed. As demonstrated, diversification is limited to unsystematic risks. Therefore, a strategy to support the decision on investments given the risks not manageable through diversification - the Capital Asset

[146] See for example (Awerbuch, et al., 2003), (Dunlop, 2004) (Hulsch, et al., 2006), (Marco, et al., 2009).

Pricing Model - was another focus. In view of the link between the Modern Portfolio Theory and the practice of investment decisions, the first part of the chapter was concluded by a review of the basic principles of capital budgeting. The second part of the fifth chapter was dedicated to the analysis of the limits of the Markowitz investment selection model for assets other than financial ones. Within a review of the literature dealing with this aspect, the limits of the Modern Portfolio Theory applied to the management of investments in wind farm projects were analysed. The acknowledgement of the limitations in parallel to the conclusion that diversification is a valuable strategy to improve investments in wind farms delineated the development of a new diversification assessment approach introduced at the end of the chapter. As discussed, the assessment is initially focused on the reduction of the overall uncertainties around the energy production estimation of a portfolio of wind farms, and complemented by an evaluation of the impact of this reduction on the financing conditions of the portfolio of projects. The change of focus from the energy production to financing made it necessary to review the overall economic characteristics of wind farm projects.

The sixth chapter was therefore dedicated to this task. It begins with the review of the current capital, operational, and unit costs of wind farms. A discussion on the existing support mechanisms and the applied tariffs to wind energy projects was followed by an evaluation of the financing strategies applied by the industry so far. To extend the analysis from an energy production level to a financing level, an introduction to a financial model proposed to support this evaluation concluded the chapter.

The work was concluded with a discussion of the results of two case studies evaluating the drawbacks and the capabilities of the proposed diversification assessment approach. Being based on the analysis of a portfolio of operating wind farms, the first case study focused on the diversification of the risks imposed by the technical performance of the wind turbines. The second case study focused on the diversification of wind regimes. All in all, the case studies together with the overall analyses throughout the work supported the reflection on the research questions addressed in the sequence.

8.2. Discussion of the Research Questions

1) What limits the application of an approach designed for the risk management of investments in financial assets to a physical asset such as a wind farm?

The Modern Portfolio Theory as proposed by Markowitz is designed to support decisions on investments in financial assets such as securities. By analysing the historical development of the returns and the co-variance of the returns of a bundle of different financial assets, Markowitz demonstrated how it is possible to combine these assets in a portfolio able to meet investors' expectations of risk and return. The strategy of combining assets with complementary returns in a portfolio is guided by the principles of diversification. The co-variance is the variable measuring the

diversification potential of a pair of assets with different characteristics of return. All possible asset combinations are plotted on an risk x return space. The combination of assets best able to provide investors their expected level of return under their acceptable level of risk lies on a curve limiting efficient to unefficient combinations, *the efficient frontier*. The delimitation of this curve is the main drawback of a 1:1 approach to applying the principles of the Modern Portfolio Theory to assets such as wind farms.

This drawback is imposed by relevant differences in the nature of financial and physical assets. A financial asset such as a bond is a continuous short-term investment. Financial markets rely on a significant range of different kinds of financial assets, available daily to be exchanged. The circulation of these assets is mostly limited by the decision of an investor to trade it or not. The exchange of financial assets is not subject to the physical limits an asset such as a chemical factory, or a power plant is subject to. In this sense, the possibility of arranging all possible combinations of securities is less limited than the possibility of arranging multiple physical assets to achieve the desired conditions of risk and return.

As discussed in the section reviewing the project development process of a wind farm, the decision to choose a investment like this is firstly limited by the quality of the local wind resource: No wind, no project… However, high wind speeds do not alone guarantee the implementation of a wind farm project. The decision is in practice influenced by a wide range of issues beyond the willigness of an investor, or a mean-variance simulation. As seen in recent years, the capacity of local transmission grids, bottlenecks on the manufacturing of turbines, environemntal licensing constraints, as well as restrictions on the provision of sufficient external financing are just a few of the possible “obstacles” wind farm investors may come up against. In view of all the possible constraints, investment in a wind farm, compared to investment in a portfolio of securities, is a long term initiative. Due to the variety of necessary efforts linked to the success of a wind farm project, investment in wind farms has a rather discrete character in comparison to investment in securities.

In this sense, even to an investor able to investigate participation in multiple projects simultaneously, the decision to allocated a limited amount of funds to a combination of different projects leading to a specific expectation of return on these funds is not taken based on the outcomes of a mean- variance programme, but guided by the classic principles of capital budgeting. Therefore, the establishment of an efficient frontier of wind farm portfolios, even if mathematically possible, is far from the reality of wind energy investors.

2) ***Once the limitations of applying an approach designed for financial assets to a physical asset like a wind farm are taken into account, is diversification a relevant strategy to improve the investment conditions of wind farms? If yes, to what extent?***

As demonstrated in the case studies concluding this work, diversification is still a valuable strategy against the income risk involved in wind farm projects. The benefits of diversification are however clearly limited to the level of unsystematic risks of these projects.

As thoroughly demonstrated by Markowitz, Sharper and Litner, diversification is a relevant way to minimize the risks specific to a certain asset. All the other risks, imposed by general conditions of the economy and therefore affecting most investments, are better evaluated using other techniques, such as the Capital Asset Pricing Model.

In the case of wind farms, the wind resource is seen as the greatest source of uncertainty in an investment decision process. Since the local wind resource is one of the most distinct characteristics of a specific site, investing simultaneously in different sites subject to complementary wind regimes might be a way to reduce this uncertainty.

Beyond the wind, the technical performance of the turbines is another relevant source of uncertainty. The experience of leading countries has shown that much of this uncertainty is manageable through efficient contracting. In combination with insurance, the inclusion of performance guarantees in the sales and operation and maintenance contracts of wind turbines and wind farms is becoming a frequent strategy to offset this sort of technical risk. However, these strategies require not only experience, but also effective management. They are therefore far from a reality in young markets. For this reason, the assessment of the complementarity of this kind of technical risk through the analysis of the energy production of operating wind farms might be as relevant as the complementarity of wind regimes, as seen in the comparison of the two case studies previously mentioned.

Issues such as equipment supply conditions, local grid access, conditions of energy offtake (e.g. renewable energy mechanisms such as the EEG in Germany or the PTC in the U.S.), efficiency of operation and maintenance, as well as political issues are mainly systematic risks. These are not particular to an specific site but apply, in general, to most of the projects.

Therefore, in view of a sufficient complementarity of unsystematic risks such as the wind regime or the technical performance of the equipment, diversification might be an alternative to improve the risk characteristics of wind farm investments. Investors pursuing more than one wind farm project at the same time might benefit from a portfolio finance strategy. Nevertheless, in view of the systematic risks not manageable with diversification, it is clear that decisions on these investments are guided and will continue to be guided by capital budgeting practices. In this sense, diversification adds a new perspective to the search for ways to improve the competitiveness of wind farm projects, but there is still much to be done.

8.3. Outlook

One of the main obstacles against the consolidation of diversification as a risk management practice to wind farm investments is the availability of past production reference data. One of the alternatives to deal with this problem would be the establishment and the maintenance of databases relying on production information from existing projects. Investors active in different countries, as well as large utilities, might directly benefit from a reliable source of information on the production potential of their already operating sites.

The analysis developed here discussed among other issues the limitations of the Modern Portfolio Theory once applied to other assets than financial ones. The focus on wind farm projects limited part of the analysis to the assessment of the complementarity of wind regimes as a risk management strategy. A further step on the evaluation of strategies to promote the expansion of renewable energy in line with the findings of the present work would be the assessment of the interdependency between wind and solar power as natural resources subject to uncertainty. The same applies to "fuel-dependent" renewable technologies like biomass and small hydro plants, whose production potential is much more flexible than the production potential of wind or solar power plants.

Assuming that wind or solar power plant projects are treated as "weak" investments in view of their "inflexible" character, and biomass or small hydro power plants as "strong" investments in view of its "flexible" character, it would be interesting to address the question: To what extent are investors open to supporting their investment decisions on "weak" projects solely with the compensation potential offered by "strong" projects?

Back to the context of wind farms, the general conclusion of the analysis addressed here is that the Modern Portfolio Theory alone cannot provide the answer to all the questions involved in the decision process of this kind of investment. The uncertain character of an asset like a wind farm and the urgency to improve its attractiveness requires further research on risk management strategies. An extension of the discussion introduced here regarding the assessment of the potential and the limitations of investment decision theoretical backgrounds when applied to wind farm investments could be for example an evaluation of Real Options techniques[147] as an alternative to deal with the uncertainties not manageable through diversification.

[147] See for example (Frølunde et al., 2010)

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Annex A

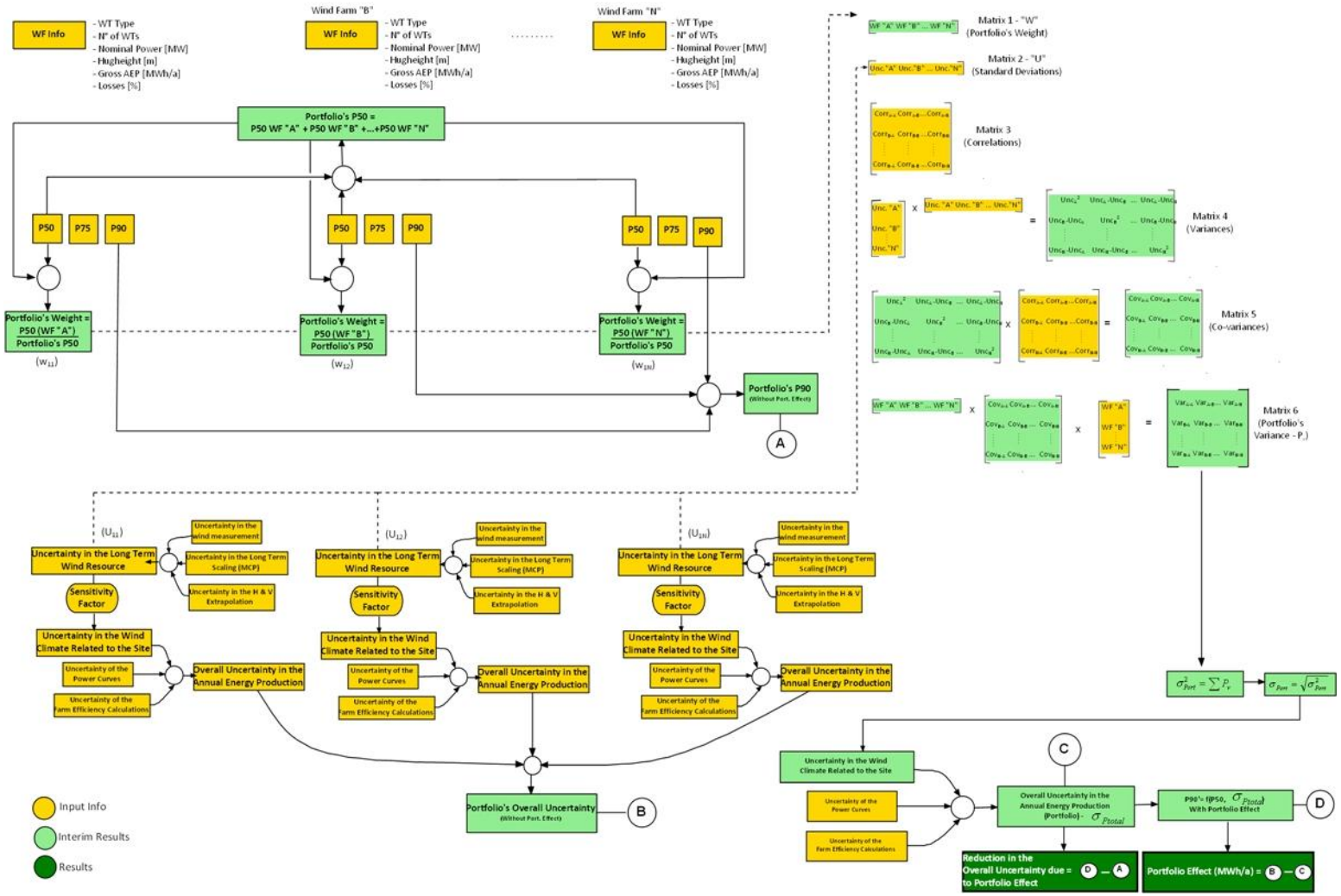


Figure A.1: Topology of the Portfolio Effect Quantification Approach. (Source: the Author)

Annex B

This annex details the project finance model developed for the analysis of the financial parameters of the portfolios assessed in the case studies.

B.1 Basic Assumptions

The first part of the model provides all the necessary input information for the following calculations. The information is divided between the information regarding the income of the wind farm, like energetic production and the applied tariff, its investment costs, operational costs and the basic conditions of the loans like duration and applied interest rate. The figure 6.4 summarizes all the inputs. The assumptions are based on the information from the previous sections. The illustrative example shown below, concerns a wind farm with 36 turbines equivalent to a total installed capacity of 90 MW, and a total unit cost of 1,4 million Euros/installed MW.

Topology of the Financial Model

Assumptions

Revenues	
N° of Units	36
Power/Unit	2.5 MW/unit
Total Capacity	90 MW
Net Production	300.000 MWh/y
Tariff	60,00 €/MWh
Indexation of the Tariff	2%
Interest Rate on cash Balance	2%
Investment Costs	
Total Unit Cost	1.400.000,0 €/MW
Total Investment Costs	126.000.000,0 €
Operational Costs	
% of total invest. costs (yr. 1-5)	2.5%
% of total invest. costs (yr. 6-20)	5.0%
Indexation of the operational costs	2%
Insurance	13%
Land Lease	18%
Service and Spare parts	26%
Administration	21%
Electricity	5%
Miscellaneous	17%
Decomissioning	1.500,0 €/MW/y
Others	
Depreciation Period	16 years
Depreciation	7.875.000,0 €/y
Taxes	35% (of profit)
Taxes Exemption Amount	0%

Senior Debt	
Percentual of total Debt	78%
Loan Life	12 years
Debt Interest	4.5%
Opening Balance	98.280.000,0 €
Repayment	8.190.000,0 €
Private Equity	
Percentual of total Debt	22%
Opening Balance	27.720.000,0 €

Figure B.1: Financial Model - Model assumptions subpart. (Source: the Author)

Revenues: In the example, the calculations were based on a net production of 300.000 MWh/a and a tariff of 60,00 €/MWh to be corrected by an inflation index of 2% a year. It is assumed that the

project has a tariff guarantee for its entire operational life and that no reductions or increases (apart from indexation) will occur over this period. The interest to be paid on the cash available in the wind farm's account is also 2%.

Investment Costs: Investment costs (capital costs) are relative to all capital expenses necessary to build the wind farm. It includes the turbines, the civil and electric works as well as grid connection costs, consultancy and permitting costs. Assumed is a unit cost of 1.400.000, 0 €/MW installed, meaning a total investment cost of 126 million Euros. This is the equivalent amount that will be partially financed by a bank loan and the equity of the investor.

Operational Costs: The operational costs are assumed to be equivalent to 2,5% of the total investment costs in the first five operational years of the wind farm, and increase to 5% after its sixth operational year. An indexation of 2% is also considered in the calculations.
To illustrate how much every operational activity accounts for the total costs, the individual costs are calculated yearly according to the percentage values available in the specific literature (DEWI GmbH, 2002).

Depreciation: Depreciation costs are the costs relative to the reduction of the initial value of the turbines and the wind farm's infrastructure. It has to do with the usage and the level of degradation of the turbines, as well as the technological outdating of the technology over the operational years of the wind farm. Erich Hau considers a linear depreciation of 16 years (Hau, 1988, pg. 768), which means that for example, a wind farm with a total investment cost of 126 million Euros, will have a value reduction of about 7,8 million per year (Hau, 1988).

Taxes: The taxation structure, and with this the amount of taxes to be paid during the operation of wind farms, depends strongly on the local tax structure. Therefore in the cash flow simulations, an assumption of 35% income tax is taken into account (Brealey, et al., 2010, pg. 165). No tax exemptions or deduction of losses are being considered.

Senior Debt: In project finance the loans are usually provided simultaneously by more than one bank or investor. These loans are classified as senior or junior debts. The main difference between both is the interest rate and the priority of payment. Senior debts have top repayment priority followed by junior debts and private equity contributions. Therefore, junior debts are subject to higher interest rates. Although a junior debt could have been easily integrated to the model, the financial analyses

developed here follow a simple approach. For this reason, only senior debts are considered in the analyses.

The percentage of debt is originally set to a determined value, i.e. 70%, as a kick-off to the calculations. The final value is one of the main output information and will be obtained by setting the DSCR to a desirable value.

The input cell with the loan life is variable. The values can be set between 10 and 17 years, so a sensitivity analysis with this value can be performed. The simulations described here applied a loan life of 12 years.

The input cell with the debt interest is variable as well, ranging from 0 to 10% so that sensitivity analyses can be easily performed. In the simulations, a fixed value of 4,5% is taken into account.

The opening balance is the product between the total investment cost of the wind farm and the debt finance percentage. It is the whole amount to be taken as a loan. The repayment parcels are obtained by dividing the opening balance by the loan life (eq. B.1).

$$\boldsymbol{Repayment} = \frac{\boldsymbol{Opening\ \ Balance(€)}}{\boldsymbol{Loan\ \ life(years)}} \qquad \text{(Eq. B.1)}$$

Equity: The amount of private equity to finance the project is the difference between the total investment cost and the opening balance of the senior debt. The percentage value is automatically set according to the expression 100%-percentage of the senior debt. The equity parcel is one of the main outputs of the simulations.

B.2 Cash Flow

The cash flow is the core of the financial model. In the cash flow the production revenues, as well as all the expenses, are summarized so the amount of cash available for the repayment of the debt and distribution of equity can be estimated. The figure 6.5 illustrates how the calculations were structured. A detailed description of all cash flow calculations is given in the sequence.

Cash Flow Waterfall

Cash Flow Waterfall

	Year 1	...	Year 12	...	Year 20
Revenues					
Production	300.000,0		300.000,0		300.000,0
Tariff	60,0		74,6		87,4
Production Revenues	18.000.000,0		22.380.737,6		26.222.601,1
Operating Costs					
Insurance	(-409.500,0)		(-922.327,0)		(-1.080.653,1)
Land lease	(-597.000,0)		(-1.277.068,2)		(-1.496.288,9)
Service and Spare Parts	(-819.000,0)		(-1.844.654,0)		(-2.161.306,2
Administration	(-661.500,0)		(-1.489.912,9)		(-1.745.670,4)
Electricity	(-157.500,0)		(-354.741,2)		(-415.635,8)
Miscellaneous	(-535.500,0)		(-1.206.120,0)		(-1.413.161,8)
Decomissioning	(-135.000,0)		(-167.855,5)		(-196.669,5)
Total Operating Costs	**(-3.285.000,0)**		**(-7.262.678,8)**		**(-8.509.385,7)**
Operating Income	**14.715.000**		**15.118.058,8**		**17.713.215,4**
Taxes	**(-846.090,0)**		**(-2.406.078,1)**		**(-3.443.375,4)**
Cash Flow Available for Debt Service (CFADS)	**13.868.910,0**		**12.711.980,7**		**14.269.840,0**
Debt Service -Senior					
Principal Repayment	(-8.190.000,0)		(-8.190.000,0)		-
Interest	(-4.422.600,0)		(-368.550,0)		-
Total Debt Service	(-12.612.600,0)		(-8.558.550,0)		-
Average DSCR 1,29x **DSCR**	1.10x		1.49x		-
Proceeds Account Balance					
Opening Balance	-		-		-
Additions	1.256.310,0		4.153.430,7		14.269.840,0
Interest Earnings on Dec. Account	2.700,0		40.285,3		78.667,8
Cash Avail. for DSRA	1.259.010,0		4.193.716,0		14.348.507,8
DSRA out/in	(-6.122.025,0)		4.279.275,0		-
Cash Avail. for Equity Payment	-		8.472.991,0		14.348.507,8
Cash Transfered to Equity Payment	-		(-8.427.991,0)		(-14.348.507,8)
Closing Balance	-		-		-
Distribution Tests					
DSCR 1.25x	-		1.0		1.0

Figure B.2: Financial Model - Cash Flow Waterfall subpart. (Source: the Author)

Revenues: Is the product between the total energy produced in the year (MWh/a) and the tariff paid for it. It could include the payment for the provision of additional services, like for instance, ancillary services, but due to the simple character of the simulations these are not included.

Total Operating Costs: Is the sum of all partial operational costs, including the amount to be deposited in the decommissioning account. The decommissioning costs are the costs related to the future disassembly of the wind farm and are assumed to be of 1.500,0 €/MW installed. The decommissioning costs are not classic running costs. They are yearly deposited in a reserve account subject to interests that will be accounted as additional earnings as seen later on.

Operating Income: Is the difference between the production revenues and the total operating costs.

Cash Flow Available for Debt Service (CFADS): Is one of the key output values of the model and equal to the operating income minus taxes. In other words, the CFADS is the amount of cash

available after the payment of all obligations in the period. It is the cash available to the repayment of the debt, the payment of interests, the coverage of a reserve account and other obligations.

Senior Debt Service: Is the addition of the repayment and the interest of the period. In this part of the cash flow, the DSCR of the period is calculated. It is the ratio between the Cash flow available for debt service and the debt service itself. The average DSCR is the average of the DSCR of all periods within the loan life.

Proceeds Account Balance: In this part the cash available after the payment of the senior debt service will be balanced with the income from other sources then the production revenues, and the debt service reserve account (DSRA). Moreover, the DSCR distribution test is performed. Due to the importance of this part to the comprehension of the model, the sub items of the proceeds account balance will be detailed separately:

a) Opening Balance: It is effectively the cash available in the project's account at the beginning of the analysed period. The opening balance is equal to the closing balance of the last period. Therefore, in the first year, or first accounting period, the opening balance is equal to zero, since no payments were either received or made.

b) Additions: The additions are equal to the CFADS minus the senior debt service. It is effectively all the cash available in the project's account related merely to the project's activities. It does not include interests or premiums coming from reserve accounts or any other types of investment.

c) Interest earnings on Decommissioning Account: It is the interest from the cash decommissioning account cash deposits.

d) Cash Available for DSRA: It is the additions plus the interest earnings on the decommissioning account. It is the total cash available at the project's account.

e) DSRA out/in: Is the balance of the Debt Service Reserve Account. It is the difference between the required balance minus the opening balance.

f) Cash Available to Equity Payments: This interim result value is conditional to the required balance of the reserve account. If the sum of the cash available for DSRA and the DSRA out/in is negative, more cash should be available in the reserve account than actually is, and the cash available to

equity payment is set to zero, meaning that no equity will be repaid in this period. If the sum is positive, the balance of the reserve account is positive and will be available to be transferred to the repayment of the equity. The question on whether it will be transferred or not is answered by the testing of the next condition.

g) Cash Transferred to Equity Payments: In this line, the DSCR of the period will be tested. The model was designed in a way that a minimum DSCR is required to permit the transference of the cash in the wind farm's account to the equity investor. If the period indicates a DSCR smaller than the minimum requested the cash is available but will not be transferred, since the reserve account must be covered. If the DSCR is higher or equal to the required then the balance can be transferred to the payment of equity.

h) Distribution Test: This line has the input of the minimum DSCR required to permit the transfer of the available cash to equity payments. In the simulations the minimum required DSCR was set to 1,25x. The DSCR of every period is tested. If it's higher than the required 1,25x, the cash transferred to equity payments is equal to the cash available to equity payments. If it's lower than 1,25x, the cash transferred to equity payments is set to zero. 1.25x is a mere assumption.

B.3 Profit & Losses

This is a small part of the model and summarizes the main results. The figure 6.6 illustrates how it is built. As with the other parts of the model all containing lines will be shortly summarized.

Profit and Losses

Profit & Losses

	Year 1	...	Year 20
Total Revenues	18.000.000,0		26.222.601,1
Total Operating Costs	(-3.285.000,0)		(-8.509.385,7)
EBITDA	14.715.000,0		17.713.215,4
Depreciation	(-7.875.000,0)		(-7.875.000,0)
Interest	(-4.422.600,0)		-
Profit Before Taxes	2.417.400,0		9.838.215,4
Taxes	(-846.090,0)		(-3.443.375,4)

Figure B.3: Financial Model - Profit and losses subpart. (Source: the Author)

Total Revenues and Operating Costs: Lines "production revenues" and "total operating costs" of the cash flow part.

EBITDA: EBITDA stands for **E**arnings **before** **I**nterest, **T**axes, **D**epreciation and **A**mortization. It is a key parameter of cash flows. It is just the difference between the total revenues and the total operating costs.

Depreciation: The depreciation is a fixed value, and it is determined in the assumptions. The depreciation is not taxable, since it is accounted as a loss. Therefore it must be excluded from the revenues before the tax calculations.

Interest: It is all the interest paid for the loans. Simply, when only a senior debt is considered, the interest is the interest respective to this debt. Like the depreciation, the interest cell is accounted a loss, since it is cash going out from the balance.

Profit before Taxes: It is the cash actually generated in the period that will be subject to the deduction of taxes. It is equal to the EBITDA deducted by the amortization and interest.

Taxes: It is the amount of the total profit that will be destined to the payment of incident taxes. Due to the simple character of the financial model it is calculated as the proportion of the profit before taxes relative to the applied tax percentage.

B.4 Supporting Calculations

The supporting calculations part of the model contains all the "by-side" calculations necessary to the cash flow main calculations. The calculations linked to the DSRA and the taxes are made in loop modus. Part of the input values comes from the cash flow to the supporting calculations part and returns back to the cash flow. The figure 6.7 details the calculations performed in the supporting calculations part. A short explanation of the main lines is given in the sequence.

Supporting Calculations

Supporting Calculations

		Year 1	...	Year 20
DSRA				
% of the Debt Service	50%			
Required Balance		6.122.025,0		-
Opening Balance		-		-
Additions from CFs		6.122.025,0		-
Draws		-		-
Release		-		-
Closing Balance		6.122.025,0		-
Taxes				
Profit before tax		2.417.400,0		9.838.215,4
Management Fee		-		-
Taxable Profit for the year		2.417.400,0		9.838.215,4
Losses		-		-
Deductions		-		-
Decomissioning Account				
Account		135.000,0		3.933.390,2
Interest		2.700,0		78.667,8

Figure B.4: Financial Model – Supporting Calculations. (Source: the Author)

DSRA: The first line has the input cell for the percentage of the debt that should be kept in the reserve account for the payment of the next period debt repayment. The required balance is then the respective amount of cash. The opening balance is equal to the closing balance of the previous period. The line Additions from cash flows is the most important line. It is equal to the cash necessary to keep the DSRA balance positive. The release line contains the cash going in or out of the reserve account (DSRA out/in). If the opening balance is greater than the required balance, then the release is equal to the difference between the required balance and the opening balance, or the leftover of the reserve account. If the opening balance is lower than the required balance then the release is zero, what means that the whole balance is kept in the account. The closing balance is equal to the opening balance, plus the additions and the release. It is the balance of the reserve account at the end of the period.

Taxes: The lines related to the taxes include the possibility of adding other source of return, like for example management fees[148], to the tax shield calculations. The same with the inclusion of losses or deductions. The result, which goes back to the profit&losses part as "taxes", is the taxable profit of the year multiplied by the tax ratio defined in the assumptions. Due to the simple character of the calculation simulation assumptions, the management fees, as well as losses and deductions are not considered.

Decommissioning Account: The two lines of the decommissioning account just display the status of the account (balance + interest). This account is not active over the operational life of the wind farm, and works like a savings book to cover the decommissioning costs at the end of the operational life of the wind farm.

B.5 Financial Ratios

In the financial ratios part of the model the main results are presented. All the parameters indicate the quality of the cash flow and its ability to repay the debts and provide return to the investors. The figure 6.8 illustrates how this part is structured in the model. A short description of all the parameters follows the figure.

Financial Ratios

Financial Ratios

		Year 1	...	Year 12	...	Year 20
Operating Costs/Revenues	28,9% (average)	18,3%		32,5%		32,5%
Operating Costs/Production (€/MWh)	21,4 (average)	11,0		24,2		28,4
PLCR						
Initial Debts Outstanding	98.280.000,0	98.280.000,0		8.190.000,0		-
Average Interest Rate to apply	4,50%					
CFADS		13.868.910,0		12.711.980,7		14.269.840,0
Cumulative Present Values	173.041.902,1					
PLCR 1,76x		0,14x		1,55x		
LLCR						
Initial Debts Outstanding	98.280.000,0	98.280.000,0		8.190.000,0		
Average Interest Rate to apply	4,50%					
CFADS		13.868.910,0				14.269.840,0
Cumulative Present Values	113.191.932,4			12.711.980,7		
PLCR 1,15x		0,14				
Equity Results						
Initial Cash Outflow	(-27.720.000,0)					
Cash Available to be transfered to equity		(-27.720.000,0)		8.472.991,0		
Internal Rate of Return 20,76 %						14.348.507,8

Figure B.5: Financial Model – Financial Ratios. (Source: the Author)

[148] In some locations, the management fees, which are accounted as an operational cost can be deducted from the tax amount.

Project Life Cover Ratio (PLCR): Is the ratio between the cumulative present value of the project over its complete operational life and the total debt service. It is a measure of the capacity of the cash flow to cover the debt service. Since the cumulative Net Present Value includes all the periods, or the full operational life of the wind farm (20 years), this parameter is higher than the LLCR.

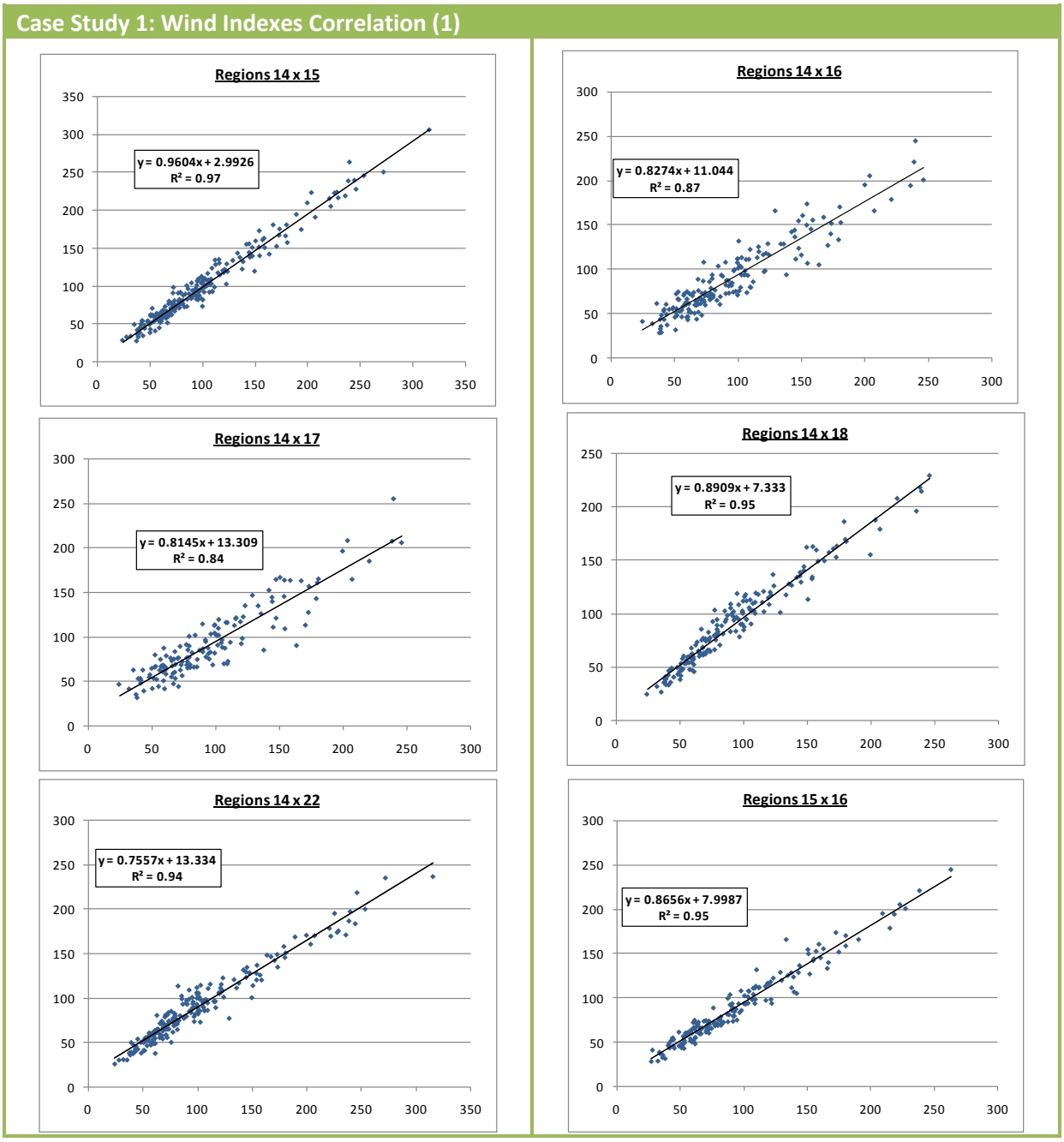
Loan Life Cover Ratio (LLCR): Is the ratio between the cumulative present value of the project over the scheduled life of the loan and the total debt service. The LLCR provides information on the number of times the cash flow can repay the outstanding debt for the duration of the loan.

Equity Results: The main parameter indicating the quality of the project's cash flow from the equity investor's point of view is the internal rate of return (IRR). The IRR is a measure of the yield of the equity invested in the project. Therefore it considers the initial cash invested by the equity provider (opening balance) and the cash available to equity payments in every accounting period.

Annex C

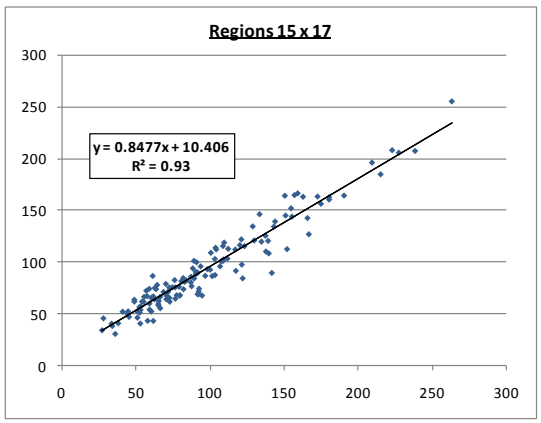
C.1 Case study 1

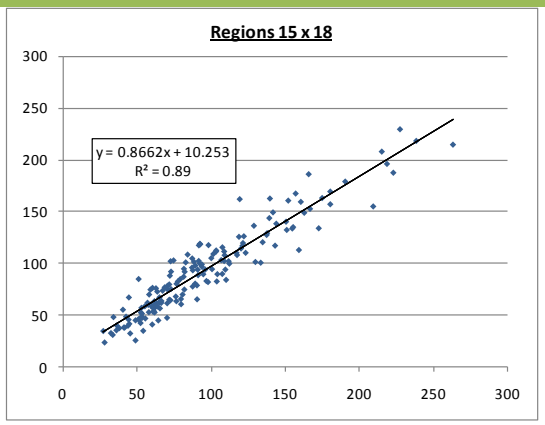
C.1.1 Correlation of the Applied Wind Indexes

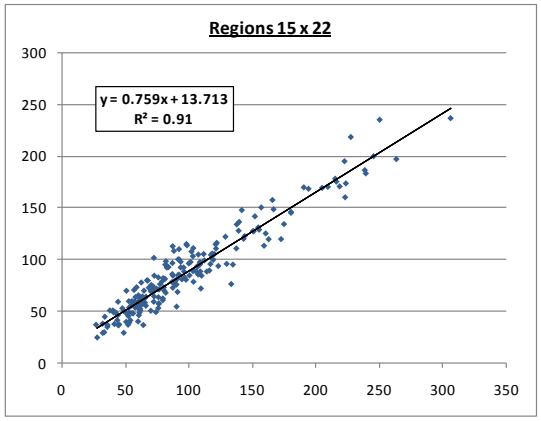


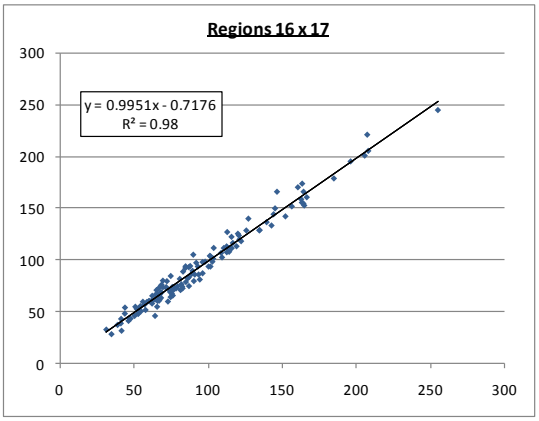
Graph C.1.1 (a): Wind index correlations (1).

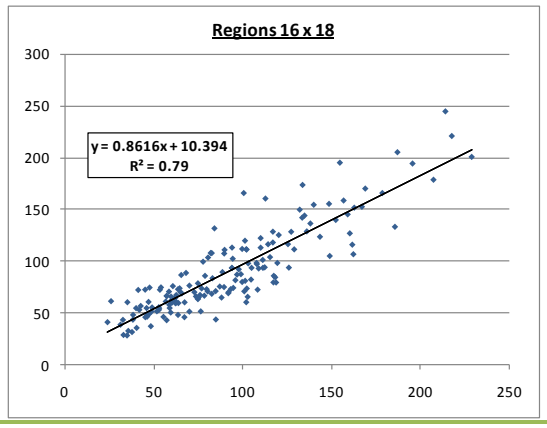
Case Study 1: Wind Indexes Correlation (2)

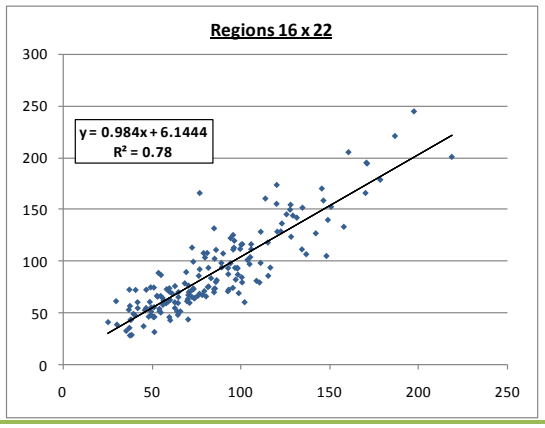






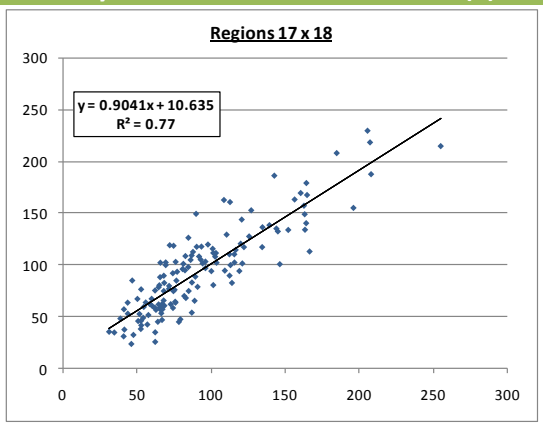


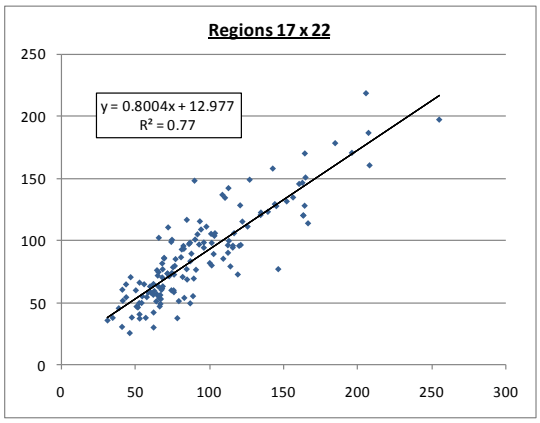


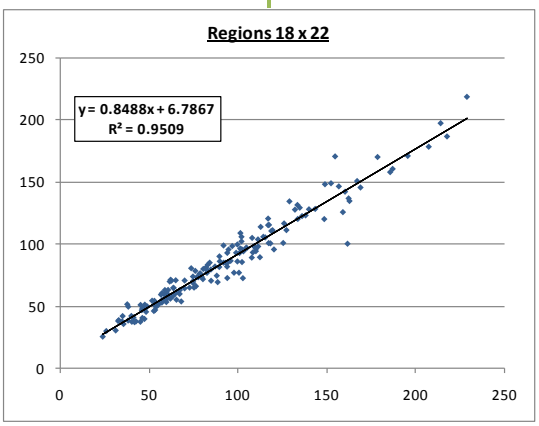


Graph C.1.1 (b): Wind index correlations (2).

Case Study 1: Wind Indexes Correlation (3)



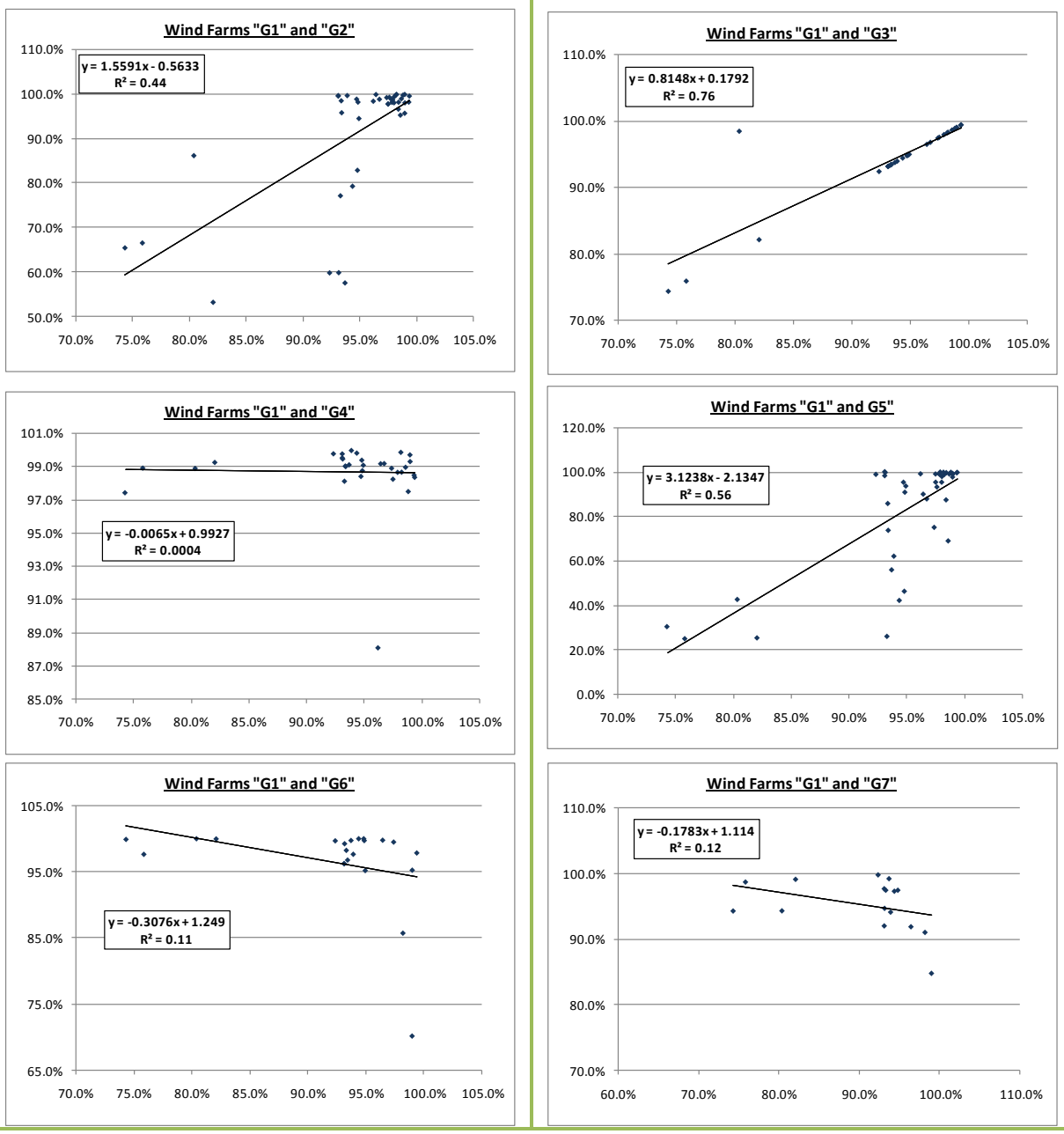




Graph C.1.1 (c): Wind index correlations (3).

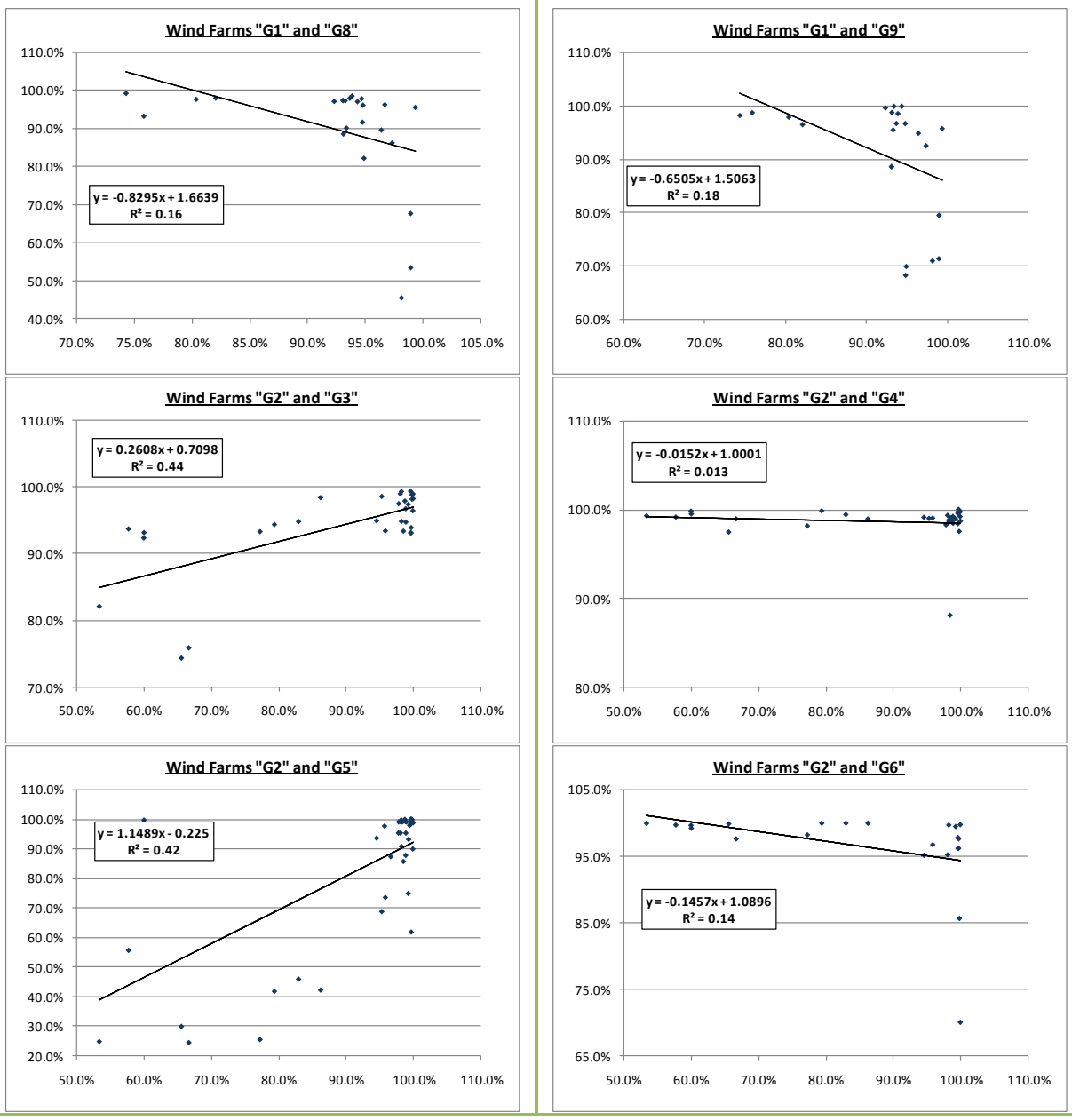
C.1.2 Correlation of the Operational Data

Case Study 1: Operational Data Correlation (1)



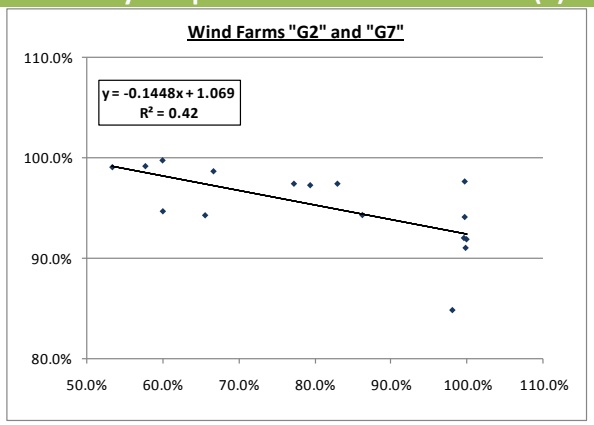
Graph C.1.2 (a): Operational Data Correlations (1).

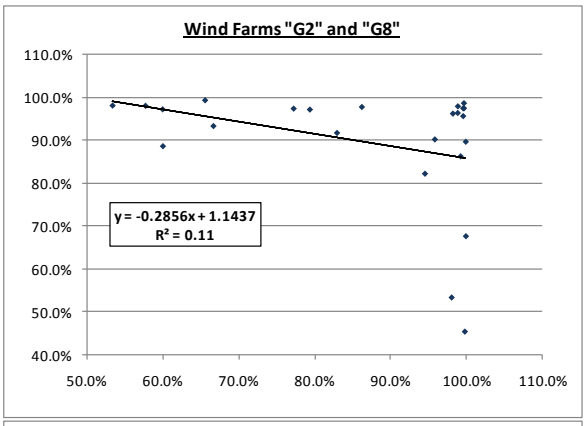
Case Study 1: Operational Data Correlation (2)

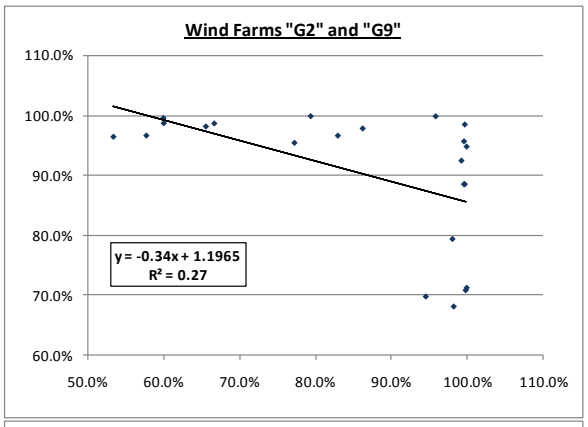


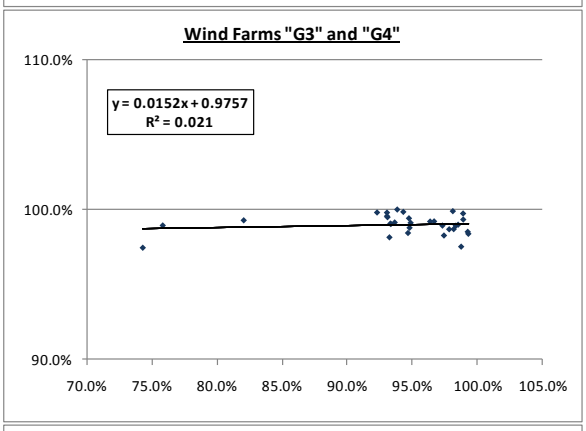
Graph C.1.2 (b): Operational Data Correlations (2).

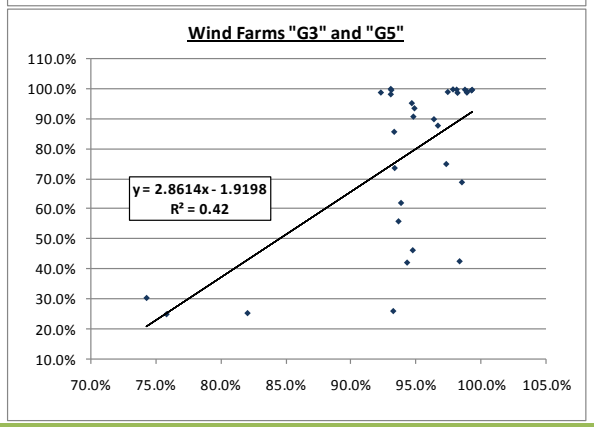
Case Study 1: Operational Data Correlation (3)

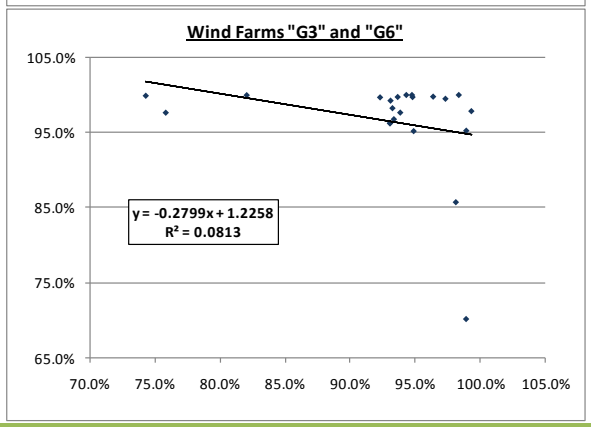






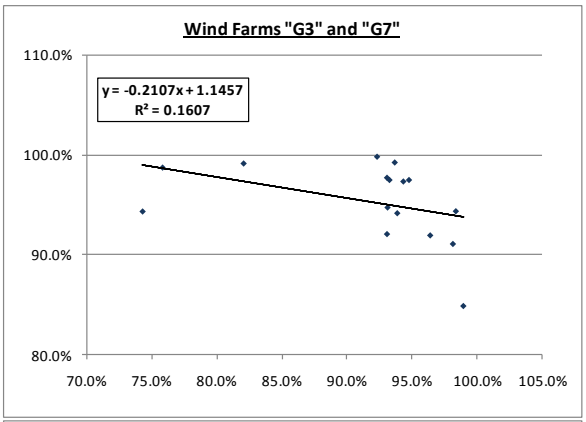


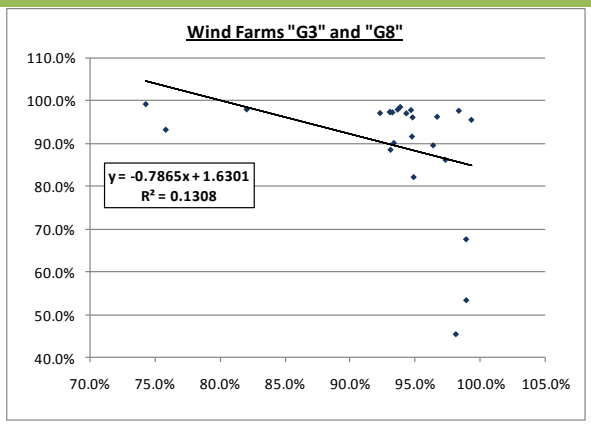


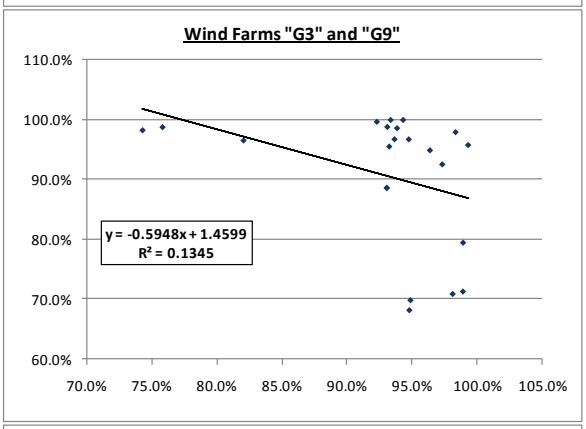


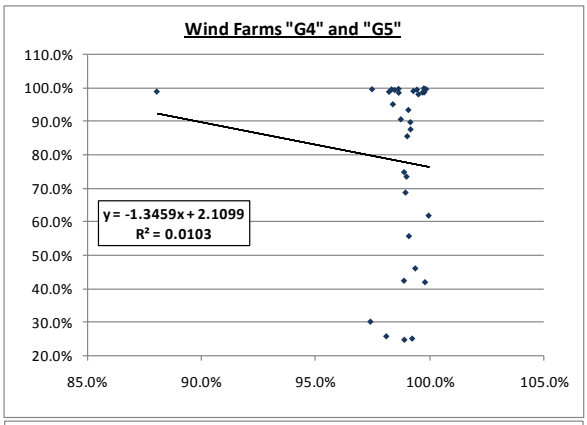
Graph C.1.2 (c): Operational Data Correlations (3).

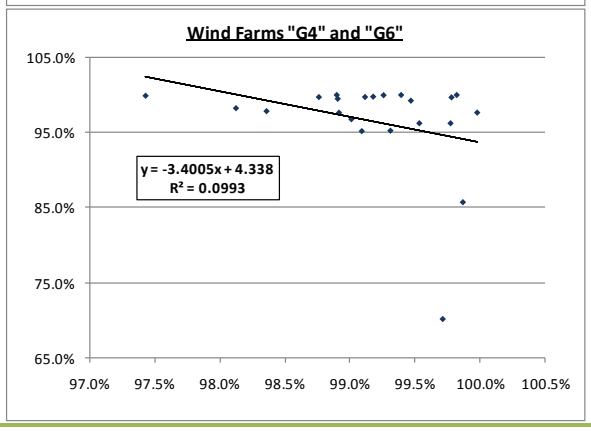
Case Study 1: Operational Data Correlation (4)

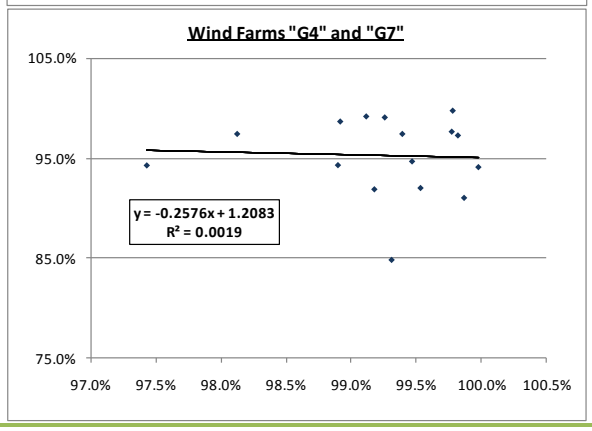






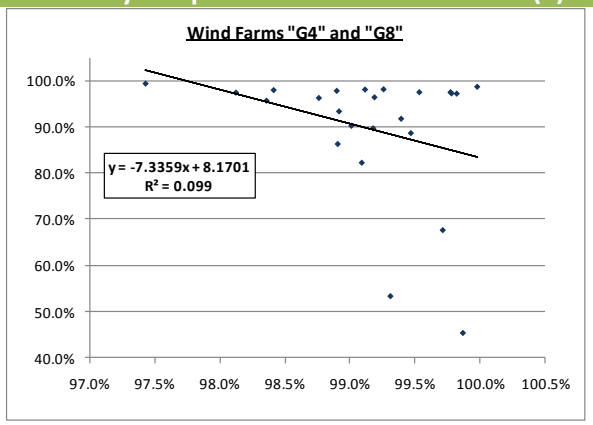


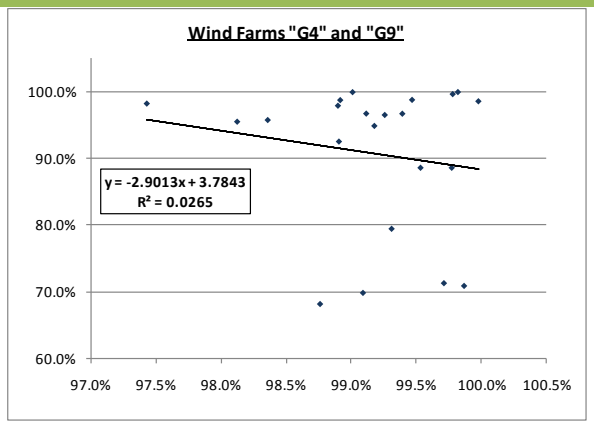


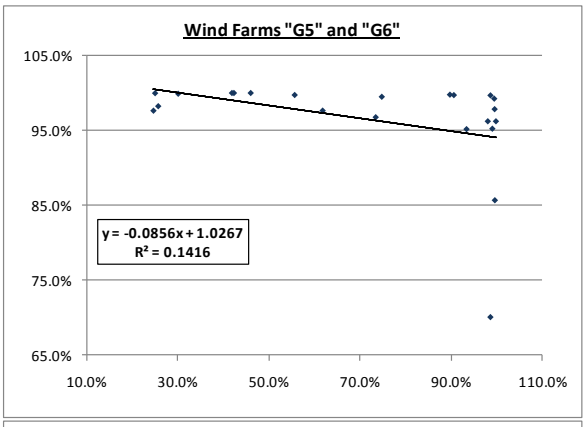


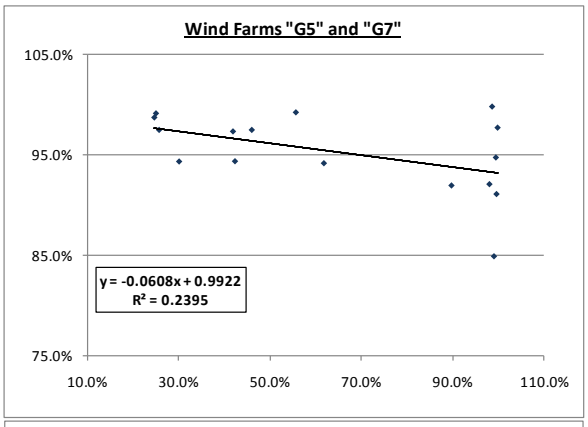
Graph C.1.2 (d): Operational Data Correlations (4).

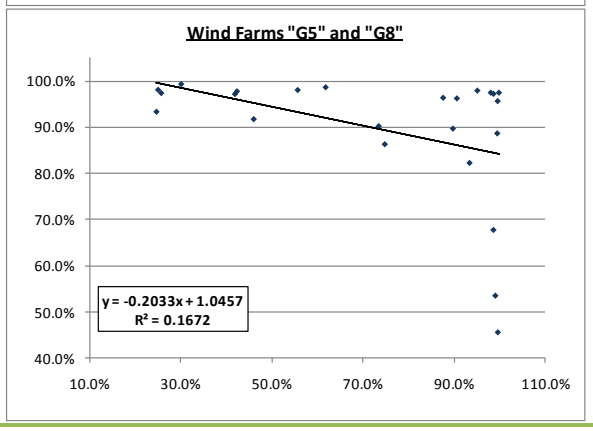
Case Study 1: Operational Data Correlation (5)

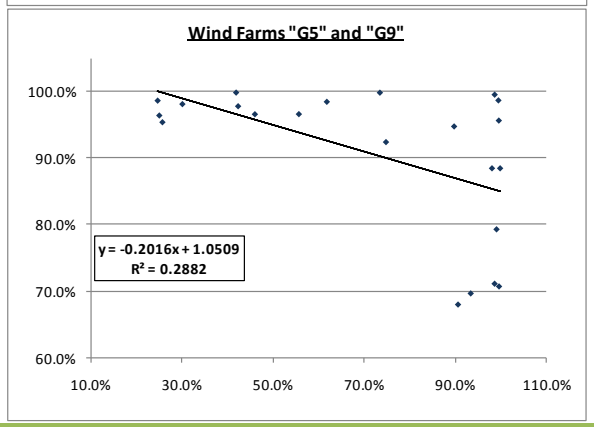






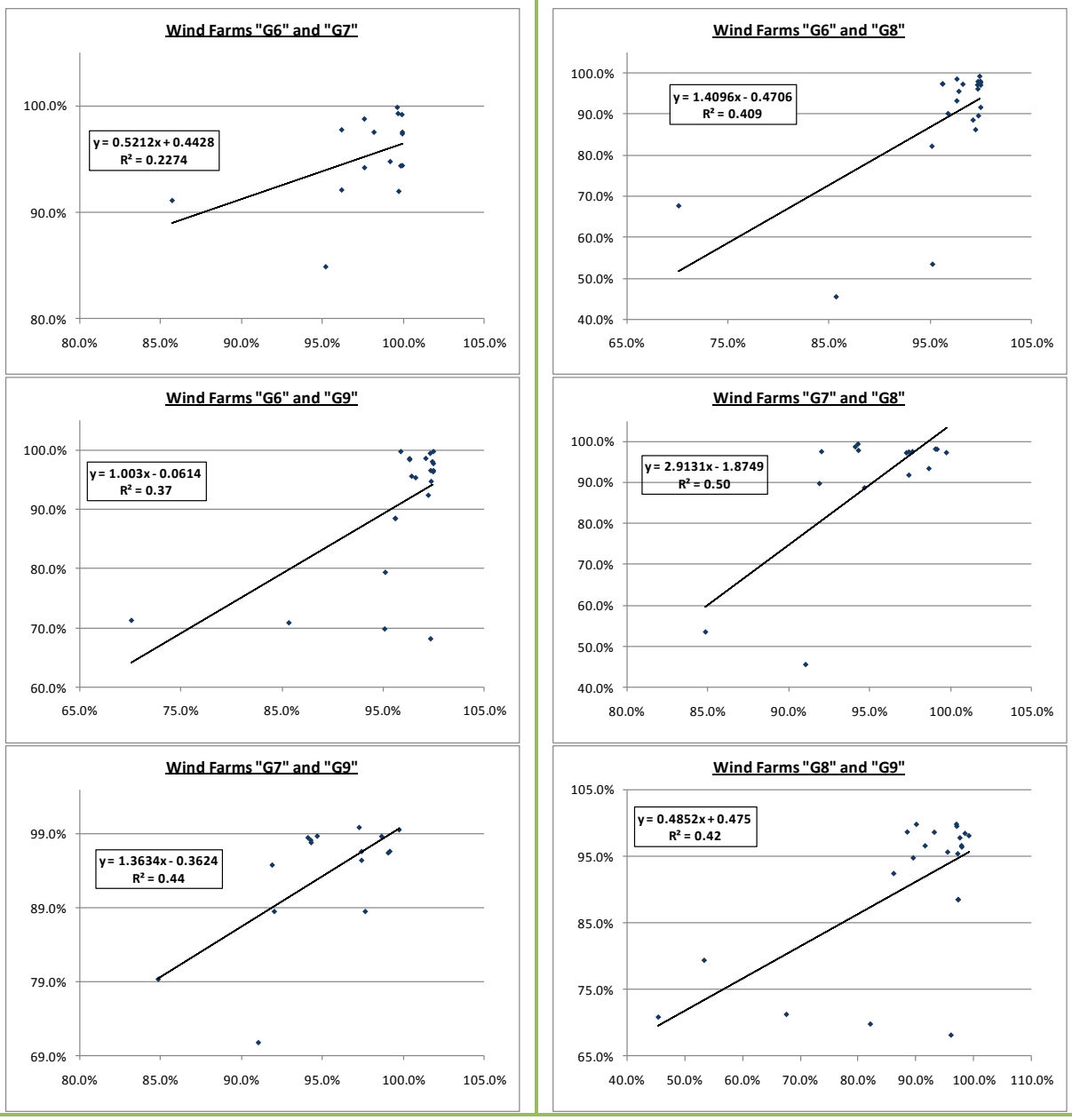






Graph C.1.2 (e): Operational Data Correlations (5).

Case Study 1: Operational Data Correlation (6)



Graph C.1.2 (f): Operational Data Correlations (6).

C.1.3 Financial Model Inputs

Case Study 1 – Financial Model General Assumptions	
1. Operating Costs	
- General Assumption (year 1-5)	2.5%
- General Assumption (year 6-20)	5.0%
- O&M Costs Split	
- Insurance	13.0%
- Land lease	18.0%
- Service and spare parts	26.0%
- Administration	21.0%
- Electricity	5.0%
- Miscellaneous	17.0%
- Decommissioning [€/MW]	1,500.0
2. Others	
- Depreciation Period [years]	16
- Taxes	35%
- Interest rate on cash balance	2.0%
- Indexation of the tariff	2.0%
- Indexation of operational costs	2.0%
- Debt Interest Rate	4.5%
- Loan life [years]	12

Table C.1.3: Financial Model general assumptions applied to all projects.

Case Study 1 – Financial Model Input Parameters			
Wind Farm	**"G1"**	**"G2"**	**"G3"**
1. Revenues			
- N° of Units	9	5	10
- Power/Unit [MW/unit]	1.5	1.5	1.5
- Total Capacity [MW]	13.5	7.5	15.0
- Net Production (P90) [MWh/a]	14,899.0	9,936.0	26,465.0
- Tariff [€/MWh]	92.00	92.00	92.00
2. Investment Costs			
- Turbines [€]	11,340,000.0	6,300,000.0	12,600,000.0
- Planning, Infrastructure and Financing [€]	4,860,000.0	2,700,000.0	5,400,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	16,200,000.0	9,000,000.0	18,000,000.0
3. Others			
- Depreciation [€/year]	1,012,500.0	562,500.0	1,125,000.0

Table C.1.3 (a): Financial Model specific assumptions – Wind Farms "G1", "G2" and "G3".

Case Study 1 – Financial Model Assumptions			
Wind Farm	**"G4"**	**"G5"**	**"G6"**
1. Revenues			
- N° of Units	4	8	2
- Power/Unit [MW/unit]	2.0	1.5	0.85
- Total Capacity [MW]	8.0	12.0	1.7
- Net Production (P90) [MWh/a]	12,303.0	17,340.0	2,670.0
- Tariff [€/MWh]	92.00	92.00	92.00
2. Investment Costs			
- Turbines [€]	6,720,000.0	10,080,000.0	1,428,000.0
- Planning, Infrastructure and Financing [€]	2,880,000.0	4,320,000.0	612,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	9,600,000.0	14,400,000.0	2,040,000.0
3. Others			
- Depreciation [€/year]	600,000.0	900,000.0	127,500.0

Table C.1.3 (b): Financial Model Assumptions – Wind Farms "G4", "G5" and "G6".

Case Study 1 – Financial Model Assumptions			
Wind Farm	**"G7"**	**"G8"**	**"G9"**
1. Revenues			
- N° of Units	4	4	7
- Power/Unit [MW/unit]	2.0	2.0	0.85
- Total Capacity [MW]	8.0	4.0	5.95
- Net Production (P90) [MWh/a]	10,876.0	7,839.0	6,415.0
- Tariff [€/MWh]	92.00	92.00	92.00
2. Investment Costs			
- Turbines [€]	6,720,000.0	3,360,000.0	4,998,000.0
- Planning, Infrastructure and Financing [€]	2,880,000.0	1,440,000.0	2,142,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	9,600,000.0	4,800,000.0	7,140,000.0
3. Others			
- Depreciation [€/year]	600,000.0	300,000.0	446,000.0

Table C.1.3 (c): Financial Model Assumptions – Wind Farms "G7", "G8" and "G9".

Case Study 1 – Financial Model Assumptions		
Wind Farm	**"Sum of All WFs"**	**"Portfolio"**
4. Revenues		
- N° of Units	51	51
- Power/Unit [MW/unit]	1.52	1.52
- Total Capacity [MW]	77.6	77.6
- Net Production (P90) [MWh/a]	108,743.0	110,249.0
- Tariff [€/MWh]	92.00	92.00
5. Investment Costs		
- Turbines [€]	65,212,000.0	65,212,000.0
- Planning, Infrastructure and Financing [€]	27,948,000.0	27,948,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	93,160,000.0	93,160,000.0
6. Others		
- Depreciation [€/year]	5,822,500.0	5,822,500.0

Table C.1.3 (d): Financial Model Assumptions – All wind farms and the Portfolio.

C.1.4 Financial Model Results

Wind Farm "G1"

Case Study 1 – Financial Model Results			
Wind Farm – "G1"			
- Total Investment Cost	16,200,000.0	- Wind Farm's Capacity Factor	12.6%
- Debt Finance percentage	43.2%	- Rate Operating cost/Revenues	49.0%
- Debt Finance amount [€]	6,998,394.0	- Rate Operating cost/Production [$/MWh]	55.7
- Equity percentage	56.8%	- Project Life Cover Ratio (PLCR)	1.76x
- Equity amount [€]	9,201,606.0	- Loan Life Cover Ratio (LLCR)	1.19x
- Internal Rate of Return	1.46%		

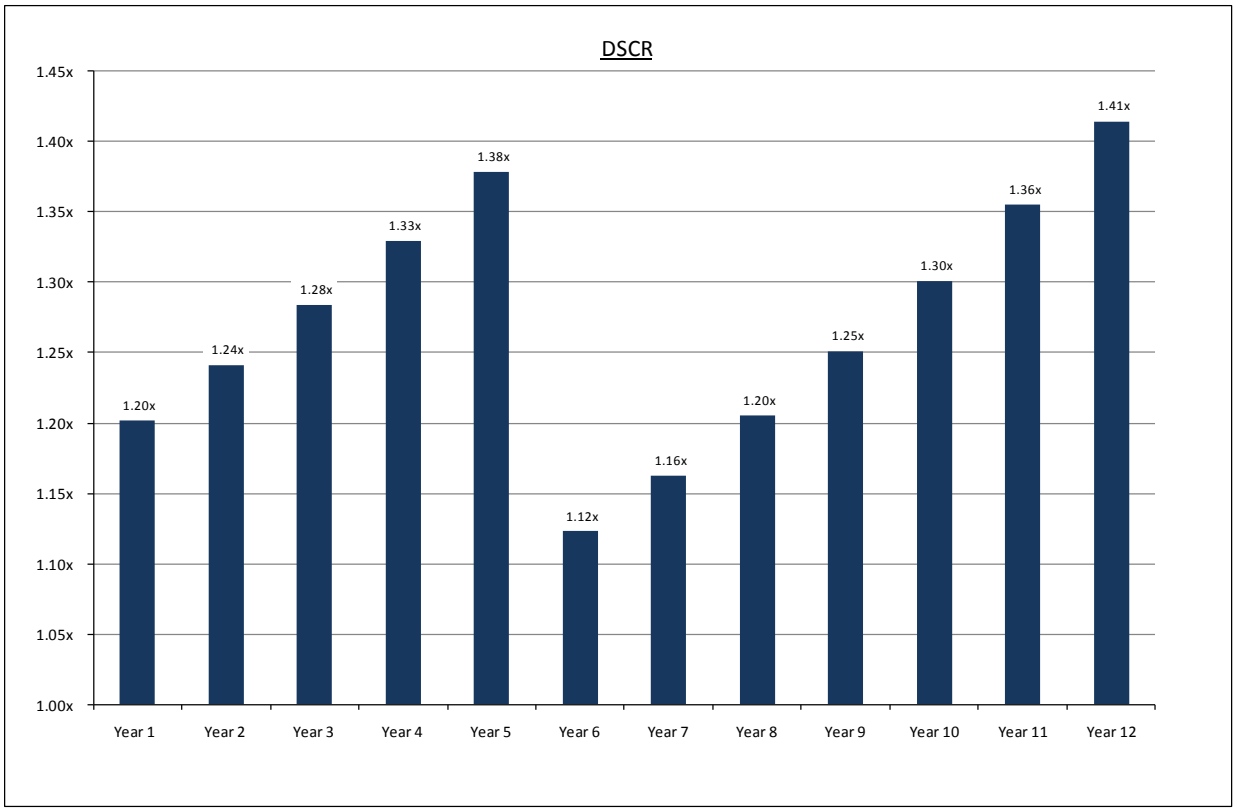


Table C.1.4 (a): Financial Model Main Results – Wind Farm "G1".

Wind Farm "G2"

Case Study 1 – Financial Model Results			
Wind Farm – "G2"			
- Total Investment Cost	9,0000,000.0	- Wind Farm's Capacity Factor	15.1%
- Debt Finance percentage	53.5%	- Rate Operating cost/Revenues	40.8%
- Debt Finance amount [€]	4,817,700.0	- Rate Operating cost/Production [$/MWh]	46.4
- Equity percentage	46.5%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	4,182,300.0	- Loan Life Cover Ratio (LLCR)	1.17x
- Internal Rate of Return	5.60%		

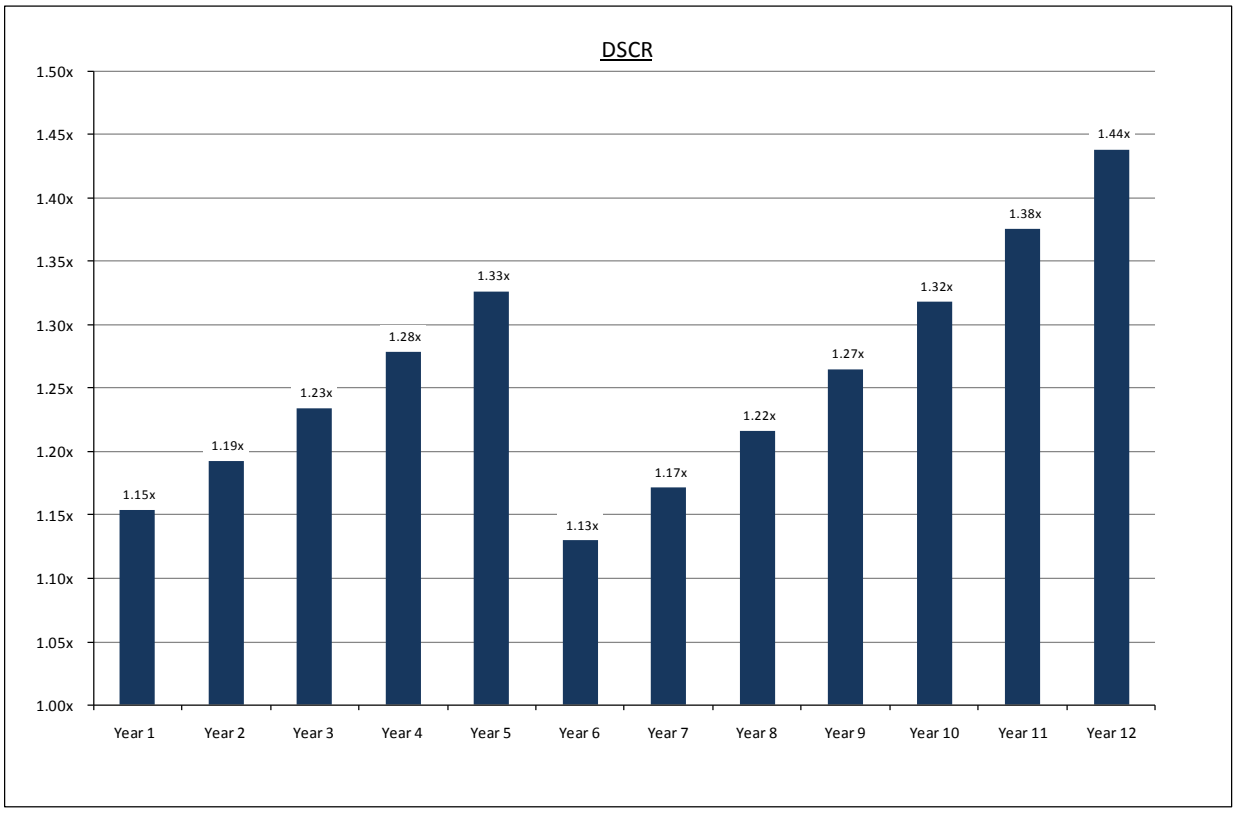


Table C.1.4 (b): Financial Model Main Results – Wind Farm "G2".

Wind Farm "G3"

Case Study 1 – Financial Model Results			
Wind Farm – "G3"			
- Total Investment Cost	18,000,000.0	- Wind Farm's Capacity Factor	20.1%
- Debt Finance percentage	74.1%	- Rate Operating cost/Revenues	30.7%
- Debt Finance amount[€]	13,333,787.0	- Rate Operating cost/Production [$/MWh]	34.9
- Equity percentage	25.9%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	4,666,213.0	- Loan Life Cover Ratio (LLCR)	1.14x
- Internal Rate of Return	16.9%		

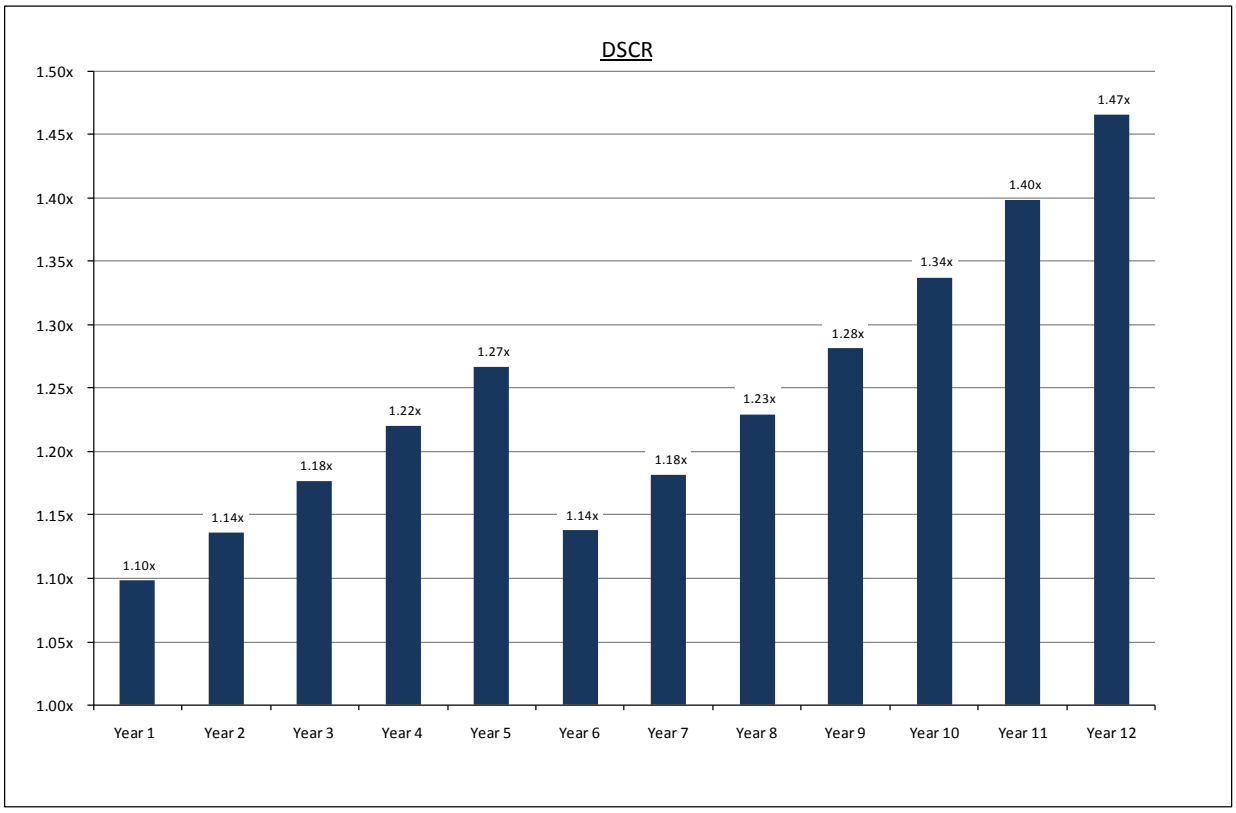


Table C.1.4 (c): Financial Model Main Results – Wind Farm "G3".

Wind Farm "G4"

Case Study 1 – Financial Model Results			
Wind Farm – "G4"			
- Total Investment Cost	9,600,000.0	- Wind Farm's Capacity Factor	17.6%
- Debt Finance percentage	63.5%	- Rate Operating cost/Revenues	35.2%
- Debt Finance amount[€]	6,095,140.0	- Rate Operating cost/Production [$/MWh]	40.0
- Equity percentage	36.5%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	3,504,860.0	- Loan Life Cover Ratio (LLCR)	1.15x
- Internal Rate of Return	10.8%		

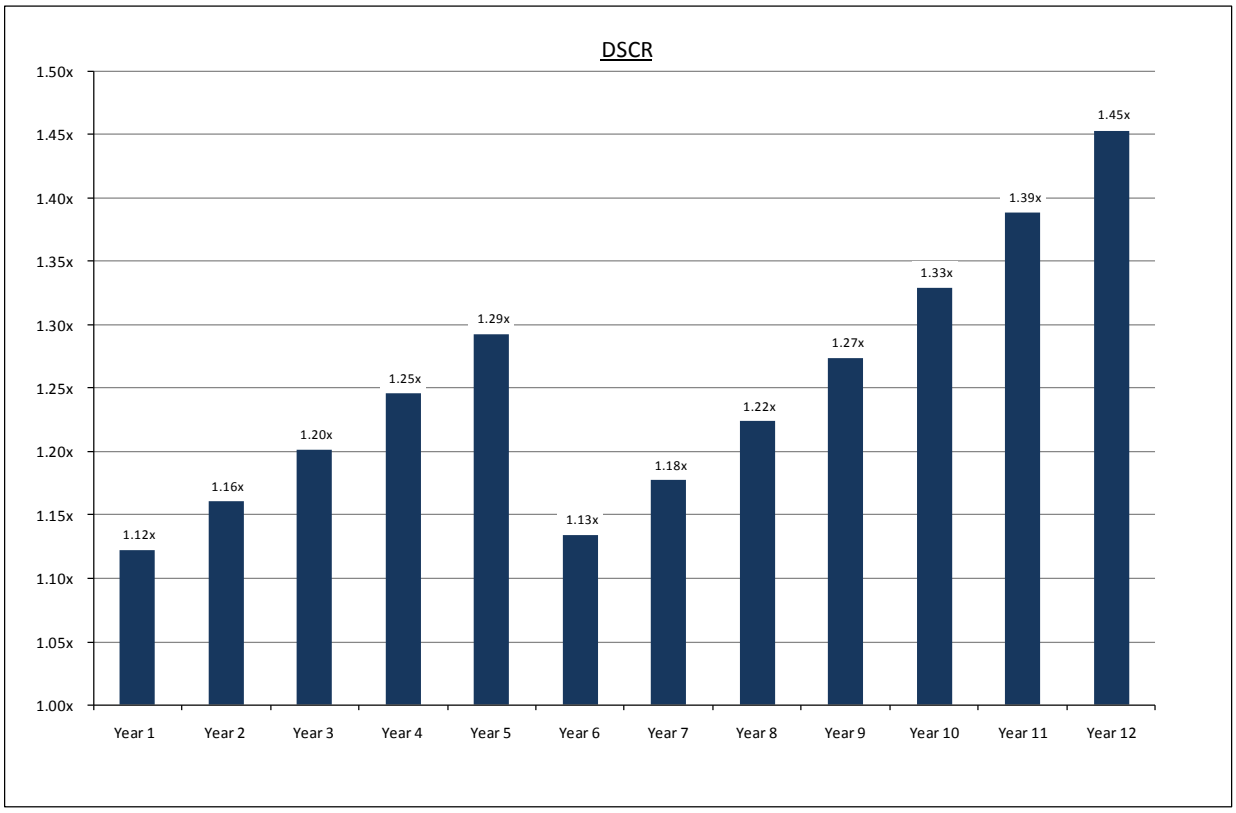


Table C.1.4 (d): Financial Model Main Results – Wind Farm "G4".

Wind Farm "G5"

Case Study 1 – Financial Model Results			
Wind Farm – "G5"			
- Total Investment Cost	14,400,000.0	- Wind Farm's Capacity Factor	16.5%
- Debt Finance percentage	59.2%	- Rate Operating cost/Revenues	37.4%
- Debt Finance amount[€]	8,522,079.0	- Rate Operating cost/Production [$/MWh]	42.6
- Equity percentage	40.8%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	5,877,921.0	- Loan Life Cover Ratio (LLCR)	1.16x
- Internal Rate of Return	7.80%		

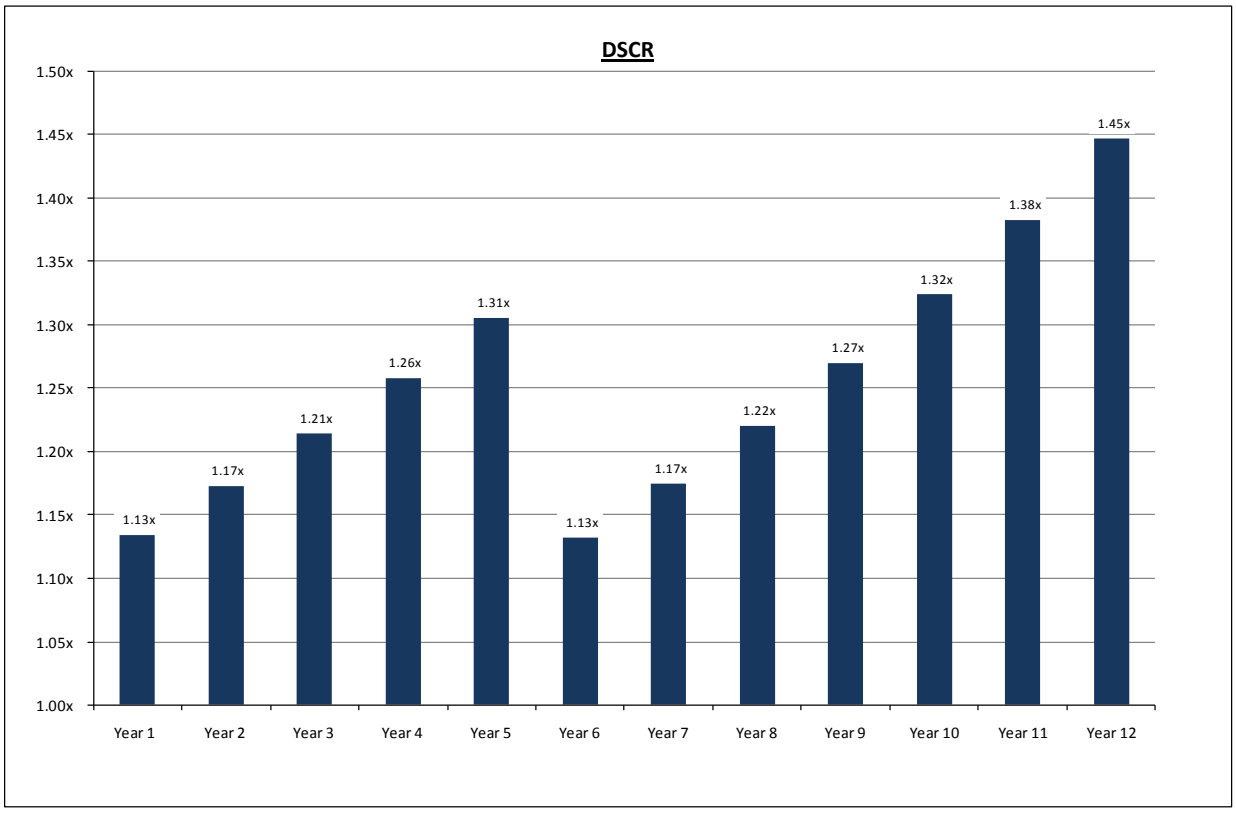


Table C.1.4 (e): Financial Model Main Results – Wind Farm "G5".

Wind Farm "G6"

Case Study 1 – Financial Model Results			
Wind Farm – "G6"			
- Total Investment Cost	2,040,000.0	- Wind Farm's Capacity Factor	17.9%
- Debt Finance percentage	65.0%	- Rate Operating cost/Revenues	34.4%
- Debt Finance amount[€]	1,326,771.0	- Rate Operating cost/Production [$/MWh]	39.2
- Equity percentage	35.0%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	713,229.0	- Loan Life Cover Ratio (LLCR)	1.15x
- Internal Rate of Return	11.5%		

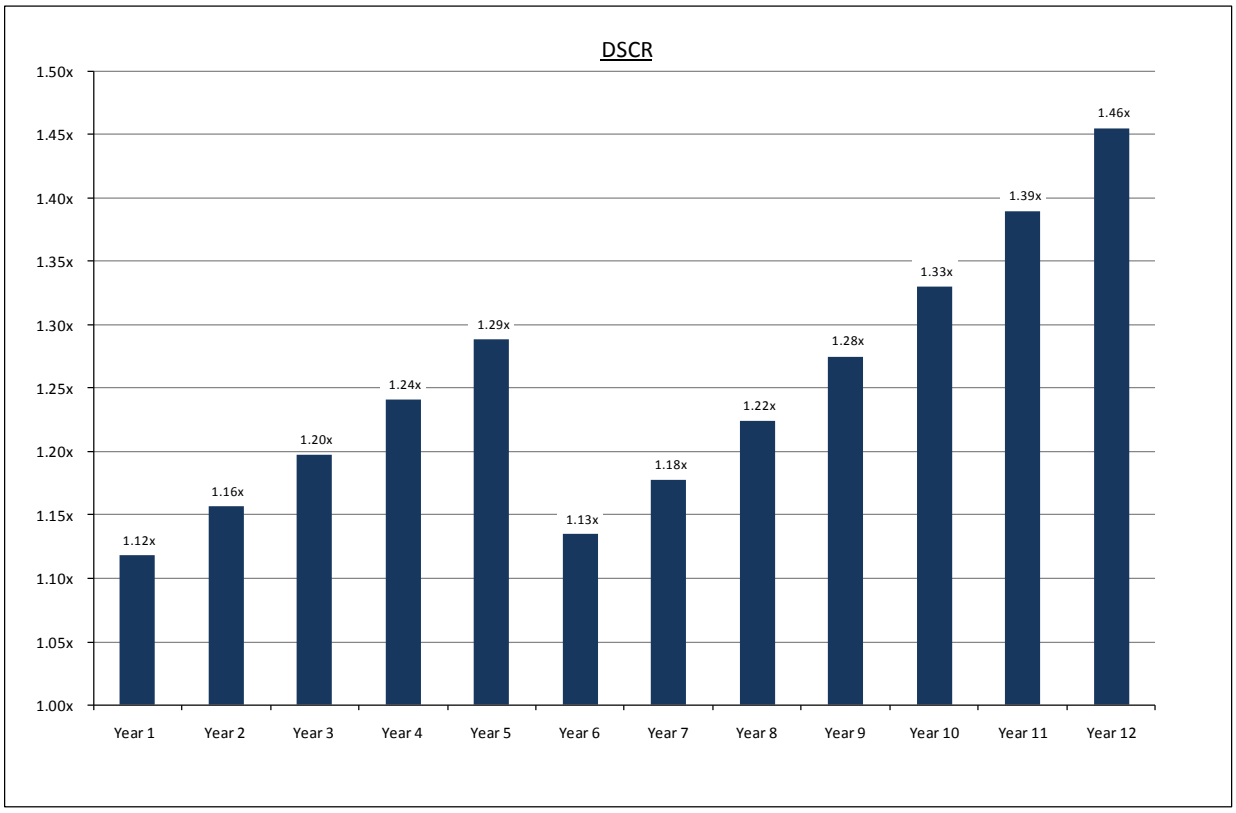


Table C.1.4 (f): Financial Model Main Results – Wind Farm "G6".

Wind Farm "G7"

Case Study 1 – Financial Model Results			
Wind Farm – "G7"			
- Total Investment Cost	9,600,000.0	- Wind Farm's Capacity Factor	15.5%
- Debt Finance percentage	55.2%	- Rate Operating cost/Revenues	39.8%
- Debt Finance amount[€]	5,295,239.0	- Rate Operating cost/Production [$/MWh]	45.2
- Equity percentage	44.8%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	4,304,761.0	- Loan Life Cover Ratio (LLCR)	1.17x
- Internal Rate of Return	6.2%		

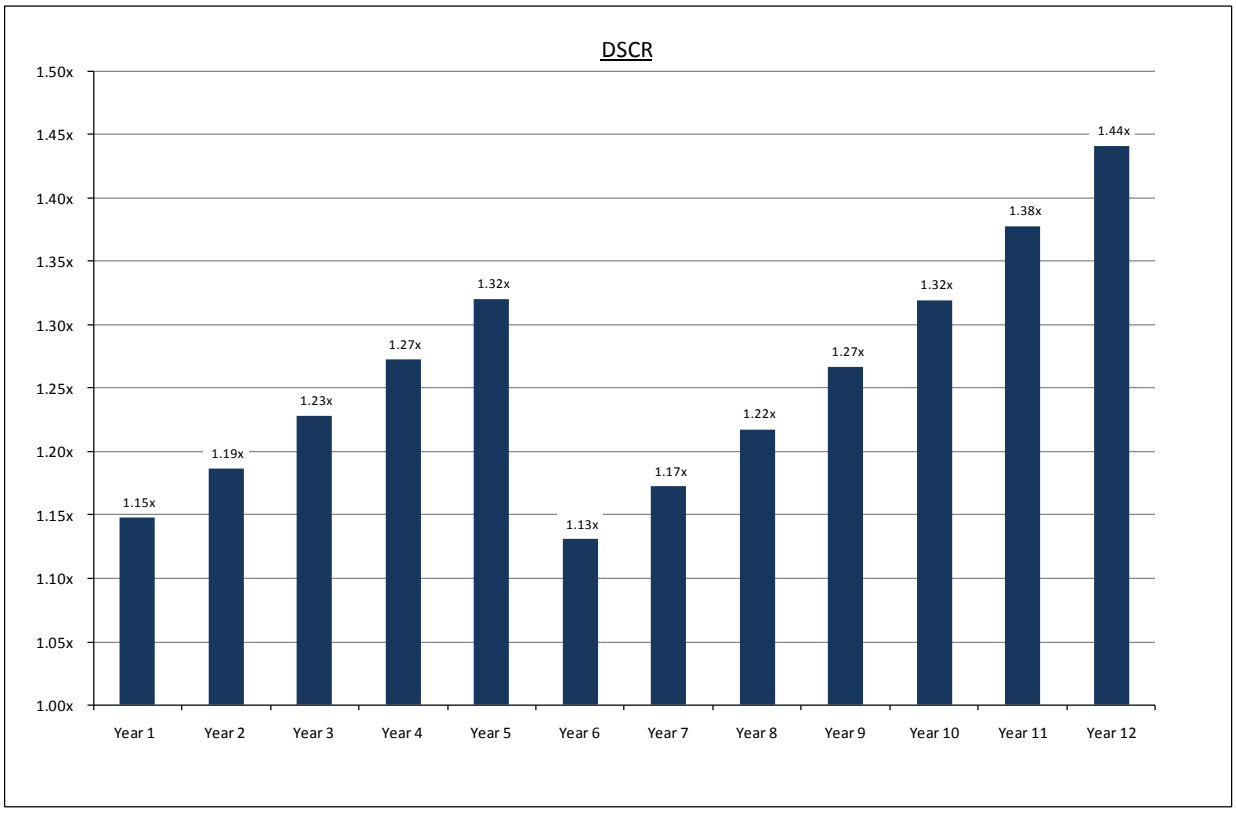


Table C.1.4 (g): Financial Model Main Results – Wind Farm "G7".

Wind Farm "G8"

Case Study 1 – Financial Model Results			
Wind Farm – "G8"			
- Total Investment Cost	4,800,000.0	- Wind Farm's Capacity Factor	22.4%
- Debt Finance percentage	83.2%	- Rate Operating cost/Revenues	27.6%
- Debt Finance amount[€]	3,994,088.0	- Rate Operating cost/Production [$/MWh]	31.4
- Equity percentage	16.8%	- Project Life Cover Ratio (PLCR)	1.74x
- Equity amount [€]	805,912.0	- Loan Life Cover Ratio (LLCR)	1.14x
- Internal Rate of Return	33.7%		

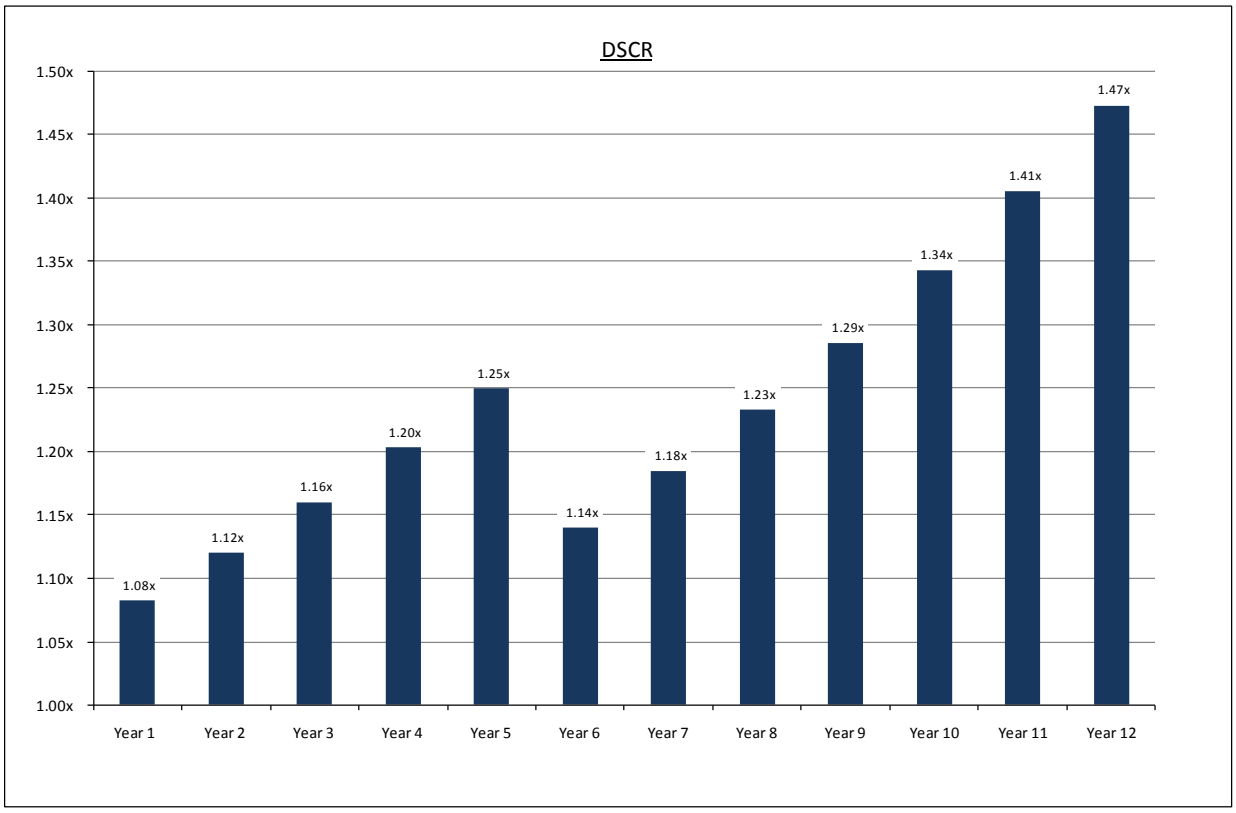


Table C.1.4 (h): Financial Model Main Results – Wind Farm "G8".

Wind Farm "G9"

Case Study 1 – Financial Model Results			
Wind Farm – "G9"			
- Total Investment Cost	7,140,000.0	- Wind Farm's Capacity Factor	12.3%
- Debt Finance percentage	42.0%	- Rate Operating cost/Revenues	50.2%
- Debt Finance amount[€]	2,999,686.0	- Rate Operating cost/Production [$/MWh]	57.0
- Equity percentage	58.0%	- Project Life Cover Ratio (PLCR)	1.76x
- Equity amount [€]	4,140,314.0	- Loan Life Cover Ratio (LLCR)	1.19x
- Internal Rate of Return	1.5%		

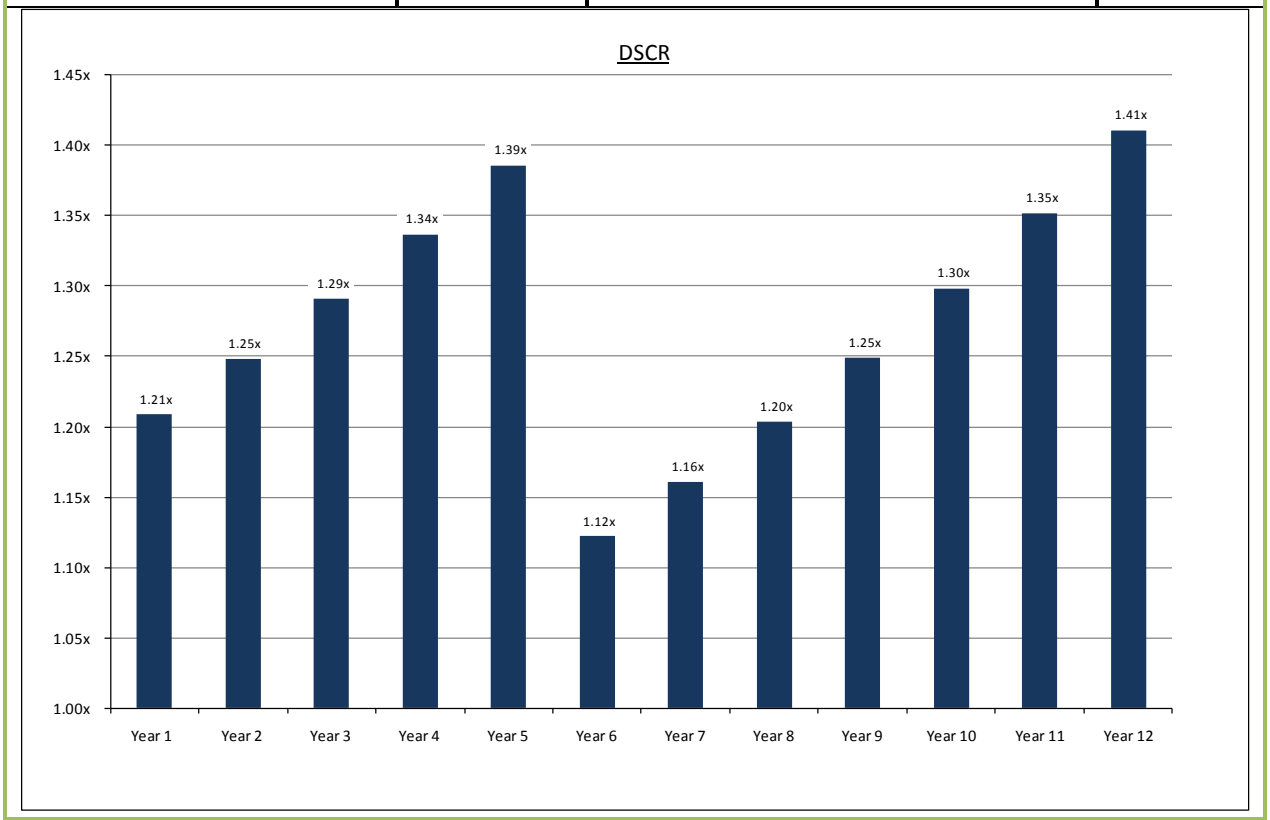


Table C.1.4 (i): Financial Model Main Results – Wind Farm "G9".

Sum of All WFs

Case Study 1 – Financial Model Results			
Sum of all WFs (Not considering Portfolio Effects)			
- Total Investment Cost	93,160,000.0	- Wind Farm's Capacity Factor	16.0%
- Debt Finance percentage	57.1%	- Rate Operating cost/Revenues	38.6%
- Debt Finance amount[€]	53,182,892.0	- Rate Operating cost/Production [$/MWh]	43.9
- Equity percentage	42.9%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	39,977,108.0	- Loan Life Cover Ratio (LLCR)	1.16x
- Internal Rate of Return	6.97%		

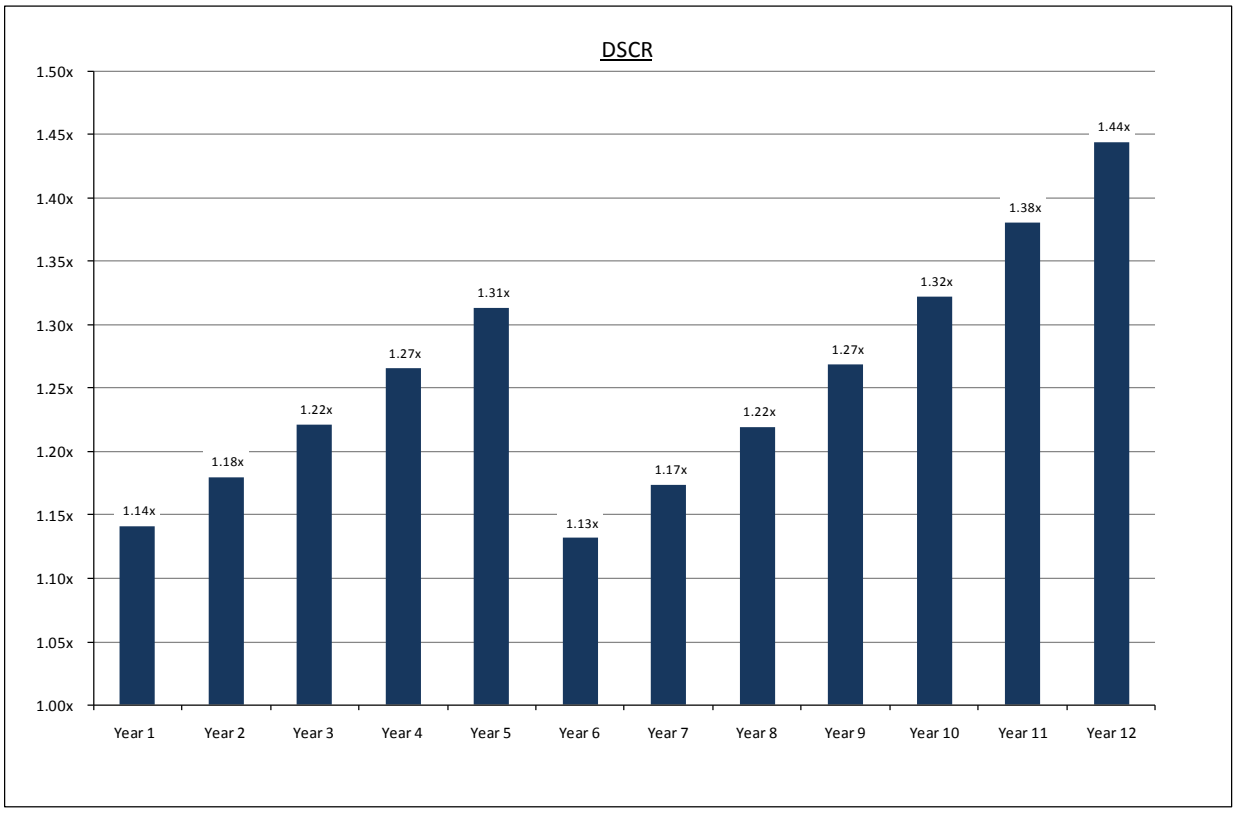


Table C.1.4 (j): Financial Model Main Results – All wind farms. Not considering Portfolio Effects.

Portfolio

Case Study 1 – Financial Model Results			
Portfolio			
- Total Investment Cost	93,160,000.0	- Wind Farm's Capacity Factor	16.2%
- Debt Finance percentage	58.0%	- Rate Operating cost/Revenues	38.1%
- Debt Finance amount[€]	54,027,319.0	- Rate Operating cost/Production [$/MWh]	43.3
- Equity percentage	42.0%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	39,132,681.0	- Loan Life Cover Ratio (LLCR)	1.16x
- Internal Rate of Return	7.33%		

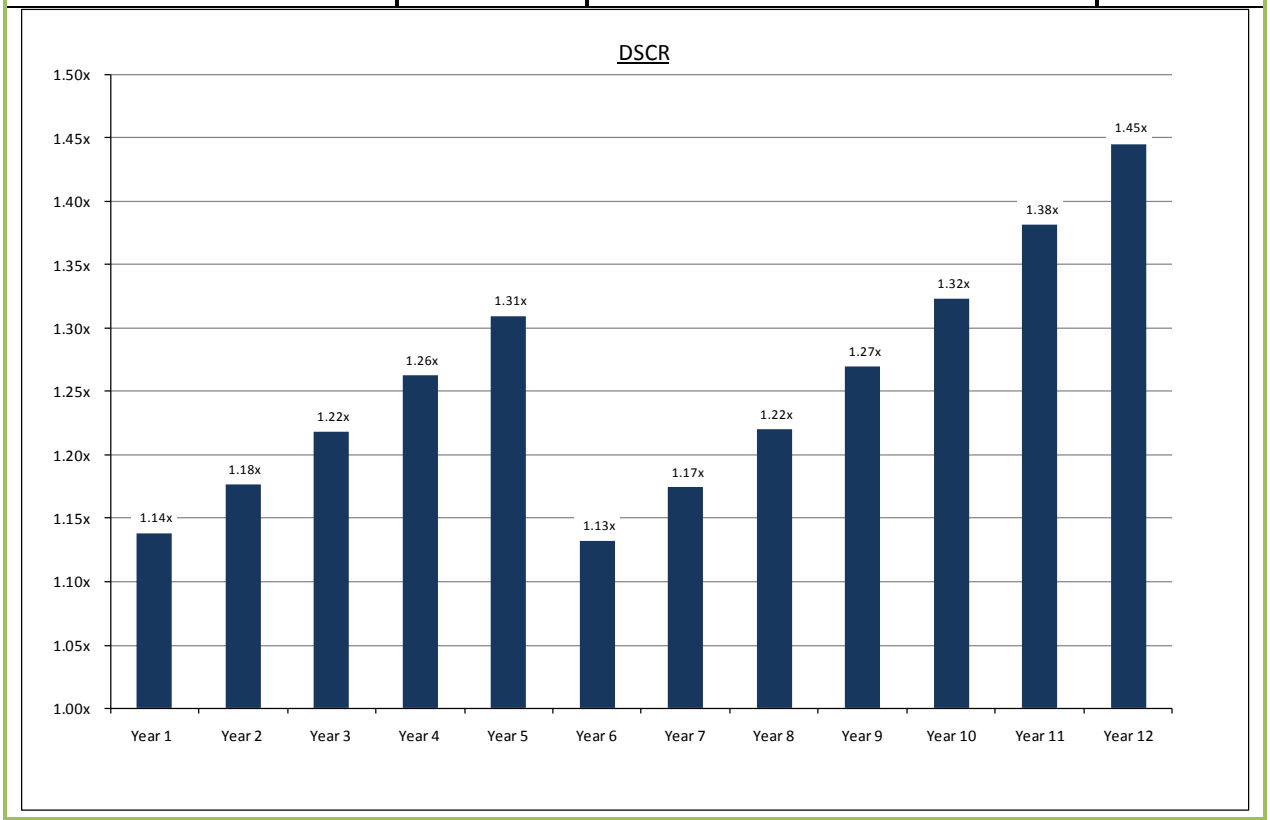
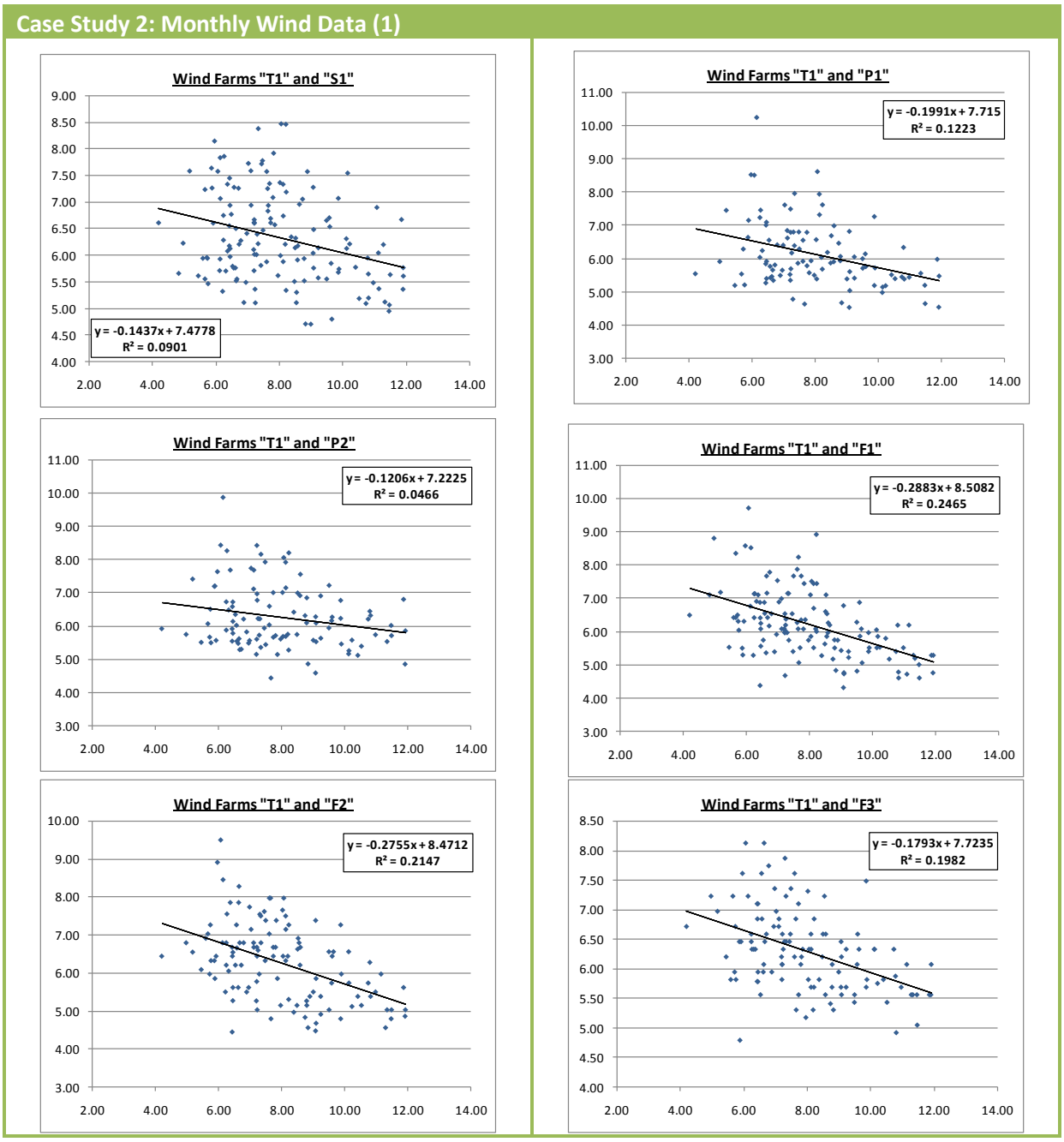


Table C.1.4 (k): Financial Model Main Results – Portfolio.

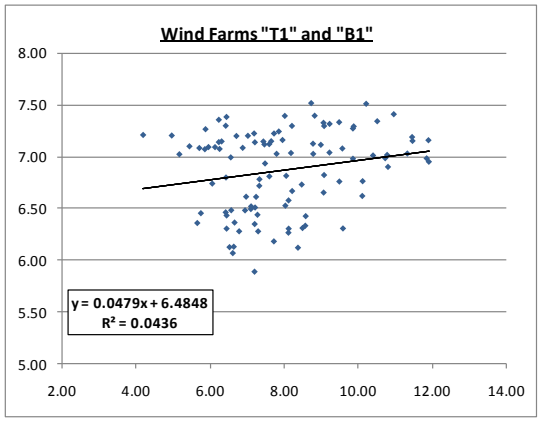
C.2 Case study 2

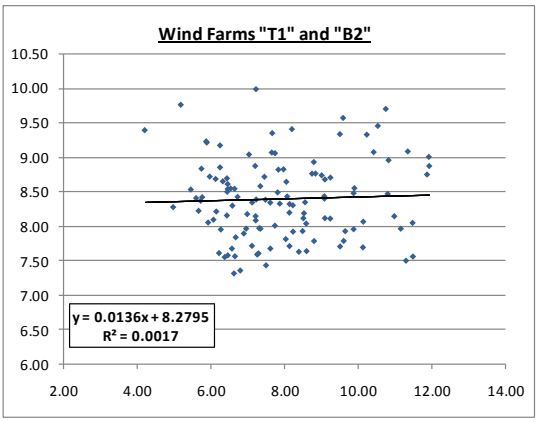
C.2.1 Correlation of the Applied Meteorological Input Data

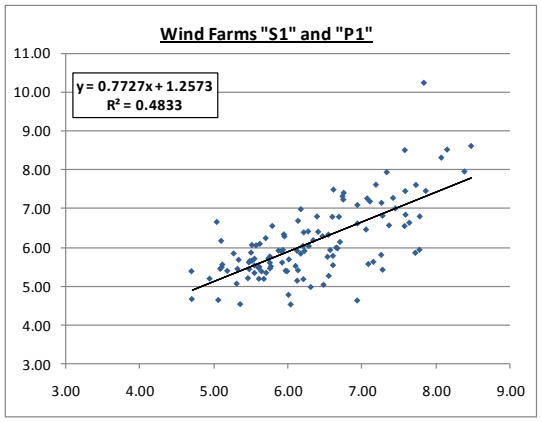


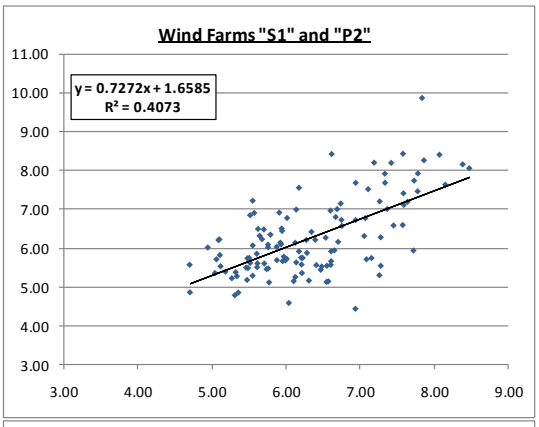
Graph C.2.1 (a): Correlation of the monthly averaged wind data (1).

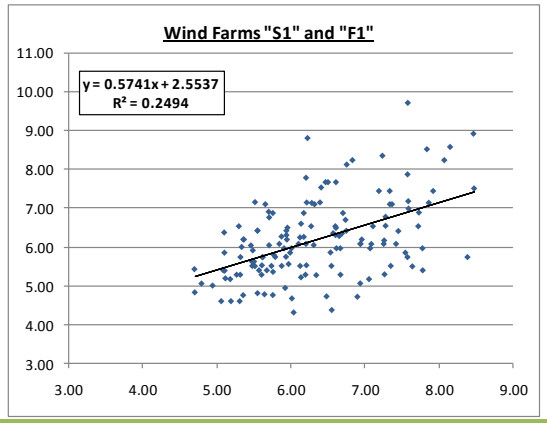
Case Study 2: Monthly Wind Data (2)

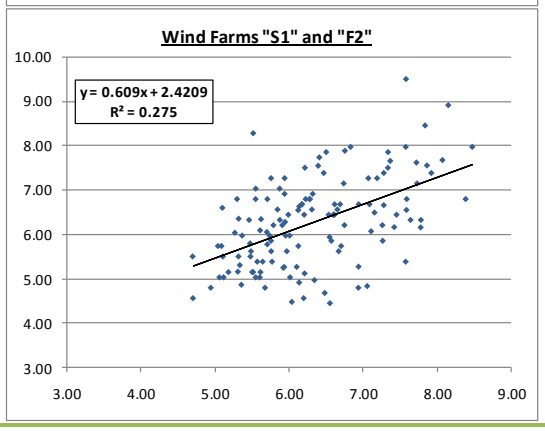






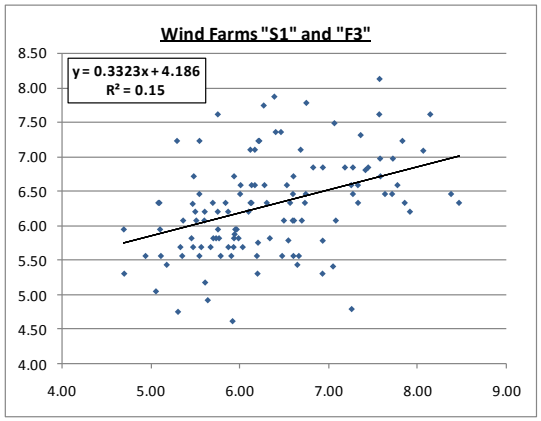


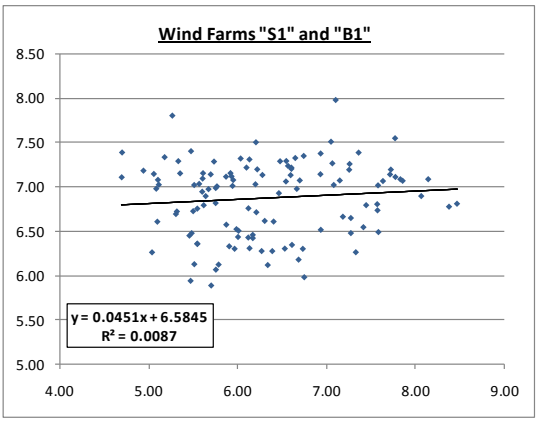


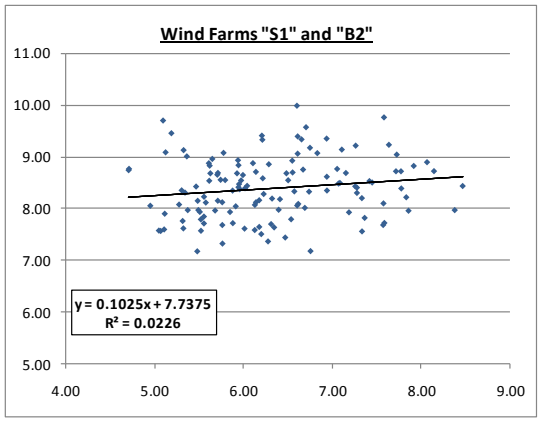


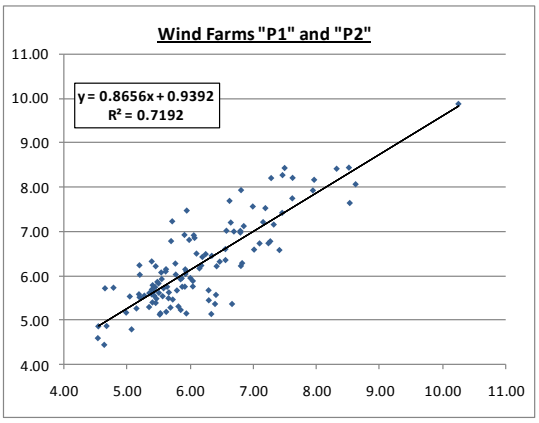
Graph C.2.1 (b): Correlation of the monthly averaged wind data (2).

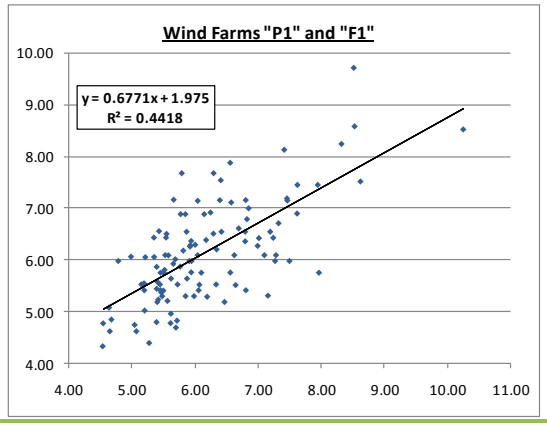
Case Study 2: Monthly Wind Data (3)

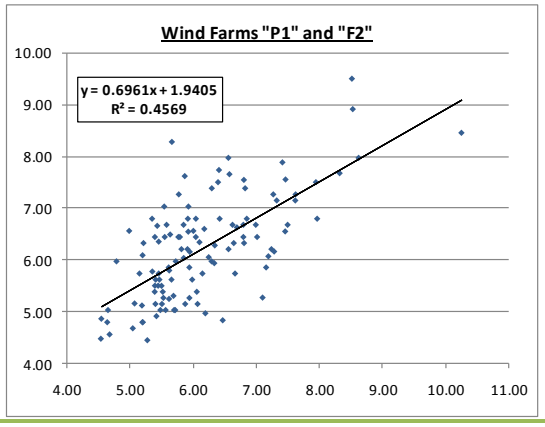






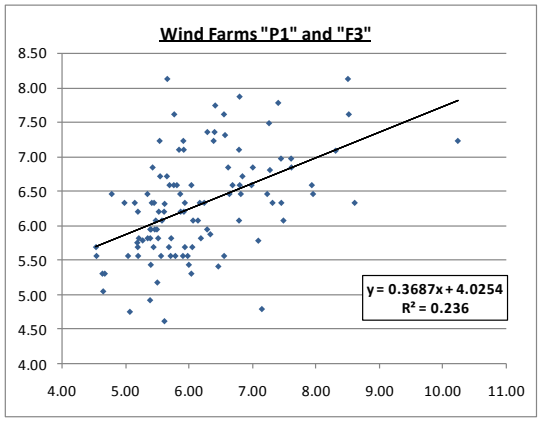


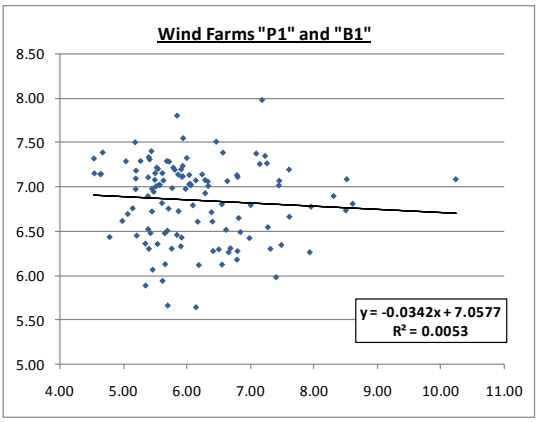


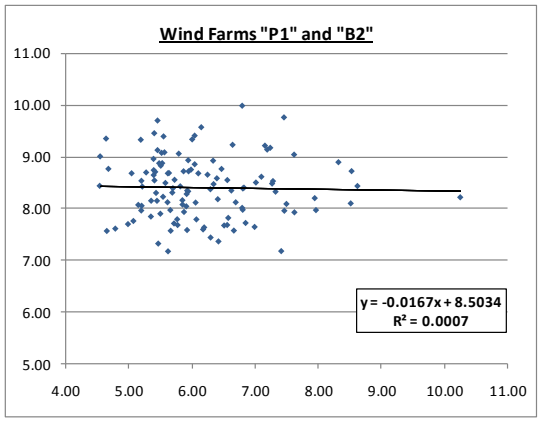


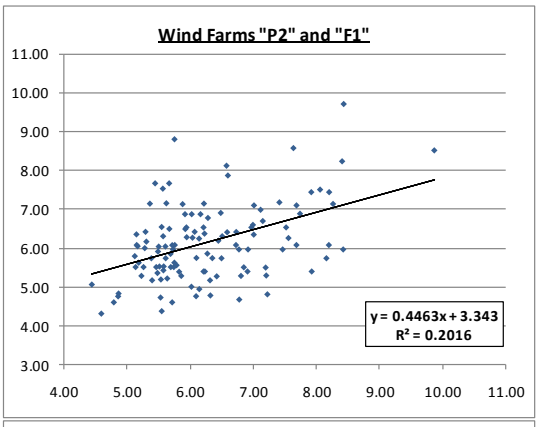
Graph C.2.1 (c): Correlation of the monthly averaged wind data (3).

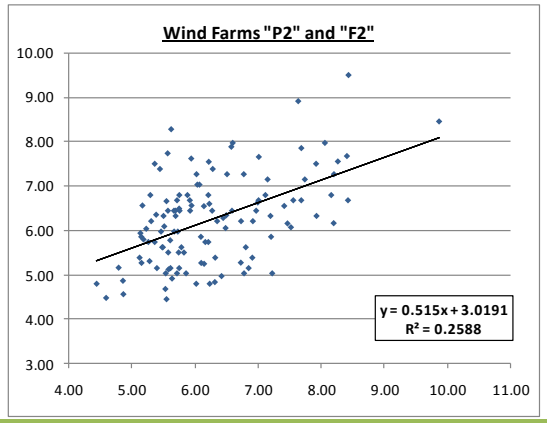
Case Study 2: Monthly Wind Data (4)

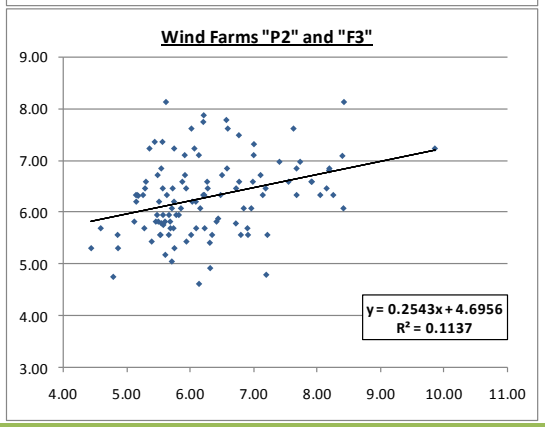






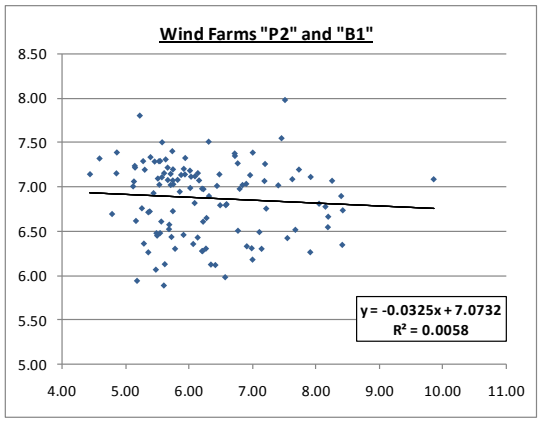


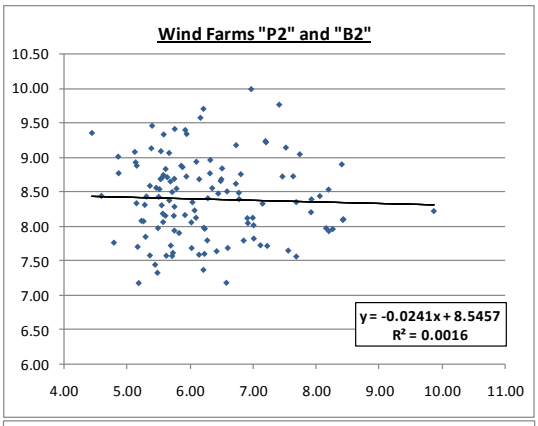


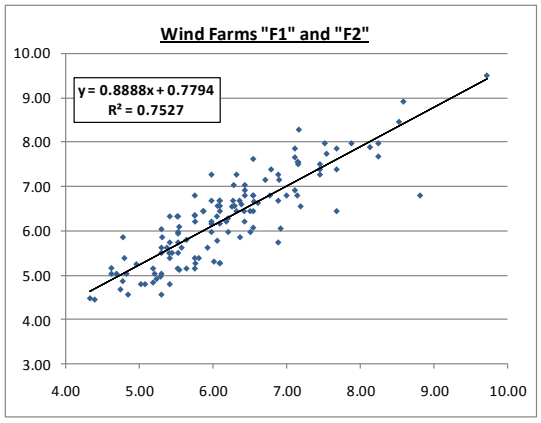


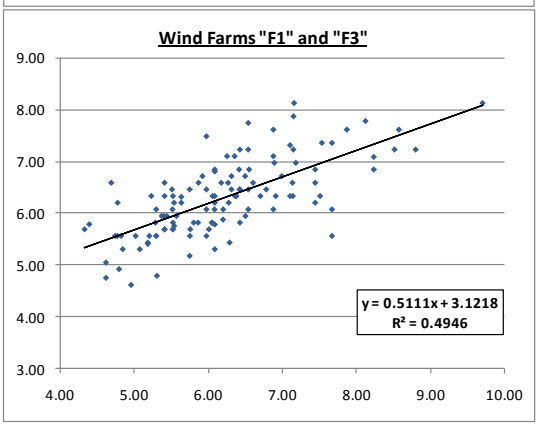
Graph C.2.1 (d): Correlation of the monthly averaged wind data (4).

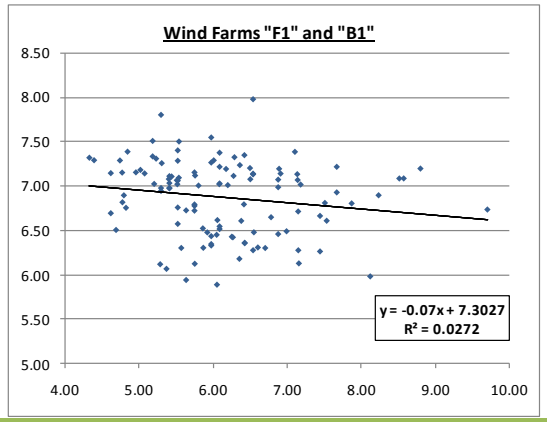
Case Study 2: Monthly Wind Data (5)

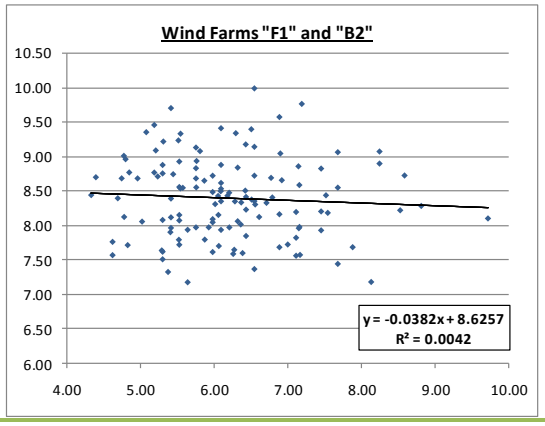






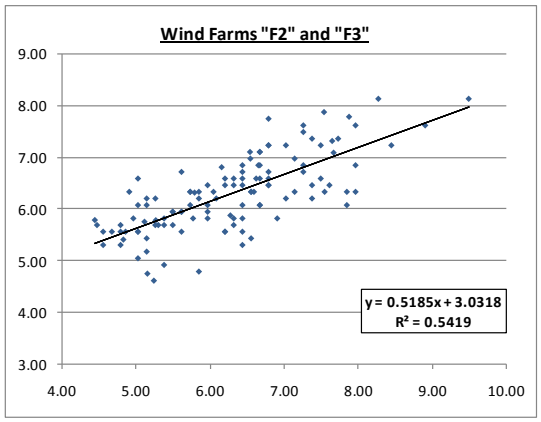


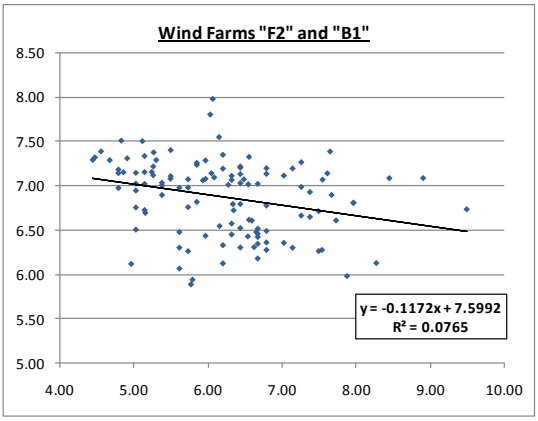


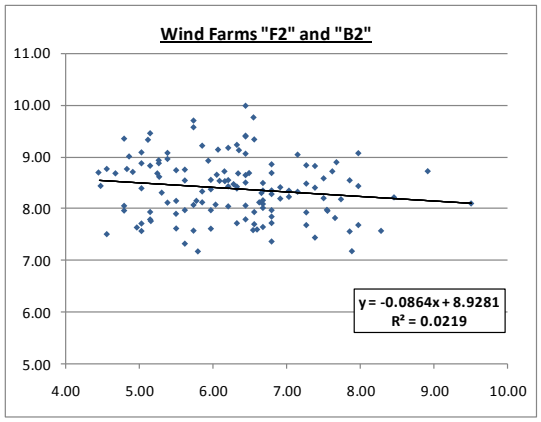


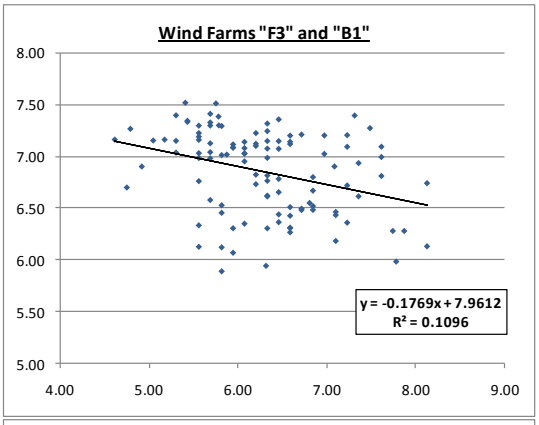
Graph C.2.1 (e): Correlation of the monthly averaged wind data (5).

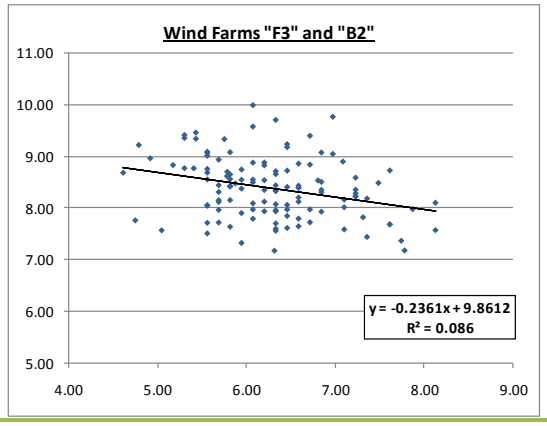
Case Study 2: Monthly Wind Data (6)

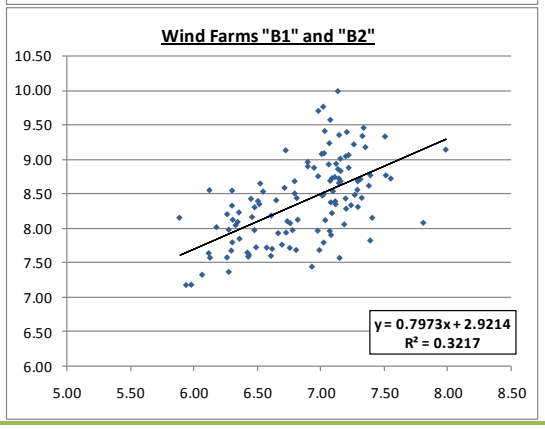












Graph C.2.1 (f): Correlation of the monthly averaged wind data (6).

C.2.2 Financial Model Inputs

Case Study 2 – Financial Model Input Parameters			
Wind Farm	**"T1"**	**"S1"**	**"P1"**
1. Revenues			
- N° of Units	36	2	22
- Power/Unit [MW/unit]	2.5	2.0	2.0
- Total Capacity [MW]	90.0	4.0	44.0
- Net Production (P90) [MWh/a]	262,010.0	7,600.0	94,810.0
- Tariff [€/MWh]	60,00	56,00	90,00
2. Investment Costs			
- Turbines [€]	75,600,000.0	3,360,000.0	39,960,000.0
- Planning, Infrastructure and Financing [€]	32,400,000.0	1,440,000.0	15,840,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	108,000,000.0	4,800,000.0	52,800,000.0
3. Others			
- Depreciation [€/year]	6,750,000.0	300,000.0	3,300,000.0

Table C.2.2 (a): Financial Model specific assumptions – Wind Farms "T1", "S1" and "P1".

Case Study 2 – Financial Model Input Parameters			
Wind Farm	**"P2"**	**"F1"**	**"F2"**
1. Revenues			
- N° of Units	17	6	5
- Power/Unit [MW/unit]	2.5	2.0	2.3
- Total Capacity [MW]	42.5	12.0	11.5
- Net Production (P90) [MWh/a]	77,995.0	20,235.0	16,720.0
- Tariff [€/MWh]	90,00	82,00	82,00
2. Investment Costs			
- Turbines [€]	35,700,000.0	10,080,000.0	9,660,000.0
- Planning, Infrastructure and Financing [€]	15,300,000.0	4,320,000.0	4,140,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	51,000,000.0	14,400,000.0	13,800,000.0
3. Others			
- Depreciation [€/year]	3,187,500.0	900,000.0	862,500.0

Table C.2.2 (b): Financial Model specific assumptions – Wind Farms "P2", "F1" and "F2".

Case Study 2 – Financial Model Input Parameters			
Wind Farm	**"F3"**	**"B1"**	**"B2"**
1. Revenues			
- N° of Units	9	12	247
- Power/Unit [MW/unit]	2.0	2.5	1.8
- Total Capacity [MW]	18.0	30.0	444.6
- Net Production (P90) [MWh/a]	40,660.0	59,280.0	1,177,145.0
- Tariff [€/MWh]	82,00	59,48	59,48
2. Investment Costs			
- Turbines [€]	15,120,000.0	25,200,000.0	373,464,000.0
- Planning, Infrastructure and Financing [€]	6,480,000.0	10,800,000.0	160,056,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	21,600,000.0	36,000,000.0	533,520,000.0
3. Others			
- Depreciation [€/year]	1,350,000.0	2,250,000.0	33,345,000.0

Table C.2.2 (c): Financial Model specific assumptions – Wind Farms "F3", "B1" and "B2".

Case Study 2 – Financial Model Input Parameters			
Wind Farm	**"All Wind Farms"**	**"Portfolio – V1"**	**"Portfolio – V2"**
1. Revenues			
- N° of Units	356	356	356
- Power/Unit [MW/unit]	2.18	2.18	2.18
- Total Capacity [MW]	775.3	775.3	775.3
- Net Production (P90) [MWh/a]	1,756,455.0	1,815,850.0	1,812,233.0
- Tariff [€/MWh]	63,55	63,55	63,55
2. Investment Costs			
- Turbines [€]	651,242,667.0	651,242,667.0	651,242,667.0
- Planning, Infrastructure and Financing [€]	279,104,000.0	279,104,000.0	279,104,000.0
- Total Unit Cost [€/MW]	1,200,000.0	1,200,000.0	1,200,000.0
- Total Investment Cost [€]	930,346,667.0	930,346,667.0	930,346,667.0
3. Others			
- Depreciation [€/year]	58,146,667.0	58,146,667.0	58,146,667.0

Table C.2.2 (d): Financial Model specific assumptions – all wind farms and the portfolios.

C.2.3 Financial Model Results

Wind Farm "T1"

Case Study 2 – Financial Model Results			
Wind Farm – "T1"			
- Total Investment Cost	108,000,000.0	- Wind Farm's Capacity Factor	33.2%
- Debt Finance percentage	80.4%	- Rate Operating cost/Revenues	28.5%
- Debt Finance amount [€]	86,784,787.0	- Rate Operating cost/Production [$/MWh]	21.1
- Equity percentage	19.6%	- Project Life Cover Ratio (PLCR)	1.74x
- Equity amount [€]	21,215,213.0	- Loan Life Cover Ratio (LLCR)	1.14x
- Internal Rate of Return	22.4%		

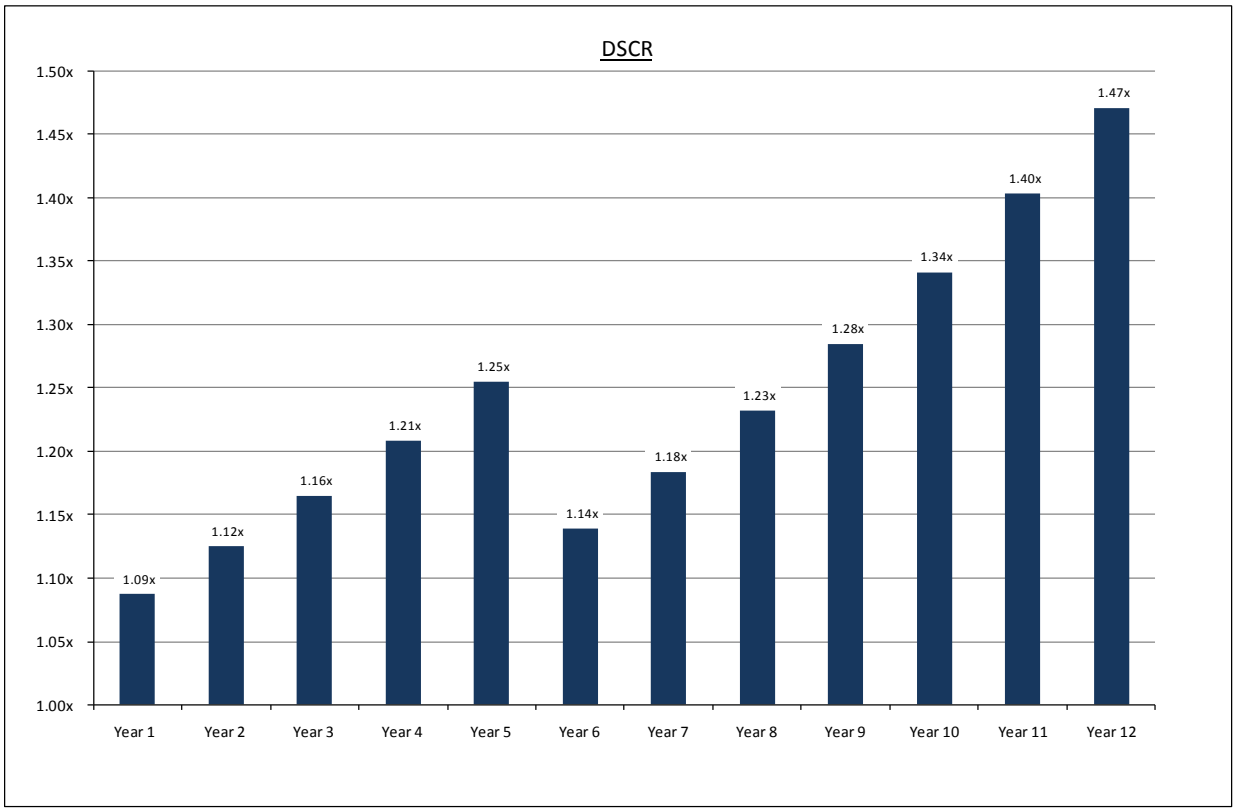


Table C.2.2 (a): Financial Model Main Results – Wind Farm "T1".

Wind Farm "S1"

Case Study 2 – Financial Model Results			
Wind Farm – "S1"			
- Total Investment Cost	4,800,000.0	- Wind Farm's Capacity Factor	21.7%
- Debt Finance percentage	45.7%	- Rate Operating cost/Revenues	46.8%
- Debt Finance amount [€]	2,192,334.0	- Rate Operating cost/Production [$/MWh]	32.4
- Equity percentage	54.3%	- Project Life Cover Ratio (PLCR)	1.76x
- Equity amount [€]	2,607,666.0	- Loan Life Cover Ratio (LLCR)	1.18x
- Internal Rate of Return	2.3%		

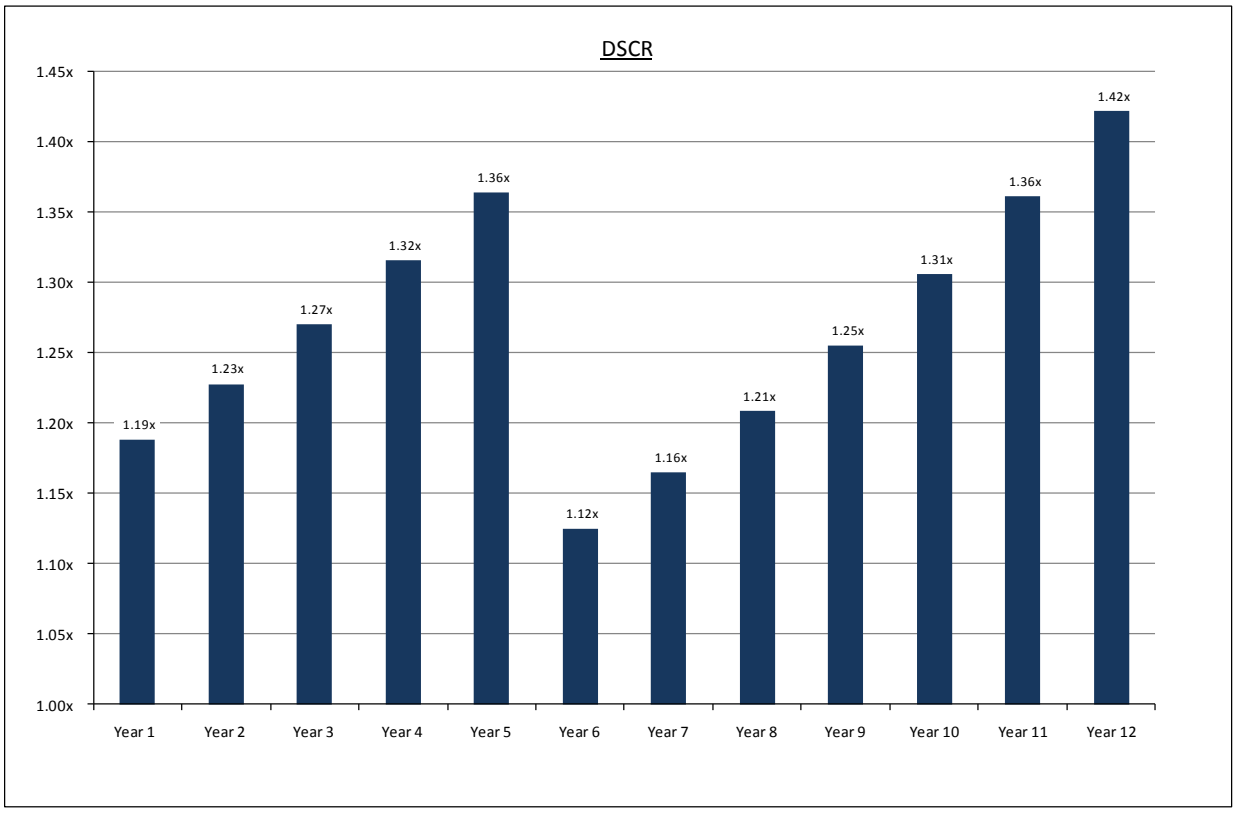


Table C.2.2 (b): Financial Model Main Results – Wind Farm "S1".

Wind Farm "P1"

Case Study 2 – Financial Model Results			
Wind Farm – "P1"			
- Total Investment Cost	52,800,000.0	- Wind Farm's Capacity Factor	24.6%
- Debt Finance percentage	90.1%	- Rate Operating cost/Revenues	25.7%
- Debt Finance amount [€]	47,595,471.0	- Rate Operating cost/Production [$/MWh]	28.5
- Equity percentage	9.9%	- Project Life Cover Ratio (PLCR)	1.74x
- Equity amount [€]	5,204,529.0	- Loan Life Cover Ratio (LLCR)	1.13x
- Internal Rate of Return	49.9%		

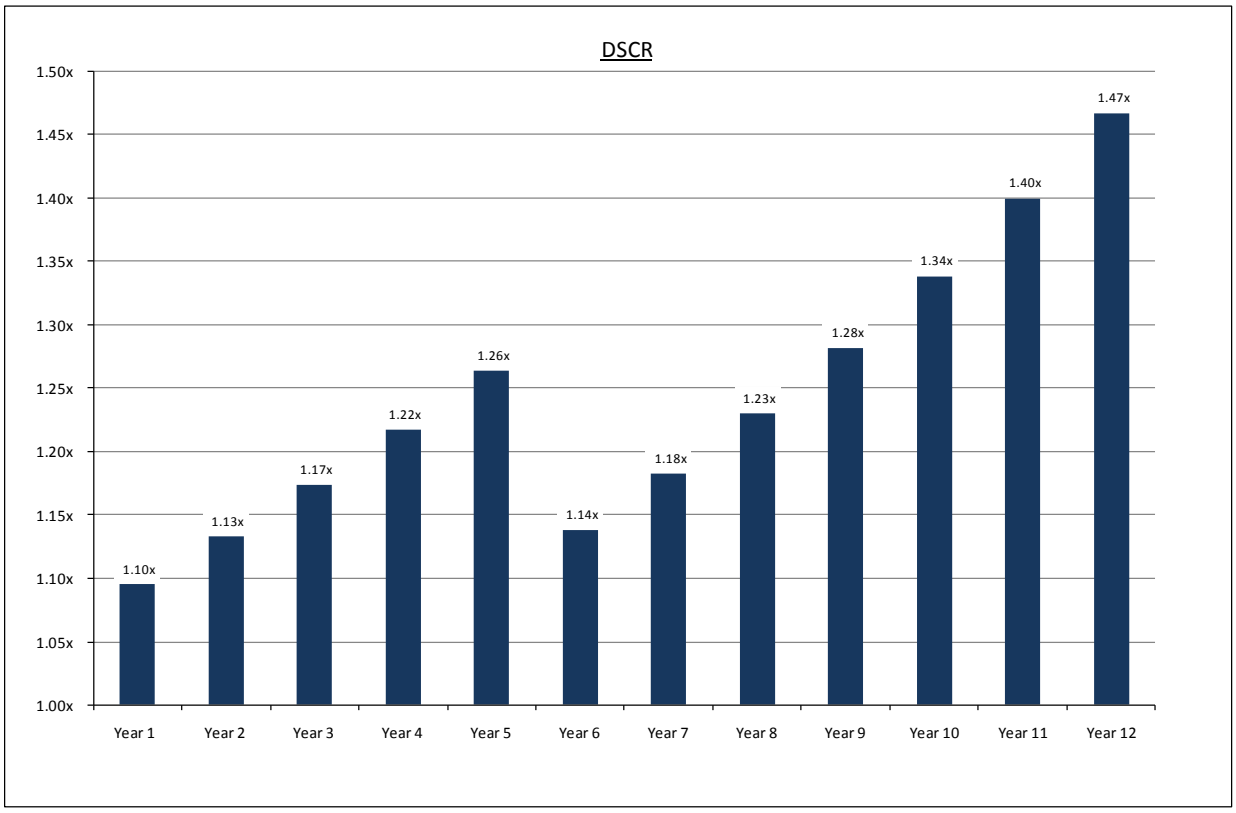


Table C.2.2 (c): Financial Model Main Results – Wind Farm "P1".

Wind Farm "P2"

Case Study 2 – Financial Model Results			
Wind Farm – "P2"			
- Total Investment Cost	51,000,000.0	- Wind Farm's Capacity Factor	20.9%
- Debt Finance percentage	75.5%	- Rate Operating cost/Revenues	30.1%
- Debt Finance amount [€]	38,521,717.0	- Rate Operating cost/Production [$/MWh]	33.5
- Equity percentage	24.5%	- Project Life Cover Ratio (PLCR)	1.74x
- Equity amount [€]	12,478,283.0	- Loan Life Cover Ratio (LLCR)	1.14x
- Internal Rate of Return	18.0%		

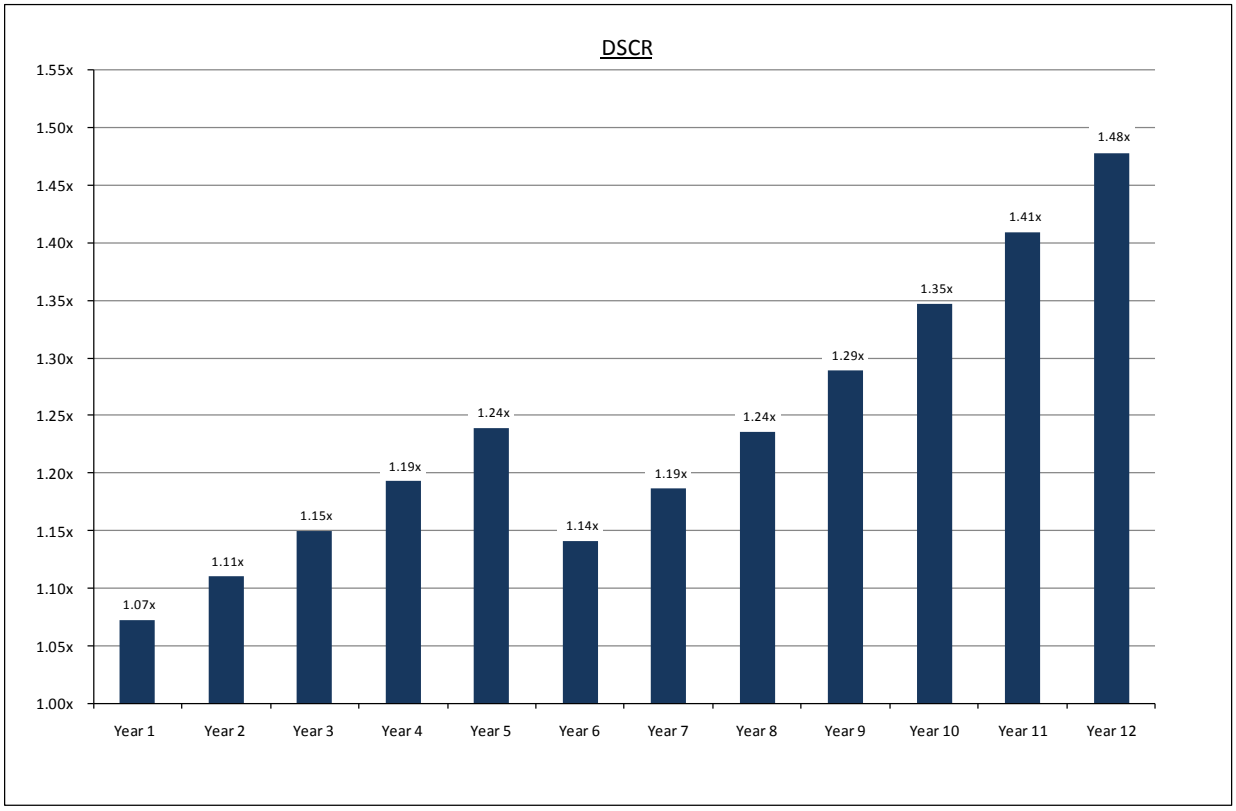


Table C.2.2 (d): Financial Model Main Results – Wind Farm "P2".

Wind Farm "F1"

Case Study 2 – Financial Model Results			
Wind Farm – "F1"			
- Total Investment Cost	14,400,000.0	- Wind Farm's Capacity Factor	19.2%
- Debt Finance percentage	61.9%	- Rate Operating cost/Revenues	36.0%
- Debt Finance amount [€]	8,908,665.0	- Rate Operating cost/Production [$/MWh]	36.5
- Equity percentage	38.1%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	5,491,335.0	- Loan Life Cover Ratio (LLCR)	1.16x
- Internal Rate of Return	8.95%		

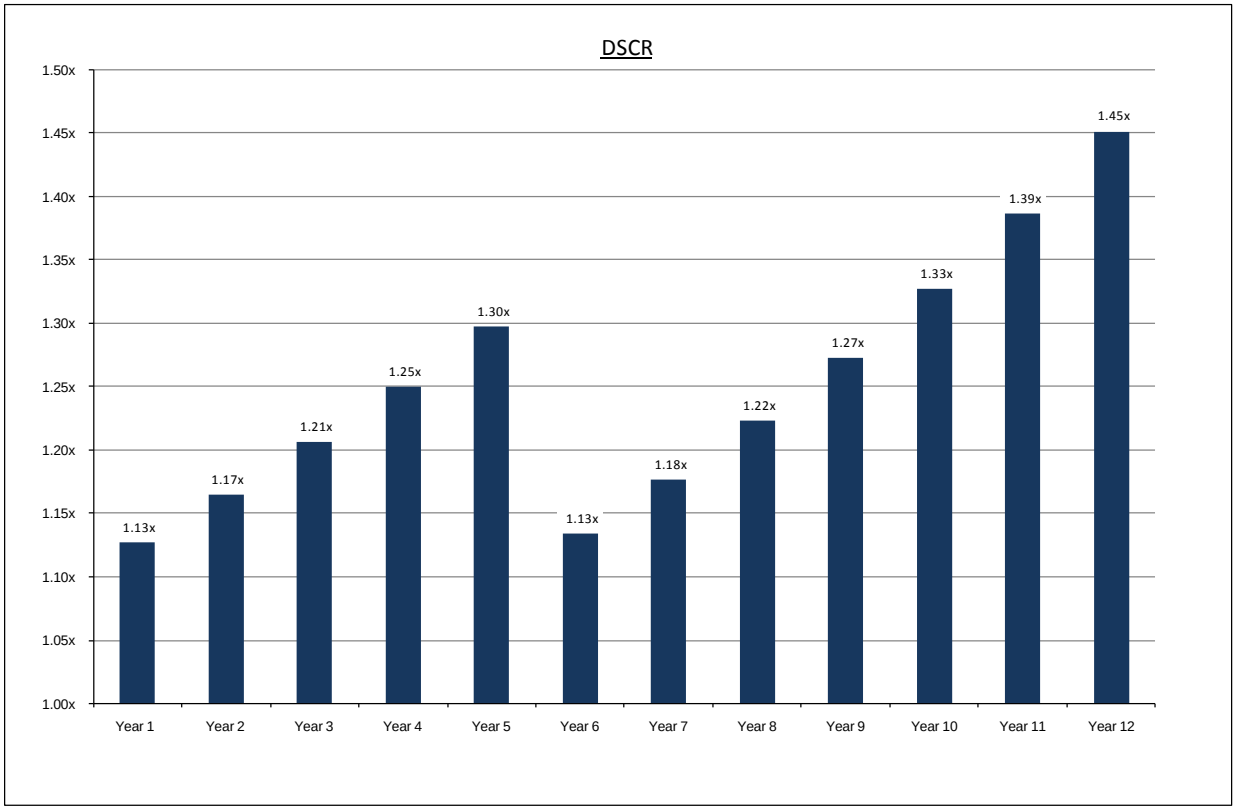


Table C.2.2 (e): Financial Model Main Results – Wind Farm "F1".

Wind Farm "F2"

Case Study 2 – Financial Model Results			
Wind Farm – "F2"			
- Total Investment Cost	13,800,000.0	- Wind Farm's Capacity Factor	16.6%
- Debt Finance percentage	52.2%	- Rate Operating cost/Revenues	41.7%
- Debt Finance amount [€]	7,201,939.0	- Rate Operating cost/Production [$/MWh]	42.3
- Equity percentage	47.8%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	6,598,061.0	- Loan Life Cover Ratio (LLCR)	1.17x
- Internal Rate of Return	5.09%		

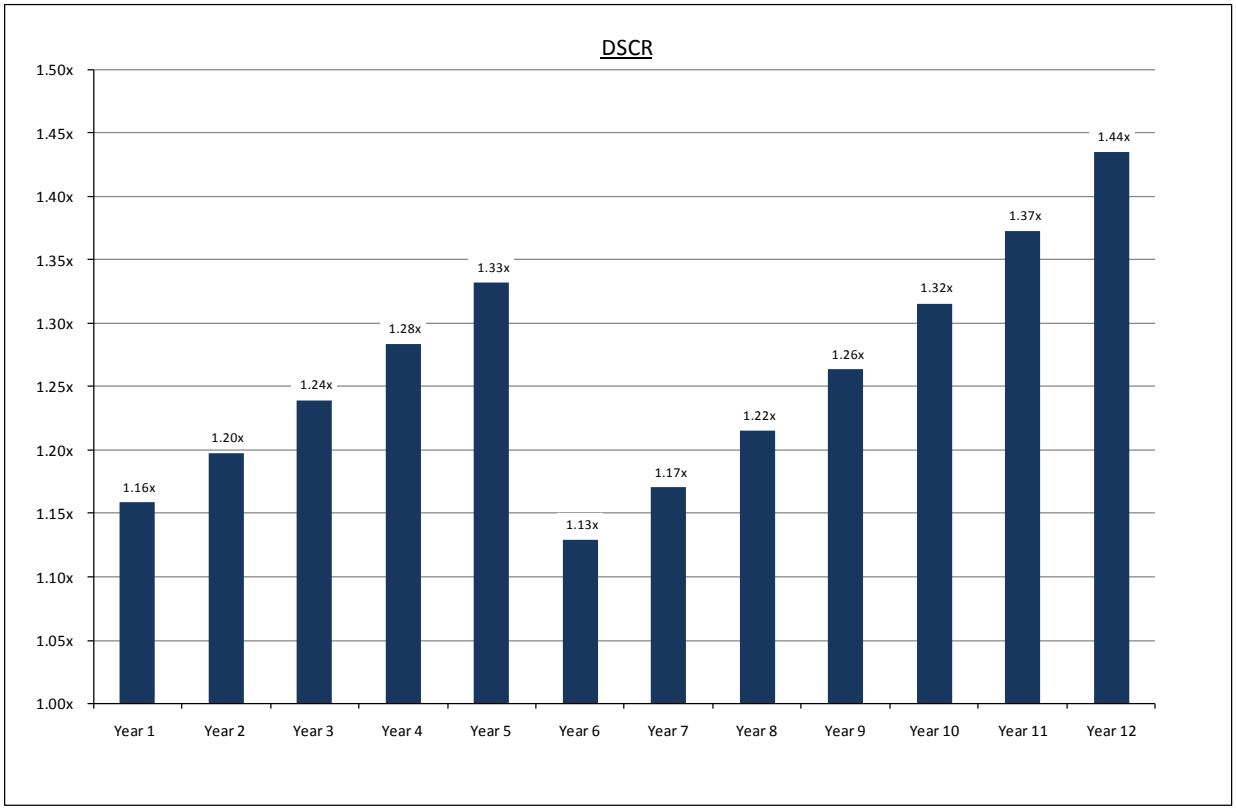


Table C.2.2 (f): Financial Model Main Results – Wind Farm "F2".

Wind Farm "F3"

Case Study 2 – Financial Model Results			
Wind Farm – "F3"			
- Total Investment Cost	21,600,000.0	- Wind Farm's Capacity Factor	25.8%
- Debt Finance percentage	85.7%	- Rate Operating cost/Revenues	26.9%
- Debt Finance amount [€]	18,515,652.0	- Rate Operating cost/Production [$/MWh]	27.2
- Equity percentage	14.3%	- Project Life Cover Ratio (PLCR)	1.74x
- Equity amount [€]	3,084,348.0	- Loan Life Cover Ratio (LLCR)	1.14x
- Internal Rate of Return	38.2%		

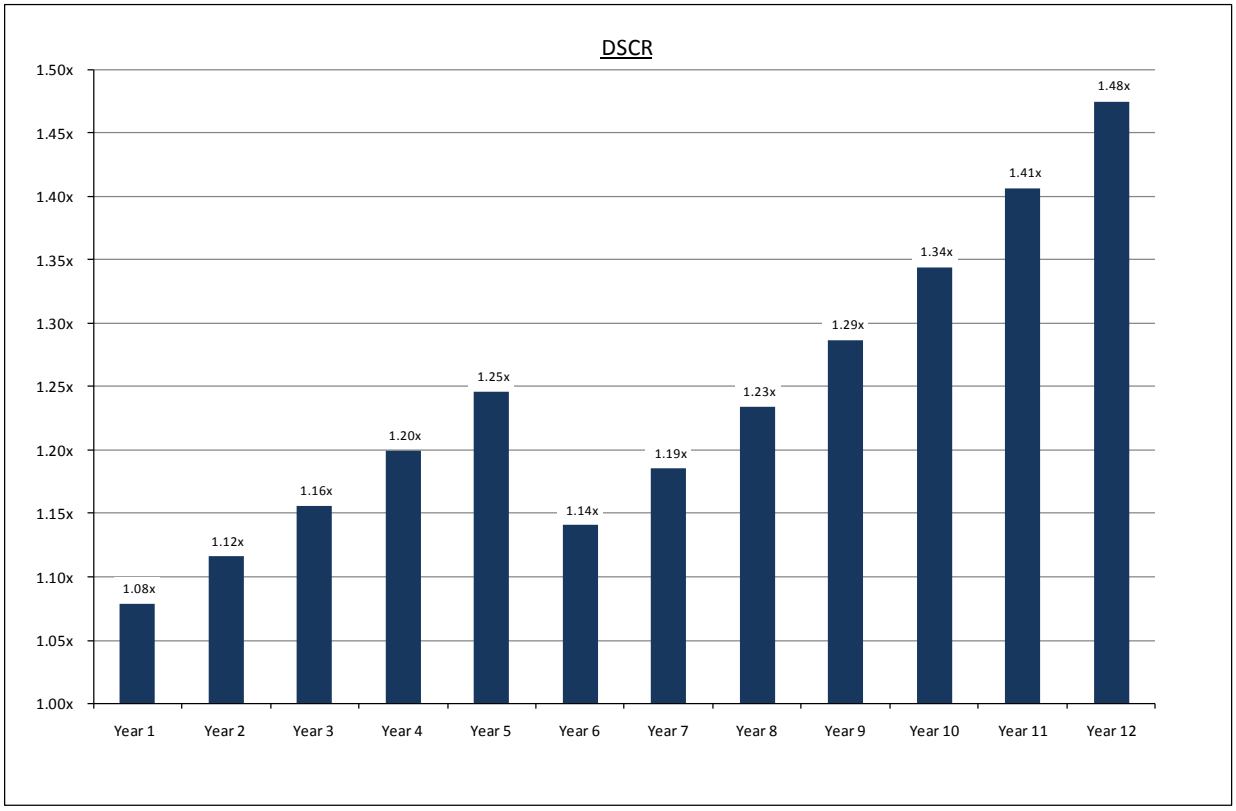


Table C.2.2 (g): Financial Model Main Results – Wind Farm "F3".

Wind Farm "B1"

Case Study 2 – Financial Model Results			
Wind Farm – "B1"			
- Total Investment Cost	36,000,000.0	- Wind Farm's Capacity Factor	22.6%
- Debt Finance percentage	51.3%	- Rate Operating cost/Revenues	42.3%
- Debt Finance amount [€]	18,478,654.0	- Rate Operating cost/Production [$/MWh]	31.3
- Equity percentage	48.7%	- Project Life Cover Ratio (PLCR)	1.76x
- Equity amount [€]	17,521,346.0	- Loan Life Cover Ratio (LLCR)	1.17x
- Internal Rate of Return	4.8%		

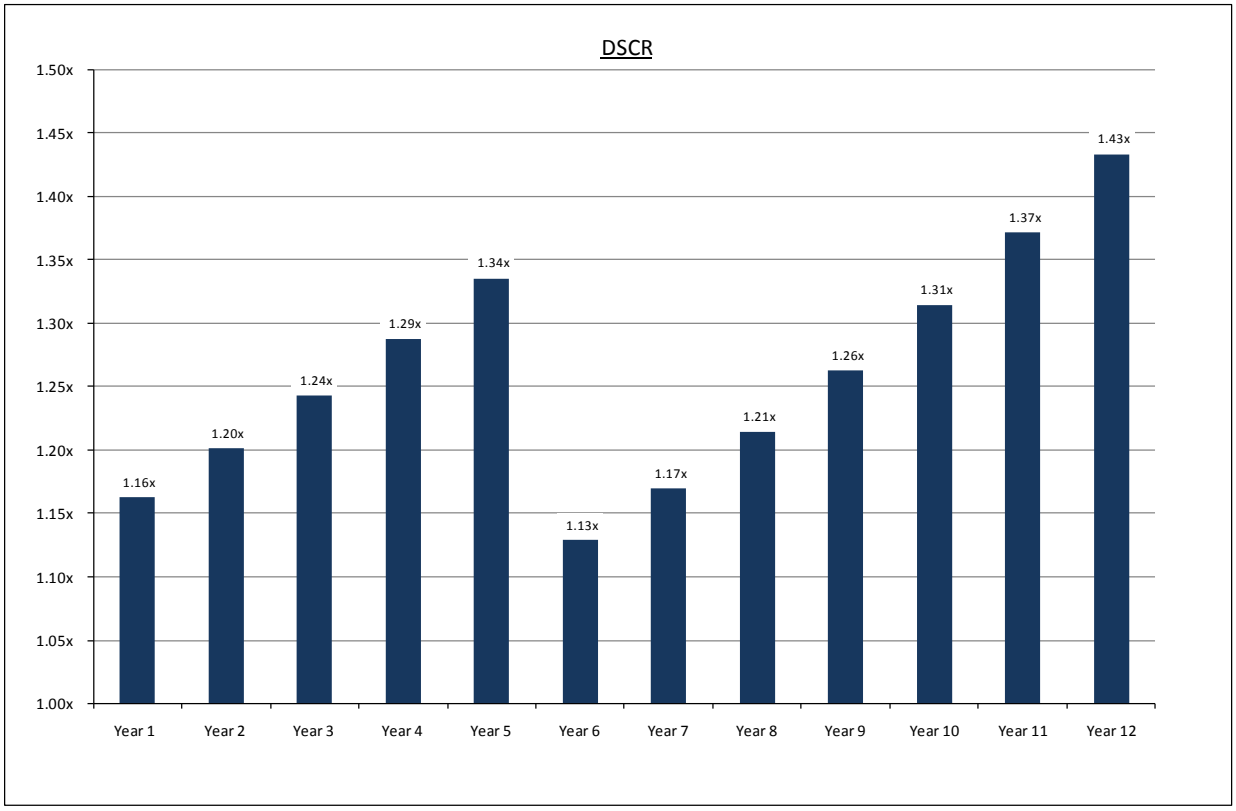


Table C.2.2 (h): Financial Model Main Results – Wind Farm "B1".

Wind Farm "B2"

Case Study 2 – Financial Model Results			
Wind Farm – "B2"			
- Total Investment Cost	533,520,000.0	- Wind Farm's Capacity Factor	30.2%
- Debt Finance percentage	71.6%	- Rate Operating cost/Revenues	31.6%
- Debt Finance amount [€]	382,161,112.0	- Rate Operating cost/Production [$/MWh]	23.2
- Equity percentage	28.4%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	151,358,888.0	- Loan Life Cover Ratio (LLCR)	1.15x
- Internal Rate of Return	15.3%		

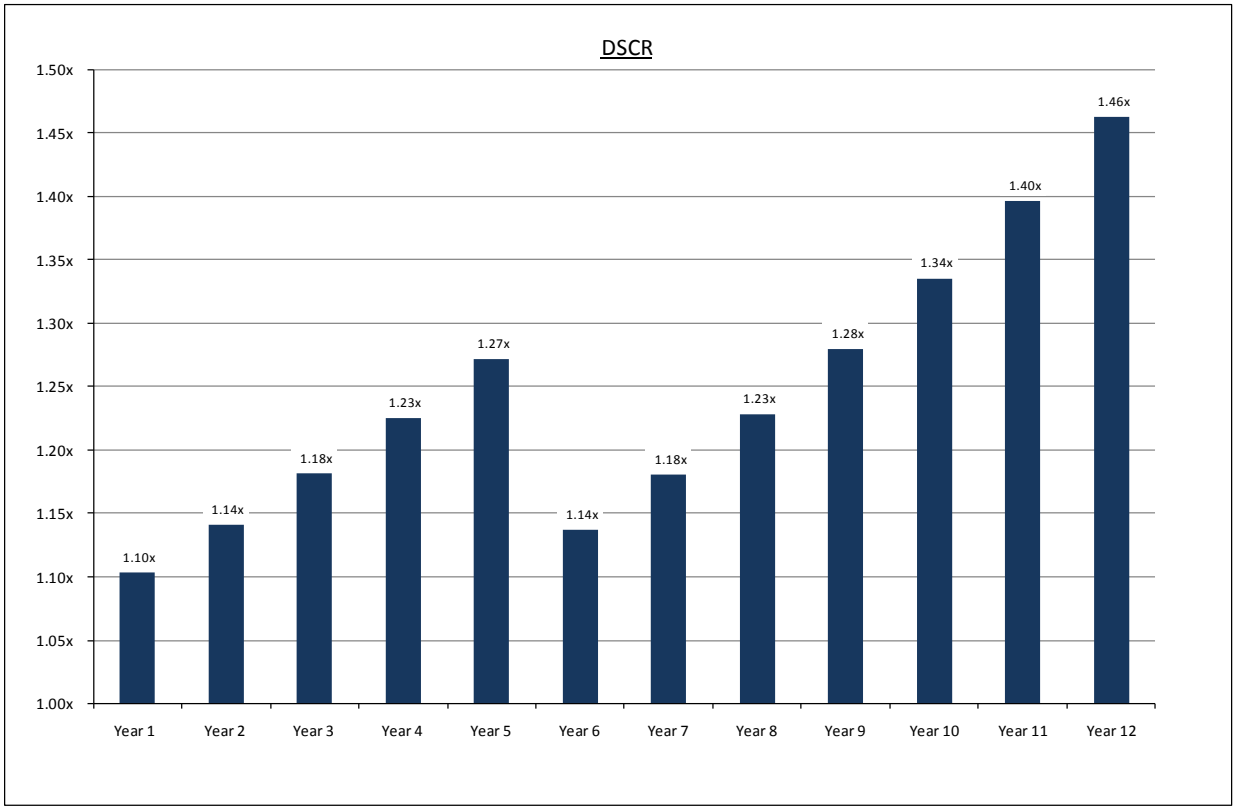


Table C.2.2 (i): Financial Model Main Results – Wind Farm "B2".

Sum of All WFs

Case Study 2 – Financial Model Results			
Sum of all WFs (Not considering Portfolio Effects)			
- Total Investment Cost	930,346,667.0	- Wind Farm's Capacity Factor	28.8%
- Debt Finance percentage	64.8%	- Rate Operating cost/Revenues	34.6%
- Debt Finance amount[€]	602,571,905.0	- Rate Operating cost/Production [$/MWh]	27.1
- Equity percentage	35.2%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	327,774,762.0	- Loan Life Cover Ratio (LLCR)	1.15x
- Internal Rate of Return	11.4%		

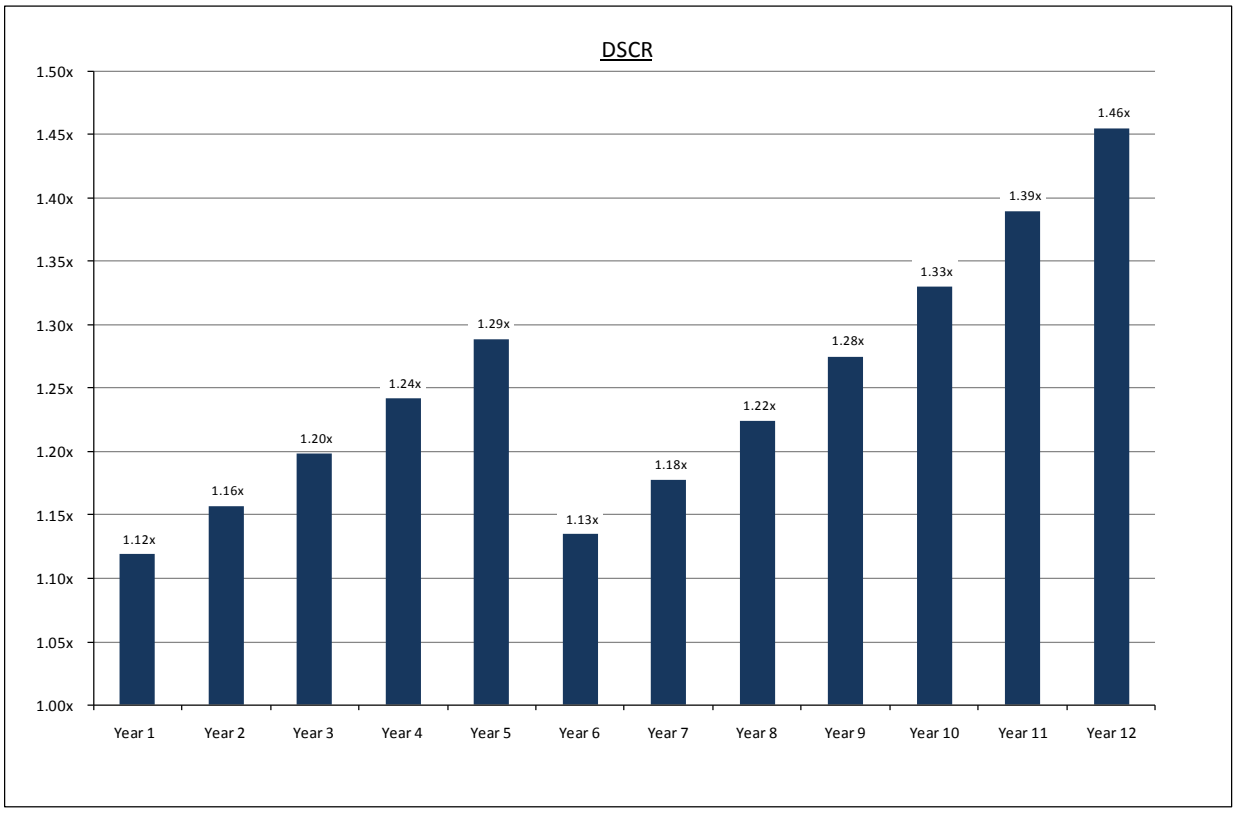


Table C.2.2 (j): Financial Model Main Results – All wind farms. Not considering Portfolio Effects.

Portfolio – Variant 1

Case Study 2 – Financial Model Results			
Portfolio – Variant 1			
- Total Investment Cost	930,346,667.0	- Wind Farm's Capacity Factor	29.8%
- Debt Finance percentage	67.2%	- Rate Operating cost/Revenues	33.4%
- Debt Finance amount[€]	625,623,223.0	- Rate Operating cost/Production [$/MWh]	26.3
- Equity percentage	32.8%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	304,723,444.0	- Loan Life Cover Ratio (LLCR)	1.15x
- Internal Rate of Return	12.7%		

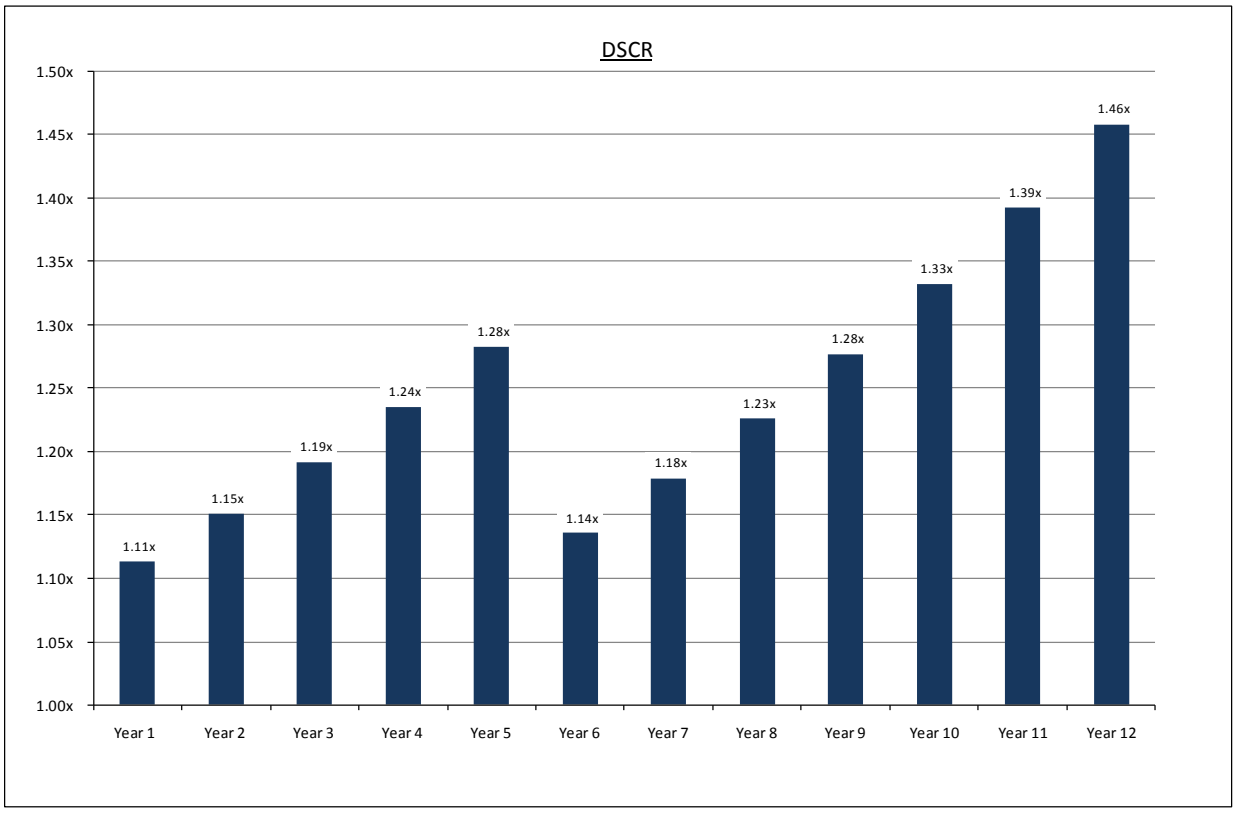


Table C.2.2 (k): Financial Model Main Results – Portfolio Variant 1 (Correlation of 10 min wind data)

Portfolio – Variant 2

Case Study 2 – Financial Model Results			
Portfolio – Variant 2			
- Total Investment Cost	930,346,667.0	- Wind Farm's Capacity Factor	29.7%
- Debt Finance percentage	67.1%	- Rate Operating cost/Revenues	33.5%
- Debt Finance amount[€]	624,217,688.0	- Rate Operating cost/Production [$/MWh]	26.3
- Equity percentage	32.9%	- Project Life Cover Ratio (PLCR)	1.75x
- Equity amount [€]	306,128,978.0	- Loan Life Cover Ratio (LLCR)	1.15x
- Internal Rate of Return	12.6%		

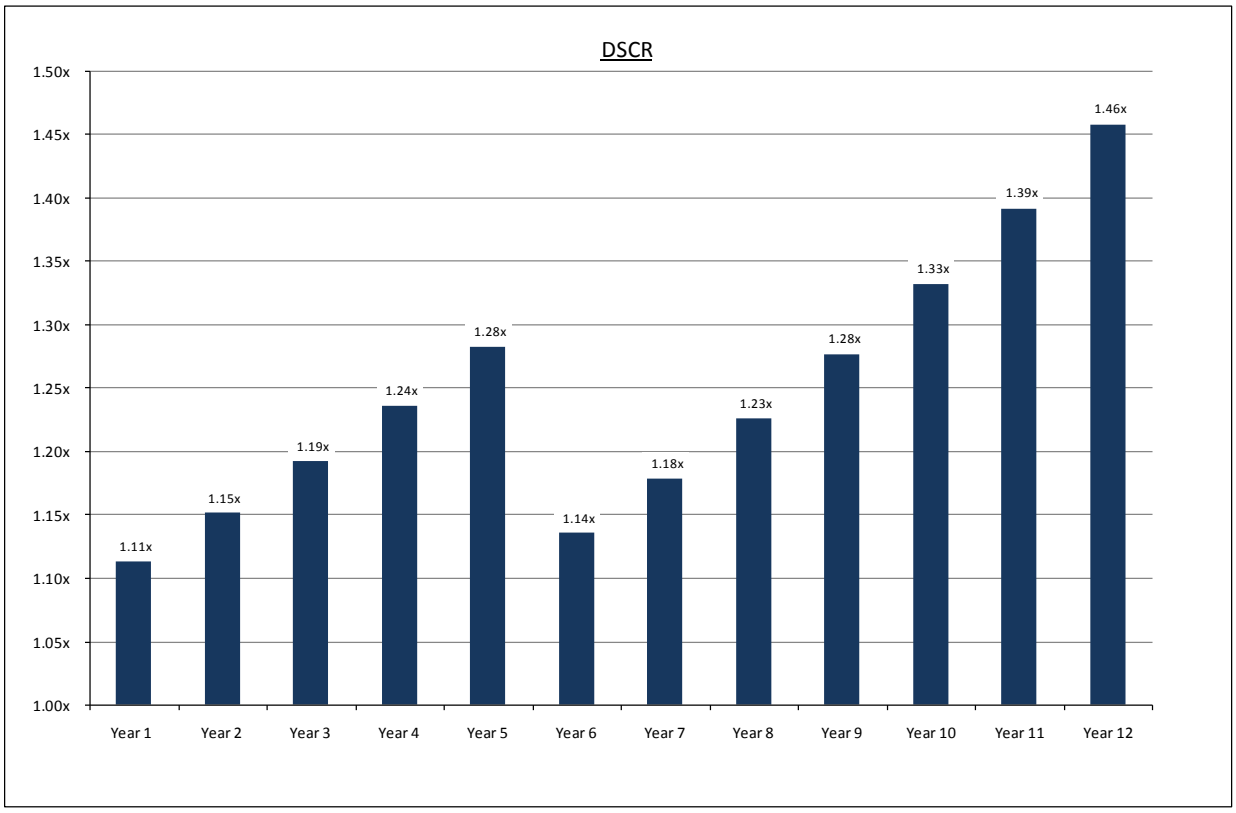


Table C.2.2 (l): Financial Model Main Results – Portfolio Variant 2 (Correlation of monthly averaged wind data)

Erklärung

Ich erkläre hiermit gemäß § 9 Satz 2 c der Promotionsordnung, dass ich die Leitlinien guter wissenschaftlicher Praxis von der Carl von Ossietzky Universität Oldenburg befolgt habe.

Oldenburg, den 28.01.2013

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Patricia Chaves-Schwinteck