Postgraduate Programme Renewable Energy (PPRE)

Universität Oldenburg

DLR (German Aerospace Center)

Institute of Technical Thermodynamics
System Analysis and Technology Assessment Department

Renewable Electricity (RES-E) Policy Implications On Market Actors In Germany

Modelling and Analysis focusing on Onshore Wind and PV Plant Operation and Investment

Master Thesis

Author :	Mohamed Mamdouh M. Labib ELKadragy	
1st Supervisor :	Prof. Dr. Jürgen Parisi	PPRE (University of Oldenburg)
2nd Supervisor :	Dr. Detlev Heinemann	PPRE (University of Oldenburg)
Direct Supervisor:	Dipl.-Ing. Matthias Reeg	DLR (German Aerospace Center)
Examination Date:	25.03.2014	

"THE ULTIMATE THANKS TO ALLAH (ALMIGHTY) WHO GAVE ME THE STRENGTH AND OPPORTUNITY TO COMPLETE THIS WORK,,

Acknowledgements

Special thanks for the efforts of the technical advisors:

Prof.	Wolfgang Pfaffenberger	University of Oldenburg
Dr.	Marc Deissenroth	DLR - TT, Stuttgart
Ms.	Kristina Nienhaus	DLR - TT, Stuttgart
Mr.	Jörg Könisser	Advace Group, Germany
Dr.	Ole Langniss	Fichtner, Germany

For my family, wife "Mariam" and three month old son "Omar" who were and will always be the backbone of any achievement in my life. Thanks to Dr. Rageb who gave me the main motivation for doing this scientific work. Thanks to Mattias Reeg who gave me the opportunity to work on such an interesting topic, Dr. Heinemann who supported this work scientifically and managerially. My appreciations for Hans Holtorf and all the PPRE stuff members and lecturers. Thanks to my PPRE and DLR colleagues, Christoph, Casten, Uwe, Tobias, Yvonne, Jürg, Hussien, Henrik, Franz, Massimo, Karl, Marlene, Sonja, Thomas, Steffen, Hans, Denis and special thanks for Sven.

Declaration

I state and declare that this thesis was prepared by me in accordance with the best practice guidelines for scientific work of the University of Oldenburg and that no means or sources have been used, except those, which I cited and listed in the References section.

Stuttgart, 18th of March 2014

Mohamed Mamdouh M.Labib Elkadragy

Contents

List of Abbreviations

Auc	Auctioned
CAPM	Capital Asset Pricing Model
CP	Capacity Payment
DSCR	Debt Service Coverage Ratio
EU	European Union
FIT	Feed-In Tariff
IRR	Internal Rate Of Return
LCOE	Levelized Cost of Electricity
MPexante	Market Premium Ex-Ante
MPexpost	Market Premium Ex-Post
NPV	Net Present value
O&M	Operation and Maintenance
PV	PhotoVoltaic
Reg	Regulated
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources Electricity
RESMIP	RES-E Support Mechanisms implications on Investment and Plant Operation
SM	Support Mechanisms
TSO	Transmission System Operator
WACC	Weighted Average cost of Capital

List of Figures

List of Tables

1 Introduction

The term "*alternative energy*" was born in 70's as a consequence of the political situation in the Middle East (in the year 1973) when the oil supplies (specially from Saudi-Arabia and Iran) to the west was stopped or redirected to Egypt on the background of the war situation. And since then, the security of the supply and searching for alternative energy resources is on the top of the agenda of the industrialized countries. The term was then changed to the most widely used one "*renewable energy*" , and renewable energy sources now are a fundamental element in the energy mix in the future scenarios of many countries whether developing or industrialized.

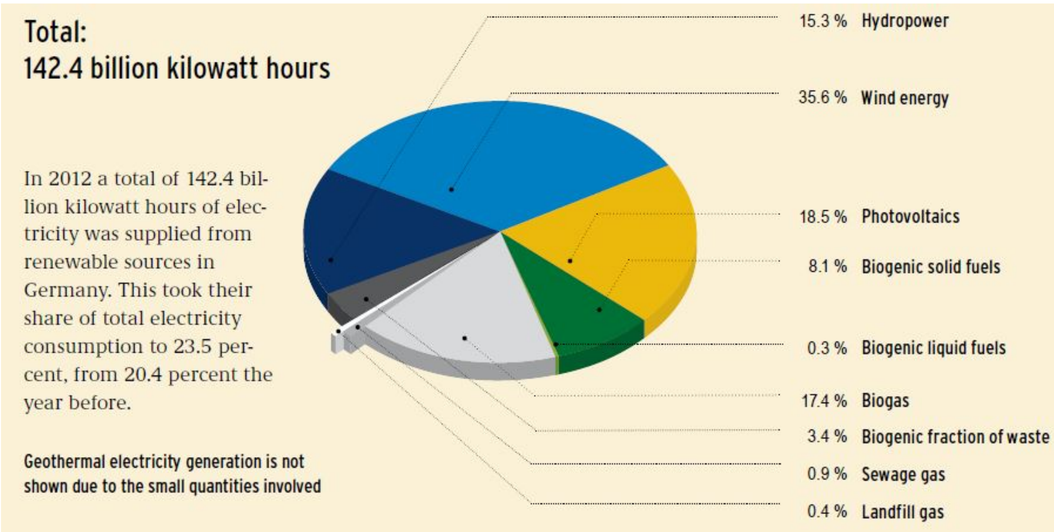

Figure 1.1: Structure of RES-E supply in Germany 2012
Source: [BMU14]

In Germany Renewable Energy Sources for Electricity (RES-E) are transforming from a supportive to a main source of Electricity. In the year 2000 the Energy Source Act (EEG) was implemented with a fixed feed-in-tariff (FIT) to build a foundation for the RES market , and boost the RES-E share in the electricity profile of Germany [DBMF12]. The current RES-E share of the total electricity consumption has risen above expectations with a share of 23.5 % in the year 2012 [BMU14]. This share which includes a high portion of fluctuating and inflexible RES such as wind and solar as presented in figure 1.1 on one hand, and the need of generation and demand balancing on the electricity grid on the other hand, requires reconsideration of the incentive schemes oriented to shifting the operation behaviour from the current "produce and Forget" strategy into a more demand oriented one. Some politicians and scientists are arguing that this RES increase is too fast and can have a negative effect on the electricity market. They also refer to the Fixed Feed In Tariff (FIT) scheme as the reason of such an effect and that it is outdated[BPAZB12]. Consequently it has to be reviewed or replaced with other schemes supporting RES direct marketing to create a supply and demand coordination in order to avoid any consequences on the energy security in the presence of high shares of highly fluctuating RES.

The new proposed supporting mechanisms for the German energy policy, aim to integrate the RES-E into the market. Introducing mechanisms as Market Premium to link the remuneration with energy market prices, doesn't target a fundamental change in the supporting mechanisms structure, but it gives an incentive for the RES-E market actors (like investors and power plant operators) to gain the initial market experience that can help in the future steps of RES-E wide market integration [GP13a]. The existence of the sliding market premium on monthly bases in parallel with the fixed feed-in tariff, gives the investor the choice to take his investment decision based on the lower risk coupled with the adapted scheme on one hand, and the possibility of achieving higher revenues on the other hand. In addition to helping the market actors to gain enough market experience, the German RES-E supporting schemes and mechanisms have a positive influence on the deployment of the RES-E helping to reach the future RES-E scenario targets [BMU12a]. On the long term when today's technologies become more mature, the market actors can take advantage of the early gaining of market experience and participating in a "Competitive Auction" RES-E market, which appears to be the unavoidable heirs to successful Feed-In Tariff programs[BPAZB12].

1.1 Background

Why RES-E needs support mechanisms? The high costs of RES-E, in addition to the dispatchability and high fluctuation of resources have made it impossible for the RES-E to grow without regulatory intervention. The design of mechanisms varies in order to create incentives that can lead to the fulfilment of certain objectives. Mechanisms design criteria differ according to digression rules, caps, eligibility periods and the degree of differentiation between RES-E technologies[LEG12]. Different mechanisms are currently implemented in the EU like the feedin-tariffs, feedin-premiums, quota obligations and other instruments as shown in figure 1.2 , even parallel existing RES-E schemes are adapted like the current case in Germany with the feedin-tariff and the market premium.

Germany had successfully boosted the deployment of diverse RES-E technologies helping in taking them along the learning curves and support the immature technologies to move beyond the R&D phase to participate in the RES-E market. This diversity is extremely important as we do not know which of these technological mixes can create the optimum solution for a 100% RES future. In comparison with other European members like UK, the German support mechanisms have been more successful as shown in figure 1.3. The installed capacity of wind energy in Germany has risen from 48 MW in 1990 to 4500 MW in 2000 (when the EEG replaced the StrEG), reaching 20,622 MW in 2006 [BME06].UK remained with low increase from 10 MW in 1990 to 1960 MW by the end of 2006 [IEA04].

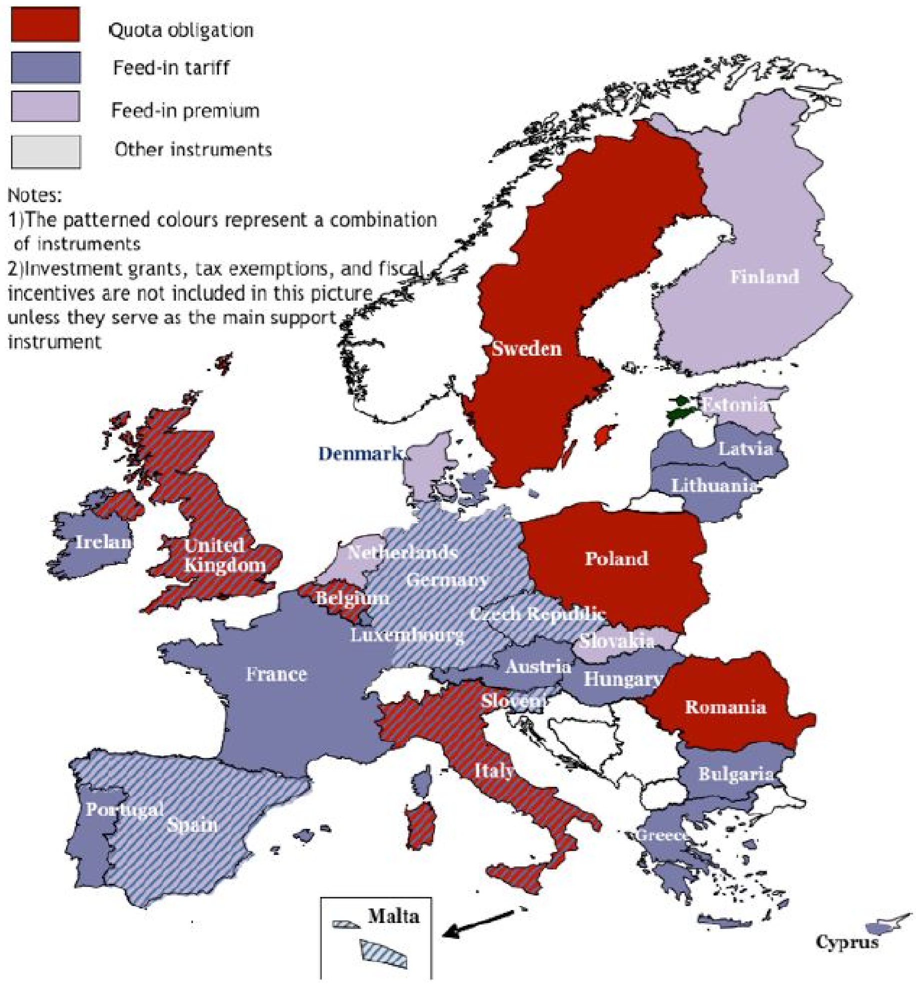

Figure 1.2: Renewable Energy support mechanisms in EU Member states
Source: [Bey12]

The market premium schemes have three main objectives in general; First is the market integration of RES-E in a narrow sense, second is the RES-E system integration by providing the RES-E plant operators with incentives to supply balancing power and ancillary services and encourage demand oriented production. Finally, to create an incentive for the change of distribution channels through direct marketing [GP13a].

These objectives can be effective to engage the RES-E plant operators to the market prices in terms of gaining enough experience about the market. However, it is questionable whether it is confirmed that the current mechanism design is sufficient to integrate all kinds or RES-E specially the non-dispatchable intermittent RES like wind and solar into electricity market in the future, beside the encouragement of investments in flexible plant designs on the longer run or not.

1.2 Objectives and Questions

New policies have to be proposed and adapted to structure an economical sustainable and environmental friendly RES market under the scenario targets of the "energy con-

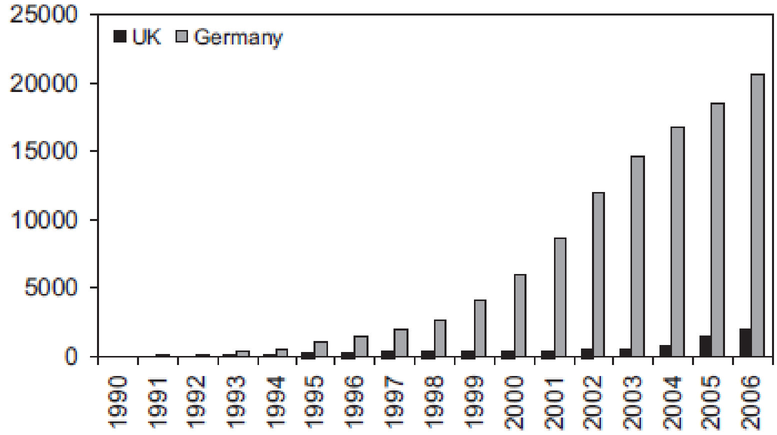

Figure 1.3: Installed capacity in Germany and the UK (1990-2004).
Source:[BN08]

cept" of the year 2011 (35% share of RES in electricity production by 2020, 50% by 2030, 65% by 2040 and up to 80% by 2050), and even more ambitious scenarios like the (BMU) "lead Study"[DLR12] (86%— of RES share in 2050). The other scenarios target is 100% renewable by 2050 . These new policies will lead to a new market structure which will have an impact on all actors of Energy market.

Most of the regulatory design of RES-E support mechanisms focus on discussing the effectiveness and efficiency of the different mechanisms. While there are some few studies take into consideration the analysis of impact on market actors and market structure, in addition to the advantages and disadvantages of the support mechanism components[BPAZB12]. An empirical market related research or practical modelling efforts have to be carried out to avoid these impacts being overlooked, while the importance of RES-E is raising in Germany.

"On the one hand, VRE[1] generators need to be exposed to price signals that reflect the different value of electricity (depending on the time and location of generation), so as to facilitate system integration. On the other hand, VRE requires capital-intensive technology and as such, is highly sensitive to investment risk, a risk that is increased by short-term price exposure. An appropriate market design will need to strike a delicate balance between these two objectives." [IEA14].

This is the main challenge this study is trying to come up with a solution for ; through focusing on the analysis of the implications of RES-E support mechanisms on two key actors, RES-E **Investors** and **Power Plant Operators** , trying to answer the following questions:

1. How different support mechanism scenarios can affect the RES-E investment ?

2. How new support mechanisms can create an incentive for plant operation, in

[1] Variable Renewable Energy (e.g. Wind and PV)

order to achieve a coordination in electricity market between the demand and supply in the existence of high shares of fluctuating RES ?

1.3 Thesis Structure

This study contains seven chapters, starting with the introduction which gives an overview on the the study scope, the motivation behind selecting this point of research and the main research questions needed to be answered within the scope of the study.

The second chapter gives a basic knowledge regarding the electricity markets, through discussing briefly the different market types and contracts. It also discusses the history of electricity market liberalization, and the changes of the electricity market after liberalization. In addition, the impact of high share of RES-E on the electricity market.

The third chapter is focusing on the RES-E investment and operation related aspects. It give a fundamental knowledge regarding the economic assessment of RES-E generation investment, and the different risks faced by investors and operators in a liberalized electricity market. Moreover, an important section of this chapter is the sensitivity analysis for the impacts of the risk factors on the project financial indicators. An introduction for the RES-E policy is given in this chapter as well. Moreover, a description for the currently used support mechanisms in Germany.

Chapter four is the core part of the study. It gives a description for the RESMIP (RES-E Support Mechanisms implications on Investment and Plant Operation) Model, which is a developed model to analyze the implications of different RES-E support mechanisms on investment and plant operation. This chapter also includes a detailed description regarding the different scenarios investigated in the study using the RESMIP model, and the assumptions related to each stage of the investigation. The outcome and results of each investigation stage in the model presented in the second section of this chapter, are essential for understanding the results, as they already represent a part of the final results.

In chapter five the different scenarios analysis final results are presented for Wind Onshore and PV, using various support mechanism scenarios.

The conclusion and recommendations chapter highlight the important findings of the study. In addition, this chapter discuss the RESMIP model capabilities, strengths, factors of uncertainty and how these uncertainties can be improved. Furthermore, it includes one of the most important parts of the study, which is what the study recommends for policy makers to take into consideration while structuring a RES-E support mechanism or policy.

The outlook gives a wide overview on the study, and the points of future enhancement and development for the RESMIP model.

2 Electricity Markets Fundamentals

What is the difference between electricity and any other commodity?

Electric energy is treated as a commodity in the electricity market. However, there are major differences between it and other commodities, this have an effect on the organization and the rules of electricity markets.

The fundamental difference is that the electrical energy is linked with and the physical system that function much <u>faster</u> than any market. This physical power system need to have a second by second balance between supply and demand. Otherwise,the system will collapse and the consequences can be catastrophic on the technical, social and economical scales. An imbalance in a gas pipeline between production and consumption will last much longer before it cause a collapse of the pipeline network. But for electricity it is totally different, and the consequences of slight changes in electric power criteria (e.g voltage or frequency) for a very short period of time can be undesirable. That is why balancing the supply and demand on the short run is a process which can not be left to the relatively slower and unaccountable entity such as a market.

Another significant difference is that in the electric power system, the energy produced by a specific generator can not be directed to a specific consumer (unless they are not isolated from the system). This require all the connected generators to be synchronized to be able to feed the loads, not to be a burden on the network. This system can have an advantage on the economic scale as the maximum generation capacity has to be comparable with the maximum needed demand, not with the sum of all the maximum individual demands connected to the system. However, it also has a disadvantage due to the dependency in the system, in case a breakdown takes place, everybody will be affected.

Comparing economical storage of electricity to other commodities can surely give an indication for another difference. Electric energy must be produced at the time it is consumed, as storing big quantities of electric energy is not an economic feasible solution as in other commodities.

Finally, the variations of the cost and price of electricity over the course of the day are very unusual compared to other commodities.[Kir04]

All these differences make the electric energy a different and dynamic commodity, which needs a special market design that can guarantee the security of supply and the reliability of the system on second bases.

2.1 Overview of the types of Electricity Markets and Contracts

The following section will give a brief overview of some selected (not all) electricity markets and contracts.

Spot market

In the spot market, the seller delivers a commodity and the buyer pays for it ”on the spot”, which means that neither party can back out of the deal. A spot market has the advantage of immediacy. But on the other hand a sudden increase in the demand (or drop in production) affects the prices dramatically, which makes the prices in the spot market tends to change quickly.[Kir04]

Electricity day-ahead market is an electric energy spot market example. It is a market that is held a day before the actual operation take place in the physical system. Electricity is negotiated for a provision of 24 hours ahead. Participants involved in this market are committed to supply or consume the electrical energy quantities agreed on the time adapted by the contract at defined market prices. This market set a spot price which reflect the supply and demand balance on the short term. However, these short term prices are subjected to volatilities, which is primarily due to the non-storable nature of electric energy, and the potential of change in the supply or demand because of the resource availability needs or demand behavior sudden changes. A complimentary market to the day-ahead market is the hour-ahead market which takes place at the same day of operation.[HS13b]

Forward contracts

Forward contract is a non-standardized contract for delivering a defined fixed quantity of product at a fixed price at a specific date between two market participants (a seller and a buyer). These contracts are almost exclusively negotiated or traded in the over the counter market[1], and they are difficult to resell the no longer needed traded quantity.[HS13b].

Future contracts

The contracts in this market are not backed by physical delivery, this is why they are called future contracts [Kir04]. It is like a forward contract but standardized and easier to trade. Quantity of electricity, price, delivery period and delivery profile (during peak or base load period) are defined in advance, and the parties involved are obligated to fulfill their contracts at the adapted time in the contract. They are also eligible to close their position before the time of selling there contracts[HS13b].

Options

An option is a contract that can be exercised only if the holder of the contract decides that it is in his interest to do so[Kir04]. It is not obligatory for options to be exercised

[1] In a direct way between the two market participants

from a buyer or a seller. There are two types of options: (call options) which is an option to buy, and (put options) which is an option to sell[HS13b]. Options are exercised differently in different markets. A European option can be exercised only on it's expiry date, on the other hand an option can be exercised at any time before the expiry date in the US.

Contracts for difference

In the contract for differences, the parties agree on a quantity and a "strike price". Then they take a part of the market and once the trading is completed the contract for difference has two settlement options. If the strike price is higher than the market price, the buyer pays the seller the difference between these two prices multiplied by the amount agreed in the contract, on the other hand if the stick price is lower the seller pays the buyer the difference. It insulates the parties from the market prices, while allowing them to take part in this market.[Kir04]

2.2 Electricity Markets Liberalization and The Impact of High Shares of RES-E

2.2.1 Introduction to the Liberalization of Electricity Markets

The trend of energy market liberalization was initiated in Chile at the early 1980s in the generation sector[HS13a]. Then distributed around Europe starting the late 1980s in the United Kingdom and gradually migrated to many European countries like France, Germany and others since 1999[Sio13]. Today many political systems around the world are adapting this energy market structure. This new market structure made a remarkable shift on the bases of investment choice. Before liberalization cost minimization was the base of the investor behavior. However, after liberalization the investment choice base is shifted to profit maximization in a competitive environment[FBH13]. Introducing renewable energy sources to the electricity market eventually, create a paradigm shift on the understanding of the whole electricity system. This shift will include an effect on both the technical level and the market structure and behavior. The effect on the technical level is by switching from an inflexible one way grid where changes is load behavior that can be followed by adjustment on the generation level, and load and generation matches. To a flexible grid that allows two ways of electricity flow with smarter system to handle the management of generation and load matching in the existence of high share of intermittent RES-E. On the other side of the coin, the effect on the RES-E market can be seen in the prices and market actors (investors and RES-E plant operators) behavior under new mechanisms and incentives. This section is focusing on the Impact of high shares of RES-E on the market, which is highly important point in the existence of rapid growth of RES-E generation in the German electricity market, in addition to the scenarios of reaching high shares of RES-E in the future.

2.2.2 Changes of Electricity Markets After Liberalization

When the liberalization of energy markets started in Europe, considerable excess capacities existed, and the expectations was that the prices will (always) reflect the short term marginal costs (STMCs)[2][Sio13]. Figure 2.1 illustrate how the prices are defined in the market with conventional capacities of hydro, nuclear and conventional electricity power plants.

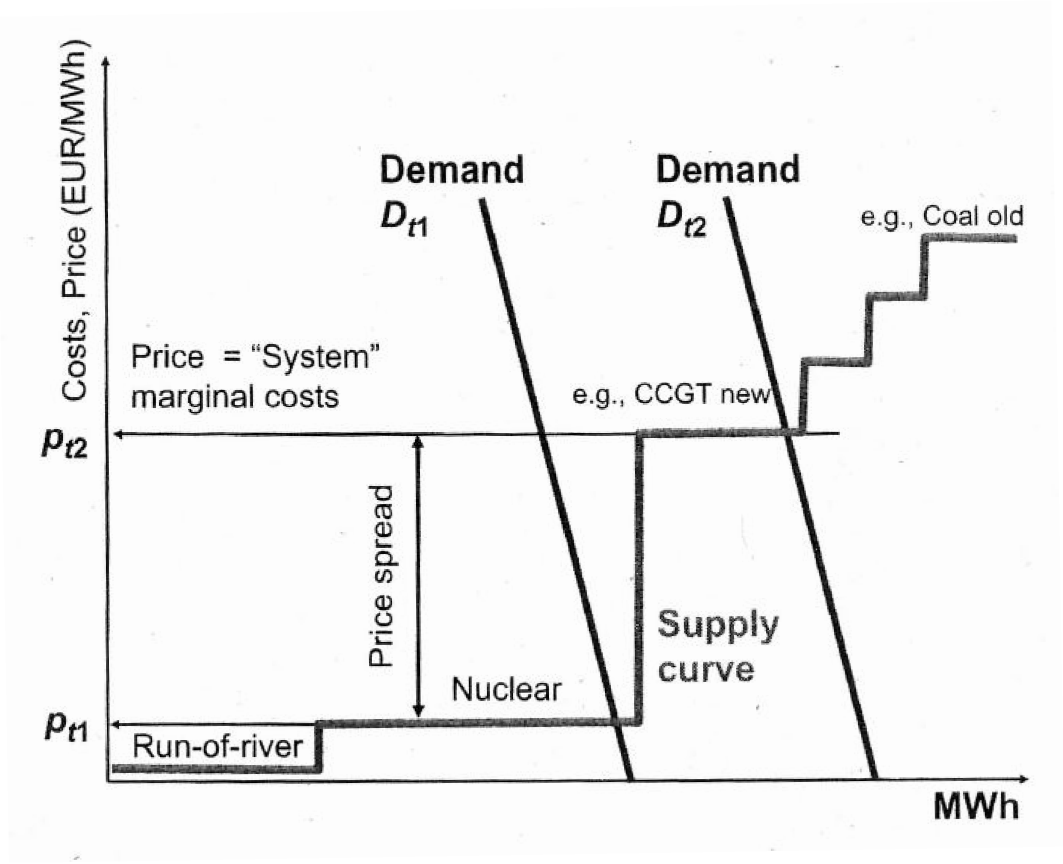

Figure 2.1: Merit order supply curve with conventional capacities.
Source: [Sio13]

As seen in figure 2.1 , the interaction between the demand curve and supply curve define what is called the market clearing price based on the system marginal costs. The first demand curve D_{t1} represents a low demand period and the second demand curve D_{t2} represents a high demand period. The clearing market price for electricity for D_{t1} is as can be seen P_{t1}. This price is lower than the clearing price at D_{t2} which is P_{t2}. The difference between Pt1 and Pt2 is called *price spread*, which is a high relevant term to a market with high share of RES-E.

The price patterns in Germany and other European countries[3] came with a different behavior than what it was expected as a consequence of electricity market liberalization. The prices experienced considerable differences between various markets. There

[2] STMCs is a representation for the variable costs
[3] As illustrated in figure 5.12 at [Sio13]

was high prices in 2008 and then a fall in the prices in Europe. The reason for the high prices in 2008 is due to low hydro availability, and the falling prices after 2008 were attributed to the economic crisis.

There was a change in the average costs of production which defines the electricity prices after liberalization as presented in figure 2.2. However, it can be expected that there will be a deviation from the concept of the STMC price regime explained before in figure 2.1 once excess generation capacity is exhausted. As there will be a shift toward long-term marginal costs (LTMC)[4], it can also be expected that generators will try to influence the prices by acting strategically during the periods of high demand and limited available generation capacity and the consequence can be higher electricity prices rather than the prices defined by the STMC. But what the case will be if a generation with zero marginal costs is introduced with high shares in the market like RES-E, affecting the principles behind STMC. This question will be further discussed.

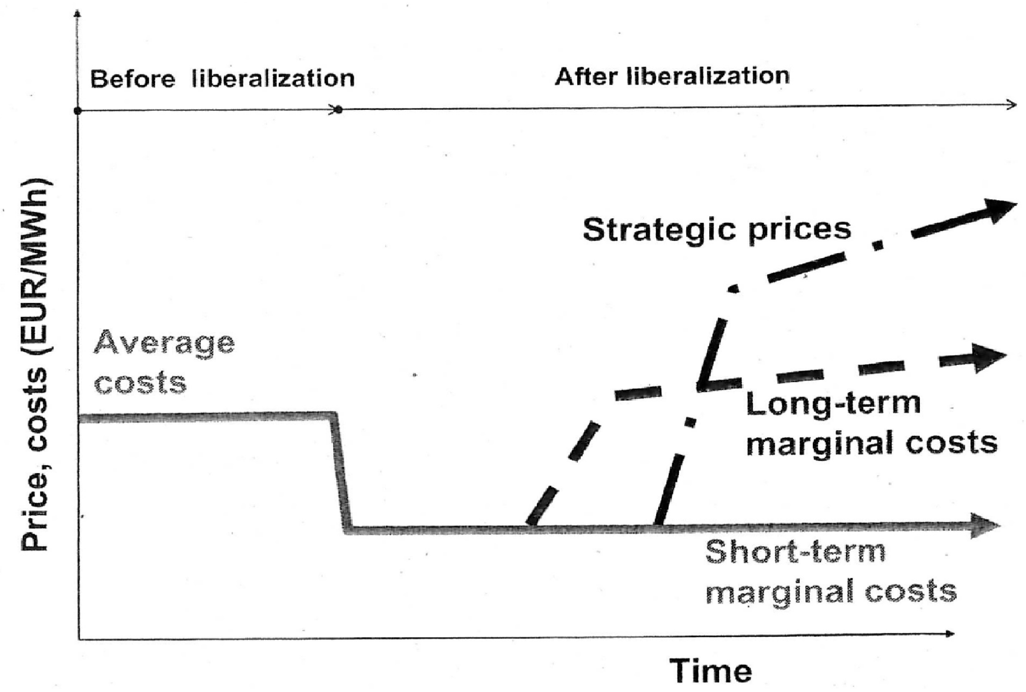

Figure 2.2: Changes of pricing electricity before and after liberalization of electricity markets

Source: [Sio13]

2.2.3 The Impact of High Shares of RES-E in the Electricity Market

RES-E shares are rapidly growing in the EU, with some backdrops that arises three key questions in countries like Germany, Denmark, Spain and others [Sio13]:

[4]LTMC represents variable plus fixed costs

1. What is the impact of large amounts of RES-E generation feeding in the grid especially during low demand periods?

2. What is the impact of intermittent RES-E on the costs at which fossil especially natural gas - capacities are offered?

3. What is the effect of renewables on price spreads overtime?

In the following sections we will discuss only the impact of RES-E on the market prices and price spreads as they are relevant to the scope of the study. The RES-E impact on fossil capacities will not be discussed in details, but it can be checked at [Sio13].

The Impact of RES-E on the Market Price

Renewable resources except few (hydro, geothermal and biomass) are intermittent by nature, not predictable nor dispatchable. The introduction of large shares of RES-E takes into consideration the major difference in the marginal costs between the conventional power plants, and some RES-E like Wind and PV with essentially zero marginal cost, and feeding into grid in the periods of low demand results in lowering the market clearing price, even leading to negative prices [Sio13][GP13a].

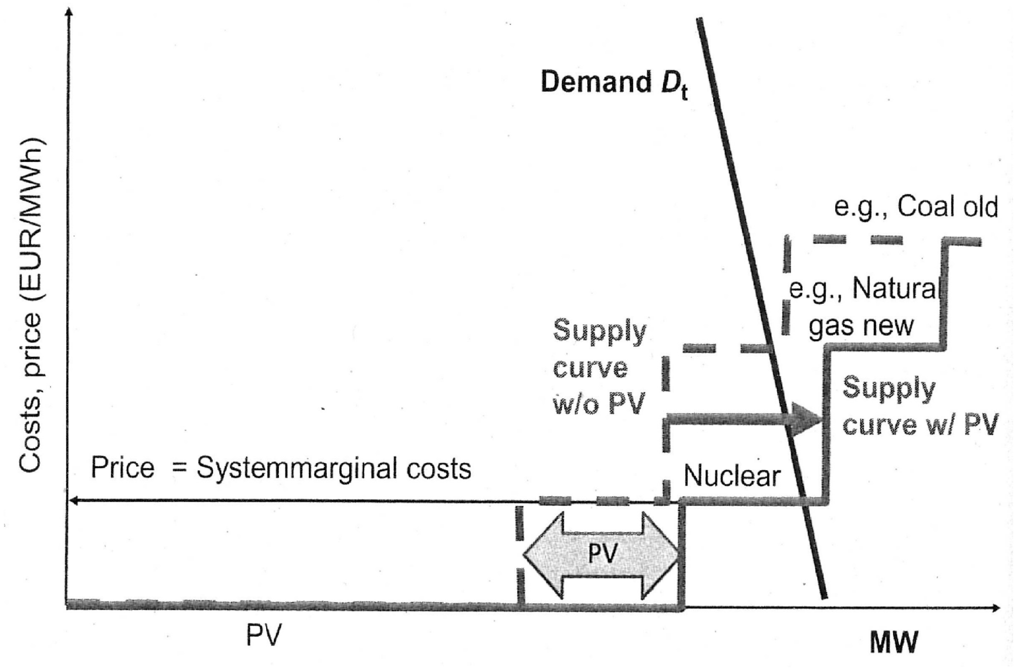

Figure 2.3: Merit order supply curve with and without additional PV capacities at on-peak time of a bright summer day with STMCs for conventional capacities Source: [Sio13]

The effect of RES-E on the market prices has been experienced in many countries like Germany. This effect can be called *the merit order effect of RES-E*. An example of this effect in a sunny day in Germany on the 22 of October 2011 is illustrated in figure 2.3. It can be recognized that the PV generation not only displaced virtually all hydro generation, but also shifted the supply curve to the right, which essentially pushed nuclear and fossil-fuelled generation out of the market due to that the marginal costs of the PV is zero as other RES-E technologies (e.g. Wind energy). There is an effect as well on the formation of the price, as this shift results in lower spot prices during a period when they tend to be high. If this effect happened in an off-peak period when prices are already low, it will cause the prices to be even lower, leading to increase the volume of intraday trading, as traders will want to take advantage of the price difference in different market [Sio13].

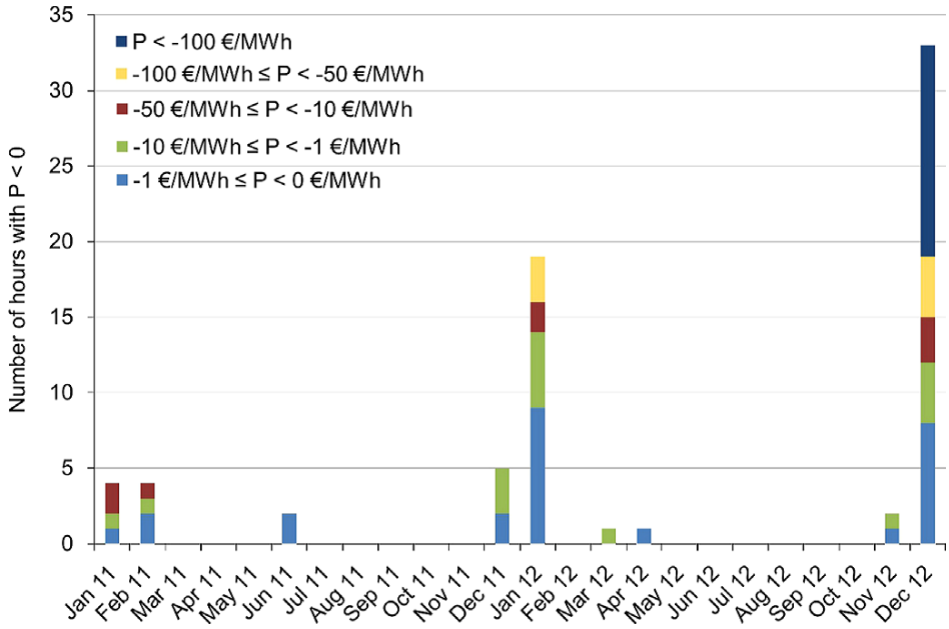

Figure 2.4: Negative electricity prices on the EPPEX spot market from 01.01.2011 to 31.12.2012.
Source: [GP13a]

Prices can also reach negative values if the demand is very low, and there is excess of zero marginal cost RES-E supply. Figure 2.4 shows the amount of negative prices in EPEX spot market in Germany during the years 2011 and 2012, In 2011, negative prices occurred in 15 hour of the year, affecting a total of 464.2 GWh. In 2012 up to November prices were negative in 23h, and 33h in December, which makes a total of 56 negative prices hours in 2012 affecting 1811.4 GWh [GP13a]. One can expect more dramatic impacts on the market prices in the existence of high share of RES-E.

2.2.4 Effect of Renewables on Price Spreads

Figure 2.5 presents a hypothetical scenario with high levels of generation from Wind, PV and hydro plants over a week in summer using synthetic hourly data for an average year in Germany done by [Sio13]. The aim of the scenario is to answer the question

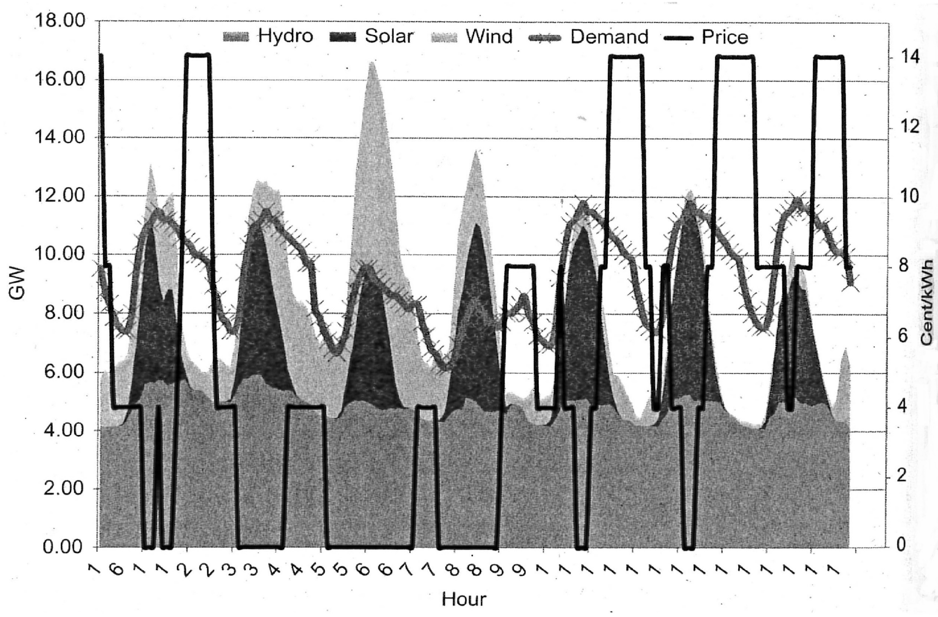

Figure 2.5: Development of intermittent renewables from Wind,PV, and run-of-river hydro plants over a week in summer on an hourly basis in comparison to demand and resulting electricity market prices with total costs charged for conventional capacities in Germany
Source: [Sio13]

how will the price spread in Europe markets evolve in the future as large amounts of PV, Solar thermal and Wind generation are added to the network?

It can be recognized that the electricity market prices (black solid line) experiences high volatility[5] due to the variation of the demand and RES-E supply. It can be possible that future high prices will not necessarily appear at peak-demand time but as times of low availability of RES-E supply. Such a high volatility in the prices is subjected to an increase as a consequence of the attractiveness to invest in storage technologies to take advantage of the price difference, and make flexible peaking unites much more valuable than they currently are. However, currently the business model of the pumped hydro plants is affected, as the depended before in the differences between low and high prices (for example low prices at night due to low demand and high at noon due to high demand) to make profit from selling electricity at the high price period. But due to that the PV production lower the prices at noon time, this affects the price spreads and creates a need for a new business model for the low responding (in terms of time) storage technologies.

[5] As defined before the price spread is the difference between the off-peak and on-peak price of electricity

The effects of the development of RES-E on the prices in electricity markets can be summarized as:

- More price volatility on hourly and daily bases.
- Increasing relevance of intraday markets.
- Higher prices for fossil and flexible capacities and storage for balancing the intermittent renewable generation.
- Growth of balancing markets and intensified completion at the level of decentralized balancing organization.[Sio13]

3 RES-E Generation Capacities Investment and Operation

This chapter is based on there main sections. In the first section the economic assessment of RES-E generation investment will be discussed. Followed by the different risks faced in a liberalized electricity market section, which includes a sensitivity analysis for the different risk factors impacts for Onshore Wind and PV cases. The last section will focus on the RES-E policy and support mechanisms applied currently in Germany, and the interaction between the RES-E policy in general with the different risks in the liberalized electricity market.

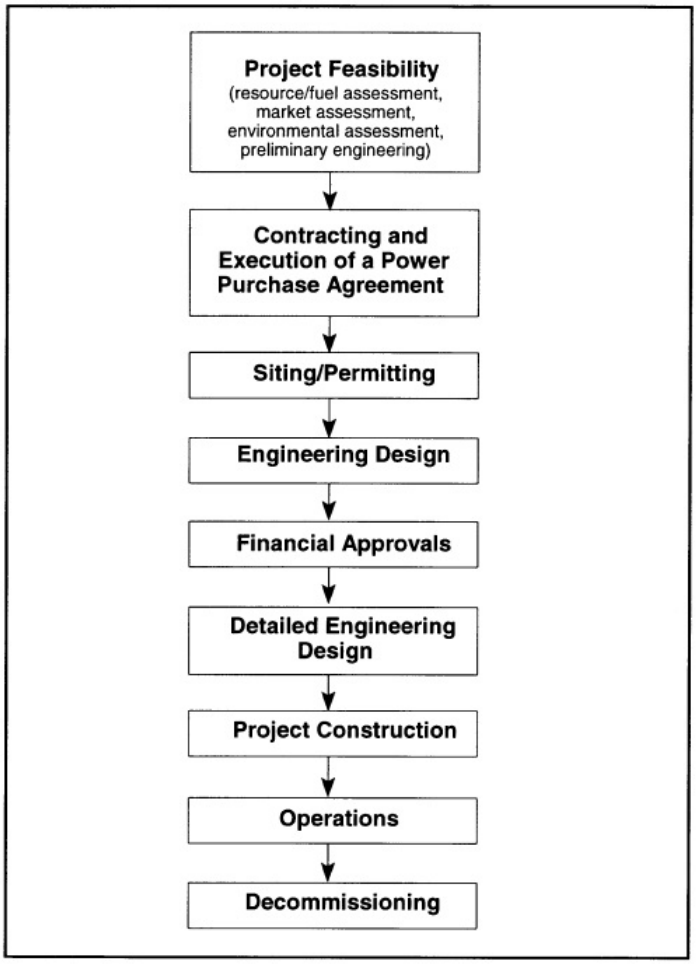

Figure 3.1: Conceptual stages of project development
Source:[WP98]

It is important to have an overview on the project development process before discussing the related points to investment and operation of RES-E generation capacities, but we can not specify a certain project development process applicable on all RES-E technology types and different business segments. An overall process of project development is shown in figure 3.1 [WP98].

In general the figure shows that there are nine stages starting from the project feasibility to the decommissioning of the plant. Understanding the details related to each stage is not necessary, however it is important to keep in mind the different stages as it will be referred to it in later sections.

3.1 Economic Assessment of RES-E Generation Investment

3.1.1 Financial evaluation Approaches in General

A financial evaluation over the project lifetime is a logical way to assess the economic feasibility of a project. Such evaluation have two approaches to be done, a **static** approach and a **dynamic** approach [Fin85].

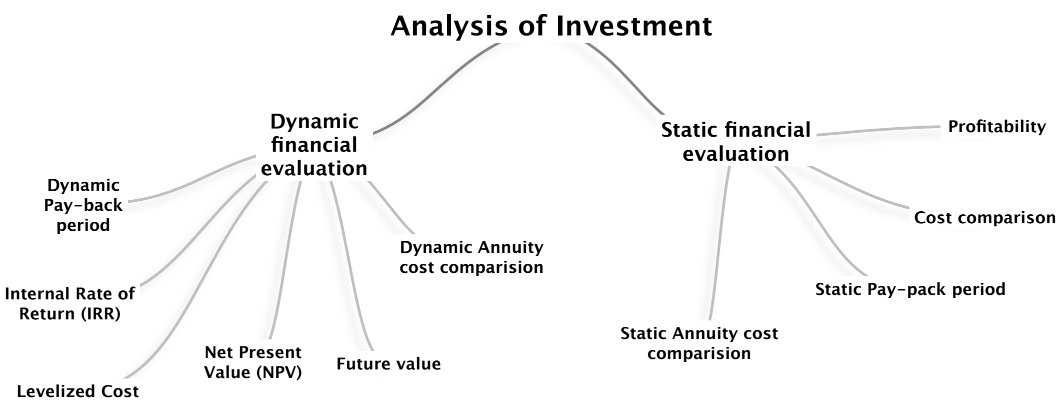

Figure 3.2: Financial Evaluation different approaches and methods
Source: Author's illustration based on information provide by [Fin85]

Figure 3.2 presents the different methods used under each evaluation approach. The Static evaluation methods are calculated of profitability, static pay-back period, static annuity costs and cost comparison. The dynamic evaluation methods are the dynamic pay-back period, calculation of future value, dynamic annuity cost comparison, net present value(NPV), internal rate of return (IRR) and levelized cost.

The difference between the static and dynamic evaluation is the consideration of the time component. The dynamic evaluation approach takes into account the different times at which a transaction takes place. Under this approach all payments are *compounded* at a reference point in time (e.g. before the plant is commissioned at t=0) in case they fall due before this time, or *discounted* if they come after this time. Because of this consideration of the time component in investment evaluation, "the dynamic procedures undoubtedly produce better results than the static procedures" [Fin85]. But on the other hand, the static evaluation is more simpler, and easier evaluation approach which can serve as an approximation of the dynamic evaluation. Therefore only selected dynamic evaluation methods will be further discussed in this section.

3.1.2 Dynamic Financial Evaluation Methods

Advantages and disadvantages of the dynamic evaluation methods are discussed in table 3.1.

Dynamic method	Advantages	Disadvantages
NPV	- Includes discounting for future value (inflation rate, opportunity cost,interest rate, liquidation of assets).	- Dose not include portfolio effect analysis. - Comparison between investment with similar life times.
IRR	- A comparison tool for investment option with the same risk level	- Assumption have to be made for the calculation process
Future Value	- Same concept of NPV, however the calculation are referring to the end of the project life time.	- Non specialised investors are not familiar of it's meaning.
Dynamic payback	- Simple calculation method	- Cash flow have to be constant over years of the project. - Does not look at the rate of return.
Levelized cost	- Used to compare different technologies costs per unit of production.	- Based only on the costs of the project, not the net cashflow.
Dynamic Annuity	- Simple calculation method.	- Used if all investment items have a constant lifetime.

Table 3.1: Dynamic financial evolution methods overview
References: [MR11, Fin85, Fra12, Pfa12a]

The following section will give more details related to the selected evaluation methods which will be used under the scope of the study, as in the sensitivity analysis in the following section in the current chapter, and in the modelling in chapter 4 and the results in chapter 5.

Net Present Value (NPV)

The Net Present value is the sum of the present values of the revenues and costs (cash inflows and outflows) linked to investment discounted to a reference point in time (usually before the project commissioning at t=0), at a given discount rate.[Fin85, MR11, Hol12].

It is defined as:

$$NPV = -I_0 + \sum_{t=1}^{n} \frac{NCF_t}{(1+r)^t}. \tag{3.1}$$

References: [Fin85, MR11, RET05, Hol12]
Where:
I_0 = initial investment costs at a time period (t=0),
n = number of years (e.g. project lifetime),
NCF_t = Net Cash-Flow at time period t,
r = Discount rate,
t = time of payment (e.g. project year).

If the NPV can be calculated in Euro, a $NPV \geq 0$ reflects that the sum of the discounted cash flows is greater than the initial investment. This gives an indication that there is a possibility of making profits, in order to make the investment fleabites.

NPV is an important financial indicator, it is used as a base to calculate other financial indicators (e.g. IRR). In addition, it reflects the economic feasibility of a certain investment including all types of cash flows (e.g. revenues and costs) over the project lifetime, taking into consideration the time component.

Internal Rate of Return (IRR)

The Internal Rate of Return is the interest rate at which the cumulative NPV of the project is zero. It can be considered as a special form of the NPV, and it represents the achievable interest on the capital tied-up in the investment [Fin85].

It is defined as:

$$0 = -I_0 + \sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t}. \tag{3.2}$$

References: [Fin85, MR11]
Where:
I_0 = initial investment costs at a time period (t=0),
n = number of years (e.g. project lifetime),
NCF_t = Net Cash-Flow at time period t,
IRR = Internal Rate of Return,

t = time of payment (e.g. project year).

IRR is calculated in %. It is a common used evaluation method, which can be understandable by investors to be used as a compared value to a minimum defined interest rate (e.g. cut-off interest rate). A project is considered desirable if the IRR is equal or bigger than a minimum acceptable interest rate defined by the investor [1][Fin85, MR11].

Levelized Cost

The levelized cost is the cost per unit of output taking into account the time pattern (discounting) of costs as in the NPV [Pfa12a, Pfa12b].

It is defined as:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{C_a}{(1+r)^t}}{\sum_{t=1}^{n} \frac{P_{el}}{(1+r)^t}}. \tag{3.3}$$

References: [Fra12, Fra13, Pfa12a, Pfa12b]

Where:
I_0 = initial investment costs at a time period (t=0),
n = number of years (e.g. project lifetime),
C_a = annual costs (after t=0),
P_{el} = annual electricity production,
r = discount rate,
t = time of payment (e.g. project year).

Calculating the levelized cost of electricity (LCOE) for an investment in a generation plant, represents the minimum price of electricity which is required to make the investment in the project viable. The LCOE is a commonly used figure for the assessment and the comparison of investing in different electricity production technologies (e.g. conventional, and renewable plants).

A summary of the discussed financial evaluation methods (NPV,IRR and LCOE) is shown in table 4.6. The following section will consider the variation of these evaluation methods, in case selected sensitivity parameters are changed for selected RES-E technologies.

[1] Which varies from investor to another, and can represents investing in other options of the same risk level.

3.2 Risk on Investment in a Liberalized Electricity Market

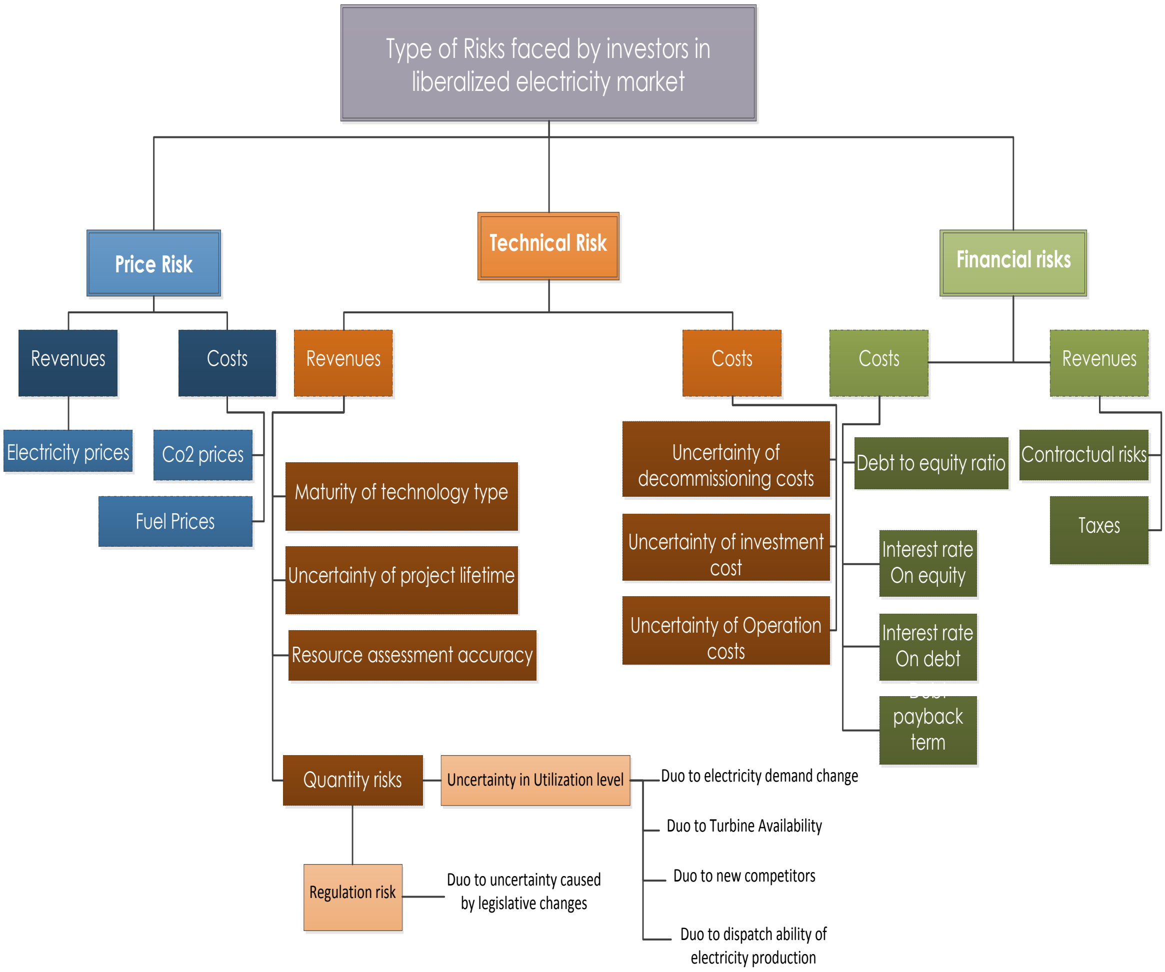

Figure 3.3: Investment Risk in a Liberalized RES-E Market
Source: Author's illustration based on information provided in [GBH10] & [FBH13]

The market changes after liberalization have an impact on the risks faced by investors. Figure 3.3 illustrate the different risk types faced in liberalized electricity markets. There are three major risk categories: price risks, technical risks and financial risks. These three main categories have an effect on the revenues and costs of the project through different risk factors. Regarding price risk, revenues can be affected by the changes in the electricity prices, and costs can be affected by the fuel prices. For the technical risks, revenues can be affected by the uncertainties in the lifetime of the project or technology type maturity. Uncertainties in estimating the resources availability (e.g. Wind forecasting for a wind generation plant) also can be a possible risk factor affecting the revenues. In addition, quantity related risks due to uncertainty in the dispatchability of production (operation side risk factor), or regulatory legislative changes, can influence the revenues. Technical risk factors on costs are mainly due to the uncertainties in the investment, operation or decommission costs. Financial risks on revenues are due to contractual risks or taxes. Costs under the financial risks category can be affected by the changes in the debt or equity financial figures as the interest rate, shares, or required payback time.

Each of these risk factors have different impact on the RES-E Investment and operation, which can lead to a significant change in the investment wellness in renewable technologies and have an effect on the plant operation behaviour, and RES-E integration in the market as well.

In order to assess the different impacts of these risks, a sensitivity analysis of a selected risk factors impact on various indicators is done in the next section.

Sensitivity analysis of risk factors Impacts

The sensitivity analysis scenario included the change of selected parameters in each case, with a range of change from $\pm$ 30%. RETScreen wind and PV case studies [RET13a] are used for the analysis, with modifications in the financial and project input data in order to be up to date to the current German market situation. The criteria of selecting the parameters is based on covering the three major risk categories (price, technological and financial), and focusing on the risk factors that will be used under the study scope in the next chapters.

RETScreen international overview: RETScreen is an international clean energy project analysis software developed in 1996 by the Natural Resources Canada's Canmet Energy Research Center. It can be used to prepare both pre-feasibility and feasibility analysis, specially addressing this issue by providing quick and valid results at low cost on which "go/no-go" decision can be made. RETScreen also provides a renewable energy projects database for different technologies and locations around the world [RET05].

Independent reviews of RETScreen and comparisons with other project analysis software reported accurate results from RETScreen. For example a study [Gau08] explored RETScreen and HOMER models in comparison with SunSim (Matlab based software). The study found that PV energy output for the location of the study is underestimated by 6-9% by HOMER, and 0-6% by RETScreen for the locations simulated, compared to a "best case" SunSim model. Other studies can be found as well related to the accuracy of the free model in comparison with other software packages like[Gil07] and others.

RETScreen has five step analysis model and includes updated climate database expanded to 4700 ground-stations and NASA satellite dataset integrated in the software, in addition to products database and case studies.

Wind case study

- The yearly average wind speed of the plant(m/s).
- Debt interest rate(%).
- Electricity feed-in tariff(€/MWh)

- Plant capacity factor(%).

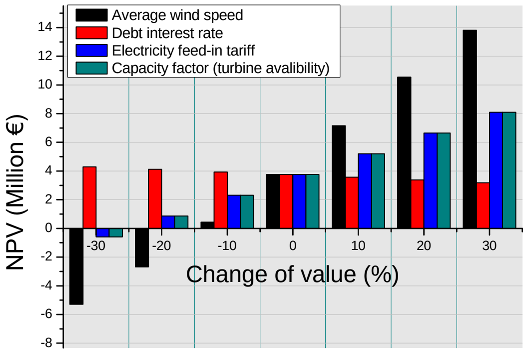

Figure 3.4: Wind NPV sensitivity results

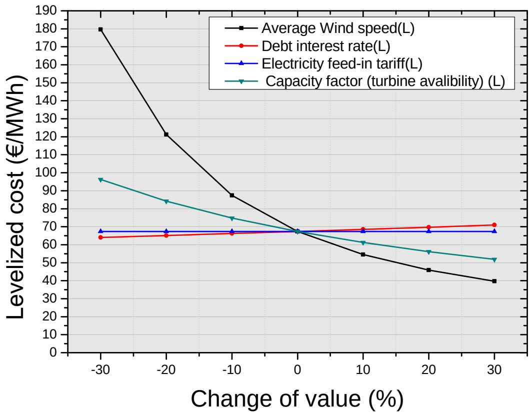

Figure 3.5: Wind LCOE sensitivity results

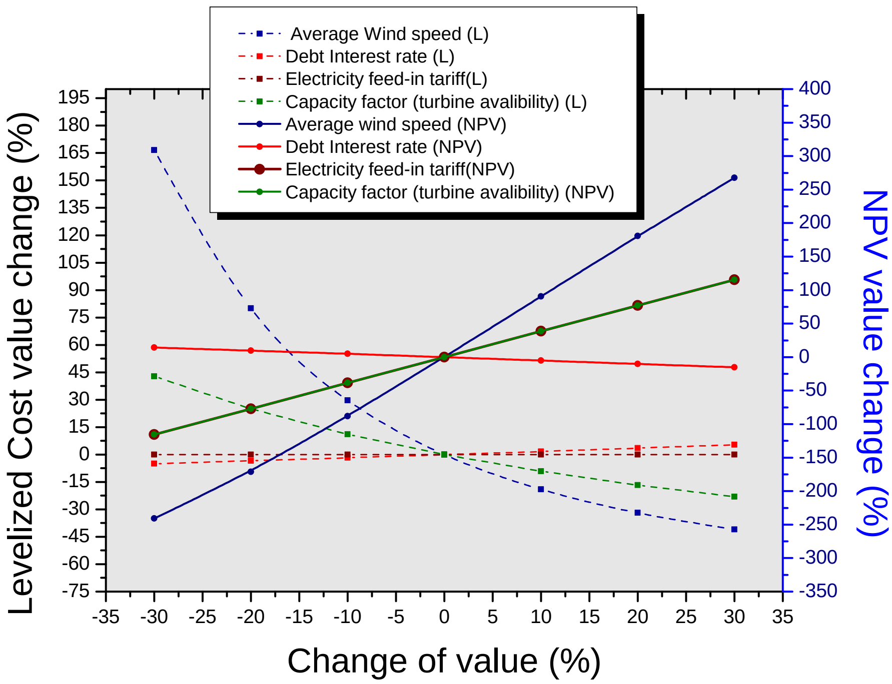

Figure 3.6: Wind sensitivity analysis results represented as change in (%) for the NPV & LCOE

The Net Present value (NPV) calculates the expenses for investment and operation during the lifetime of the plant and calculates the incomes by discounting to the same reference point [Fra12]. However that the energy policy have no influence on the average wind speed (which make it unconsidered in the RES-E policy analysis studies), it is important to note that the average wind speed change has a dramatic effect on the project economic feasibility.

A slight change of the mean wind speed have a remarkable impact on the NPV resulting in a range of change from -240% to 267% as shown in figure 3.6. The change in the capacity factor (which can be due to technical reasons like turbine availability or RES-E policy reasons like curtaining the plant output in case of negative electricity prices) has an important impact on the project revenues (the same impact caused by the feed-in tariff). This is represented by a change in the NPV from -115% to +115% as shown in figure 3.6. Such impact makes the capacity factor and feed-in tariff important points of analysis in the effect of different RES-E support mechanisms on investment. The debt interest rate change influence is the smallest among the study parameters (NPV changes from -15% to +14%), in addition it can't be directly influenced by the RES-E support mechanisms, but it can't be neglected as a factor taken into account in the decision making process from the investor prospective.

The levelized cost is the cost of producing a unit output (in this case MWh of electricity)[Pfa12a]. The average wind speed has a significant effect on the levelized cost with a change in values between -41% and +166.5% as shown in figure 3.6. For the capacity factor change the levelized cost changes between -23% and +42.8%. Increasing the capacity factor almost have the same effect increasing the average wind speed, however decreasing the capacity factor have less impact than the average wind speed on the levelized cost. The debt interest rate and the electricity feed-in tariff don't follow the same pattern (as the case in the NPV analysis), this is because changing the feed-in tariff will affect the project revenues but not the cost of electricity production (the change in levelized cost is 0% due to the feed-in tariff), on the other hand changing the debt rate will affect the cash flow of the project and the electricity production cost. The result of change in levelized cost is due to changing the debt rate between -15% and +14%, this is the same as the effect on the NPV.

Figure 3.6 shows the wind case study sensitivity analysis results. The levelized cost scale point 0% represents 67.39 (€/MWh). The Net Present Value(NPV)scale point 0% represents 3.755 (Million €).

PV case study

- The project lifetime (year).
- Debt interest rate (%).
- Debt term -payback time of the debt share- (year).
- Electricity feed-in tariff (€/MWh)
- Plant capacity factor(%).

The feed-in tariff and the capacity factor follow the same pattern in the NPV analysis (explained in section 3.2) and the change in the NPV value is between -136% and +136% as shown in figure 3.9. Changes in the project lifetime can be due to technical aspects regarding the PV plant components lifetime, or economic reasons such as the plant is no longer profitable for operation. The effect of project lifetime change on the NPV is in the range between -89.5% and +61%. A debt financial detail plays a role in the investment, the debt rate and term both affects the NPV. The debt rate has a higher impact than the debt term, as the change in NPV due to the debt rate is

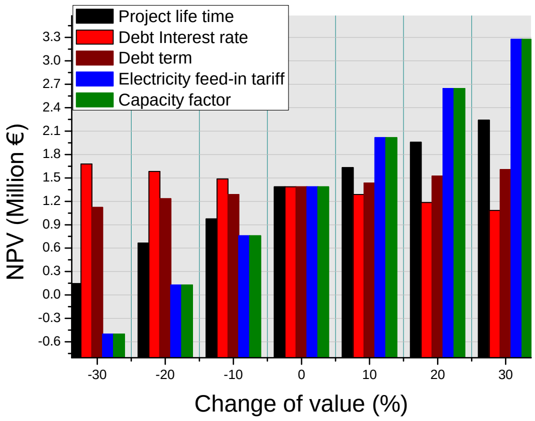

Figure 3.7: PV NPV sensitivity results

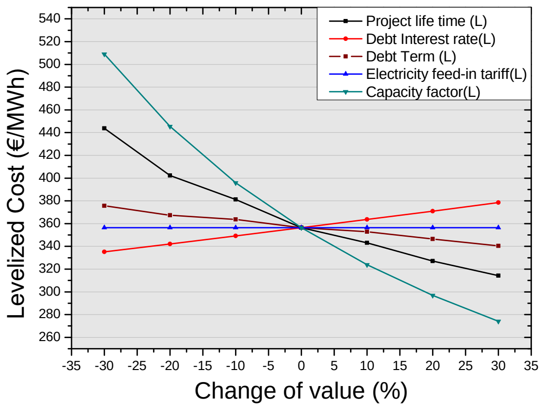

Figure 3.8: PV LCOE sensitivity results

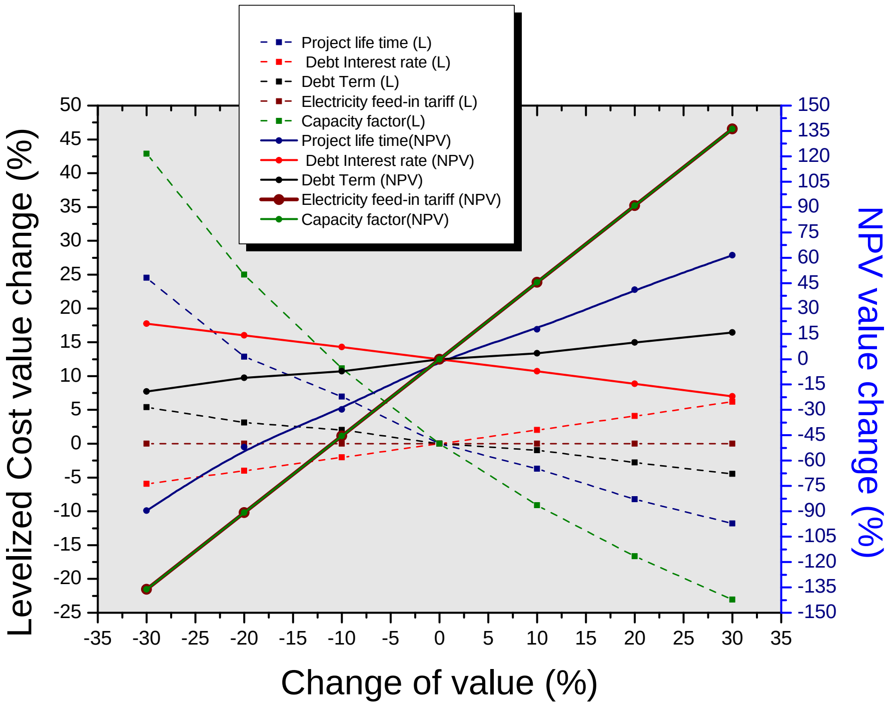

Figure 3.9: PV sensitivity analysis results represented as change in (%) for the NPV & LCOE

between -20.9% and +21% and for the debt term it is between -19% and +15.7% as illustrated in figure 3.9.

Figure 3.9 shows the pv case study sensitivity analysis results. The levelized cost scale point 0% represents 356.33 (€/MWh). The Net Present Value(NPV)scale point 0% represents 1.38744 (Million €).

The major impact on the levelized cost is due to the capacity factor and the project lifetime which can be changed due to technical reasons, economic reasons, or political reasons in case of capacity factor (as explained in section 3.2). The change in the levelized cost is between -23% and +42.8% (as shown in figure 3.9) due to the impact of capacity factor change. The levelized cost change range is smaller for project lifetime as it is between -11.7% and 24.5%. The debt rate and term both have almost the same range of effect (between -5 % and +6%) on the levelized cost, but the correlation between the increase and decrease of levelized cost values is due to changing the debt rate and term vies versa as seen in 3.8. The feed-in tariff does not have an effect on the levelized cost (as highlighted in the wind case section 3.2).

Sensitivity Analysis Conclusions

The First conclusion on the sensitivity analysis for the wind and PV case studies is that the project feasibility is affected with many risk factors. The major factors are the resource assessment accuracy (the average wind speed in the wind case), the capacity factor and the electricity feed-in tariff. Project lifetime has less effect than the previous mentioned factors but it has to be taken into consideration as an important factor in the analysis of different mechanisms design, as policy can have an effect on the decision of whether operating a plant is still profitable or not due to political changes. Debt financial details (interest rate and payback term) have the lowest impact on the project feasibility; however they can not be neglected as a factor of study in the policy analysis.

As for second conclusion, the study shows that different project economic feasibility tools have to be used in the evaluation, as the levelized cost of electricity can't indicate the effect of changing the feed-in tariff (as it has an influence on the project revenues not costs) but the net present value (NPV) has identified the effect clearly.

The third conclusion is that the RES-E policy can only influence a limited number of risk factors faced by the RES-E investors, as it can only deal with a few factors under the price and quantity risk categories.

3.3 RES-E Policy and Support Mechanisms

3.3.1 Why do RES-E Needs Regulatory Intervention and Support Mechanisms?

The comparatively higher cost of RES-E technologies as well as the impacts on the grid structure and system dispatchability, have made it virtually impossible for them to grow in competitive with conventional technologies without intervention [BPAZB12]. The attractiveness of Investment in such technologies has to be companied with long-term stability, risk mitigation instruments and electricity cost reduction. Especially for the non-dispatchable RES-E technologies like wind and solar where the generation resource can be hardly influenced by the power plant operators due to environmental externalities, which tends to be a disadvantage compared to conventional technologies. Therefore, there is a case for energy policy to correct those externalities [WM12].

In general renewable energy policies principally aim to increase the installed capacity of renewable energy, in order to achieve the ambitious targets of the renewable energy shares in the future energy mix. The main objectives of a RES-E support mechanism have to encourage the deployment of Variety of RES-E technologies and improve it's learning curves. As it is never clear which technology or technological mix will provide an efficient and reliable future of energy systems with high shares of RES.[BPAZB12].

Different EU scenarios proposing the share of the renewable energy participation into final energy consumption is in continues increase, this means that the market has to adapt high shares of renewable energy into its structure, in addition that incentives have to be defined to create the path way for the installation of the capacity required.

3.3.2 RES-E Support Mechanisms in the German Electricity Market

Germany experienced changes in the RES-E policy and support mechanisms since it started in 1991 . The historical timeline of the renewable energy policy development in Germany between the year 1991 and 2006 is presented in Figure 3.10.

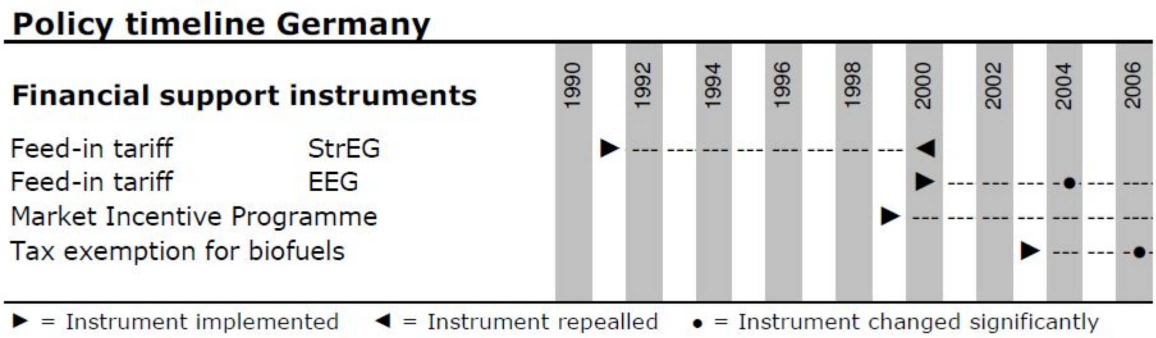

Figure 3.10: RES policy timeline in Germany
Source:[Eco08b]

FeedIn-Tariff, StrEG (1991-2000) mechanism was introduced as a single fixed feed-in tariff for all RES-E technologies [Eco08b]. It required the supply companies to buy the renewable energy generation at 90% of the average electricity price charged to customer in the previous year[BN08]. In the year 2000 the StrEG was changed with the feedin-tariff Renewable Energy Sources Act (EEG) mechanism.

FeedIn-Tariff (EEG) (2000-present)

In the year 2000 under the Renewable Energy Act (EEG), the StrEG was replaced with the feedin-tariff(EEG). It provided a guranteed grid access for the RES-E electricity production, in addition to a fixed technology specific feedin-tariff for a period of 20 years. The tariff was degrading on annual bases for the new installations in a certain percentage [Eco08b]. For example for Wind energy the tariff was 9.1 ct/kWh the first 5 years of operation and for the subsequent 15 years was 6.19 ct/kWh. For installations after 2002, the tariffs were reduced by nominal 1.5% for each subsequent year, in order to give an incentive for early investment and to take advantage of technological progress[BN08]. In 2004 new the mechanism was reviewed and a new tariff had been adapted, in general the new remuneration was lower for Onshore Wind, higher PV ,bio-energies and geothermal. The tariff for Onshore Wind was up to 81.6 €/MWh for five years after installation at least, with reduction in the tariff depending on yield of system to 52.8 €/MWh. The annual reduction of tariff is 2%. For PV the tariff was between 406 and 568 €/MWh, depending on yield of the plant size (installed capacity) and whether it is a building integrated or ground installed. The annual reduction of tariff is 5% in 2005 and 6.5% from 2006 on.[Eco08b]. Figure 3.11 illustrates the changes in the Onshore Wind feedin-tariff, as can be seen the remuneration went down from 9.95 ct/kWh in the year 1991 to 7.65 ct/kWh in 2005. This implies a reduction by 23%[EEG10].

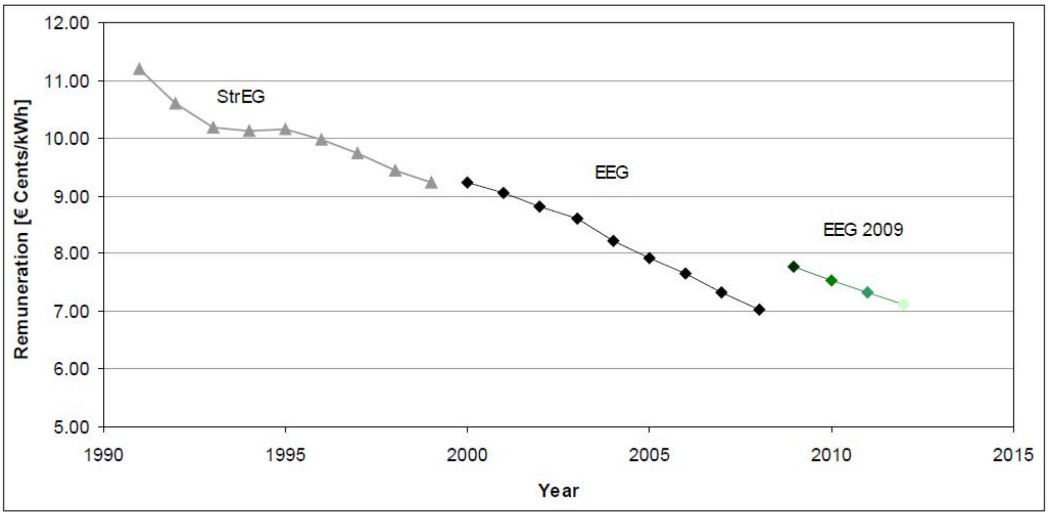

Figure 3.11: Development of the remuneration of electricity from onshore wind energy in Germany (inflation-adjusted to values of 2005)
Source:[EEG10]

Currently as shown in figure 1.2 the feedin-tariff (EEG) exists including several EGG amendment reviews, in parallel to the Market premium mechanism (described in the section below) currently in Germany. The amount of tariff for a given plant is the tariff level as defined by law minus the degression rate, which depends on the year in which the plant was put into operation. For Onshore Wind the amount of remuneration varies between 4.87 and 8.93 ct/kWh according to the duration of payment, plus a bonus of 0.5 ct/kWh for repoweing and plant service bonus of 0.48 ct/kWh. For PV still the remuneration depends on the installed capacity and the type of the plant whether it is a building integrated or mounted systems or ground installed plans. The remuneration level for PV from 1 january 2014 is defined as following based on the installed capacity[2]: [LEG12]

- $\leq$ 10 kW: 13,68 ct/kWh
- $\leq$ 40 kW: 12,98 ct/kWh
- $\leq$ 1 MW: 11,58 ct/kWh
- Other systems $\leq$ 10 MW: 9,47 ct/kWh

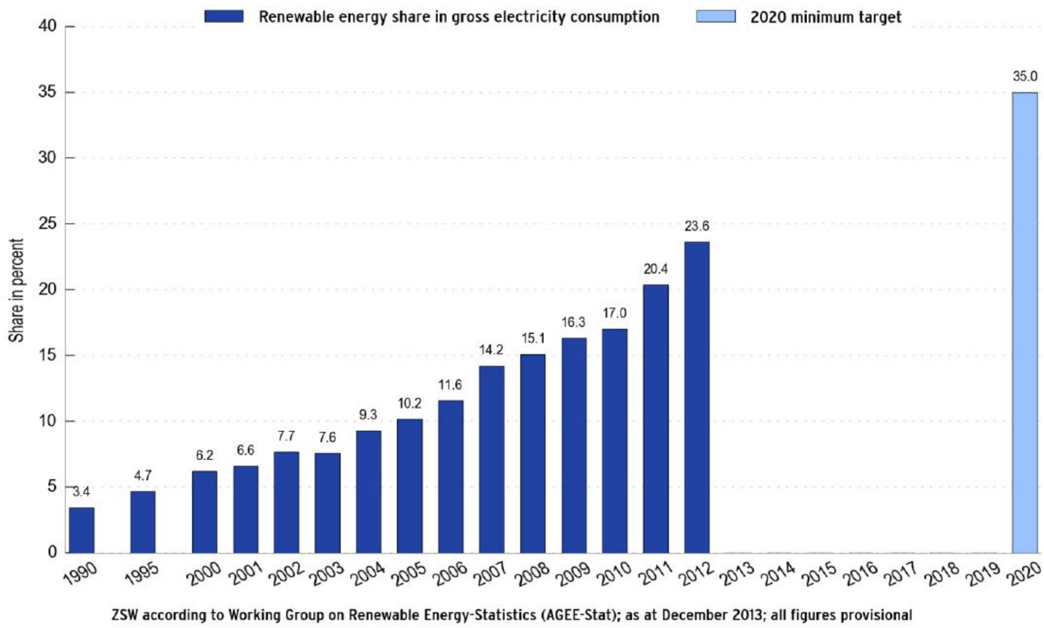

Figure 3.12: Development of the share of Renewable energy in the total gross electricity consumption in Germany
Source:[BMU12b]

Since 2000 the feedin-tariff under the Renewable Energy Sources Act (EEG) had a successful impact on the renewable energy deployment in general and the RES-E shares in the total gross electricity consumption in particular as shown in figure 3.12. The RES-E share in the final electricity consumption raised from 6.3 % in 2000 to

[2] The current structure for the feedin-tariff can be found (in German language) in Federal Network Agency (Bundesnetzagentur), website:www.bundesnetzagentur.de, under the EEG information section

14.8% in 2008 . Expressed in installed capacity, an addition of over 4900 MW of grid connected solar PV capacity, and over 19000 MW of Wind power have been installed between 2000 and 2008[CG10]. Currently the RES-E share in total gross electricity consumption reached 23.6% in the year 2012 [BMU12b].

That is why it is important to mention that the Germany feedin-tariff represents perhaps the most widely recolonized and commonly cited successful example of a feedin-tariff policy [CG10].

German market premium

The market premium was introduced in the 2012 amendment of the Renewable Energy Sources Act (EEG) aiming to give an incentive of demand oriented electricity production and providing the operators with experience regarding the market dynamics and prices. As mentioned before plant operators have the flexibility to choose between the former feedin-tariff or the market premium since 01.01.2012, not as in the feedin-tariff where the transmission system operators are responsible to sell the RES-E on the market. Under the market premium operators have to directly market their electricity production in the market. The reason that two parallel mechanism exist is that the direct marketing may be challenging for some plants (e.g. small-scale installations). The market premium dose not aim for creating a fundamental change in the RES support mechanisms, but rather to prepare the foundations for a future transition to a market-based regime.[GP13a]

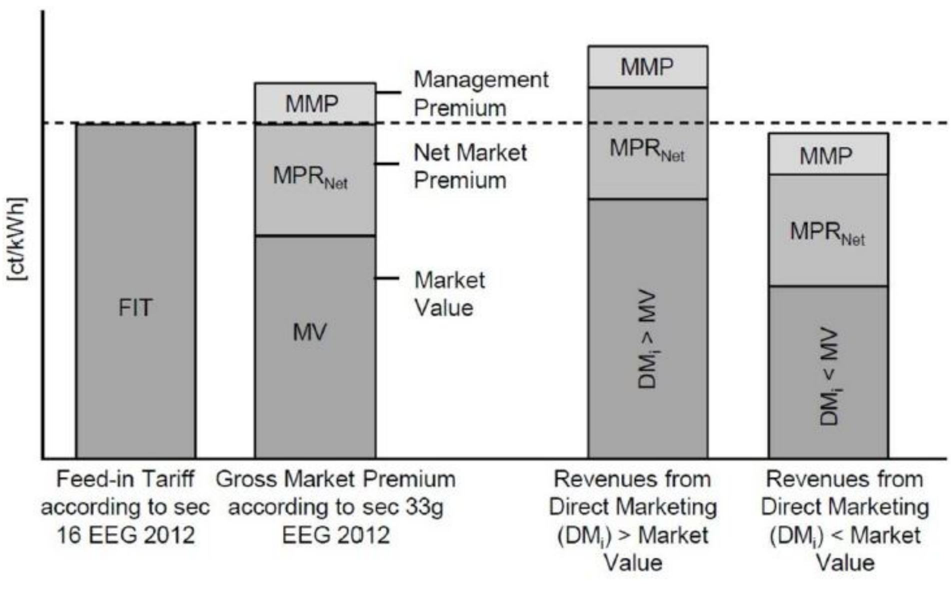

Figure 3.13: German Market Premium structure overview
Source:[GP13a]

Market premium structure is presented in figure 3.13. In the *premium scheme* operators are paid the difference between a technology specific defined feedin-tariff and the average market value of the generated electricity. In addition, operators receive a management premium as a coverage for their direct participation in the market (e.g. balancing or transaction costs). Electricity producers can choose to directly market their production under the *direct marketing scheme* and benefit from the of transmission priority and grid access rules with a possibility of having a higher or lower average market value than the market premium scheme value as shown in figure 3.13.

In the premium scheme the remuneration amount is calculated as following:

$$MPR_{Gross} = FIT - MV + MMP \tag{3.4}$$

Source: [GP13a]
Where:
MPR_{Gross} = Total premium in the premium scheme
FIT = Technology specific feedin-tariff
MV = The monthly technology specific average market value
MMP = Management premium

MPR_{Gross} is the total gross premium in the market premium scheme. FIT is the technological specific regulated feedin-tariff a plant can claim. MV is the average market value which is calculated on monthly ex post bases, based on the hourly prices at the electricity stock exchange in Germany (EEX). For dispatchable RES-E technologies, the market value is the actual arithmetic average of the hourly prices in the market. But for Wind and PV a technology, specific relative market value is used in stead of the arithmetic average value and this is because of the difference in the production times between Wind and PV. Wind energy is frequently produced at times when the demand is low, so the electricity prices are low as well. On the other hand, Solar energy is generated frequently at a peak demand time at noon when prices are high. The difference between the FIT and the MV (FIT-MV) is called the Market net premium (MPR_{net}). MMP is the management premium, it distinguishes between dispatchable and non-dispatchable RES-E technologies in order to account for the costs of balancing forecasting errors.

Year	Dispatchable RES	Wind / PV according to EEG 2012 (old)	Wind / PV according to MaPrV, 29.08.2012 (new)	
			Plants whose output can be remote controlled	Other plants
2012	0,30 ct/kWh	1,20 ct/kWh		
2013	0,275 ct/kWh	1,00 ct/kWh	0,75 ct/kWh	0,65 ct/kWh
2014	0,25 ct/kWh	0,85 ct/kWh	0,60 ct/kWh	0,45 ct/kWh
From 2015	0,225 ct/kWh	0,70 ct/kWh	0,50 ct/kWh	0,30 ct/kWh

Table 3.2: Management premium rates and the management premium ordinance (MaPrV) 2012
Source:[GP13b]

Table 3.2 shows the management premium rates according to EEG 2012. There is a yearly decrease in the management premium as it can be seen, as well it can be clearly seen that Wind and PV revives significantly higher premium than the dispatchable technologies. It can also be seen that the new management premium ordinance (MaPrV) creates an incentive for creating a capability in Wind and PV plants to be remotely controlled with higher management premium than the other plants, which will have a positive reflection on the congestion management problem of the grid, and give more flexibility for the curtailment of production if needed, in the existence of high share of RES-E fluctuating wind and pv shares.

3.3.3 RES-E Support Mechanisms Interaction with Risk

Regarding RES-E investment, the interaction between the policy and investment can be described using the simple model in figure 3.14. Policy can influence the risk-return consideration of RES-E investment. As investors rationally weigh the level of risk and return of a possible investment option, and pick those options that provides the best return for a given level of risk. In other words, investors compare different investment opportunities through evaluating their risk-adjusted returns.[WM12]

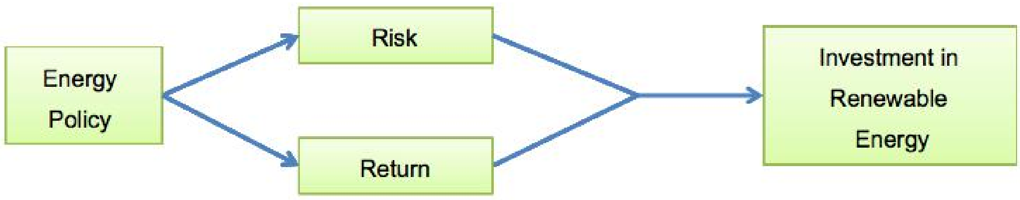

Figure 3.14: Simple model of renewable energy policy and investment
Source:[WM12]

Although that policy can not interact or mitigate the different risk factors faced by investment and operation in the market illustrated in figure 3.3. But the structure of the support mechanism can influence dramatically the investment and operation. The policy features can shape two risk categories, first the policy risks and second the quantity risks.

As illustrated in figure 3.15, not all the risk factors under the price and quantity risk categories can be influenced or mitigated by RES-E policy. The risk factors which can be influenced are represented by the coloured blocks under each category.

Regarding price risks, the electricity feed-in tariff and CO_2 prices are the risk factors which can be influenced by the policy. The fuel prices are not considered in that case as there is no fuel prices for RES-E technologies like Wind and PV.

Regarding quantity risks, policy can not interact with all the risk factors under this risk category. But it can influence the uncertainty in utilization level related factors, which represents the risk factors on the operation side. like the feed-in ability and timing into the grid and the long-term guaranteed purchasing contracts for renewable electricity. In addition, policy can mitigate the regulatory risk that can take place due to legislative changes.

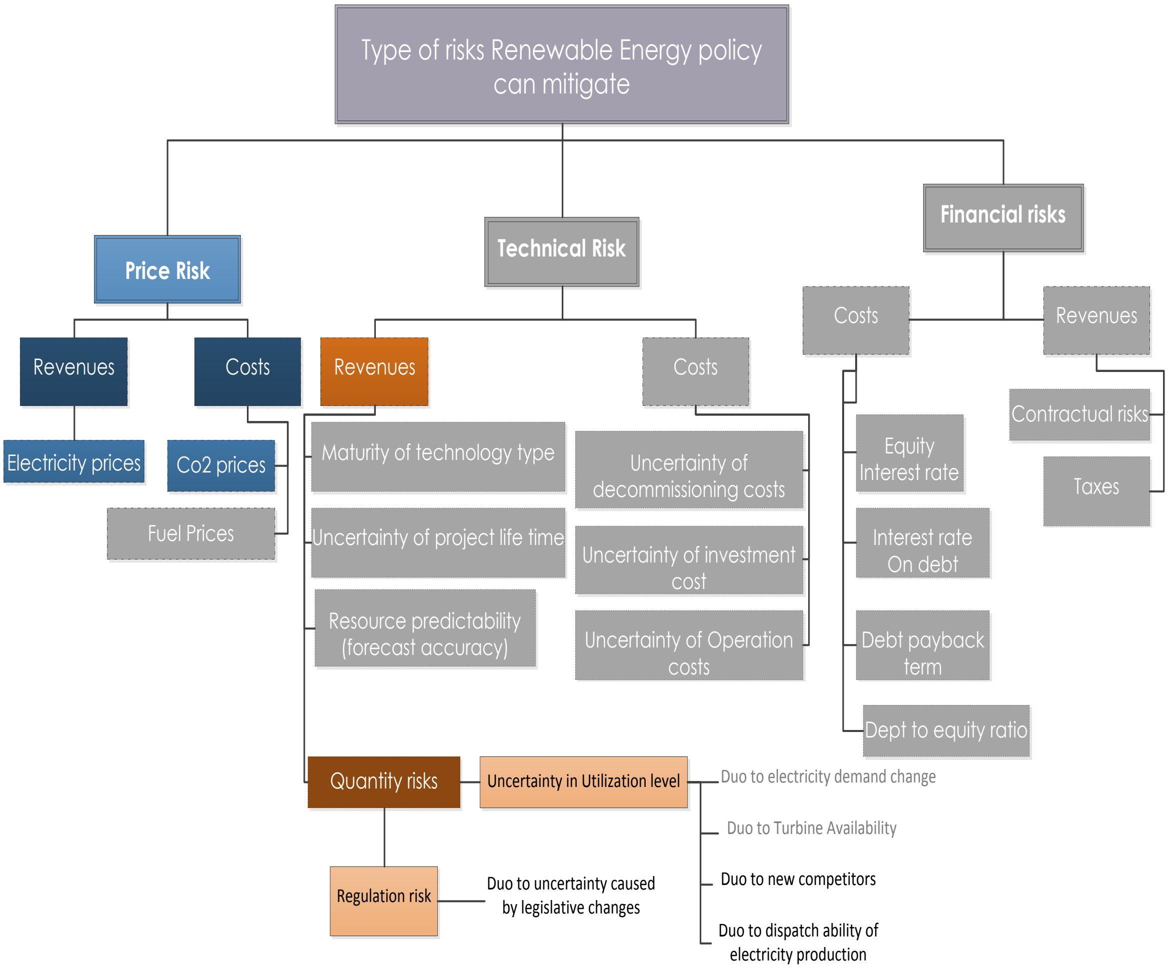

Figure 3.15: RES-E policy interaction with risks faced by investment and operation in a liberalized energy market
Source: Author's illustration based on information provided in [FBH13]

Those risk factors that can be influenced by RES-E policy will play a major rule in the analysis of the implication of the support mechanism on the investment and operation in the next chapter.

3.4 Risk Economic Evaluation Approaches

There are different attempts to quantify investment risks, however all of them need a clear picture of the risk factors affecting a project. As mentioned before in section 3.1, a financial evaluation of investment is a logical approach for measuring the feasibility of a project. Different methods are available for such an evaluation [GX04], such as:

- Value-at-Risk (or profit-at-risk)
- Scenario analysis
- Required green price calculations

Each of these methods has advantages and disadvantages that needs to be evaluated. Taking into consideration the final target of building the model, other market actors involved in the assessment rather than investors, and the level of complexity required in the evaluation.

3.4.1 Value-at-Risk (VaR)

Monte Carlo analysis has been introduced to the cash flow analysis to build distribution functions for each factor which is subjected to uncertainty and can be a risk factor. In such analysis a large number of calculations are made. For each calculation a new set of input data from the distribution function is used as an input for calculating different financial indicators [GX04]. It can simply be explained defining using the Monte Carlo analysis methodology as calculating a desired financial instrument like the NPV through selecting the quantities for the variables needed to calculate it, based on the distribution functions of these variables. The distribution function shape of the calculated NPV in that case will be defined based on the distribution shape of the variables used to calculate it. A number of selections and calculations are done and each calculation results in a value for the NPV. Then characterizing a cumulative probability function is possible by ranking the outcomes (from smaller to larger). The expected value is given at the end by the median value of a distribution function, so the expected NPV will be the corresponding value to the 50% cumulative probability (NPV at (P=50%)) as shown in the example in figure 3.16.

The value-at-risk (VaR) can be calculated using the distribution function values, for example for the NPV the VaR is calculated using the expected NPV (NPV at (P=50%)) minus the NPV corresponding value to the 10% cumulative probability NPV (P=10%).

Figure 3.16 gives an example of the Monte Carlo approach applied in a project investment analysis case. In this case the expected NPV (NPV at (P=50%)) is 14 Million Euro. The Value-at-Risk (VaR) equals 14 Million Euro − (-10) Million Euro (NPV (P=10%)) = 24 Million Euro, which gives an indication that such an investment has a high risk probability of not being financially feasible and the probability of having a below zero NPV is 30%.

What distinguish the Monte Carlo analysis approach is that it does not give only a calculated financial outcome, but it allows also estimating the probability of each

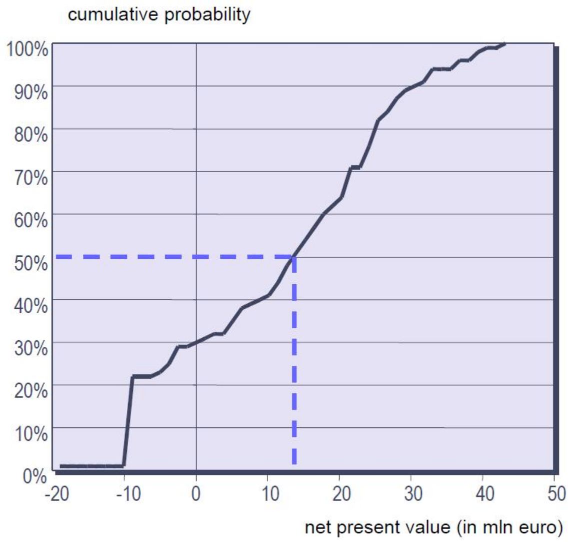

Figure 3.16: NPV results using Monte Carlo analysis.
Source:[GX04]

outcome of the calculated financial parameter. This can help the investment evaluation to measure the probability of investment feasibility.

3.4.2 Scenario Analysis

What does the word scenario refers to?

A scenario is a possible direction which is defined by certain framework and assumptions. This direction can take place in the present or in the future. It is important to mention that a future scenario is not a prediction, but it is rather a possible option which can be adapted or not in the future. Scenario analysis refers to investigating the consequences and results of following this direction in a defined framework and conditions.

The analysis of different scenarios can be described as being simple in terms of understanding, in addition of being more flexible in case of involving different market actors than investors. In this approach, building up the scenario inputs is based on estimations and assumptions not as in the case of the VaR which uses a distribution function for each risk parameter. It is important to define clearly the assumptions made in different scenarios (constant parameters, variables approximations, framework conditions,...).

In this approach each scenario represents an input which is fed into the model used to do the calculations and produce an outcome of the different financial parameters. It is easier than in VaR to define a certain framework conditions for the analysis (for example selecting a RES-E technology and support mechanism in a certain market or country), and to adapt the model to calculate the required financial parameters needed for the investment evaluation. Due to the simple and clear approach of the scenario analysis, it allows to analyze the impact of a certain parameters variation included in the scenario. This can help to understand the influence weight of specific factors on the evaluation outcome. In addition to give an impression about the direction this scenario can lead to if it is adapted.

It is clear that the main drawback of the scenario analysis is that it does not provide any information regarding the probability of events or risks. Table 3.3 gives an overview of the advantages and disadvantages of the various approaches mentioned above.

	Advantages	Disadvantages
Scenario analysis	• Simple method • Easy to understand	• May overestimate risk • No information on probability of risk
Value-at-Risk (or profit-at-risk)	• Both risk and it's probability is measured • Can calculate the probability of loss/inadequate financial returns	• Complex • Requires information on distribution of certain input

Table 3.3: Advantages and disadvantages of different investment risk analysis method. Source:[GX04]

3.4.3 Why using a simple scenario analysis method for the policy implication evaluation?

- The scenario analysis method is selected in order to take advantage of the simplicity and flexibility to include different study parameters in each scenario case.

- It is important to distinguish between the level of information needed for evaluating a scenario by politations and by investors. Politations are interested in the evaluation indicators which reflect the directions that different scenarios can lead to. The scenario analysis methodology can fulfill such a purpose in a simple understandable and straight forward manner. In addition, any changes in the scenario framework can be adapted and the consequences of such a change can be reflected on a discrete indicators which can be compared with other scenarios results quantitatively. So conclusions regarding the result direction a scenario can lead for, can be easily driven using the scenario analysis method. On the other hand, investors may be more interested in more details regarding the indicators used for the investment evaluation like the probability of the risk, which can provide the investor with additional information needed for his evaluation.

- Some companies use highly sophisticated models to assess such scenarios, many others assess them in a relatively simple way. A simplified investment analysis can provide a similarly approximate level of information about the prospects for investment in response to different forms of incentives [GBH10].

- It is not practical or necessarily appropriate for policy makers to attempt to second guess the investment decision of private companies (or different types of investors) in details. Different companies may make different investment decision even when they are faced with the same market conditions [GBH10].

The scenario analysis method is selected for modelling the support mechanisms implications on market actors in the RESMIP model, which will be discussed in the following chapter.

4 Modelling of RES-E Support Mechanisms Implications

Chapter 3 built the foundation for the understanding of the important major aspects which is needed for The assessment of the impact of different RES-E support mechanisms on Investment and power plant operation in the electricity market. Regarding the investor side a clear understanding of three major aspects is needed. First, the process in which investors bases their decision upon. Second, dealing with uncertainties and the impact of different risk types on investment economic feasibility. Third, as support mechanisms can't have an influence on all investment risk factors, a clear understanding on the interference between the RES-E support mechanisms and these factors is necessary through answering the following question; Can RES-E support mechanism influence or mitigate the risk impact? As for the power plant operation, the understating of incentives for operating behaviour changing is important.

The following chapter will explain how this understanding can be translated into a defined and clear analysis methodology, for the evaluation and quantification of how a change in RES-E support mechanism can possibly influence investment and operation for different RES-E technologies.

4.1 RESMIP Model

> The core objective of the model is to analyze the implications of different RES-E support mechanisms on investment and plant operation.

RESMIP (RES-E Support Mechanisms implications on Investment and Plant Operation) model is a scenario analysis based model. The model is developed for the analysis of the RES-E support mechanisms impact on investment and operation through adapting different scenarios for certain RES-E support mechanisms and technologies.

Each scenario framework is defined by selecting a support mechanism and a RES-E technology. The selected support mechanism is evaluated qualitatively in order to build a profile for the risk factors that can influence investment and operation. This evaluation is translated into defined quantities related to investment decision making and operation behaviour. Using these quantities an economic analysis is done for the pre-selected RES-E technologies in the scenario. This economic analysis is based on running a case study for each scenario. The output of the economic analysis is then compared to a reference scenario and conclusion regarding the implication of the support mechanism on the selected RES-E technology can be driven from the results of the comparison. Several model runs take place based on the number of scenarios need to investigated.

The following sections will clarify the general description of the model structure, and the different analysis methodologies used. In order to reach a high level of transparency in the model, a detailed description of any relevant assumptions for each stage will be highlighted clearly in the relevant sections.

4.1.1 Model Structure

The interaction between the different stages is illustrated in figure 4.1, as can be seen the model structure is defined by five main stages:

1. Scenario framework and conditions
2. Qualitative support mechanism assessment
3. Quantitative scenario assessment
4. Economic analysis
5. Comparison and results

Each scenario investigation means a model run with the involvement of the five stages. The model run starting stage is the scenario framework and conditions, going though the three following stage to end with the scenario comparison and results stage. It is a finish to start model meaning that each stage have to be finished in order to start the next stage.

The model general assumptions are stated below. These assumptions don't vary from scenario to another, it is applicable on all the scenarios investigated using the RESMIP model.

Model general assumptions:

- The analysis is focusing on the electricity market in Germany.
- No investment portfolio effects are taken into consideration in the investment evaluation
- The support mechanism reference scenario is the regulated feed-in Tariff for both Onshore Wind and PV.
- Technology investment risk is not represented by a separate variable in the model (as the focus of the study is only on two technologies). But it is included in the financial assumption related to each technology like the debt to equity share and required rates of return.
- Operation and Maintenance cost in the economic analysis is defined as following

  Euro/MWh production for Wind Onshore

  Euro/kWp installed for Solar PV

- Investors want to compensate for the risk or uncertainties, even if the possibility of them to happen is very low. They always want to make the investment secured and plan for the worst case scenario through higher requirements wherever an uncertainty exist.

4.1.2 Scenario Framework and Conditions

In this stage defining the scenario framework is done through the selection of two main variable parameters: RES-E technology and RES-E support mechanism.

Stage assumptions:

- The scope of RES-E technologies included in the analysis is Wind Onshore and Solar PV.
- The scope of RES-E support mechanisms included in the scope of the analysis are:
  - Feed-In Tariff (FIT)
  - Market premium ex-post
  - Market Premium ex-ante
  - Capacity Payment
- Each of these support mechanisms is analyzed under a regulatory defined scheme and auctioning scheme, and the related assumptions are defined in the relative stage.

4.1.3 Qualitative Support Mechanism Assessment

The first analysis stage after defining the scenario is to analyze qualitatively the selected support mechanism. This analysis is done through four main steps:

1. Highlighting the pros and cons

   Evaluating the advantages and disadvantages of the selected mechanism. In this stage the analysis is done for all market actors and for all types of risks and the uncertainties that can be produced by the selected mechanism. It is a general evaluation which can be done by literature review for different point of views regarding the selected mechanism or by market surveys on different types of market actors for empirical evaluation. Through combining both theoretical and empirical analysis, the optimum evaluation output is created. Empirical evaluation is not included in the research scope due to time constrains. On the other hand, a large number of literature include empirical approach and surveys are available which is enough for the scope of the study and the evaluation of the selected mechanism ([BN08, BPAZB12, GP13a, KNB08, Eco08a, EEG10, REN13, bde13]

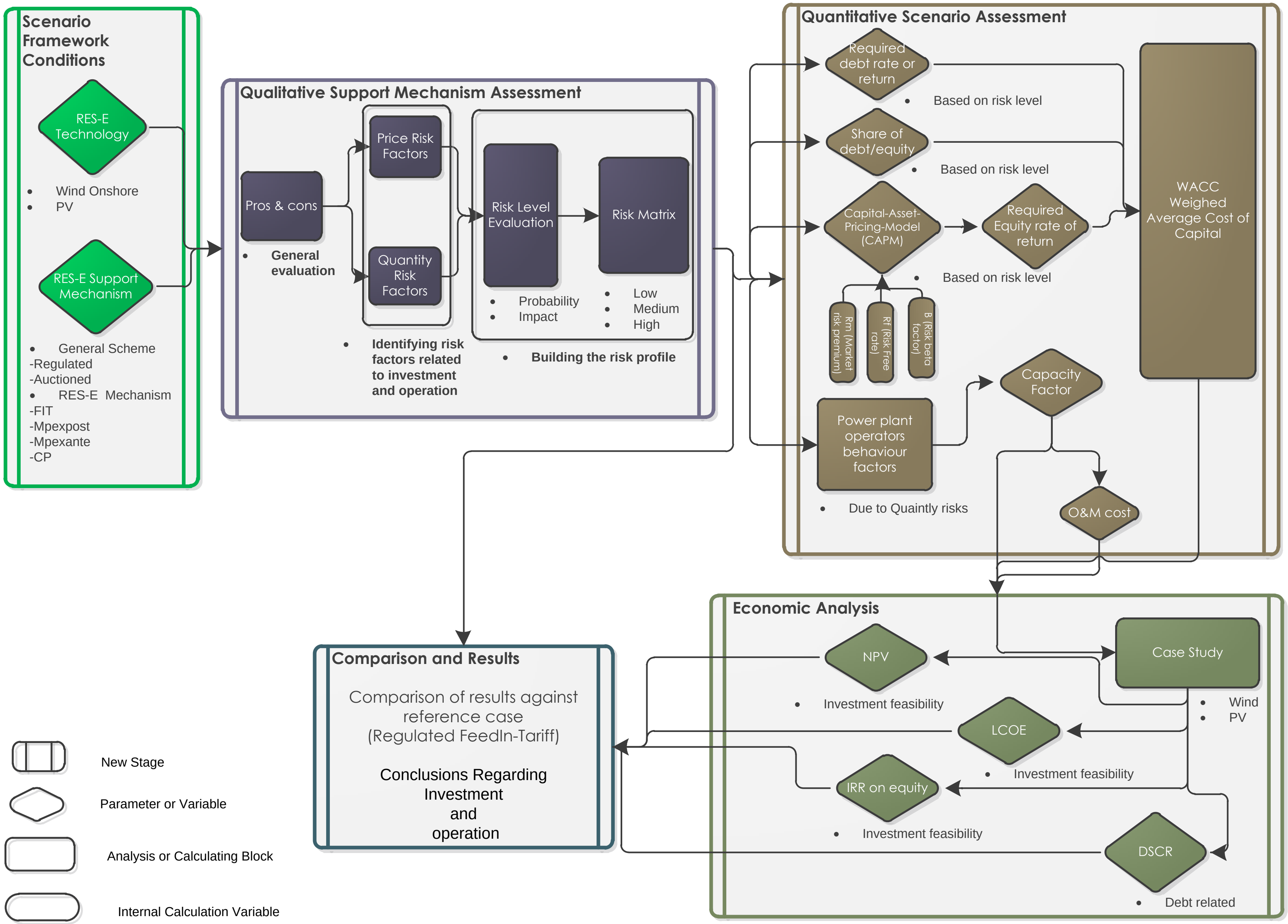

Figure 4.1: REMIP model structure
Source: Author's illustration

2. Identifying the risk factors affecting investment and operation

   In the first step, a general analysis has been carried out to give a complete picture regarding the selected mechanism. In the current step extracting the risk factors is the main objective. Focusing on price related risks and quantity related risks. The price risk factors have a direct influence on investment, and quantity risk has an influence on both investment and operation.

   Step assumptions:

   - Only price and quantity risk factors are taking into consideration in this step as the policy can not have a direct influence on other risk categories (financial risks and other technical risks) as explained in 3.3.3.

Risk profile

Risk factors have different perceptions from both investment and operations sides. This means that the influence of a certain risk can have a higher or lower rank. In this step the risk evaluation is done based on two main parameters: probability of risk to take place during the project lifetime, and the impact of the risk factor on the related market actor.

A detailed view for the different risk factors evaluation with focusing on investment and operation, are the final outcome of the support mechanism assessment stage. This is represented in the risk matrix of each scenario. The matrix is a representation for the different risk levels using the probability and impact to identify the risk category (low-medium-high).

Step assumptions:

- Different types of investors have totally different risk perceptions (which is hard to be estimated without empirical analysis). This evaluation tries to focus on small and medium types of investors as they represent a high share of renewable energy investment in Germany.
- The impact of the different risk factors evaluation is based on the sensitivity analysis in chapter 3.
- Regarding the price risk factors, the probability of risk is estimated from the support mechanism. As for the quantity risk factors the probability of risk is calculated using the likelihood of production curtailing, based on the market electricity prices.
- Evaluation for both probability and impact is done from a scale from 1 to 5 (1 is for very low and 5 is very high) .

4.1.4 Quantitative Scenario Assessment

Linking the risk profile built from the support mechanism analysis to how the investment decision is made and how the plant operation will be effected, require a defined modelling parameters that can translate the risk factors from the outcome of a qualitative assessment to defined quantities related to the investment decision making and the affected possible factors regarding the plant operation. Such a translation is done using financial instruments and operational variables that allows the calculation of the different risk levels effects both investment and operation sides.

Investment (equity) perspective

Investment orientation toward profit maximization (as explained in chapter 2) means that the acceptance of higher risk requires higher profit. Risk does not come without a price. How to compensate for different risk levels depends on the perception of the investor towards risk. Investment combined with high uncertainty is translated into an increase in the required return to accept the risk, and generate secured profits in the future cash flows. consequently this can lead to higher required selling prices for customers, or results in a conclusion that the risk have to be compensated with very high costs that makes the investment infeasible.

RES-E Technology	Required of return on investment (equity)
Wind Onshore	9.0%
Wind Offshore	14.0%
PV Small	6.0%
PV Large	8.0%

Table 4.1: Required return on investment (equity) for different RES-E technologies in the German market.
Source: [Fra13]

An example is shown in table 4.1. As can be seen the required return rate varies from one RES-E technology to another. This is due to the different risk levels related to each RES-E technology. For example investing in Wind offshore are more risky that onshore and this is reflected in the return rate which is 14.0% for wind offshore and 9.0% for wind onshore.

Bank's (debt) perspective

In current RES-E investments in wind and solar power plants, the share of debt is much higher than the privet investment equity share. Table 4.2 shows an example for the share of debt to equity in Germany for Wind onshore and PV, as shown the debt to equity share for wind onshore is between 70% to 75% and for PV is 80%. It is important to note that the renewables projects financing is developed in an off-balance sheet agreement and both debt and equity investors rely on the project future cash flows[FBH13]. The security of paying back loans is the main risk bank faces, therefore banks try to remove all kind of risks that can influence the incoming future cash flow. This is done with restrictions on the maintenance programs to be coordinated in a way that does not have a big influence on the plant production, and also asking for insurance to cover the cost of machine failure and loss of production [GX04]. Financial measurements are used to evaluate whether a project will be able to fulfill with the payback requirements or not. The main measurement is the Debt Service Coverage Ratio (DSCR)[1].

RES-E Technology	Reference	Share of debt to equity
Wind Onshore	BMU(2011)	75.0%
	Frauenhofer ISE (2012,2013)	70.0%
	Deutshe Winguard (2012)	75.0%
PV Small	Frauenhofer ISE (2012,2013)	80.0%
PV Large	Frauenhofer ISE (2012,2013)	80.0%

Table 4.2: Share of debt to equity for different RES-E technologies in the German market

Dealing with higher risk and uncertainty from banks perception can be done in many aspects:

- Requiring higher DSCR is one of the strategies to compensate for high uncertainty.
- Higher interest rate is a strategy to deal with higher risks, using the same perception of the investor.
- Limiting the debt to equity ratio for different technologies due to technical risks is another strategy to deal with the risk of the DSCR, this means that a higher equity share is required. From the banks perception this limitation will decrease the loan repayment and hence increase the DSCR to an acceptable level. On the other hand, the required rate of return on equity is always higher than the debt[MR11], and this can have an influence on the overall economic feasibility of the investment.

The Weighted Average Cost of Capital

The weighted average cost of capital (WACC) is used when an investment capital is financed by more than on entity, as in our case equity and debt. As each entity has it's share of capital and required return on it, the WACC is used to determine the average cost for the investment capital for both equity and debt. It represents the necessary rate required by a prospective investor for investment in a new plant [Eco11][SEI04].

The WACC can be either used as the discount rate for calculating the Net Present Value (NPV) or other financial figures like LCOE or IRR in an investment analysis. Or some firm's use the WACC as an overall representation of a minimum value for the internal rate of return (IRR) of a new project [GBH10].

[1] The debt service coverage ratio is the the amount of cash flow available to meet the annual loan obligations (for more details please check section 4.1.5)

Based upon the same approach of the developed model in Green-x [GX04], which is used in several studies ([SEI04, Eco11, GX04]) for linking the WACC and the project risk level, the WACC is calculated in RESMIP model as following:

$$WACC = g_d \times r_d + g_e \times r_e. \tag{4.1}$$

Where:
g_d = Share of debt,
r_d = Debt rate of return,
g_e = Share of equity,
r_e = Equity rate of return.

Each variable that defines the WACC can be determined through different ways which will lead to a different result. Estimating the value of parameters like the equity rate of return depends on the selected model of calculation. Determining the debt return rate is done based on the market conditions (which will vary from one county to another). Also assumptions for variables like the debt to equity share varies from one technology to another as shown in table 4.2.

The following subsections will discuss into details how each WACC variable is determined in the RESMIP model.

Return on equity (r_e)

The Capital Asset Pricing Model (CAPM) is a used financial model that expresses the relation between the investment risk (which is viewed in comparison with other investment opportunities) and the required return. The CAPM quantifies the additional required return (or risk premium) for accepting a certain risk, and provides a risk-return relationship based on the basic idea that only market risk matters, as measured by the $\boldsymbol{\beta}$ factor (which will be explained in details later) . In the CAPM the required return rate R_{ie} is the sum of a risk-free rate plus a risk premium and can be calculated as following:

$$R_{ie} = R_{fe} + \beta \times (R_{me} - R_{fe}). \tag{4.2}$$

Where:
R_{ie} = Required return rate,
R_{fe} = Risk free rate,
β = Risk measurement factor,
R_{me} = Average return in the financial market,
$(R_{me} - R_{fe})$ = Market risk premium.

In the CAPM model, three main quantities are needed to calculate the required return rate. First, the risk free rate (R_f) which varies from country to another and can be extracted from yearly publications. Second, the market risk premium ($R_m - R_f$) can as well be estimated as a country specific value from yearly publications (e.g. [FL13]).

Table 4.3 shows the risk free rate and market risk premium for different countries. The average risk free rate in Egypt is 12.7% , and it is 1.9% in Germany for the year 2013. This can be due to the country economical and political situation difference between countries, as they are more stable in Germany than the current situation in Egypt. The average risk premium can vary as well on country bases, (due to the difference in the normal (systematic) risk on investment between markets), for example the average value of risk premium in Germany is 5.5%, and it is 6.8% for Finland for the year 2013.

Country	Risk free rate (R_f)	Risk premium ($R_m - R_f$)
Egypt	12.7%	9.2%
Germany	1.9%	5.5%
United Kingdom	2.4%	5.5%
Sweden	2.3%	6%
Brazil	5.9 %	6.5%
Finland	1.7%	6.8%
India	6.9%	8.5%

Table 4.3: Average risk free rates (R_f) and average market risk premiums ($R_m - R_f$) for different countries in 2013
Source:[FL13]

Factor β can be estimated whether using equation 4.2 if other variables described in the equation are known, or other calculation commonly used methods.

The required rate of return on equity is calculated using the Capital Asset Pricing Model(CAPM) in the RESMIP model. However, an additional factor have been introduced to the CAPM which represents the policy risk due to the support mechanism implications. The support mechanism risk premium (a_{SM}) changes based on the risk evaluation done in the support mechanism analysis stage of the model. New β factor for each scenario is then calculated with according to the following definition:

$$\beta_{SM} = a_{SM} \times \beta_{ref}. \tag{4.3}$$

Where:
β_{SM} = The new β for the selected support mechanism in the scenario,
a_{SM} = Support mechanism risk premium,
β_{ref} = The β factor of the reference scenario.

Based on the β_{SM} calculations and the other variables, the required rate of return on equity r_e can be calculated for each scenario case.

$$r_e = R_{fe} + \beta_{SM} \times (R_{me} - R_{fe}) = R_{fe} + (\beta_{ref} \times a_{SM}) \times (R_{me} - R_{fe}). \tag{4.4}$$

Where:
r_e = Equity rate of return,

R_{fe} = Risk free rate,
β_{SM} = The new β for the selected support mechanism in the scenario,
a_{SM} = Support mechanism risk premium,
β_{ref} = The β factor of the reference scenario,
R_{me} = Return in the financial market for equity,
$(R_{me} - R_{fe})$ = Market risk premium for equity.

Debt required rate of return (r_d)

The debt rate of return is estimated in the model based on the currently used debt rates in the German RES-E market. Various RES-E technologies have different debt rates based on the risk associated with the technology type. The reason why there is a technology based difference in the required rate is depending on the risk level associated with the RES-E technology from the bank prospective. Table 4.4 shows the debt rates in Germany for the different RES-E technologies.

RES-E Technology	Reference	Debt required rate
Wind Onshore	BMU(2011)	5 to 5.5%
	Frauenhofer ISE (2012,2013)	5 to 5.5%
	Deutche Winguard (2012)	5.5%
PV Small	Frauenhofer ISE (2012,2013)	4.0%
PV Large	Frauenhofer ISE (2013)	4.0%
	Frauenhofer ISE (2012)	4.5%

Table 4.4: Debt required rate of return for different RES-E technologies in Germany
Sources: [FEL13, Win12, Fra12, Fra13]

As can be seen in the table, the debt required rate for Onshore Wind varies between 5% to 5.5% depend on the reference. Regarding the PV it depends on the size of the plant. For the small PV and building integrated plants it is 4.0%, for large ground installed plants it is around 4.5% (in 2012).

Variables like the risk free rate (r_{fd}) and market risk premium (r_{pd}) for debt[2] can be used to calculate the debt return rate (r_d) in case there is no data available about the used rates in the market using the following definition:

$$r_d = r_{fd} + r_{pd}. \tag{4.5}$$

Where:
r_d = Debt required rate of return,
r_{fd} = Risk free rate for debt,
r_{pd} = Market risk premium for debt.

[2] The risk free rate can be the same for debt and equity. However, the market risk premium can be different from equity and debt prospectives

WACC Calculation Model in RESMIP

The weighted average cost of capital (WACC) defined on equation 4.1, can be redefined using the explained definitions for the return on equity and debt in equations 4.4 and 4.5 as following:

$$WACC = g_d \times (r_{fd} + r_{pd}) \times (1 - r_t) + g_e \times (R_{fe} + (\beta_{ref} \times a_{SM}) \times (R_{me} - R_{fe})). \quad (4.6)$$

Where:
g_d = Share of debt,
r_{fd} = Risk free rate for debt,
r_{pd} = Market risk premium for debt,
r_t = Tax rate[3],
g_e = Share of equity,
R_{fe} = Risk free rate,
β_{ref} = Equity risk measurement factor for the reference scenario,
a_{SM} = Support mechanism risk premium,
R_{me} = Return in the financial market for equity,
$(R_{me} - R_{fe})$ = Market risk premium for equity.

Plant Operation Perspective

RES-E support mechanism can interact with plant operation through creating an incentive for operators to adapt a more demand oriented generation behaviour and react to market signal. This incentive is created to reach the market integration of the RES-E and the system integration as well. For non-dispatchable RES-E technologies like Wind and PV, due to the nature of the resource availability generation can not be influenced[4]. In that context if the operators have to react to market signals and behave more demand oriented this will mean curtailing the electricity production which will affect the capacity factor of the plant. Reducing the capacity factor of the plant will influence the revenues generation and this will be reflected on the financial indicators of the economic evaluation of the project. This situation has an advantage for the system stability and economic efficiency. In the RESMIP model, the effect of the support mechanism on operation is translated to an impact on the plant capacity factor. How the capacity factor is affected depends on the support mechanism evaluation done in the previous analysis stage, it is directly related to the quantity risk level.

There are different approaches to define the operation and maintenance (O&M) costs for Wind onshore and PV. These approaches are mainly to define the O&M costs as a fixed cost per year, or as a variable cost with the changes of production. As clarified

[3] The reason why the tax rate appears in the debt side as $(1 - r_t)$ is that when interest is paid to the bank, it is allowed to include that as an expense. And when it is included as an expense it lower the taxes. However, the tax rate will not play a rule in the RESMIP model scenario analysis calculations as it is not applicable on the Wind onshore and PV electricity production.

[4] Unless it is curtailed by operators, which will reduce the generation

before in the model general assumptions, the adapted approach in RESMIP model for the O&M costs in case of Onshore Wind is the variable)O&M costs based on the of amount of energy production (€/MWh). This approach is used in the model as it is a commonly used approach for Wind and PV technologies, because wind turbines have moving parts which is affected based on the production amount, but on the other hand PV does not. The approach adapted in case of PV is the fixed O&M costs defined based on the installed capacity (€/kWp).

This means that for Onshore Wind under different scenarios there is a possibility for the O&M costs to change as a consequence of changing the plant production. This change will affect the running costs during the life time of the project, which will be reflected on the yearly cash flow and all the financial indicators specially the cost related ones like the LCOE. On the other hand, for the PV the O&M costs will not be affected due to change in production.

Step assumptions:

- Plant operator will curtail the production at any value of a market negative price, not only in the high negative prices cases where the remuneration is exhausted.
- O&M costs are defined for different RES-E technologies as clarified in the model general assumptions.

4.1.5 The Economic Analysis

The first three stages define the assessment methodology used in the model. This is done through selecting a scenario then applying a qualitative analysis, and translating it's results into quantities using descriptive calculation models for both investment and operation sides. The main objective of the current stage is to reflect the previous analysis implications on real projects using different case studies. Selected financial figures are used to measure the project feasibility for both equity and debt sides, in addition to reflect the consequences of changing the plant operation.

The Case Studies

For each RES-E technology including in the study scope, a selected generation plant that represents a case study. The selection of the case studies is based on the three parameters: Plant installed capacity, the availability of project information and the plant location. The qualitative analysis results are used as inputs for the project financial informations (e.g. the discount rate of the future cashflow, the electricity feed-in tariff, the debt and equity related values) and technical conditions (e.g. the plant capacity factor and O&M costs). Based on plant case study the financial indicators are calculated for each scenarios and used in the assessment of the scenario results[5].

Step assumptions:

[5] More details regarding the selected case studies in the scope of the study are included in section (4.2).

- As it will be challenging to estimate the change in all the variables (like how much remuneration is paid for the capacity available) specially for the future support mechanism scenarios. The case studies will be used to measure the effect of the changed variables due to the price and quantity risks in comparison to the reference scenario (like the WACC, r_e, g_d, r_d, Capacity factor, O&M costs) as this is the main scope of the study.

The Analysis Financial Indicators

Four financial measurement are selected in the economic analysis

- The Net Present Value (NPV)
- The Levelized Cost of Electricity (LCOE)
- The internal Rate of Return on equity (IRR)
- The debt service coverage ratio (DSCR)

Except for the DSCR, other financial measurements are calculated as explained in chapter 3. As clarified before, the NPV is selected as it reflects the investment economic feasibility including revenues and costs over the project lifetime. In addition based on it other financial measurements can be calculated like the IRR. The IRR is used as an understandable figure for investors to evaluate the investment using a minimum desired rate of return and comparing it to the calculated IRR. The LCOE is selected as it is a commonly used figure for the assessment and comparison of investing in different electricity production technologies.

The DSCR is a main measurement used by the bank which is defined as:

$$DSCR = CF/(LR + I). \tag{4.7}$$

Source: Green-x 2004 [GX04]

Where:

CF = The annual available cash flow of the project (net operating income before depreciation, debt payments and income taxes),

$(LR+I)$ = The annual loan obligation plus the required interest rate (debt service).

The DSCR is the annual available cashflow from the net operating income divided by the debt service which is the debt repayment annual obligations [Eco08a, WP98]. It is calculated for each year of the project lifetime and the lowest ratio is reported as the DSCR of the project[RET05] .

Banks are not so much interested whether a project is profitable, as much as they want to make sure that they will get their loan repayment obligations payment back. As there is a strong link between the project profitability and the available cash flow, the bank requires a minimum DSCR to finance a project. A DSCR higher than 1% means that there is enough cash flow to fulfill the payback obligations, however it depends on the bank risk perception as explained before to evaluate the risk and set the required DSCR for each project. Table 4.5 shows an example of the level of required DSCR in different countries for various RES-E technologies.

Country	Wind Onshore	Wind Offshore	Solar PV-Large	Solar PV-Small
United Kingdom	1.45%	1.8%	1.45%	1.3%
Germany	1.3%	1.7%	1.3%	1.3%
Poland	1.45%	1.8%	1.45%	1.3%

Table 4.5: Debt service coverage ratio (DSCR) in different countries and various RES-E technologies
Source:[Eco11]

AS can be seen in table 4.5 the required DSCR changes on the country scale for the same RES-E technology like for Offshore wind in the UK (1.8%) and in Germany 1.7%). It also varies from RES-E technology to another depending on the maturity and the risk involved with the technology. As Offshore wind is more risky that Onshore and PV-large systems, the DSCR is 1.7% for Offshore Wind in Germany and it is 1.3% for Onshore Wind and PV-large in Germany.

The financial measurements will also be strongly affected in respond to the change in operation of a plant due to the quantity risks implied from the support mechanism. Using different indicators related to revenues and costs is very useful to reflect the consequences of operation change, whether in capacity factor changing or operation and maintenance costs. Changing the capacity factor will affect the plant production and the project revenues which will be reflected on all the financial indicators. The operation and maintenance costs will change only in the case of Onshore Wind as a consequence of changing the plant production (as the O&M costs defined per MWh of production) and this will affect the running costs during the life time of the project, which will be reflected on the yearly cash flow and all the financial indicators specially the cost related ones like the LCOE.

Table 4.6 summarize the financial indicators descriptions and calculation models which is used in the RESMIP model[6].

4.1.6 Comparison & Analysis Results

In terms of evaluating the different scenarios a comparison between the case study economic analysis outcomes against the reference case scenario in the model is done in this stage. The different financial indicators that reflects the selected support mechanism and RES-E technology implication on both investment and operation are compared with the financial indicators of the reference case. Although it is a simple evaluation approach, but as explained before in the section introduction the simple approach in carried out in this stage as it can provide a similarly approximate level of information regarding the implication of a changing certain incentive to another on investment and operation levels.

[6] The NPV,LCOE,IRR detailed description can be found in section 3.1.2

The quantitative assessment of the scenario is used as an input as well, as it helps to justify the results generated by the model, and to discuss the implication of the scenario on the plant operation. Using a comparison between the study scenarios and the reference case, conclusions regarding the assessment of different RES-E support mechanisms and technologies on the investment and operation can be driven.

Financial Indicator References	Calculation Model	Unit	Description
NPV [Fin85, US12, MR11, Hol12, RET05]	$NPV = -I_0 + \sum_{t=1}^{n} \frac{NCF_t}{(1+r)^t}$	€	The Net Present Value is the sum of the present values of all the cash inflows and outflows linked to investment at a given discount rate.
IRR [Fin85, MR11, RET05]	$0 = -I_0 + \sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t}$	%	The Internal Rate of Return is the interest rate at which the cumulative NPV of the project is zero. A project is considered desirable if the IRR is bigger than investing in other options of the same risk level.
LCOE [Pfa12a, Pfa12b, Fra12, Fra13, Eco08a]	$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{C_a}{(1+r)^t}}{\sum_{t=1}^{n} \frac{P_{el}}{(1+r)^t}}$	€/MWh	The levelized cost of electricity is the cost per unit of output, taking into account the time pattern (discounting) of costs as in the NPV. It represents the minimum price of electricity which is required to make the investment in the project viable.
DSCR [Eco08a, WP98, RET05, MR11]	$DSCR = \frac{NetOperatingIncome}{DebtService}$	%	The Debt Service Coverage Ratio is the annual available cashflow from the net operating income divided by the debt service which is the debt repayment annual obligation.It is calculated for each year of the project lifetime and the lowest ratio is reported as the DSCR of the project.

Table 4.6: RESMIP model financial indicators (NPV, IRR, LCOE, DSCR) calculation models and description summary

4.2 Scenarios Investigation Using RESMIP Model

The previous section gave a detailed and transparent description for the RESMIP Model structure. The following section will describe the analysis of the scenarios that have been selected to be included in the scope of the study. In each scenario the model inputs will be described, in addition to any relevant assumptions regarding technology or policy sides. The outcome of each analysis stage will be highlighted in the following section leaving the final results to be discussed in another chapter.

Figure 4.2 illustrate the scenarios that have been considered in the scope of the study using th RESMIP model.

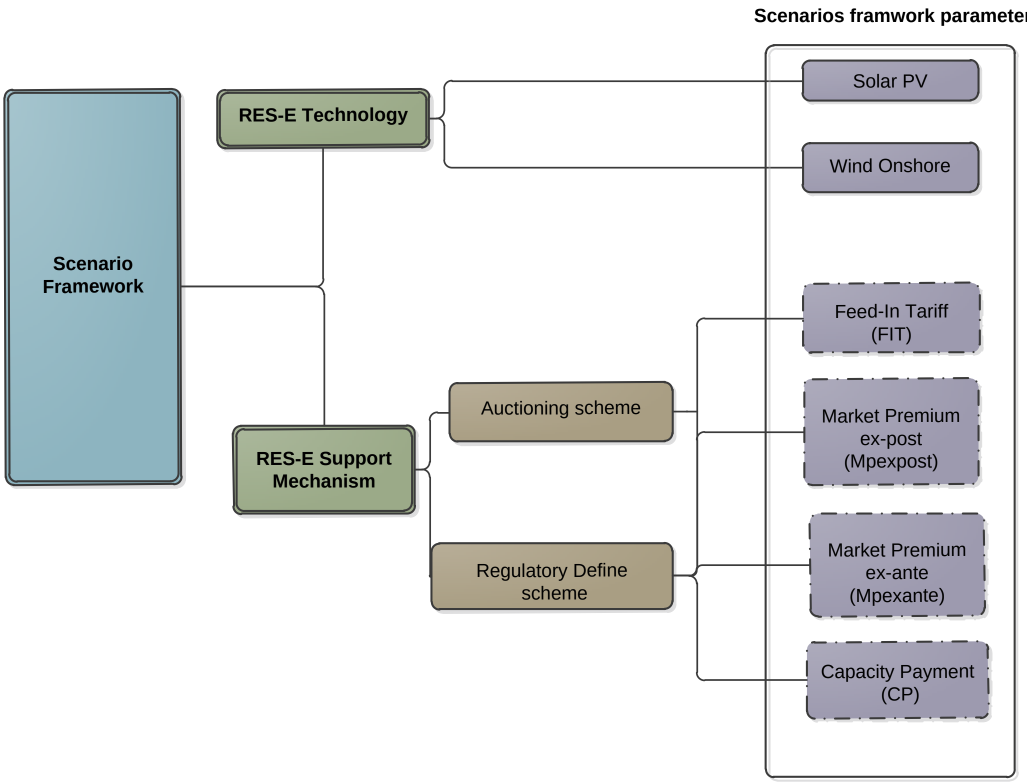

Figure 4.2: Adapted scenarios framework parameters in the study scope

The scenario is characterized by selecting one of the Two RES-E and One of the Eight RES-E support mechanisms. This result in sixteen different scenario Frameworks to be used as an input for the model. In each model run only one scenario is investigated. Two case studies have been used from the RETScreen database which have been implemented in Germany. One case study is for Wind Onshore plant and the other is for building integrated PV [7]. Adaptation for the case studies project data have been made in order to update them to the current market situation.

For each scenario the outcome of the quantitative analysis is fed into RETScreen for running the case studies. The IRR and DSCR is calculated by RETScreen and used for the comparison with the reference scenario. The annual cash flow of the project is extracted from RETScreen and used in a developed discounted cash flow model to

[7] More details regarding the case study will be illustrated in section 4.2.3

calculate The NPV and LCOE [8]. The results of NPV and LCOE calculations are then compared with the RETScreen calculated values for verification.

The reference scenario is the regulated feed-in tariff for both Onshore Wind and PV as mentioned before in the model general assumption in section 4.1.

4.2.1 Support Mechanisms Scenarios Assessment

For each of the eight scenarios of the support mechanisms different assumptions have been made upon which the mechanism is evaluated. As outlined in section 3.3 some of the mechanisms already exist in the German electricity market as the regulatory defined FIT and MPexpost. So the relevant assumption is driven based on the existing mechanism design and the evaluation is done based on the empirical effects of the mechanism on the market actors . The otter support mechanisms are future scenarios, assumptions that have been made based on the possible proposed scenario for how possibly the mechanism will look like under the regulated and auctioning schemes. These assumptions are stated clearly in each support mechanism scenario description. It is important to note that for the proposed future scenarios, changing the assumptions related to the mechanism design will result in major changes in the evaluation outcomes.

Regulated Support Mechanisms

1- Scenarios Assumptions

Regulated FIT (reference SM scenario) The remuneration level which is paid per unit production (€/MWh) is predefined before the project is developed by the electricity market regulator. The remuneration amount defined is guaranteed for a fixed project lifetime which varies from RES-E technology to another [BPAZB12].

Regulated MPexpost As explained before in section 3.3.2, under the regulated market premium ex-post mechanism. The difference between a regulatory defined technology specific feed-in tariff (€/MWh), and the actual monthly average technology specific market value, is covered by a premium payment plus a management premium . Operators are free to select between the regulated FIT or receiving a Market Premium. It is also possible to participate in the market through direct marketing scheme, by marking the electricity production directly into the market and receive the define remuneration plus the management premium over the direct marking selling price which can be lower or higher than the monthly average market price.[GP13a]

Regulated MPexante The difference between the scenario adapted for the MPexante and the MPexpost scenario is in how the remuneration is defined. In the MPexante the regulator forecasts the monthly average technology specific market value, and defines the amount of remuneration before the actual selling process take place in the electricity market. Depending on how the regulator will structure the mechanism, it can be defined before the beginning of each month, or the monthly remuneration can be announced for the next quarter or year. The scenario assumption is that it is defined

[8] The calculation of NPV and LCOE is done based on the calculation models defined in chapter 3

before the beginning of each month. Direct marketing of production is possible as well. The generator will receive in this case the predefined remuneration on top of his selling price in the market which can be lower or higher than the forecast average monthly prices.

Regulated CP The regulator define the amount of remuneration which is given for the available generation capacity. For non-dispatchable RES-E technologies like Wind and PV the remuneration is not based on the installed capacity, but on the capacity factor of the plant [REN13]. The selling price of the produced electricity is defined according to the market value.

2- Assessment Outcome

The qualitative assessment results for the regulated support mechanisms scenarios are shown in table 4.7. The assessment is done according to the methodology described in the support mechanism assessment in section 4.1.3.

FeedIn-Tariff

The FIT mechanism guarantee the remuneration over the life time of the project. That is why it does not expose the investor to market price risks, as it isolate the revenues from the electricity market prices. Duo to the long-term guaranteed contracts, there is no risk possibility because of the change of regulation, which can have a major effect on the investment security. The FIT helps the policy makers to create an incentive for investing in an energy generation mixture that includes different RES-E technologies. This is important for the future of the RES-E as it is never clear which technology or technological mix will provide an efficient and reliable future, in addition to moving technologies beyond R&D phase to maturity instead of just focusing the investment on the mature RES-E technologies.

On the other hand, The determination of the sufficient remuneration is extremely challenging and it is a burden on the regulator side. The regulator has to avoid over or under compensation for one technology over another, that will have an influence on the selection of investment in the most profitable type of RES-E technologies. Plant operators under the FIT have the advantage of guaranteed dispatchability of electricity produced combined with the isolation from the market prices. This advantage result in a "Produce and Forget" behaviour from the operation side due to reducing the inventive for operators to react to market signal. Providing the generators with guaranteed remuneration will not come out with no cost, the additional cost in the FIT mechanism due to balancing costs, or long term risk compensation costs is burden by the end consumer.[BPAZB12]

From these advantages and disadvantages of the FIT we can extract the price and quantity risk factors that can affect investment and operation. Due to the guaranteed remuneration and the isolation from market prices there is no probability for price risks. Moreover, due to the guaranteed dispatchability of the electricity production from Renewables the support mechanism do not create any possibility for quantity risk.

Market Premium ex-post

The German MPexpost aims to increase the integration of the RES on the market and system levels. It support the market integration in a narrow sense by increasing the exposure of to the market participants to market prices.Such integration aims to provide the RES-E operators with experience about the price risks which can be a step toward fully integrating RES-E into the electricity market in the future. MPexpost create an incentive for plant operators to curtail production once high negative prices (which is higher than the remuneration amount) is indicated due to excess supply of electricity. This will contribute to improve the system integration of RES-E and encourage demand oriented production in a narrow sense. Direct marketing of production has a benefit of transferring the forecasting errors costs from the TSO side to the operation side. Not as in the FIT in the MPexpost the additional costs due to risks is transferred to the consume only if they become a reality as the remuneration is determined on ex-post basis.

MPexpost encourage only voluntary curtailment of production. Making profit is guaranteed due to the management premium even if there is negative prices, only in case the premium is exhausted by high negative prices the plant operator is encouraged to curtail the production as no profit can be made in that case. As the amount of remuneration is not predefined and guaranteed as in the case in the FIT the MPexpost, this result in higher uncertainty in the future cash flow of the project. There is a possibility of creating windfall profits, in case the direct marketing value is higher than the market value adding the premium on it will result is unexpected profits. Time of generation for non-dispatchable RES-E technologies like Wind and PV can hardly be influenced during operation, therefore it has less chances to be more demand oriented.[BPAZB12, GP13a, EEG10]

Price risks exist under the MPexpost. Due to linking profits to the market monthly average prices, in addition to the uncertainty in the future cash flows and transferring the balancing costs due to forecasting errors to the operation side.Regarding quantity risks, it also take place due to the probability of production curtailing. The probability of facing these different risks is low in the MPexpost as the negative prices hours represent a small percentage of the total year hours in the years 2011 and 2012 as show in Figure 2.4. The impact is based on the sensitivity analysis results in chapter 3.

Market premium ex-ante

According to the assumptions, the regulator pre-define the remuneration which gives the investor and operator a more clear view than in the MPexpost on what to expect from selling his electricity production. MPexante supports reaching a complete market integration for the RES-E through encouraging investors and operators on making long-term forecasting for the market proceeds and risks, as the remuneration amount is not determined on monthly average ex-post basis. According to this manner, the MPexpost create an incentive for increasing the quality of market procedures and demand forecasting. As in case a high quality forecast is available in combination with the foreknowledge of the remuneration amount, profits predictability can be done with higher level of certainty.

RES-E Support mechanism		Pros	Cons	Risk evaluation		Qualitative risk assessment Probability (1 to 5)	Impact (1 to 5)	Risk level (L-M-H)
Regulated Support Mechanisms	Feed-in Tariff (FIT)	1- Guaranteed remuneration with no exposure to prices risks	1- The determination of the right remuneration is extremely challenging	Price risk	1- No price risks as remuneration is isolated from electricity prices			
		2- Long-term FIT don't expose RES-E to the risks of regulatory change	2- Reduce the incentive for RES-E generators to appropriately react to market signals					
		3- Provide support for RES-E technologies moved beyond R&D phase but didn't reach market maturity	3- The mechanism is embodied in a electricity decrees or act by the regulator and this require allocation of incurred additional costs to the consumer or taxpayer via the EEG levy .					
			4- long term market risk prices is burden by the end consumer.	Quantity risk	2- No risk as renewable electricity dispatch is guaranteed			
	Market Premium ex-post (Mpexpost)	1- Support the market integration of RES-E in a narrow sense, and providing RES-E generators with experience about the prices risks.	1- Encourage only voluntarily curtailment of production, as remuneration is guaranteed and profits can be made until there is high negative prices of electricity and the premium amount is exhausted.	Price risk	1- Uncertainty in profit amount as it is linked to market average price under the direct marketing scheme	2	2	L
		2- Improve economic efficiency more than the Feed-in-system by setting incentives for shifting maintenance and other unavoidable output reductions to hours with low or negative prices.	2- Higher uncertainty in the future cash flow than the FIT.		2- Uncertainty of Future cash flows of the project	1	3	L
		3-Create an Incentive for plant operators for curtailing production once negative prices indicated an excess supply of electricity(above a certain level of negative prices which is higher than the remuneration amount).	3- Insufficient incentive for more comprehensive investment in flexible plant design and storage systems.		3- Balancing costs due to forecasting errors	1	2	L
		4- Contribute to improve the system integration of RES-E through encouraging demand oriented production and maintaining grid stability.	4- MP has not been able to break the increasing number of congestion management measures Transmission system operators have to take to safeguard grid stability.	Quantity risk	4- Output curtailing risk	2	3	M
		5-Direct marketing of production transfers the forecasting errors balancing costs from the Transmission system operators to the plant operators.	5- long term market risk prices in case it become reality is burden by the end consumer.					
		6- Create an incetive for making an extra investing to make the plant remotly controled, through defining special remuenration for the remote controlled plants.	6- Allows higher possibility of windfall profits than in the FIT.					
		7-price risks is transferred to end consumer via the EEG levy only if they become reality, as remuneration is determined on ex-post basis based on the monthly average market prices.	7- Wind and PV operators can hardly influence the time of generation, therefore have less chances of demand oriented feeding of electricity.					
	Market Premium ex-ante (Mpexante)	1- The Predefined remuneration level increases the predictability of the tariffs amount, rather than in the Mpexpost case .	1- Forecasting the market prices to define the fixed premium is challenging for RES-E as it require knowledge of the feed-in behaviour of the generation capacities. In addition to the uncertainties in case of new market design that impair the calculation of an ex-ante premium.	Price risk	1- Long -term price risk for investors.	2	3	M
		2- Support a complete market integration for RES-E through encouraging investors and operators on long-term forecasting of the market proceeds and the entire market price risks, as the remuneration is fixed in addition to the market revenues and not determined on ex-post basis.	2- Investors and plant operators have to bear the long-term revenue risk for the volume of electricity produced without needed demand.		2- Risk of low remuneration level due to forecasting errors of the fixed premium amount.	2	4	M
		3- Create an incentive for increasing the quality of market proceeds and demand forecasting, as profits will highly depend on it.	3- Possibility of windfall profits generation in case market prices exceed expectation. In that case the premium which have been determined would create risk for end customer prices.		3- Uncertainty of Future cash flows due to the long-term revenue risk.	1	3	L
		4-If a special remuneration is taking into account, the MPexante can create the same incentive for making the plant remotly controlled as in the Mpexpost.	4- Does not produce any efficiency gains rather than a variable premium on the short term, as the operators will feed-in electricity even at negative market prices until the premium amount is exhausted and there is no profit.	Quantity risk	4- Output curtailing risk same as in the MP ex-post mechanism.	2	3	M
		5- In case a high quality forecast of the market prices is done, combined with the foreknowledge of the remuneration level. Profits prediction can be done with high level of certainty.	5-The expected value for the end customer is higher as price risks is transferred to end consumer always as remuneration is determined on fixed ex-ante basis.					
	Capacity payment (CP)	1- Potentially increased investment in generation capacity, in order to increase the reliability of supply. Specially if regulator addressed the availability and cost of long-term financing for capacity expansion and secured short-term contracts.	1- Uncertainty about capacity value of variable RES-E implies that it might not be as beneficial for these generation sources as for conventional units.	Price risk	1- Exposure to volatility of electricity prices	4	5	H
		2- More revenues can be possibly obtained from the capacity payment in addition to electricity selling in the market.	2-In case not structured for different RES-E technologies. It can locks in particular technology type. As the capacity factor is key element, technologies with higher capacity factors could be favorable for investment.	Quantity risk	2- Uncertainty of capacity factors of RES-E technologies on the long term	2	3	M
		3- Can be structured to compensate all types of available capacity, including RES-E different technologies with different capacity factors.	3- The Potential to contribute positively to the grid stability is reduced , as the capacity payment can guarantee generating revenues, even in case of excessive electricity production.		3- Production curtailing risk due to negative prices higher than the remuneration on the capacity and no profit is generated	2	3	M
		4- Reduce volatility of wholesale energy prices (Irish market empirical advantage)	4- Could case higher wholesale electricity prices (Irish market empirical advantage).					

Table 4.7: Qualitative assessment of the regulated support mechanisms

The MPexante disadvantages are mainly because of the need of market procedures and forecasting risks from the regulator side in order to define the technology specific remuneration, and from the investment side to be able to predict the profits and estimate the investment feasibility. The forecasting is extremely challenging for the RES-E as it requires knowledge of the generation capacities feed-in behaviour, in addition to demand forecasting which will be a burden on the regulatory and operation sides. Moreover, there is a risk on investors involved with generating long-term revenues, in case of excessive electricity production which can not generate any profit. On the other hand, there is a possibility of windfall profits generation in case market prices exceed expectations which is an advantage from the investment side, but a disadvantage from the customer side as it can create a risk on the prices and at the end the customer will have to burden higher prices. It can also be argued that the MPexante dose not produce any efficiency gains rather than a variable MPexpost on the short term. Operators will continue feeding electricity even in case of negative prices until the same condition of the MPexpost is applied and the premium amount is exhausted which means that there is no profit gained from selling electricity.[bde13, EEG10]

The risks which the MPexante implie on investment are due to the amount of uncertainty involved with the mechanism. There is long-term price risk on the investment due to the market prices forecasting errors . In addition to the risk on low remuneration level due to wrong forecasting or underestimation from the regulator side. The certainty in the future cash-flows is not high due to the revenues risks. On the quantity risk side the production curtailing due to exhausted premium from the high negative prices exists as in the MPexpost mechanism.

The probability of the the long-term price risk depends on the quality of the market prices forecast, and the impact is not high due to the existence of the premium which can cover a part of the negative prices. Assuming that the regulator forecast is done with high quality the probability of defining low level of remuneration is not high. However, in case that the remuneration is not sufficient, the impact on the investment can be high and the profitability of operating the plant can be questionable. For the quantity risks the probability and impact of curtailing the production is based on the same assessment criteria in the MPexpost.

Capacity payment

Capacity payment create an incentive for increasing investment in generation capacity. This is one of the solution for securing the supply and increase the reliability of the system. In case the regulator announce a defined long-term plan addressing the availability and cost of financing for capacity extension, in addition to secured short-term contracts for the lifetime of the plant this will represent a source of security for RES-E investment. CP represents a source of revenues in addition to electricity selling in the market, besides it can be structured to compensate all types of available capacity including non-dispatchable RES-E technologies. An empirical advantage of the CP mechanisms in the Irish market [REN13] is that it reduced the volatility of wholesale energy prices.

As defined in the assumptions related to the CP mechanism, non-dispatchable RES-

E technologies remuneration is based on the capacity value of the plat not the installed capacity. There is an amount of uncertainty regarding the capacity value specially that the resource can not be controlled by operators. Such uncertainty can put the dispatchable RES-E and conventional technologies in a favourable position for investment. This favourable position increases in case the structure of the mechanism is not compensating all types of available capacity, resulting in locking particulate technology types. The payment for the available capacity can guarantee generation revenues even in case of feeding in during the availability of excessive electricity. This can result in reducing the positive contribution toward the grid stability through demand oriented generation behaviour. Although that there are empirical advantages in the Irish electricity market regarding reducing the volatility of the wholesale electricity prices, an empirical disadvantage is the high prices.[REN13, Ore00]

Exposure to the market electricity price volatility is a major disadvantage of the CP, as the remuneration is not based on compensating the production price, but on the available capacity. For the non-dispatchable RES-E as the resource can not be controlled and the short experience regarding these technologies, the capacity factor has an amount of uncertainty which represents a risk for investment. Curtailing the production is possible due to exhausted remuneration by the high negative prices, this situation is most likely to take place if the capacity required to be installed is over estimated by the regulator.

The exposure to the market prices probability is high under the CP as generators have to directly sell there electricity production. The exposure to market prices volitionality has represent a very high price risk factor on investment. The uncertainty in the available capacity can be adapted from the operation side by coordination the operation and maintenance schedules in a way that do not effect the production (for example in low wind seasons), however a low amount of uncertainty still exists due to the resource and unplanned conditions. The impact of such uncertainty can be evaluated as a medium risk level as it is directly related to the remuneration received for the plant. The Quantity risk under the CP assuming good planning of the needed installed capacity can have low to medium probability, in case the capacity is covering the demand and some additional capacity is available for supply security. In that condition the probability of negative prices can be not high. In case this risk exist it can have a medium impact like the uncertainty due to the capacity availability, resulting on a medium level quantity risk.

Auctioned Support Mechanisms

1- Scenarios Assumptions

Auctioned FIT Under this scenario the same assumption under the regulated FIT is adapted. But the difference is that the remuneration amount is defined based on an auction process done by the regulator. The auction is done during the project feasibility stage (as shown before in figure 3.1) to define the required technology specific long-term remuneration to be paid per unit production (€/MWh). The project developers submit the bids and the lowest required remuneration level is adapted by the regulator for the other projects. In that case the project developers and investors can take the decision to proceed with the project commission or not based on the remuneration defined details. Redefining the remuneration amount can be done by making new auctions based on the regulator plans. Accordingly, the new remuneration will be adapted for the new installed capacities. As for the old projects the defined remuneration is not modified for the project lifetime, and in the regulated FIT the dispatchability of RES-E production is guaranteed.

Auctioned MPexpost Instead of the amount of remuneration defined based on the difference between a regulated FIT and the average monthly prices of electricity, the amount of remuneration required will be based on a monthly auction. RES-E generation plant submit there bids for the required technology specific amount of remuneration to be paid on top of the average monthly market prices. The lower bids will be adapted as a technology specific remuneration, and be paid for the generation plants. There is also a possibility of working under the direct marketing scheme.

The economic efficiency related to the costs and efforts of a monthly auctioning process can be questionable. However, a monthly auction assumption is based on the current design of the MPexpost in Germany as the remuneration is defined on monthly bases based on the average electricity monthly prices.

From risk perspective a monthly or yearly auction impact on the risk can be on reducing the uncertainty involved with the risk, but not to remove or mitigate the risk. The risk will still exist in both cases.

Auctioned MPexante An auction takes place in the project feasibility stage (as shown before in figure 3.1) as it is done in the auctioned FIT for the amount of remuneration required for the lifetime of the project on technology specific bases. The remuneration paid under the MPexante mechanism is defined as the difference between the foretasted monthly average market value price (by te regulator), and the auctioned required technology specific remuneration. The regulator adapts the lowest bids for each technology, according to the level of calculating the remuneration based on.

The auction of the required remuneration can take place before the beginning of each month, quarter or year based on the regulator plan. The assumption adapted here is that the auction done before the beginning of each month.

As mentioned before in the MPexpost a yearly or monthly auction will not result on removing a risk factor, it can have an influence in reducing the amount of uncertainty but the risk will exist in both cases.

Auctioned CP Instead of defining the remuneration which is given for the available generation capacity by the regulator, the desired remuneration is defined on auction bases. The regulator defines the amount of capacity needed to be available for each RES-E technology, and make an auction among investors and project developers for the desired remuneration for the lifetime of the project. The lowest bids for each technology is allowed to proceed with the project plans and capacity installation until the technology specific capacity target is fulfilled. It is assumed that the regulator have a long-term defined installing capacity plan, and the auctioning process take place each time installing new capacities needed based on the plan.

2- Auctioning (tendering) Advantages and Disadvantages

Auction scheme has advantages and disadvantages when compared to the regulated scheme. First it is important to highlight these advantages and disadvantages as it will have an influence on the support mechanisms risk assessment results.

The advantages of auctioning are enabling higher degree of subsidy efficiency to be obtained rather than in the regulated scheme, as the remuneration level is not defined by the regulator, but by bids from investors in a competitive environment. Defining the remuneration level through bids has another advantage on the regulator side as it removes the burden of defining the right amount of remuneration level for each technology. Leaving the market to define the desired amount of remuneration needed in a competitive environment, reduces the risk of over compensation due to a high defined remuneration by the regulator . In addition, if the remuneration is guaranteed and secured with long-term, this will result on reducing the uncertainty related to investment under the auctioning scheme as in the regulated scheme.

On the other hand, auction can result in underestimating the remuneration level and failure of finalizing the RES-E project development, like what happened in the UK between the year 1990 and 2000 under the Non-Fossil Fuel Obligation (NFFO) [BN08]. As investors have to estimate the needed remuneration level in a competitive environment, they will have to depend on mature RES-E technologies. Such behaviour can have an influence on the renewable energy generation mixture. Moreover it will not have an incentive for investors to invest in technologies beyond R&D which didn't not reach the market maturity, which can influence the development curve of these technologies. It is kind of unexpected that a successful auction or tender procedure might be a disadvantage, however this successful procedure might result in many project initiatives being prepared in vain as the case of Canada/Quebec (October 2005) in the second call for tender for 2000 MW onshore wind energy, which was overbooked by almost a factor of 4[Eco08a]. Probability of having negative prices still exist under the auctioning scheme. Assuming that under a perfect competition bids for selling and buying will match, and this will reduce the probability of having negative prices. But the perfect competition market case can hardly take place practically. Another disadvantage is that as generators do not know the auction process in advance, there is a higher uncertainty in the future cashflow more than in the regulated mechanisms.[REN13, Bey12]. Table 4.8 summarize the advantages and disadvantages of auctioning (tendering).

Advantages	1-Enables high degree of subsidy efficiency to be obtained as remuneration level is not defined by the regulator, but by bids from investors in a competitive environment. 2-Remove the burden from the regulator to define the right remuneration level for each RES-E technology. 3- Investment uncertainty can be reduced as in the regulated scheme, if the remuneration is guaranteed and combined with long-term contracts. 4- Reduce the risk of over compensation due to high level of remuneration defined by the regulator.
Disadvantages	1- Risk of underestimating the remuneration level and failure of finalizing the RES-E project development. 2- In order to determine the remuneration level investors will need to depend on mature RES-E technologies, which can affect the generation mixture required from renewables. 3- Can have an effect on the development of RES-E technologies which is beyond R&D but didn't reach the market maturity. 4-Successful tender procedure might result in many project initiatives being prepared in vain. 5-Due to the higher uncertainty in the remuneration sufficiency (than in the regulated case) for the project development due to low bid estimation, auctioning can favour large projects more than small projects. 6- Probability of negative prices still exist. However under perfect completion market status, the probability of electricity negative prices will be lower than the regulatory defined mechanisms, as bids for selling and buying will be matched. 7- Implies higher uncertainty in the future cashflow than the regulated mechanisms, as generators do not know in advance the resulting dispatch from the auctioning process.

Table 4.8: Auctioning (tendering)advantages and disadvantages

3- Assessment Outcome

The pros and cons of the support mechanisms will be affected with the advantage and disadvantages of the auctioning scheme. This will result in a different price and quantity risk evaluations from the ones that have been done under the regulated scheme in section 4.2.1, and even can result in introducing new risk factors for some support mechanisms.

The qualitative assessment results for the auctioned support mechanisms scenarios are shown in table 4.9. The assessment is done according to the methodology described in the support mechanism assessment in section 4.1.3.

RES-E Support mechanism		Risk evaluation		Qualitative risk assessment		
				Probability (1 to 5)	Impact (1 to 5)	Risk level (L-M-H)
Auctioned support Mechanisms	Feed-in Tariff (FIT)	price risks	1-Introducing uncertainty risk of remuneration amount sufficiency for the project development specially with low market experience for the RES-E technologies	1	3	L
		Quantity risks	2-No risk as renewable electricity dispatch is guaranteed			
	Market Premium ex-post (Mpexpost)	price risks	1-High uncertainty in the future cash flow due to variable remuneration based on auctioning process	3	3	M
			2-Risk due to uncertainty of remuneration sufficiency specially that the auction resulting is unknown	3	5	H
			3-In case of direct marketing there is a risk due to premium amount sufficiency uncertainty ,as it is linked to average market prices .	2	3	M
		Quaintly risks	4- Output curating risk (compared to the FIT) due to auctioning dispatch resulting	1	3	L
			5- Output curating risk due to higher negative prices than premium level	1	3	L
	Market Premium ex-ante (Mpexante)	price risks	1- Long-term prices risk on investors due to forecasting errors.	2	3	M
			2- Risk of low remuneration level due to low bids or forecasting errors.	3	4	H
			3- Uncertainty of the future cash flow as premium is paid on the top of market prices.	1	3	L
		Quaintly risks	4- Dispatchability risk due to uncertainty in the auctioning results	1	3	L
			5- Output curating risk due to higher negative prices than premium level	1	3	L
	Capacity payment (CP)	Price risks	1- Exposure to volatility of electricity prices	4	5	H
			2- Uncertainty of remuneration sufficiency due to low bids estimation	2	4	H
			3- Uncertainty of the future cash flow as revenues is based on the market prices	2	3	M
		Quantity risks	4- Uncertainty of capacity factors of RES-E technologies on the long term	2	3	M
			5- Production curtailing risk due to negative prices higher than the remuneration on the capacity and no profit is generated	1	3	L

Table 4.9: Qualitative assessment of the auctioned support mechanisms

FeedIn-Tariff

There is a possibility that some bids are estimated lower than the real required remuneration. This can be the case due to the bids submitted on competitive bases, or as for the immature RES-E technologies as there is no enough experience with the project development costs, and the risk associated with it is high. This possibility represents uncertainty for investment and a price risk factor. On the other side, as the dispatchability of the RES-E is guaranteed there is no quantity risks.

The possibility of under estimating the remuneration needed is very low. As it is assumed that the auctioning process will result in the needed remuneration level for each RES-E technologies, and the auction will be applied on the market technologies which is already implemented and there is a basic amount of experience gained regarding it like Wind Onshore and PV. However, in case it exist, it can have a medium impact on continuing the project development.

Market premium ex-post

The remuneration level varies depending on two factors, the market average prices and the auction result for the desired remuneration. This results in uncertainty of the sufficiency of the remuneration level for generating profits and securing the investment, in addition to uncertainty in the future cashflow as the remuneration level is variable. In the direct marketing case there is also uncertainty of how much premium will be paid on top of the selling price, and if it is enough or not for generating revenues.

Regarding the quantity risks, there is an output curtailing risk due to two reasons. First in comparison with the regulated FIT there is a possibility that production will not be dispatched as the operator expects that the auction will result in lower amount of remuneration than what he desires on top of the market price. Second even if the expected amount of remuneration is sufficient for operators, there is a possibility that a high negative electricity prices exhaust the remuneration and the production feeding and in that case it is not profitable any more.

The probability of the uncertainty in the remuneration level sufficiency and future cash flow is medium as there is more than one reason behind it. However the impact of having insufficient remuneration is very high on the investment, as electricity in that case is already sold in a certain price which is not compensated. In the direct marketing case the probability of having insufficient premium amount which will risk the revenues is lower than in the premium with average monthly prices case, taking into consideration that there is a probability of having higher than the average market prices under the direct marketing. For the quantity risks the probability of curtailing is very low assuming that the supply and demand will match in the auctioning process, but the impact on the operation and project revenues can be medium.

Market premium ex-ante

There is a long-term price risk because of the market prices forecasting errors in both the regulated and auctioned MPexpost. In addition, there is a risk of low received remuneration level due to two reasons, forecasting errors or low bids in the auctioning process. These price risks will result in uncertainty in the future cash flows of the project, which can affect the investment security. The dispatchability of production is not guaranteed as the auction results can be lower than the expected remuneration and selling the production is not profitable in that case. Negative prices possibility exists as well and it can be a quantity risk factor.

Price risk due to the low remuneration level can have a medium probability as the demand forecasting is challenging and can involve uncertainty in the forecast results . In case this happens it can have a high impact on the project revenues and feasibility. Regarding the quantity risks the same probabilities as in the auctioned MPexpost exist under the MPexante.

Capacity Payment

The difference in the auctioned CP from the regulated CP on the price risks is mainly in introducing two new risk factors; the uncertainty of the remuneration sufficiency due to low bids estimations,and the uncertainty in the future cash flow and revenue generation. These two price risks are introduced because of the uncertainties associated with the auction in process and due to the exposure of the operators to market price volatility.

The probability of having insufficient remuneration due to bids under estimation is low, assuming that the investors use the existing experience in the Wind Onshore and PV to estimate the needed remuneration level. On the other hand, the impact of this risk factor on continuing the project development and economic feasibility can be high. Another change from the regulated MPexpost is on the probability of curtailing due to negative prices, it can be assumed that the regulator will define the needed capacity and this will reduce the probability of having negative prices in the market to be very low.

Overview on the Scenarios Risk Profiles

Figure 4.3 gives an overview summary on the previously described risk factors under the regulated and auctioned SM different scenarios. Distribution of the risk factors for each scenario is represented in the risk matrix. The distribution of risk factors is done based on the probability and impact of each risk factor as explained before in section 4.2.1 and section 4.2.1.

Support mechanism risk premium Estimation

The risk premium (a_{sm}) (which is used in the next analysis stage) is estimated based on the price and quantity risk factors levels as shown in the risk profiles of each support mechanism scenario 4.3. An overall support mechanism risk level is defined using two parameters: The number of risk factor associated with the support mechanism, and the average of probability and impact of all the risk factors resulted from the quantitative scenario analysis as shown before for the regulated mechanisms in table 4.7, and for the auctioned mechanisms in table 4.9.

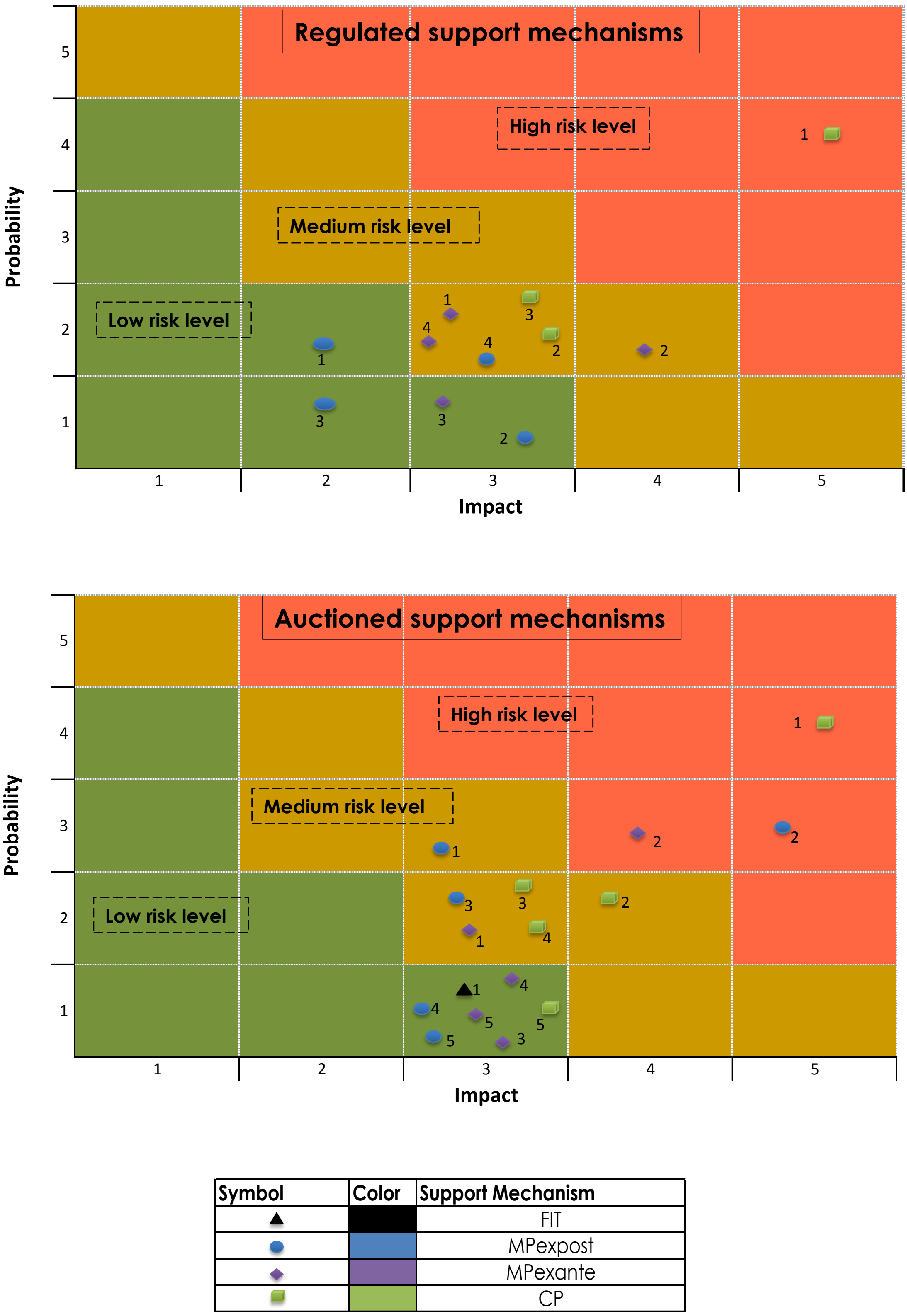

Figure 4.3: Risk profiles of the regulated and auctioned mechanisms using a risk matrix representation

Table 4.10 shows the assumed values for each risk level. These values are assumed based on the proposed support mechanisms risk premiums values in technical report by [GX04]. However, not the same support mechanisms are discussed in this report.

Risk Level	No-Risk (Reference Scenario)	Low	Medium	High
(a_{sm}) assumed	1	1.2	1.6	2.5

Table 4.10: Assumed range of a_{sm} for the different scenarios risk levels

The different support mechanisms risk premium (a_{sm}) assumptions for the various scenarios are shown in table 4.11. For the reference scenario as there are no price or quantity risk factors, the assumed (a_{sm}) value is 1. In the MPexpost (Reg) scenario the overall risk level assessment is from low to medium. The (a_{sm}) value assumed is 1.3 as most of the risk factors have low level. For the MPexante (Reg) scenario the overall risk level is medium. The assumed (a_{sm}) value is 1.6, which is at the beginning of the medium range as one of the risk factors has low level. Regarding the CP (Reg) the overall risk level is from medium to high. The assumed (a_{sm}) value is 2.0, which between the medium and high ranges defined before in table 4.10.

Scheme	Support mechanism	Risk Level Range	(a_{sm})
Regulated	FIT (Reference Scenario)	No price or quantity risk	1
	MPexpost	Low to Medium	1.3
	MPexante	Medium	1.6
	CP	Medium to High	2.0
Auctioned	FIT	Low	1.2
	MPexpost	Medium	1.8
	MPexante	Medium to High	2.1
	CP	High	2.5

Table 4.11: Assumed support mechanism risk premium (a_{sm}) for different scenarios

For the auctioned support mechanisms. The FIT(Auc) scenario has a low overall risk level. The assumed (a_{sm}) value is 1.2, which is at the beginning of the low range defined before. For the MPexpost(Auc) scenario the overall risk level is medium. The assumed (a_{sm}) value is 1.8, which is higher than the beginning of the medium rang as there is one risk factor with high level. The MPexante (Auc) scenario has Medium to high overall risk level. The assumed (a_{sm}) value is 2.1, which in almost in the middle of the medium to high range defined before. For the CP (Auc) scenario the overall risk level is high. The assumed (a_{sm}) value is 2.5, which is the highest level defined in the range as shown in table 4.10.

4.2.2 Quantitative Assessment of RES-E Technologies and Support Mechanisms Scenarios

As described in section 4.1.4, based on the results of the support mechanisms scenarios assessment the investment financial requirement $(r_e, r_d, g_e, g_d, \beta)$ will be defined. In addition, the policy risk premium a_{SM} will be evaluated based on the risk profile of the support mechanism in comparison to the reference SM scenario. Consequently the calculated value of the $WACC$ will change under each scenario. On the operation side changes in the capacity factor and O&M costs are based on the quantity risks under each support mechanism scenario.

As shown before in Figure 4.2, there are two main RES-E technologies included in the study scenarios. For each technology, the investment $WACC$ and the operation capacity factor is calculated to be used as an input for the case studies in the economic analysis stage.

Investment WACC Calculations for Wind Onshore and PV

WACC parameter assumption	Price risk factors
Requiring a higher (r_e) & (r_d)	• Uncertainty in profit generation as remuneration is linked to market prices. • Long-term price risks due to forecasting errors costs. • Uncertainty in the sufficiency of the remuneration level for securing the investment revenues or for developing the project. • Exposure to the volatility of electricity prices. • Uncertainty in profit generation as remuneration is linked to market prices.
Requiring a higher $(DSCR)$	• Uncertainty in the future cashflow.
Limiting the debt share (g_d) and requiring a higher equity share (g_e)	• Depending on the risk levels of the price risk factors.

Table 4.12: WACC calculation parameters assumption criteria based on the SM scenarios assessment .

The $WACC$ based on the calculation model described in equation 4.6. The assumptions made for the changes in the parameters which define the $WACC$ is related to the price risks in each SM scenario assessment. Table 4.12 show the assumptions adapted for defining the $WACC$ calculation parameters. After identifying which factors have to be changed in each scenario, the numerical value of each parameter assumption is based on the risk levels of the price risk factors.

Wind Onshore and PV reference scenario WACC For the reference scenario (regulated FIT), the $WACC$ estimation is done based on the values currently used in the German RES-E market shown in table 4.13 .

	Variable	Share debt/equity	Risk free rate	Risk Premium	Expected market rate of return	Equity beta	Equity rate of return	Debt rate of return	Tax rate (Corporation tax)	Weighted average cost of capital
	Appreviation	g (%)	Rf (%)	Rp (%)	Rm (%)	β	re (%)	rd (%)	rt (%)	**WACC (%)**
	Reference									
German market risk free & premium	IESE Business School Pablo Fernandez mrp (2013)		1.90	5.50	7.40					
Wind Onshore	Schwabe et al.(2011)*									6.30
	BMU (2011)*	75.00	1.90	5.50	7.40	1.84	12.00	5 to 5.5	0.00	5.1 to 5.4
	Deutshe Winguard (2010)*									5.80
	DRL et al.(2012)*									6.00
	Frauenhofer ISE (2012)	70.00	1.90	5.50	7.40	1.29	9.00	4.50	0.00	5.90
	Frauenhofer ISE (2013)	70.00	1.90	5.50	7.40	1.29	9.00	4.50	0.00	5.90
	Deutshe Winguard (2012)	75.00	1.90	5.50	7.40	1.84	12.00	5.50	0.00	6.5 to 7
PV Small	Frauenhofer ISE (2013)	80.00	1.90	5.50	7.40	0.75	6.00	4.00	0.00	4.40
	Frauenhofer ISE (2012)	80.00	1.90	5.50	7.40	0.75	6.00	4.00	0.00	4.40
PV Large	Frauenhofer ISE (2013)	80.00	1.90	5.50	7.40	0.75	8.00	4.00	0.00	4.80
	Frauenhofer ISE (2012)	80.00	1.90	5.50	7.40	1.02	7.50	4.50	0.00	5.10

Defination	Color code
calculated value	
Assumed value	

Table 4.13: WACC for different RES-E in Germany
Note: *See [FEL13].

Based on various references, the WACC assumptions and values are shown in the table above. As seen above from the different color codes there are assumed values and calculated values. The risk free rate (R_f), risk premium (R_p) are used as assumed values for the different RES-E technologies based on the table 4.3. The expected market rate of retun is the sum of the risk free rate and risk premium. One of the main objectives of these calculation is estimating β which can be calculated using the know variables from equation 4.2.

The calculation of the WACC for the Wind and PV under different scenarios is shown in table 4.14 . The reference case parameters are estimated using the values in table 4.13, and the different scenario values is estimated based on the support mechanisms assessment results and the criteria is defined in table 4.12.

Variable	Appreviation	Wind Energy															
		Regulated Support Mechanisms								**Auctioned Support Mechanisms**							
		Feed-in Tariff (reference case)		Market Premuim ex-post		Market Premuim ex-ante		Capacity payment		Feed-in Tariff		Market Premuim ex-post		Market Premuim ex-ante		Capacity payment	
Variable	**Appreviation**	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity €	Debt (d)	Equity (e)	Debt (d)	Equity (e)
Share debt/equity	g (%)	70.00	30.00	70.00	30.00	65.00	35.00	60.00	40.00	70.00	30.00	65.00	35.00	65.00	35.00	60.00	40.00
Risk free rate	Rf (%)	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Risk Premium	Rp = Rm-Rf (%)	3.30	5.50	3.30	5.50	3.30	5.50	3.30	5.50	3.30	5.50	3.30	5.50	3.30	5.50	3.30	5.50
Expected market rate of return	Rm (%)	5.20	7.40	5.20	7.40	5.20	7.40	5.20	7.40	5.20	7.40	5.20	7.40	5.20	7.40	5.20	7.40
Support mechanism risk premium	asm				1.3		1.6		2.0		1.2		1.8		2.1		2.5
Equity beta	β		1.0		1.3		1.6		2.0		1.2		1.8		2.1		2.5
Equity rate of return	re (%)		7.4		9.0		10.7		12.9		8.5		11.8		13.5		15.7
Debt rate of return	rd (%)	5.20		5.20		6.20		9.00		5.20		5.70		6.20		9.00	
Tax rate (Corporation tax)	rt (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Weighted average cost of capital	WACC (%)	**5.9**		**6.3**		**7.8**		**10.6**		**6.2**		**7.8**		**8.7**		**11.7**	

Variable	Appreviation	Small PV															
		Regulated Support Mechanisms								**Auctioned Support Mechanisms**							
		Feed-in Tariff (reference case)		Market Premuim ex-post		Market Premuim ex-ante		Capacity payment		Feed-in Tariff		Market Premuim ex-post		Market Premuim ex-ante		Capacity payment	
Variable	Appreviation	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)	Debt (d)	Equity (e)
Share debt/equity	g (%)	80.00	20.00	80.00	20.00	75.00	25.00	70.00	30.00	80.00	20.00	75.00	25.00	75.00	25.00	70.00	30.00
Risk free rate	Rf (%)	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Risk Premium	Rp = Rm-Rf (%)	2.10	5.50	2.10	5.50	2.10	5.50	2.10	5.50	2.10	5.50	2.10	5.50	2.10	5.50	2.10	5.50
Expected market rate of return	Rm (%)	4.00	7.40	4.00	7.40	4.00	7.40	4.00	7.40	4.00	7.40	4.00	7.40	4.00	7.40	4.00	7.40
Support mechanism risk premium	asm				1.3		1.6		2.0		1.2		1.8		2.1		2.5
Equity beta	β		0.75		0.98		1.20		1.50		0.90		1.35		1.58		1.88
Equity rate of return	re (%)		6.0		7.26		8.50		10.15		6.85		9.33		10.56		12.21
Debt rate of return	rd (%)	4.00		4.00		5.00		8.00		4.00		4.50		5.00		8.00	
Tax rate (Corporation tax)	rt (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Weighted average cost of capital	WACC (%)	**4.4**		**4.7**		**5.9**		**8.6**		**4.6**		**5.7**		**6.4**		**9.3**	

Defination	Color code
calculated value	
Assumed value	

Table 4.14: Wind onshore and small PV WACC calculations under different support mechanisms scenarios

Operating capacity factor and O&M costs assumptions

Based on the description of the plant operation perspective in section 4.1.4, the capacity factor of the plant will change based on the quantity risks associated with the support mechanism adapted scenario. As described in section 4.2.1, there are different quantity risk factors related to each support mechanism scenario assessment, based on the risk level of the quantity risks the capacity factor change is estimated. As most it is common in most of the assessment results that the quantity risk is due to the high negative prices, the amount of possible negative prices per year is calculated based on figure 2.4. An assumption have been made in estimating the capacity factor reduction due to the negative electricity prices, is that the plant operator will curtail the production at any value of a market negative price, so the capacity factor is reduced by the same percentage of the total negative price hours per year, which represents approximately 1% in the year 2012 .

As clarified before in section 4.1.4 there are different approaches to define the O&M costs for Wind onshore and PV. Table 4.15 give an example of the different O&M costs approaches and values used for Onshore Wind in Germany.

Type of O&M cost	Fixed (€/MW/year)		Variable costs(€/MWh)		
Reference	Schwabe et al. (2011)	DRL et al. (2012)	Eggersglüß (2012)	BMU (2011)	Frauenhofer ISE (2012)
O&M Cost	47,700	48,400	25.2	22.1	14.9
Average value	48,050		**20.7**		

Table 4.15: O&M costs for Onshore Wind in Germany
References:[FEL13, Fra12]

The used value for Onshore Wind O&M costs in RESMIP is the average value of the proposed variable costs (20.7 €/MWh). For the PV case study the same O&M costs provided in the project database is used fixed costs per year [9].

[9]Modifications on the O&M costs per year have been made, details can be found in section 4.2.3

4.2.3 Wind and PV Case Studies

The selected plants for assessing the scenarios are the same defined in the sensitivity analysis at section 3.2. However, modifications from the RETScreen[10] original case study data have been made, according to the RESMIP model assumption and the previous $WACC$ calculations of both the Onshore wind and PV case studies. These modification is describe below.

Case Studies Input for the Reference Scenario

Wind Onshore : Regarding the Onshore Wind case study the modifications made under the reference scenario are displayed in table 4.16.

Project information	RETScreen database		Value modified to
Electricity Export Cost (feed-in tariff)	0.091 €/kWh		
project lifetime	25 years		20 years
Financial assumptions	inflation rate	2.50%	
Loan	discount rate	9%	5.9%
	debt ratio	31%	70.0%
	debt interest rate	5.75%	5.2%
	debt term	15 years	
non-debt portion (equity)	69%		30.0%
Taxes	Not applicable on Wind farm income		
Project related assumptions	feasibility study	€ 45,000	
	development	€ 330,000	
	engineering	€ 30,000	
	grid connection	€ 1,300,000.00	
	balance of plant	€ 700,000	
	O&M costs definition	Fixed cost per year	20.7(€/MWh)
	total O&M costs per year	€ 277,704	€ 361,216
	capacity factor	20.10%	
	annual energy generation	17422 MWh	

Table 4.16: Wind Onshore reference scenario case study input parameters
Note: RETScreen Wind case details can be found in [RET13c]

The project lifetime is changed to 20 years instead of 25 years based on the proposal in the recent RES-E economic studies [11]. The O&M costs changes based on what have been illustrated before in the previous section. Changes in the discount rate (from 9.0% to 5.9%), debt ration from (31% to 70%), debt interest rate (from 5.75% to 5.20%) and equity ration (from 69% to 30%) are based on the $WACC$ calculations for each scenario as shown in the Wind Onshore case in 4.14.

It is important to note that some of these modifications are valid for all support mechanisms scenarios, like the project lifetime (20years) and the O&M costs per MWh (20.7 €/MWh)[12].

PV :Regarding the PV case study the modifications made under the reference scenario are displayed in table 4.17.

[10] RETScreen overview is given before in section 3.2
[11] For example[Fra12, Fra13]
[12] The total O&M costs per year will change from scenario to another depending on the amount of

Project information	RETScreen database		Value modified to
Electricity Export Cost (feed-in tariff)	0.457 €/kWh		
project lifetime	30 years		25 years
Financial assumptions	share of debt	0%	80%
	debt term		15 years
	debt rate		4.0%
	discount rate	8%	4,4%
	incentives and Grants	4,138,211 €	0 €
PV Modules Costs	inflation rate	2.00%	
	PV (polycrystalline)	€5,670/KWp	
Project related assumptions	BIPV (total installation cost)	€ 860.00	
	taxes	Not applicable on PV income	
	feasibility study, planning and Engineering	€ 560,000	
	development	€ 330,000	
	engineering	€ 30,000	
	inverters cost	€ 600,000	
	capacity factor (including inverter losses)	9.40%	
	total Energy production	819.27 MWh/year	
	O&M costs defination	Fixed over project lifetime	Annual increase with 2%
	total O&M costs increase over lifetime	€ 0	€ 7,344
	annual average O&M costs	€ 15,300	€ 15,594

Table 4.17: PV reference scenario case study input parameters
Note: RETScreen PV case details can be found in [RET13b]

The project lifetime is changed to 30 years instead of 25 years and the O&M costs assumed to have an increase of 2.0% per year [13]. Changes in discount rate (from 8.0% to 4.4%), share of debt (from 0% to 80%) with adding a debt term of 15 years and debt interest rate of 4.0%, and equity ration (from 100% to 20%) are based on the $WACC$ calculations for each scenario as shown in the small PV table 4.14. The incentive grant is removed as it is not applicable as a part of the capital structure on the current small PV installations .

It is important to note that some of these modifications are valid for all support mechanisms scenarios, like the project lifetime (25years), the O&M costs annual increase (2.0% per year), the debt term (15 years) and there will be no grants included as a part of the capital.

The case studies input details for the different scenarios assessed in the scope of the study for Onshore wind and PV cases can be found in the appendix (a) .

4.2.4 Economic Analysis Outcomes

In the economic analysis stage, the financial indicator calculations are made according to what have been illustrated in section 4.1.5 for each case study. The results of these calculations are presented below, leaving the evaluation and discussion of the results to the following chapter.

energy production.

[13] These modifications are based on the proposed in the recent PV projects studies (e.g.[Fra12, Fra13])

Wind Onshore Case Study Analysis Results under different Scenarios

The results of the financial indicator calculations for the wind onshore case study under different support mechanisms scenarios are presented in table 4.18. The first column represents the General scheme of the mechanism, as have been explained before the scope of the study includes the regulated and auctioned schemes. The four investigated support mechanisms under each scheme are presented in the second column. The selected financial indicators calculation results in absolute values under each scenario are shown from column three to six .

General Scheme	Support mechanism	NPV (M€)	IRR (%)	LCOE (€/MWh)	DSCR (%)
Regulated	FIT (Reference Scenario)	3.8152	18.0%	72.12	1.83%
	Mpexpost	2.6975	15.8%	76.3	1.73%
	Mpexante	1.7507	13.5%	80.36	1.75%
	CP	0.0925	10.9%	90.31	1.69%
Auctioned	FIT	3.6120	18.0%	72.63	1.83%
	Mpexpost	1.3471	12.2%	82.35	1.71%
	Mpexante	0.8348	11.6%	85.27	1.66%
	CP	-1.1205	7.5%	100.42	1.47%

Table 4.18: Wind Onshore Scenarios Economic analysis Results

PV Case Study Analysis Results under different Scenarios

Table 4.19 presents the financial indicators results for the PV case study under the support mechanism scenarios included in the scope of the study. The same table structure adapted as in the Wind Onshore case.

General Scheme	Support mechanism	NPV (M€)	IRR (%)	LCOE (€/MWh)	DSCR (%)
Regulated	FIT (Reference Scenario)	1.9487	9.80%	344	0.89%
	Mpexpost	1.0037	7.50%	390	0.79%
	Mpexante	0.1895	6.40%	442	0.79%
	CP	-1.3107	4.20%	590	0.70%
Auctioned	FIT	1.8337	9.80%	348	0.89%
	Mpexpost	-0.3224	4.70%	484	0.72%
	Mpexante	-0.6511	4.30%	516	0.69%
	CP	-1.9164	2.40%	691	0.61%

Table 4.19: PV Scenarios Economic analysis Results

The next chapter will focusses on explaining these results into details, and the consequences of each scenario on investment and operation.

5 Results

Results of the scenarios analysis using RESMIP model are illustrated in this chapter. Outcomes from the economic analysis stage and the support mechanisms qualitative scenarios assessment stage are used to show the implication of each scenario on investment and operation. The financial indicators calculation results are illustrated in absolute values and as percentages of the change in value in comparison with the reference scenario .

It is also important to highlight that it depends on the investor to evaluate whether the NPV,IRR,LCOE or DSCR amount is acceptable or not for the economic feasibility of the investment. A Zero or positive NPV (NPV$\geq$ 0) gives an indication that the revenues are covering the project costs over the lifetime of the project and the investment can be profitable under a certain discount rate. Investor can have a minimum required IRR, which means that a lower value than the required minimum IRR value makes the investment infeasible. However, various types of investors can have different minimum IRR for the same project depending on the risk perception. The LCOE can be compared to the amount of remuneration paid and in case it is lower this will reflect the possibility of making profit, in addition it is used as a base of assessment to compare different electricity generation technologies. DSCR value is compared to the minimum value desired by debt. If it is higher so the investment risks are acceptable from debt perspective. However, as shown before in table 4.5 that the minimum DSCR varies depending on the RES-E technology, and it can also be different from one type of investor to another. Because of these reasons a clear statement regarding the economic feasibility of investment can not be made using the results below.

On the other hand the implications of the different scenarios can be clearly recognized. So conclusions and recommendations regarding the general implications of the Wind Onshore and PV support mechanisms on investment and operational can be made. Which is important to take into consideration by policy makers while designing new support mechanisms for RES-E, and fulfill the main objectives of the study.

5.1 Wind Onshore Scenarios Assessment Results

5.1.1 Regulated FIT (reference Scenario)

For the selected Onshore Wind case study input parameters shown in table 4.16, the financial indicator calculations results are as following. The calculated NPV for the reference scenario is 3.8152 Mil€, as shown in figure 5.1, the IRR calculated value is

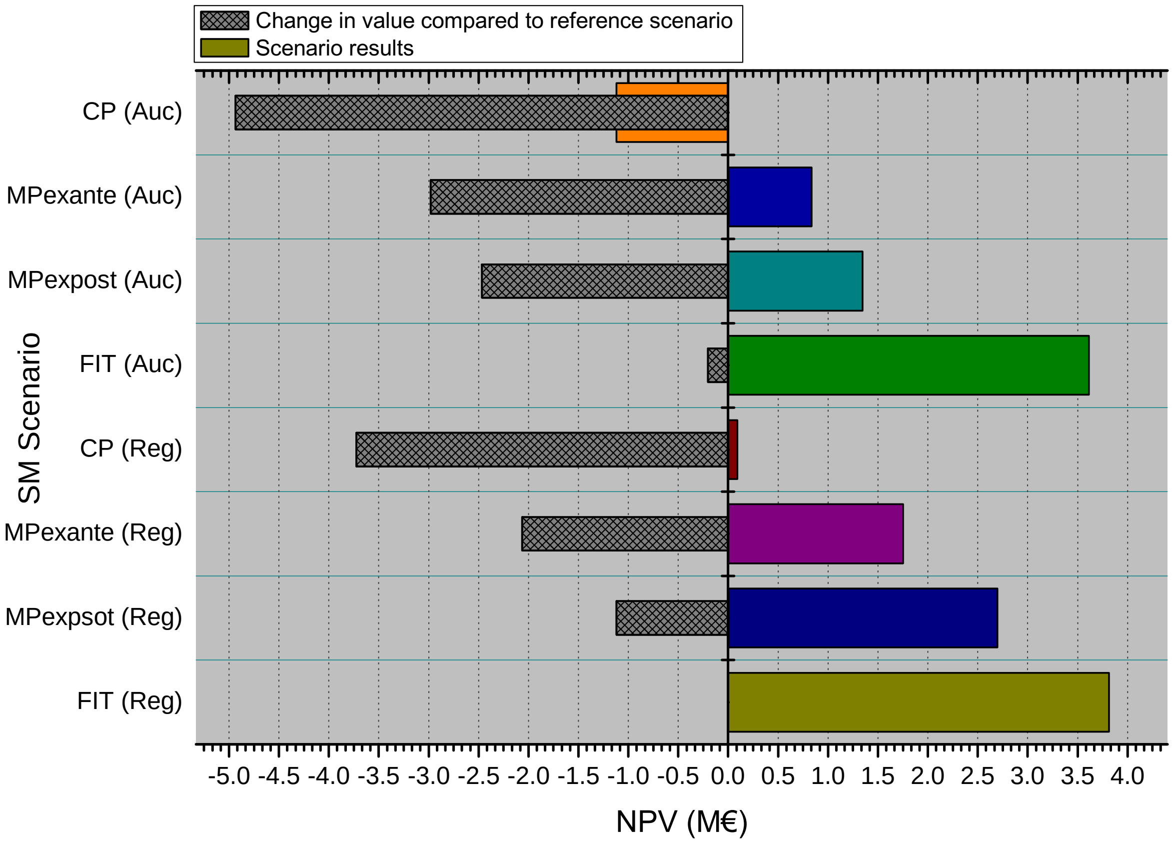

Figure 5.1: Wind Onshore NPV scenarios analysis results

18.01%, the LCOE is 72.13 €/MWh and the DSCR is 1.83% [1].

As explained in section 4.2.1, the FIT (Reg) is very successful mechanism to encourage investing in RES-E technologies. There are no price risks associated with it, as the investors are isolated from the electricity market prices volatility with a guaranteed long term contracts along the lifetime of the project. In addition, as the production dispatching is guaranteed for RES-E electricity, there are no quantity risks as well. These are the main reasons of making the FIT (Reg) a successful mechanism on the level of RES-E investment, since the StrEG policy have been changed to the FIT from the year 2000 onwards [BN08]. This positive impact on investment is reflected on the RES-E deployment in Germany as the share of RES is total gross electricity consumption reached 23.6% in the year 2012 [BMU12b].

On the other hand, the implication of FIT (Reg) on the market economic efficiency is negative. The costs related to the market risks, whether the reasons behind these risks became reality or not, are transferred from the generators to the end customer who have to burden these extra costs as an impeded cost in the electricity price provided for him by the retailer represented as a part of the EEG levy.

Moreover, the FIT (Reg) mechanism does not create any incentive for the opera-

[1] The financial indicators calculation results are summarized in table 4.18 for all the Wind onshore scenarios.

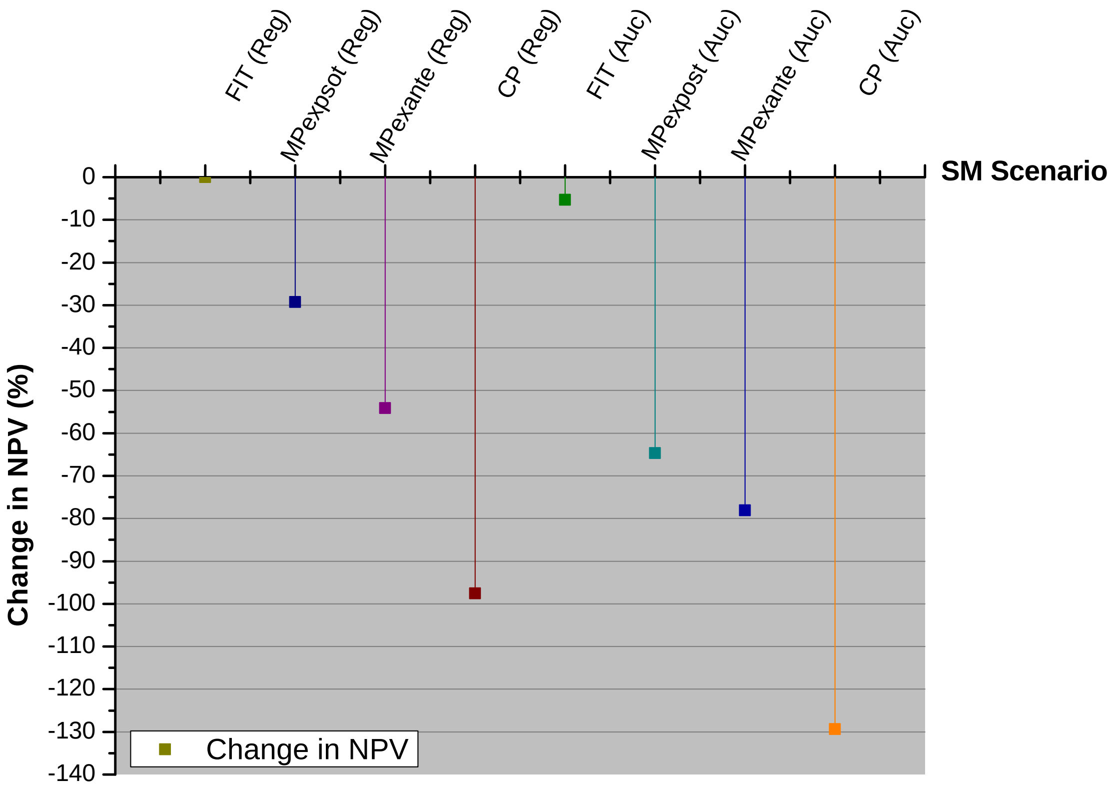

Figure 5.2: Wind Onshore NPV results comparison against the reference scenario

tors to appropriately react to the market signals, or even having the wellness to gain experience regarding the market dynamics, demand behaviour and electricity prices volatility. Such operation attitude does not support the future integration of RES-E technologies on the market and system levels, making the sustainable development of RES-E shares in the electricity consumption, and reaching the future scenario targets in a economic efficient manner arguable.

5.1.2 Regulated Market Premium ex-post

In the MPexpost (Reg) scenario, The project NPV is 2.6975 Mil€ as presented in figure 5.1. Compared to the reference scenario NPV there is a decrease of -1.1177 Mil€ . As shown in figure 5.2 the reduction in the NPV under the MPexpost (Reg) compared to the reference scenario is -30%. However there is a decrease in the NPV which is a project general financial indicator that gives an indication for both equity and debt regarding the future cashflow of the project along the lifetime, but the project is still profitable as the NPV is above zero.

The Calculated IRR the MPexpost (Reg) scenario is 15.8% which is lower by around -12% compared to the reference scenario as shown in figure 5.3. Depending on the minimum required IRR by investor the investment will still be feasible or not. However, as the IRR is much higher than the WACC (6.3%), this gives an impression that the profitability of the investment could be secured. On the other hand, Compared to the reference scenario, there is a decrease on the IRR value. This situation can make the

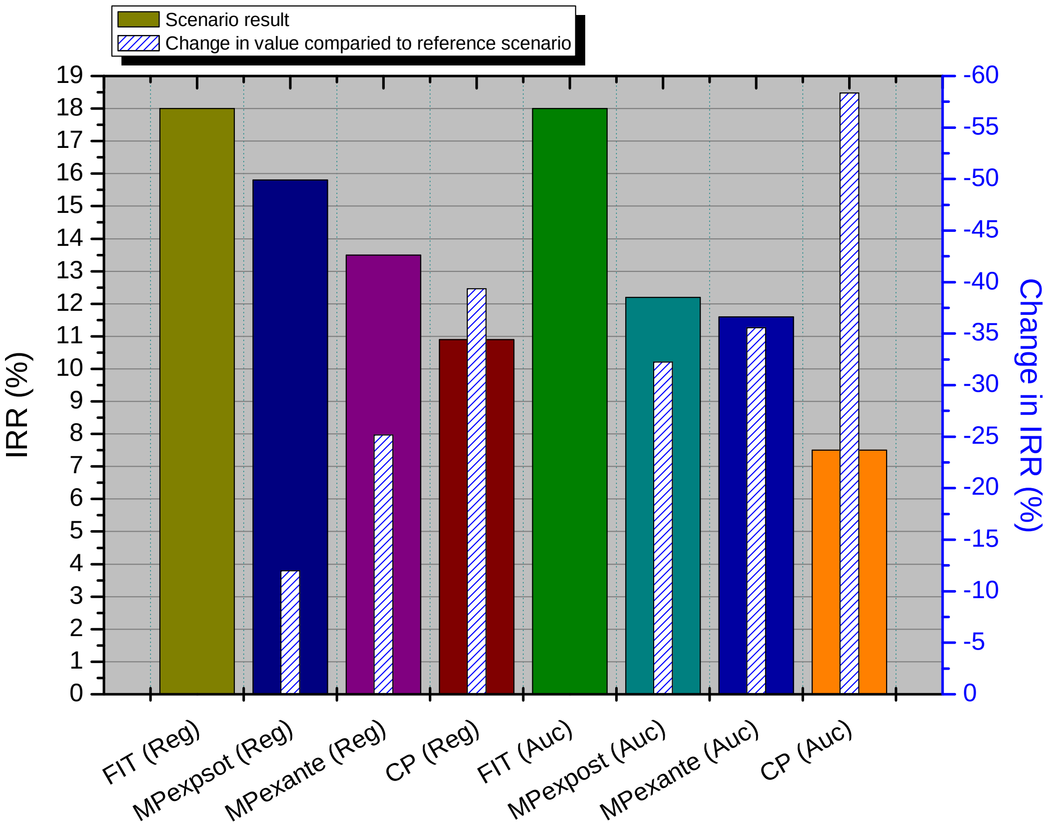

Figure 5.3: Wind Onshore IRR results under the different support mechanisms scenarios and change compared to the reference scenario

investment less attractive than in case of the reference scenario, or require higher share of debt with low required rate of return.

The decrease in the NPV and IRR values is due to the price and quantity risk levels, which results in a WACC that is higher than the reference case as shown in table 4.14, and lower capacity factor as shown in the case study input parameter table (see appendix (a)). Nevertheless, MPexpost (Reg) can result in the same or higher NPV and IRR in case of direct marketing scheme, as discussed before in the support mechanisms assessment section, but the adapted case in the analysis includes the possible risks that can be taken into consideration from investment and operation sides.

The LCOE value slightly increased by 5.7% in the MPexpost (Reg) compared to the reference scenario to reach 76 €/MWh as shown in figure 5.4. The increase in the LCOE is mainly due to the reduction in the electricity production due to the quantity risks. Although that the O&M costs will be reduced, which will result in reducing the overall yearly costs of the project, but the lower production effect on the LCOE is still higher as other project related costs are not reduced.

The DSCR calculated value under the MPexpost is 1.73%. Although that the debt related financial figures (r_d,g_d, debt term) did not change from the reference case to the MPexpost but there is a decrease in the DSCR by around -5% as shown in figure 5.5. This decrease is due to the changes in the annual cashflow (net operating income)

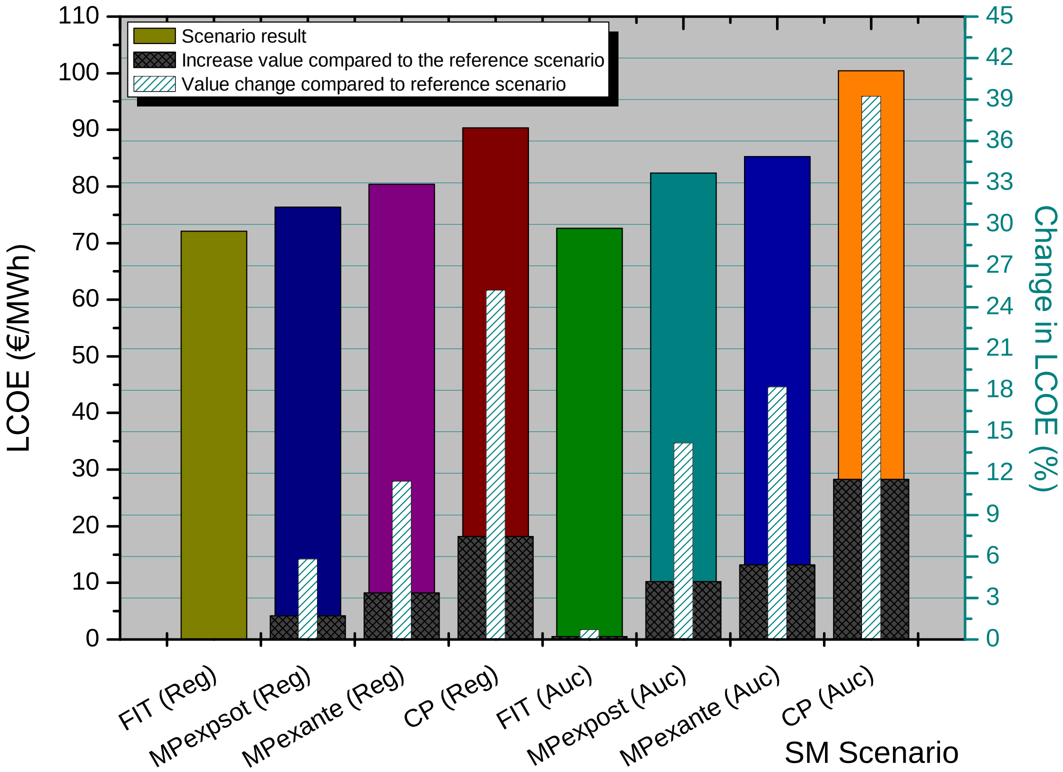

Figure 5.4: Wind Onshore LCOE calculation results under different support mechanism scenarios and changes compared to the reference scenario

due to the changes in the WACC and capacity factor. In general the DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5. The DSCR is lower than the reference case which can result in limiting the debt ratio or applying some restrictions on the plant operation from the debt side.

The financial indicators values changed slight compared to the reference scenario . This gives a conclusion that the investment attractiveness is not to be dramatically affected under the MPexpost (Reg). On the contrary, it the case in the Germany electricity market an estimated 68% of all on and off shore wind power production in 2012 was reimbursed according to the Market premium scheme [GP13a]. Moreover, the MPexpost (Reg) creates an incentive for extra investment in making the plant remotely controlled through defining a specific remuneration level for the remotely controlled plants. This have an implication on the system level of having a real-time knowledge of the status of each plant and give enough flexibility to utilize the production.

On the operation side, can provide the operators with experience regarding the market dynamics and prices, which can be the foundation of fully integrating RES-E into

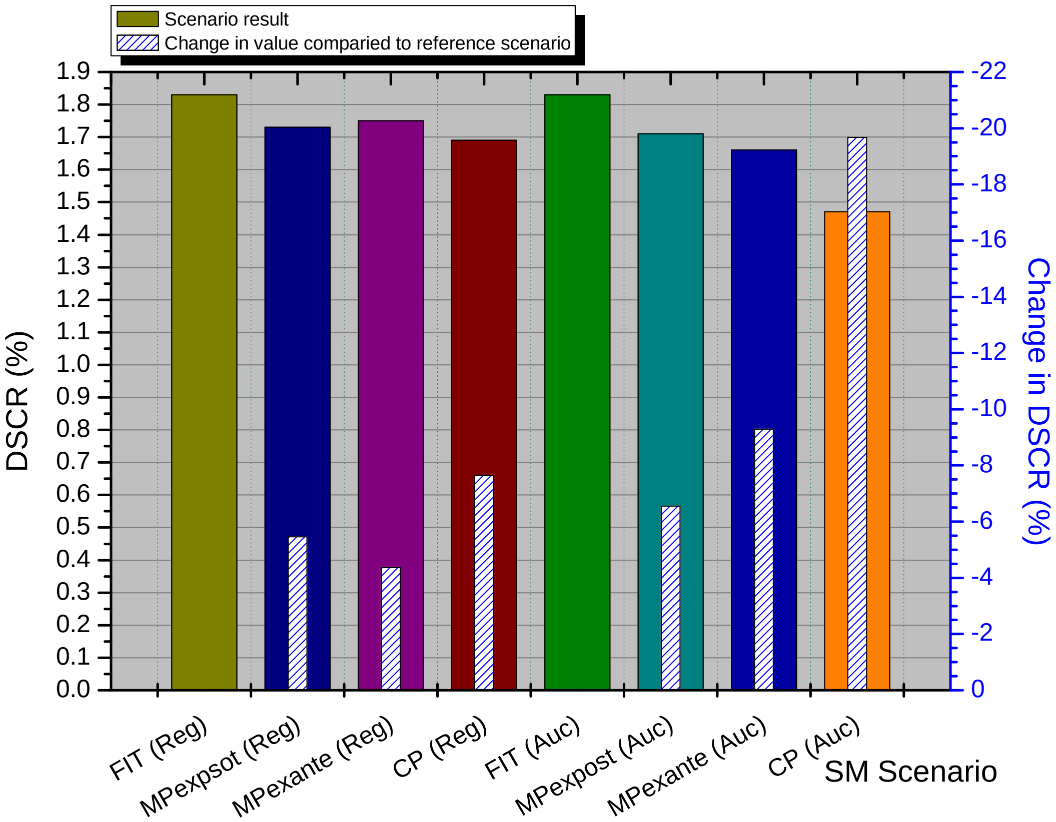

Figure 5.5: Wind Onshore DSCR results for different support mechanisms scenarios and changes compared to the reference scenario

the market. On the other side, quantity risks due to output curtailment possibility exist, which affects the economic feasibility of the project.

It can be concluded that the MPexpost can guarantee the investment in RES-E as in the feed-in tariff, and provide the operators with market dynamics and prices experience, but in a high cost due to over compensation possibilities as discussed in section 4.2.1.

5.1.3 Regulated Market Premium ex-ante

The calculated NPV for the MPexante Scenario is 1.7507 Mil€ as presented in figure 5.1, this value is reduced by -2.0645 Mil€, which is -54% lower than the reference scenario NPV as shown in figure 5.2. The NPV is higher than Zero, so the project can still be profitable.

The IRR is reduced by around -25% compared the reference scenario to be 13.3% as shown in figure 5.3. The IRR is higher than the WACC (7.8%), this gives an impression that the investment profitability can be secured.

The main reasons of having a lower NPV and IRR compared to both the reference and the MPexpost (Reg) scenarios, is that the amount of risks associated with the

MPexante resulted in a calculated WACC and almost the same level of quantity risks as in the MPexpost, which means a lower capacity factor and electricity production per year as shown in the MPexante case study input parameters table (see appendix (a)).

As illustrated in figure 5.4 the LCOE under the MPexante (Reg) scenario is 80 €/MWh. It increased by 11% compared to the reference scenario. This increase is not only due to the change in the amount of electricity production as a consequence of the quantity risks; but also due to the increase in the annual project costs due to the change in the capital structure. Although that the O&M costs are reduced as production decreases, but still the other LCOE calculation parameters effects is higher than the reduction in the O&M costs. The calculated LCOE is lower than the assumed remuneration amount (91 €/MWh).

The calculated DSCR for the MPexante scenario is 1.75%. It was expected due to the higher risk levels in the MPexante that the DSCR will be lower in the MPexante than the MPexpost. However, due to the new debt financial figures structure as shown in the case study input parameters table (see appendix (a)), the share of debt is limited to 65% with slightly higher rate of return than in the reference scenario, because of the higher uncertainties related to price risks as explained in section 4.2.1. This new capital structure result in a DSCR, which is -4.3% lower than the reference scenario DSCR and slightly higher than the MPexpost (Reg) scenario. In general the DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5.

The MPexante (Reg) can have some advantages over the FIT (Reg) and the MPexpost (Reg) regarding the quality of market proceeds and the transfer of price risks to the end customer (and other advantages) as illustrated in table 4.7. Yet on the investment and operation sides; the MPexante has more disadvantages than advantages. The decreases in the NPV of the project future cash flows and the IRR due to the higher uncertainties and price risk levels compared to the reference scenario, in addition to the increase in the LCOE, can have an effect on the wellness of investment under such scenario, as the differences in the NPV and IRR compared to the reference scenario quantities are considerable. The only positive indication in the analysis is that the DSCR value is higher than the MPexpost (Reg), but the difference between the two quantities can not be considerable in terms of influencing the debt side decision of preferring one scenario over the other. And still the MPexante DSCR lower than the reference scenario value.

There are benefits regarding operation, as the MPexante (Reg) support the complete market integration of RES-E and creates an incentive for increasing the quality of demand side forecasting, which can help maintaining more demand oriented feeding of electricity and increase the grid stability as illustrated in section 4.2.1. But on the other side, such operation behaviour can not be practically maintained as operators still do not have clear incentive to curtail the production rather than the high negative prices as in the case of the MPexpost (Reg). So the quantity risk still exist without any additional benefits on changing the operation behaviour. This results in leaving the MPexante (Reg) without any significant effect on the operation side compared to the FIT (Reg) as in the MPexpost (Reg) case.

5.1.4 Regulated Capacity Payment

The NPV calculated for the CP (Reg) scenario is 0.0925 Mil€. As shown in figure 5.1 this value is lower than the reference scenario NPV by -3.7227 Mil€. This means that there is a -97% difference in the NPV between the CP (Reg) and the reference scenario as seen in figure 5.2. As the NPV is slightly higher than Zero, the project profitability could be questionable.

The IRR value under the CP (Reg) scenario is 10.9%, this value is -39% lower than the reference scenario IRR as presented in figure 5.3. The calculated WACC for the CP (Reg) scenario is 10.6% as can be seen in the case study input parameters table (see appendix (a)) and table 4.14. Although that the IRR is higher than the WACC, but the gap between the two values is very low (0.3%), which increase the uncertainty of whether this investment is profitable or not.

The WACC value reflects the price risks on investment in the CP (Reg) scenario. Due to the high WACC compared to the reference scenario combined with the quantity risk factors in that scenario, the decrease of the NPV and the IRR is significantly high compared to the reference scenario and the other regulated scenarios.

LCOE increased by 25% compared to the reference scenario, to reach 90 €/MWh. This is due to the different quantity risks under the CP (Reg) scenario, in addition to the increase in the annual costs due to the higher required rate of returns as shown in table 4.2.1 and in the case study input parameters table in appendix (a). The LCOE is almost equal to the assumed total remuneration (91 €/MWh).

The calculated value for the DSCR is 1.69%, this value decreased with -7.5% compared to the reference scenario. Despite the share of the debt is limited to 60% due to the uncertainties related to the future cashflow; but on the other hand, the required return rate on it increased to 9.0% due to the price risk factors, and lower annual cash flow (net operating income). That is why the DSCR examined such a decrease in it's value compared to the reference scenario. In general the DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5.

In general among the regulated support mechanism scenarios, the CP (Reg) case reported the lowest project financial indicators on both equity and debt sides. This is due to the high level of price risks associated with such a scenario, and in addition to the different quantity risk factors as illustrated in section 4.2.1. The NPV and IRR of the project are very low and the LCOE is almost approaching the total assumed remuneration amount, this can threaten the wellness of investment in such a risky environment, specially for private investors who do not have a portfolio of investments that can reduces the overall investment risk. The DSCR did not experience a dramatic change in that case, this is due the reasons mentioned before. However, the debt share limitation and higher required rate of return reflects that the project can be financed but with high debt obligations.

On the operation level there are many disadvantages (in case a remote production control option is not integrated in the plant) which can reduce the potential of contributing positively to the grid stability as explained in section 4.2.1 . Moreover, there is a doughy that operators will react to negative price signals, as long as the capacity payment amount can guarantee making profit.

CP (Reg) can have some advantages on the level of capacity availability and supply reliability, in addition regarding the possibility of generating revenues, and decreasing the volitionality of wholesale energy prices as explained in section 4.2.1.

5.1.5 Auctioned FIT

As shown in figure 5.1, the NPV under the FIT (Auc) is 3.611 Mil€ this value is only -5 % lower than the reference scenario as seen in figure 5.2. As the NPV is higher than Zero, the project can still be profitable.

The calculated IRR is 18%, which is the same value as in the reference scenario. The IRR is higher than the WACC (6.2%), this gives an impression that the investment profitability can be secured.

The change in the NPV is due to the slight increase in WACC compared to the reference scenario as shown in table 4.14. This increase is due to the new price risk factor introduced under the FIT (Auc) as explained in section 4.2.1.

The LCOE under the FIT (Auc scenario) is 72 €/MWh as shown in figure 5.4, which is the same as in the reference scenario. There is no change in the plant production as there is no quantity risks associated with the FIT (Reg) scenario, in addition that the change in the annual project costs (because of the discount rate changes) is very small compared to the reference scenario. The calculated LCOE is lower than the assumed remuneration amount (91 €/MWh).

DSCR value has no change from the reference scenario as shown in figure 5.5, as there is no changes in debt financial requirements and the change in the annual cashflow due to the increase of the WACC is low. In general the DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5.

The FIT (Auc) scenario seems theoretically optimal, as it can benefit from the key advantages of auctioning as listed in table 4.8, of enabling higher degree of subsidy efficiency and remove the burden of defining the right remuneration from the regulator. However, there is uncertainty regarding the sufficiency of the remuneration level for completing the project, which introduce a price risk on investment as illustrated in table 4.9. Specially in order to be able to depend on it in estimating the sufficient remuneration amount in a competitive market environment. This can lead to increase the investment in certain RES-E technologies over another, which can affects the generation system in the future as discussed before in section 4.2.1. On the other hand, in case the estimated remuneration is not sufficient, this can make the profit generation from the project questionable.

On the other hand, from the operation side, there are no quantity risks associated with the FIT (Auc). This can result in the same disadvantages in the FIT (Reg) reference scenario of isolating the operation from the market prices and reducing the incentives for integrating the RES-E on the market and system levels as discussed in section 4.2.1.

5.1.6 Auctioned Market Premium ex-post

The NPV calculated for the MPexpost (Auc) scenario as shown in figure 5.1 is 1.3471 Mil€. Compared to the reference scenario this value is -65% lower as shown in fig 5.2. The NPV is higher than Zero, so the project can still be profitable.

The IRR under this scenario is also reduced by -32% compared to the reference scenario, the calculated IRR value is 12% as shown in figure 5.3. The IRR is higher than the WACC which is 7.8%, this gives an impression that the investment profitability can be secured.

The reduction in the NPV and IRR is reflecting the higher price and quantity risks associated with the MPexpost (Auc). The WACC is higher compared to the reference scenario as shown in table 4.14 , and the capacity factor is reduced by 2 % as can be seen in the MPexpost (Auc) scenario case study input parameter table (see appendix (a)). These assumptions reduces the net cashflow and resulting in lowering the NPV and IRR.

The resultant LCOE increases by 14% in the MPexpost (Auc) scenario compared to the reference scenario. As shown in figure 5.4 the calculated value of the LCOE is 82 €/MWh. In spit of this increase, but the cost is still lower than the remuneration assumed to be amount paid[2]. The calculated LCOE is lower than the assumed remuneration amount (91 €/MWh).

As shown in figure 5.5, the DSCR related to the MPexpost (Auc) scenario is 1.7%. This value is slightly lower than the reference scenario DSCR by -6.6%. As the debt share is limited to 65% and the required rate of return have not been changed significantly from the reference scenario as shown in table 4.14. The DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5.

Regarding the implications on investment, the financial indicators results for the MPexpost (Auc) scenario shows that the project economic feasibility is highly affected compared to both the reference and MPexpost (Reg) scenarios. This is due to the higher uncertainties related to the price risk factors as shown in table 4.9. Even under the direct marketing scheme there is uncertainty regarding profit making, as the auction outcome is unknown.

On the operation side, the MPexpost (Auc) scenario does not provide a clear incentive for demand oriented feeding of electricity. Curtailing of production is done based on voluntarily bases due to the quantity risks. That is why there is no clear advantage

[2] The assumed remuneration is 91 €/MWh as shown in the case study input parameters table in the appendix

of the MPexpost (Auc) scenario the investment or operation compared to the reference and MPexpost(Reg) scenarios.

On the Market level, there is a high possibility that the main advantage of achieving higher degree of subsidy efficiency through auctions can not be achieved. As the auction is done after the electricity is sold in the market, it give the generators an advantage to ask for high remuneration level, even higher than what is really needed in order to maximize the profits. This also can motivate the generators to create market power through cooperation in order to control the bids and influence the minimum amount of remuneration in the auctioning process. In addition, the costs and efforts related to running and managing a monthly or even yearly auctioning process can affect the economic efficiency of such a scenario, and create a burden of handling these costs and efforts on the regulator.

The quantitative assessment[3] and economic analysis of the MPexpost (Auc) scenario, clearly give an indication that there are more related disadvantages than the advantages not only on the investment and operation levels, but also on the electricity market economic efficiency.

5.1.7 Auctioned Market Premium ex-ante

The difference between the Calculated NPV for the MPexante (0.8348 Mil€) and the reference scenario NPV is -2.9804 Mil€ as shown in figure 5.1. This value means that the NPV is -78% lower than the reference scenario NPV as shown in figure 5.2. The project can still be profitable, as the NPV is higher than Zero.

IRR calculated value is 11.6%, which is -35.5% lower than the reference scenario IRR as shown in figure 5.3. The IRR is higher than the WACC which is 8.7% this gives an impression that the investment profitability can be secured.

This reduction in values is due to the reduction in the annual cashflow, as the WACC increases as shown in table 4.14, and the plant production is affected with the quantity risks as discussed in section 4.2.1.

The LCOE increased by 18% compared to the reference scenario. It reaches 85 €/MWh as shown in figure 5.4. This increase is due to the changes in the capacity factor, which causes a reduction in the annual energy produced. In addition to the increase of annual costs due to the high required WACC as shown in the MPexante (Auc) case study input parameters table the appendix (a). The calculated LCOE is not much lower than the assumed remuneration amount (91 €/MWh).

As shown in figure 5.5 the calculated DSCR for the MPexante (Auc) scenario is 1.66%, which is lower than the reference scenario DSCR by -9.5%. Unlikely in the MPexante (Reg) scenario, the DSCR calculated under the MPexante (Auc) scenario is not higher than the MPexpost (Auc) case, as the capital structure difference affected the DSCR in that case. The share of debt is the same as in the MPexpost (Auc) scenario, but due to the price risk the debt required rate of return is higher than the reference and the MPexpost scenarios. This higher required rate of return

[3] As explained in section 4.2.1

increases the debt repayment annual amount. In addition, the cashflow is affected by the higher annual costs than in the MPexpost (Auc) case. The DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5.

The MPexante (Auc) scenario create higher level of price risks on investment than in the reference and the MPexante (Reg) scenarios. As shown in table 4.9, investors have not only to bear the forecasting risks on revenues, but also the risk of insufficient remuneration estimation as the bids are submitted in a competitive environment and the only low bids are adapted. As can be seen from the financial indicators results, the investment attractiveness is highly affected due to the high reduction in the NPV and IRR, in addition to the increase in the LCOE. This can encourage private investors to consider other investment opportunities with lower risks, or to require higher share of lower return financing capital from debt. However, due to the uncertainties in the cashflow it is doubted that the share of debt will be increased, and even if it is increased higher required rate of return than what have been assumed in that case will be required in correspond to the risk levels. This will result in lowering the calculated DSCR, and the acceptance of financing the project can be questionable. Moreover, as explained in section 4.2.1, there are more quantity risk factors under the MPexante (Auc) scenario than in the MPexante (Reg) scenario.

Regarding the implication on operation, it is challenging but can be argued that the scenario creates an incentive for improving the quality of forecasting the demand behaviour on the long-term, as the bids will be submitted on ex-ante bases in a competitive auction. So the operators have a previous expectation regarding when the demand is high and need to be fulfillled, and when there is an excessive supply and profits can not possibility be made. In addition, a disadvantage on operation is that the same risks of having high negative prices exist, which will lead to a voluntarily curtailment of production if the remuneration is exhausted. But it is an advantage for the system integration of RES-E into the electricity market.

The advantages of auctioning on the market economic efficiency level , as higher subsidy efficiency and removing the burden of defining the remuneration from the regulator side, or over compensating the production due to high level of remuneration can be obtained in the MPexante (Auc) scenario.

As a conclusion, due to the high price and quantity risks in the MPexante (Auc) scenario, the project economic feasibility and investment wellness can highly be affected. However, the advantages of auctioning can be obtained and it can be argued that it will have a positive effect on the operation toward being more demand oriented, which may support integrating the RES-E generation on the market and systems levels.

5.1.8 Auctioned Capacity Payment

In the CP (Auc) scenario, the NPV has a negative value of -1.1205 Mil€ as shown in figure 5.1, this value is different than the reference scenario NPV by -4.9357 Mil€, which is -129% as presented in figure 5.2. The NPV in that case is lower than Zero, which means that there is no possibility for the project to be profitable, and the investment costs are higher than the revenues over the project lifetime.

The calculated IRR is 7.5 %,this value is lower than the IRR of the reference scenario by around -58% as shown in figure 5.3. There is a big gap between the IRR and the WACC which is 11.7%, this means that the profitability of the project is unsecured under the discount rate (which is the WACC) defined in that case.

The NPV and IRR have been highly affected due to the high price and quantity risks in the CP (Auc) scenario as shown in table 4.9, and the high WACC as shown in table 4.14.

The LCOE is 100 €/MWh, this value is higher than the remuneration amount paid[4]. Even that the annual O&M costs are reduced due to the reduction in the annual production (as a consequence of the quantity risks impact on the capacity factor) as shown in the CP(Auc) case study input parameter table (see appendix (a)), which can participate in reducing the annual costs and the LCOE. On the other hand, the high WACC and the reduction in the energy production have a higher impact on the LCOE that the O&M costs reduction, which leads to such increase in the LCOE value compared to the reference and CP (Reg) scenarios. The increase in the LCOE compared to the reference scenario is 39% as shown in figure 5.4.

The DSCR have reduced by around -20% compared to the reference scenario and it's calculated value is 1.47% as presented in figure 5.5. The DSCR is be highly affected under the CP (Auc) scenario and to reach a value lower than 1.00%, due to the negative NPV. However, due to the assumption of limiting the debt share to 60% as shown in table 4.14 because of the uncertainty in the future cashflow as explained in section 4.9. The DSCR is higher than 1%, which means that there is enough cashflow to fulfill the debt repayment obligations. Moreover, the DSCR value is slightly higher than 1.3% which is the required DSCR for Wind Onshore in Germany as shown in table 4.5.

It can be clearly seen that the investment economic feasibility is highly affected in this scenario, even in that case the financial indicators that reflect the investment can not be profitable due to the low IRR, negative NPV, in addition to the high LCOE. From the debt perspective the project still can meet it's repayment obligations but only under the assumptions that have been made for the debt financial figures. It can be highly uncertain that the scenario will provide the incentive of investment to reach the needed Wind Onshore capacity available targets to guarantee a reliable supply of energy. In addition, an incentive for making extra investment to make the available capacity remotely controlled in order to obtain the system flexibility in using this capacity when it is needed, needs a clear incentive or special compensation as in the case of the current structure of the German market premium ex-post. It can be also daughter than taking advantage of increasing the degree of subsidy efficiency can be obtained. As there is an incentive of creating cooperation between investors to influ-

[4] The assumption is the total remuneration assumed to be paid is 91 €/MWh.

ence the auctioning process through using market powers, and take advantage of high proposing bids with high desired remuneration in order to maximize the profits. This can also be an incentive for the big market player to participate, and make it harder for private investors to participate in the market.

On operation side, although that there is an exposure to market prices but as long as the capacity payment remuneration can guarantee making profits, the operators will not react to market signals until the remuneration is exhausted by the negative prices. However, it can be argued that as the available capacity needed is defined by the regulator and the required capacity payment is granted based on the auction results. As a consequence the supply and demand will match and the likelihood of having negative prices due to excessive supply will be reduced in that case, and that would be an advantage for both operation and grid stability sides.

But to support this argument the regulator must defining exactly the needed available capacity and give an incentive to make it fully monitored and controllable by the system operator who will be responsible for balancing the grid. This will increase the burden that the regulator would handle, in addition to the increase in costs, which can have an influence on the economic efficiency of the electricity market, and at the end tax payers and end customer have to pay for these costs in case they exist, which will increase the burden on them as well. Due to this it can be costly and hard to achieve even the main objective of having available capacity in order to maintain higher a reliable supply of energy.

5.2 PV Scenarios Assessment Results

Most of the arguments stated in the Wind Onshore case regarding the directional influence of the different support mechanisms scenarios are applicable on the PV case as well. But there is a difference between the two cases (Wind onshore and PV) in the absolute values of the financial indicator results, and in the relative changes in percentage for each scenario compared to the reference scenario.

The difference in the financial results between the Wind Onshore and PV scenarios is due to three main reasons: the technological difference, the selected case study plant location and capacity, and the energy resource availability difference between solar and wind. These differences can be recognized in the PV case financial results as: First, the project NPV and IRR absolute values are lower because of the effect of the of the above mentioned difference factors on the cashflow (revenues and costs) of the project. Second, the LCOE is much higher than in the wind onshore, this is mainly due to the solar resource nature which affects the amount of energy production, but on the other side the project costs are not affected (O&M and investment costs are fixed) which results in a high LCOE. third, the DSCR is lower than 1% in all the scenarios (including the reference scenario). This is because of the project do not produce enough revenues (in that particular case study) than the costs, which lower the cashflow (net operating income) and result in that there is no enough cashflow to meet the debt obligations[5].

Despite these financial values differences, investing in PV can not be replaced by investing in Wind Onshore, due to the higher NPV, IRR and DSCR and lower LCOE of the Wind Onshore. because first both technology are needed in building the optimal renewable energy mix. There are locations where PV is more efficient than Wind, because of the availability of the resource in that location, or the plant size restrictions (for example supplying a building with a roof top or building integrated PV). Second, the remuneration is adjusted for each RES-E technology to make the investment attractive in the locations which provide enough resources. Third, without making investment it will be hard to move the technology from the R&D phase to the market maturity and take the associated costs down, as the learning curve and experiences related to this technology will not be further developed.

The difference between the Wind Onshore and PV relative changes in percentage for each scenario compared to the reference scenario, is because the PV related financial assumptions for each scenario like the debt and equity shares, required rate of return, the WACC and the concept of defining the O&M costs, are different from the Wind Onshore assumptions as illustrated in table 4.14. This makes the PV and Wind Onshore cases different from the financial point of view, but still the risks of different support mechanisms and conclusions regarding the implications of each scenario on investment and operation are generally as argued in the Wind Onshore section.

[5] It is important to be taken into consideration that the project grant was removed due to the reasons explained in section 4.2.3.

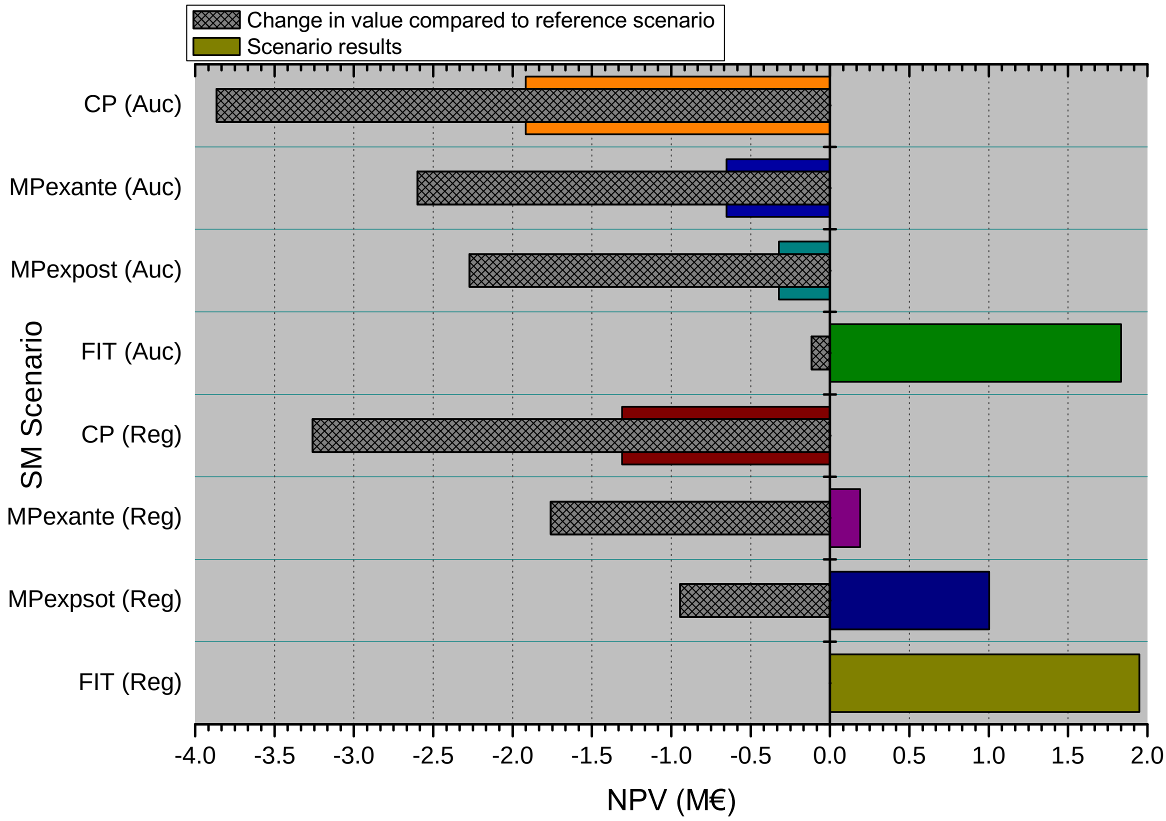

Figure 5.6: PV NPV results for different support mechanism scenarios

5.2.1 Regulated FeedIn-Tariff (reference scenario)

The input parameters for the PV reference scenario case study are shown in table 4.17. The results of financial indicators calculations are 1.9487 Mil€, for the NPV, 9.8% for the IRR, 344 €/MWh for the LCOE, and 0.89% for the DSCR[6].

The NPV is higher than Zero which indicates that the investment can be profitable. Also there is a gap between the IRR and the WACC (4.4%), in addition the LCOE is lower that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

The implications for the reference scenario on investment and operation are as illustrated before in the Wind case in section 5.1. Investment is highly secured under this scenario, but there is no incentive for operators to react to market signals as they are isolated from the market prices.

5.2.2 Regulated Market Premium ex-post

The NPV calculated for the MPexpost (Reg) scenario is 1.0037 Mil€, as shown in figure 5.6. This value is reduced by -48.5% compared to the reference scenario NPV as

[6] The financial indicators calculation results are summarized in table 4.19 for all the PV scenarios.

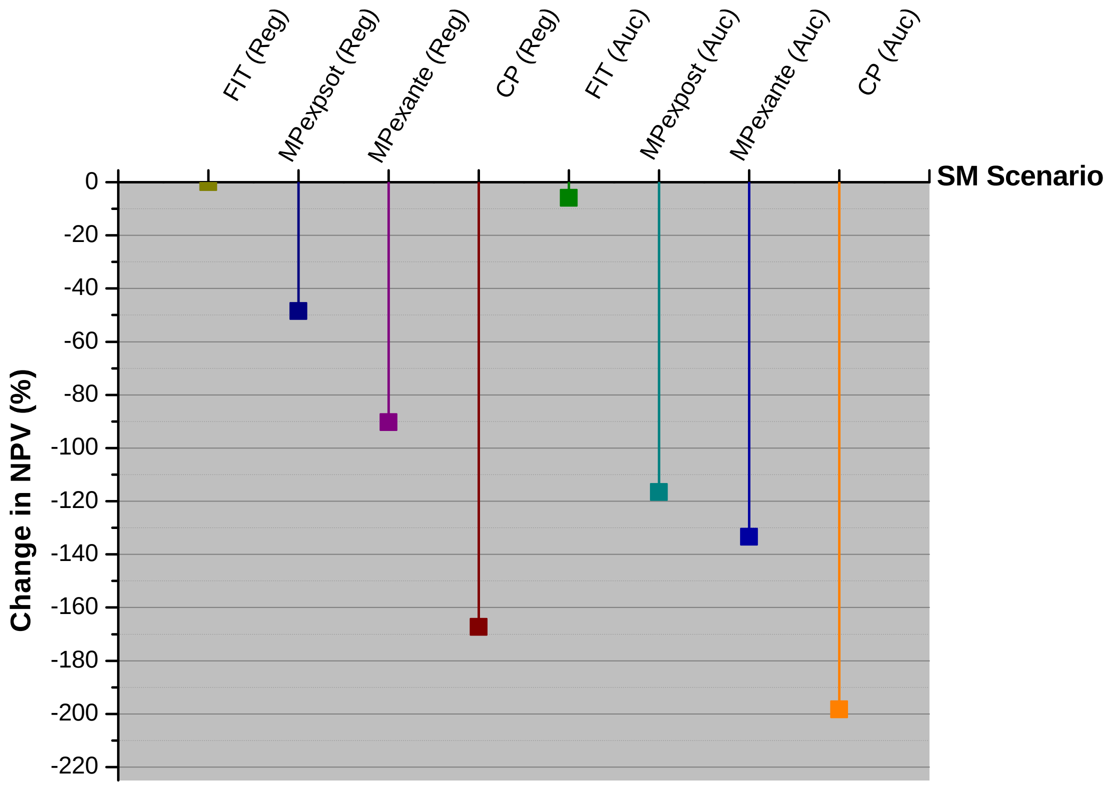

Figure 5.7: PV NPV results comparison against the reference scenario

presented in figure 5.7. The IRR calculated is 7.5% for the MPexpost (Reg) scenario, this value is -23 % lower than the reference scenario. The reduction in these values is due to the same reasons illustrated in the Wind Onshore MPexpost (Reg) scenario.

As presented in figure 5.9, the LCOE increase by 13% compared to the reference scenario, to reach 390 €/MWh. this increase is due to the same risk implications explained in the Wind Onshore section.

The DSCR for the MPexpost (Reg) is 0.79%, this value is -11% lower than the DSCR in the reference scenario as shown in figure 5.10. The reduction in the DSCR is due to the same reasons illustrated in the Wind Onshore MPexpost (Reg) scenario.

In the MPexpost (Reg) scenario, the NPV is higher than Zero which indicates that the investment can be profitable. Also there is a gap between the IRR and the WACC (4.7%), in addition the LCOE is lower that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

As explained in details before in the Wind Onshore section, the investment attractiveness will not be dramatically affected compared to the reference scenario, and regarding operation the MPexpost (Reg) scenario provide operators with experiences regarding market dynamics and prices, but do not create a dramatic change in the operation behaviour compared to the reference scenario.

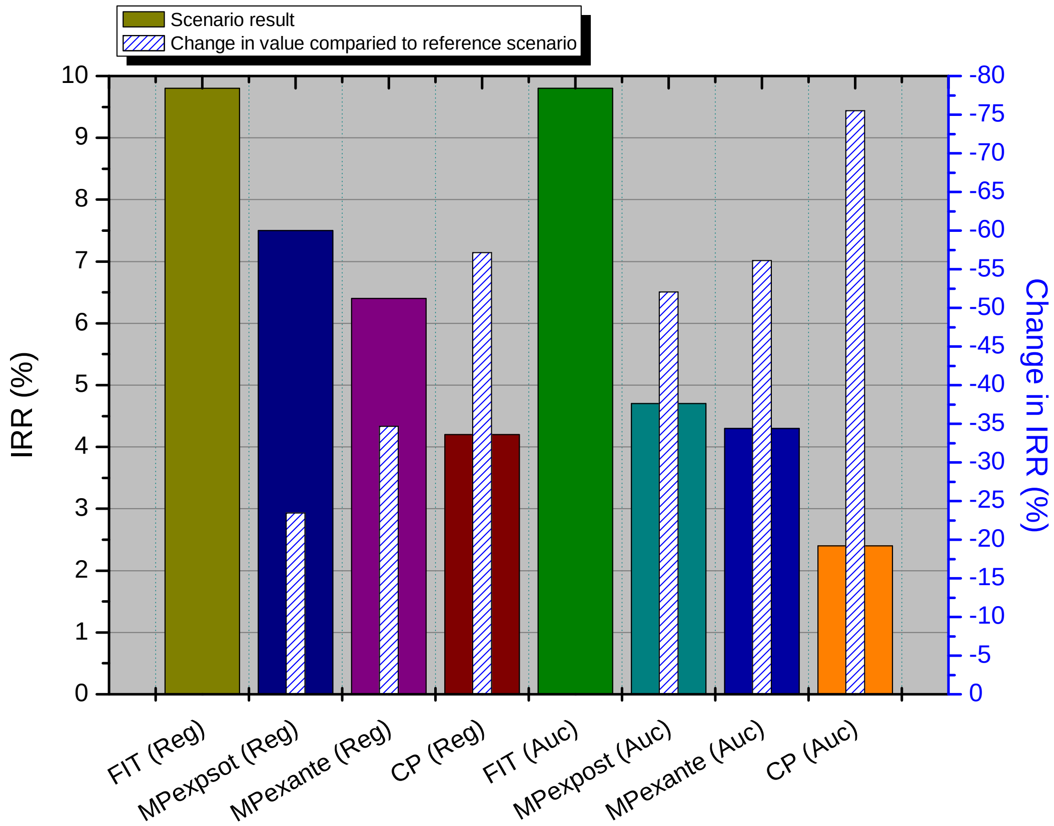

Figure 5.8: PV IRR results for different support mechanism scenarios and changes compared to the reference scenario

5.2.3 Regulated Market Premium ex-ante

The calculated NPV for the MPexante (Reg) scenario is 0.1895 Mil€, as shown in figure 5.6. The difference between this value and the reference scenario NPV is -1.7592 Mil€, this means that the NPV is reduced by -90% compared to the reference scenario NPV as shown in figure 5.7. The calculated IRR is 6.4 %. As shown in figure 5.8 this value is -34.7% lower than the reference scenario IRR. The LCOE calculated is 442 €/MWh, which is 28.5% higher than the reference scenario LCOE as shown in figure 5.9. The reasons for NPV and IRR reduction, and the increase in the LCOE are as previously explained in the Wind Onshore Mpexante (Reg) scenario.

In the MPexante (Reg) scenario, the NPV is slightly higher than Zero which indicates that the investment can be profitable. Also there is a small gap between the IRR and the WACC (5.9%), in addition the LCOE is slightly lower that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can be (but not highly) secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

Implications on investment and operation is in the same direction as in the Wind Onshore case. Investment wellness can be highly affected under this scenario. Moreover,

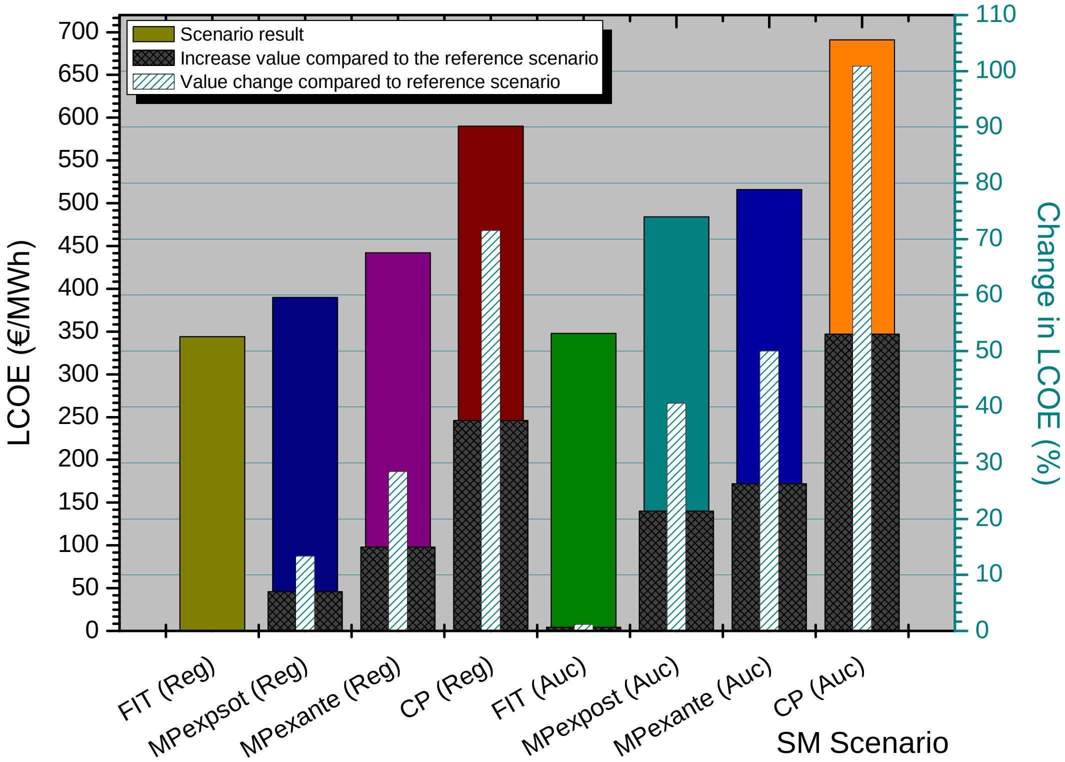

Figure 5.9: PV LCOE results for different support mechanism scenarios and changes compared to the reference scenario

there are no additional benefits regarding changing the operation behaviour. MPexante (Reg) scenario have other implications as well, which are illustrated in the Wind Onshore section.

5.2.4 Regulated Capacity Payment

As shown in figure 5.6, the value of the NPV for the CP(Reg) scenario is -1.3107 Mil€. This negative NPV is lower by -167% compared to the reference scenario NPV as shown in figure 5.7. The IRR calculated value is 4.2%, this value is reduced by -57 % compared to the reference scenario IRR as shown in figure 5.8. As presented in figure 5.9, the LCOE increases by 71% compared to the reference scenario, to reach 590 €/MWh. this increase is due to the same risk implications explained in the Wind Onshore CP(Reg). The DSCR value is 0.7%, it is reduced by -21% compared to the reference scenario DSCR as shown in figure 5.10.

The NPV is lower than Zero which indicates that the investment can not be profitable. The IRR is lower than the WACC (8.6%), in addition the LCOE is higher that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can not be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

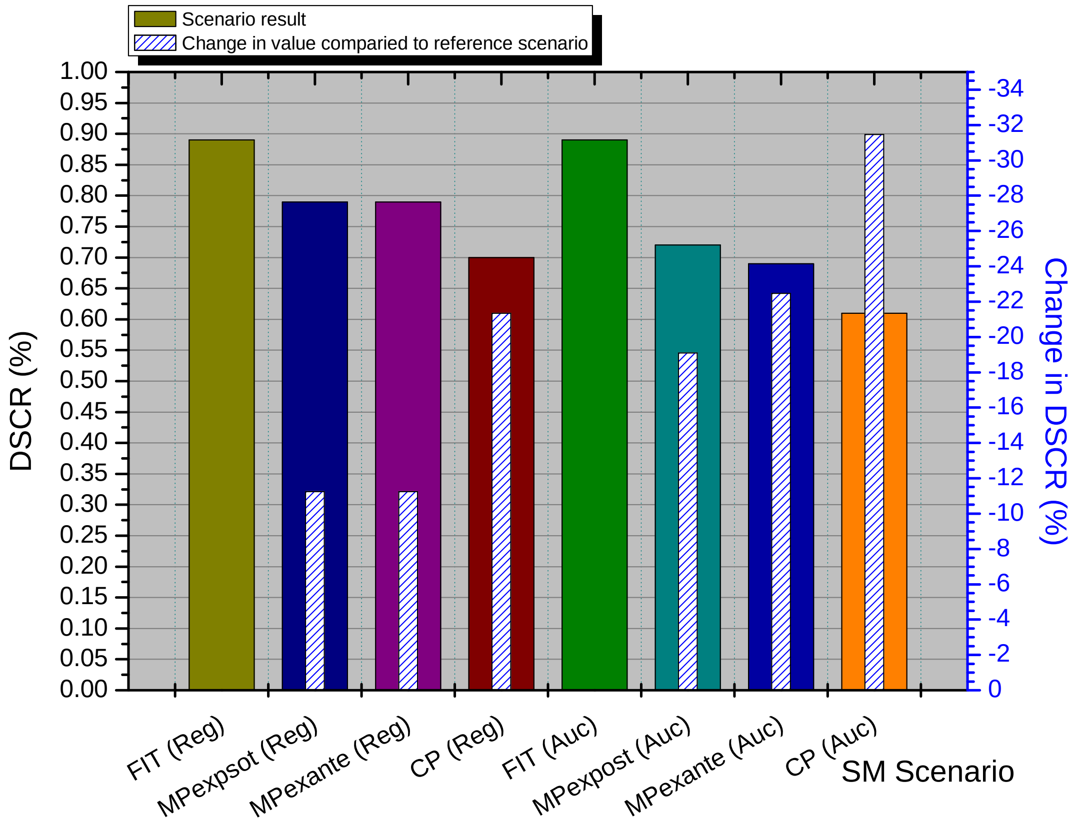

Figure 5.10: PV DSCR results for different support mechanism scenarios and changes compared to the reference scenario

Generally the implications of the CP (Reg) on investment and operation is in the same direction as in the Wind Onshore case. The economic feasibility of the project were highly affected in the PV case. On the operation level making profit can be guaranteed even in the existence of negative prices in the market, as long as the remuneration form the capacity payment is not exhausted.

5.2.5 Auctioned FIT

As shown in figure 5.6, the value of the NPV for the FIT (Auc) scenario is 1.8337 Mil€. This value is lower by -6% compared to the reference scenario NPV as shown in figure 5.7. The IRR calculated value is the same as in the reference scenario 9.8% as shown in figure 5.8. As presented in figure 5.9, the LCOE slightly increased by 1.2% compared to the reference scenario, to reach 348 €/MWh. The DSCR value is the same as in the reference scenario 0.89% as shown in figure 5.10.

In the FIT (Auc) scenario, the NPV is higher than Zero which indicates that the investment can be profitable. There is a gap between the IRR and the WACC (4.6%), in addition the LCOE is lower that the assumed remuneration value (which is 457

€/MWh), which gives an impression that making profits can be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

As in the Wind Onshore FIT (Auc) scenario, there are slight changes in NPV and LCOE, but the IRR and DSCR share the same values with the reference scenario. This is due to the price risks introduced under the FIT (Auc) scenario as explained in the Wind Onshore case.

The implications of the FIT (Auc) scenario on the investment and operation are in the same directions effect as in the Onshore Wind FIT(Auc) scenario. Investment economic feasibility is not affected, but on the other hand as operation is isolated from the market prices, there is no incentive to have demand oriented behaviour.

5.2.6 Auctioned Market Premium ex-post

The calculated NPV for the MPexpost (Auc) scenario is -0.3224 Mil€, as shown in figure 5.6. The difference between this value and the reference scenario NPV is -2.2711 Mil€, this means that the NPV is reduced by -116% compared to the reference scenario NPV as shown in figure 5.7. The calculated IRR is 4.7%. As shown in figure 5.8 this value is -52% lower than the reference scenario IRR. The LCOE calculated is 484 €/MWh, which is 40.7% higher than the reference scenario LCOE as shown in figure 5.9. Figure 5.10 shows that the DSCR decreased by -19% compared to the reference scenario. The calculated value for the DSCR is 0.72%.

The NPV is lower than Zero which indicates that the investment can not be profitable. The IRR is slightly lower than the WACC (5.7%), in addition the LCOE is slightly higher that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can not be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

The project feasibility is highly affected. In addition, there is no clear incentive for demand oriented operation behaviour. In general the MPexpost (Auc) scenario implications on investment and operation will lead to the same directional consequences as explained in the Wind Onshore MPexpost (Auc).

5.2.7 Auctioned Market Premium ex-ante

As shown in figure 5.6, the value of the NPV for the FIT (Auc) scenario is -0.6511 Mil€. This negative NPV represents a reduction of -133% compared to the reference scenario NPV as shown in figure 5.7. The IRR calculated value is 4.3%, this value is reduced by -56% compared to the reference scenario IRR as shown in figure 5.8. As presented in figure 5.9, the LCOE has 50% increase compared to the reference scenario; The calculated LCOE value is 516 €/MWh. The DSCR calculated value is 0.69%, it is reduced by -22.5% compared to the reference scenario DSCR as shown in figure 5.10.

The NPV is lower than Zero which indicates that the investment can not be profitable. The IRR is lower than the WACC (6.39%), in addition the LCOE is slightly higher that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can not be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

The changes in the financial results is because of the MPexante scenario risks, capital structure changes and WACC increase [7] implications as discussed before in section 5.1 under the Wind Onshore MPexante (Auc) scenario.

Under the MPexante (Auc) scenario, the project feasibility is affected in the PV case to a higher extent that in the Wind Onshore case. The project feasibility under the same risk assumptions is giving negative indicators as can be seen in the NPV, and the LCOE is higher than the assumed remuneration. However, the advantages of auctioning can be obtained and it can be argued that it will have a positive effect on the operation toward being more demand oriented. In general, the implication of the MPexante (Auc) in the PV case are in the same direction as in the Wind Onshore MPexante (Auc) scenario.

5.2.8 Auctioned Capacity Payment

The calculated NPV for the CP scenario is -1.9164 Mil€, as shown in figure 5.6. The difference between this value and the reference scenario NPV is -3.8651 Mil€, this means that the NPV is reduced by -200% compared to the reference scenario NPV as shown in figure 5.7. The calculated IRR is 2.4 %. As shown in figure 5.8 this value is -75.5% lower than the reference scenario IRR. The LCOE calculated is 691 €/MWh, which is 100% higher than the reference scenario LCOE as shown in figure 5.9. The DSCR calculated value is 0.61%, which is reduced by -31.5% compared to the reference scenario DSCR.

For the CP(Auc) scenario, the NPV is much lower than Zero which indicates that the investment can not be profitable. The IRR as well is much lower than the WACC (9.26%), in addition the LCOE is much higher that the assumed remuneration value (which is 457 €/MWh), which gives an impression that making profits can not be secured. The DSCR is lower than 1%, that may have an influence on the debt decision of financing the project.

As in the Wind Onshore CP (Auc) scenario, the economic indicators are highly affected due to the risk levels associated with the scenario and other factors illustrated in the Wind Onshore section. According to the financial indicators of the project, the economic fesability of the project is highly affected and the implications of the CP (Auc) scenario in the PV case is taking the investment attractiveness to the same direction as in the Wind Onshore case . On the operation level, there is still no clear incentive to respond to market signals due to the same challenges explained in the Wind Onshore CP(Auc) scenario.

[7] Risk factors are in table 4.9, capital structure and WACC calculation are in table 4.14

While looking at the results it is important to take into consideration that the financial indicators calculated do not only depend on the selected RES technology and support mechanism scenario, but also on the selected case study for each RES-E technology. In other words, different locations for Onshore Wind or PV plant can result in different calculated values for NPV,LCOE,IRR and DSCR. However, in general the same directional effect of the scenario implication regarding the increase or decrease of the value can be recognized in other case studies. Because the effect of increasing or deceasing is a result of the support mechanism risks, but the quantity of such increase or decrease is a factor of the risk level and the RES-E technology case study as well.

6 Conclusion and Recommendations

RESMIP Model is developed to analyze the implications of difference RES-E support mechanisms on investment and operation using a scenario analysis base. It has been demonstrated in the case studies that, selected financial indicators are calculated taking into consideration different risk types on investment and operation levels, these indicators can give a pre-feasibility analysis result for investment decision making on go or not-go basis. Moreover, the model fulfils the objective of giving policy makers an impression regarding the directional effect of a support mechanism on investment and operation for different RES-E technologies.

Simple and transparent modelling approach can help the non-specialist policy makers to understand the different analysis stages in the model, and have an overview about how the results are driven. Such understanding can help in analysing the results and building conclusions, taking into account the uncertainties and assumptions that have lead to the final results. It can be seen from each analysis stage outcome and the results that the model is consistent, as each step depends on the outcome of the previous one to build up a big picture of the final result. An important factor taken into consideration in the model description is the transparency of assumptions related to each analysis stage in order to give a clear understanding of the reasons behind each driven result.

Although that the scope of the study focused only on two RES-E technologies (Wind Onshore and PV), but the model can be used to analyze other technologies using the proper technology specific assumptions. Furthermore, the analysis of other RES-E support mechanisms outside the scope of the study is possible as well using the model. In general the RESMIP model provide a flexible tool that can be integrated into a wider scope models like the AMIRIS Model[1].

Regarding the model related uncertainties; estimating the level of the risk factors under each scenario is challenging in the qualitative assessment stage. The sensitivity analysis benefits in the determination of different risk factors impacts. But there is a positive or negative uncertainty amount in the assumption of the risk factor probability amount, as some of the risk factors can be related to indicators like the probability of having negative prices in the market, but others can not and the estimation has to be

[1] AMIRIS is an agent-based simulation model developed in the system analysis and technology assessment department at DLR (German Aerospace Center), used on the one side to analyze relevant market actors in the German electricity system and their changes in behaviour due to modifications in the energy policy framework. On the other side the impacts on the system level due to these changes in behaviour of the relevant actors in the context of market integration of RES are investigated.

done on qualitative analysis bases.

The study scope included the analysis of proposed support mechanisms scenarios. It was challenging to determine the assumptions related to the WACC calculation variables like the debt and equity shares and required rate of return, specially that it will vary depending on how different investors perceive the risk and evaluate it. It was also challenging to estimate the support mechanism risk premium used in the CAPM model under each scenario, specially that the values for such assessment factor can not be found in previous studies and it is relevant as well to the perception towards risk. The determination of the change in the capacity factor as well is simplified and made under a general assumption related to the negative prices. On the other hand, for the current used support mechanisms (regulated FIT and MPexpost), estimating the financial figures for the WACC calculations is done using the published market figures in literature and recent studies. Due to the PV market status, more studies can be found related to Wind Onshore than to PV, which increase the uncertainty in the PV assumption more than in the Wind assumptions due to the dependency on limited number of publications.

The case studies as well included a simplification assumption of adapting the same remuneration level as in the reference scenario. This assumption is done for the proposed support mechanisms scenarios as it is challenging to estimate the amount of remuneration under each scenario, due to the amount of details which have to be taken into consideration, as the difference between the remuneration amount based on the plant size, the differences of remuneration between different technologies, the structure of the mechanism whether to be degrading or fixed over time, how much the degradation rate will be and how it will be implemented, will the remuneration be linked to the energy yield of the plant or not, and more support mechanism details. On the other side, this simplified assumption does not hardly affect the model outcomes and it makes the comparison between different mechanisms more transparent, in addition to reducing the uncertainties in the comparison results. Moreover, the main scope of the study is to evaluate the implications of the different risk levels associated with each scenario on the investment compared to the reference scenario, not to make a detailed precise economic feasibility study of the project for investment evolution.

One of the strengths considered in the model, is using various financial indicators. This is an important element for the assessment as the results showed. Each indicator represents a measurement that is used by one of the project participates (equity and debt) to assess the project feasibility from his point of view. Moreover, it can happen that some indicator values can experience a decrease and others experience an increase or remain unchanged under the same scenario, due to the difference in the financial variable structure between equity and debt as in the case of the Regulated Market Premium ex-ante in the Wind Onshore and PV scenarios.

On the support mechanisms level, the assessment shows that some mechanisms can work successfully in terms of securing the investment and encouraging the deployment of RES-E technologies, but neglecting the implication on the market economic efficiency, and do not encourage the operation to react to the market signals like the FIT. Others can lead to a more demand oriented operation behaviour and support the integration of RES-E on the market and system levels, but with involving higher uncertainties on the security of investment, which have to be taken into consideration from policy makers like the MPexpost and MPexante. Moreover, it is highly arguable for other support mechanisms that can have benefits on the system level like the CP, whether that it introduces a benefit for the operation and investment or not.

This study recommends for policy makers:

First, not only the effectiveness and efficiency of the support mechanism have to be taken into account in assessing the implication of a support mechanism (as in most of the recent studies), but also it is very important to consider certain aspects related to the implications on investment and operation in more details. Moving beyond depending on the traditional ex-post evaluation of the installed capacity in Megawatts for a certain time of period and using it as an effectiveness indicator for a support mechanism, toward including the analysis of the implications on the investment decision and the financial indicators, can help to solve the inherent problem of data availability and allow policy makers to take decisions with the benefit of foresight. "An interesting feature of looking at investment rather than installed capacity is that it works almost like a time machine" [WM12]. In addition, consideration of investment risk is an important factor for policy assessment. While two support mechanisms (such as the case of the feedin-tariff and the green certificate mechanisms) might be expected to have similar outcomes in economic models without proper consideration of investment risks, a decision can be made based on such analysis and then empirical evidences prove that it was not appropriate. This have been offered as the reason of the feedin-tariff success over the green certificate mechanism [WM12]. On the other side of the coin, overlooking the policy implications on plant operation can lead to the same current problems in Germany, of having the desired installed capacity on one hand, but having economic and technical challenges related to the fluctuating RES-E (which one of the reasons for it is the operation behaviour) on the other hand.

Second, in the case of infrequent RES-E technologies like Wind Onshore and PV, linking the remuneration directly to the market prices can create an incentive for more efficient plant operation, and reduces the technical and economical implications of imbalances. But on the other hand, it has a major effect on the project economic feasibility as there is almost no means of adjusting the production as it is based on resource availability, which can have an effect on investment attractiveness in these technologies. So balancing between these two sides is an important element to be considered by policy makers.

Third, it is important to structure the support mechanism in a way that differentiate between the RES-E technologies. It is not sufficient to develop a general market mechanism that takes all RES-E infrequent technologies as one package, and differentiate only by defining a technology specific remuneration for each RES-E technology. As it was clear from the model analysis results that there is a difference between how the project feasibility react differently in the Wind Onshore and PV cases under the same scenario. This gives an indication that certain mechanism structure can be acceptable from the investment side for one RES-E technology, but not for the other. In addition, another empirical indicator supporting this recommendation is that in the current case in Germany even that the market premium is introduced and big portion of the Wind production is reimbursed under the Market Premium scheme, but still the majority of the PV generators are adapting the FIT and do not have an incentive to change to the market premium [GP13a].

Fourth, the level of maturity of the RES-E technology has to be considered as one of the policy design elements for a successful mechanism. An argument quoted in [BPAZB12] that " Auctions appear to be the unavoidable heirs to successful FIT programs " can be applicable only in the case of technologies that have reached the market maturity as it can be reliable in estimating the required remuneration. It has to be considered as well that such transaction from regulatory based schemes to auctioning, will benefit only the investment and market economic efficiency, but it will not lead to a full integration of RES-E in the electricity market.

Fifth, placing parallel active mechanisms like the current case in Germany with the FIT and MPexpost, will benefit the investment and give the freedom to adapt the mechanism that suits the resource nature as in the PV and Wind current market case. This overlapped transaction also provide experiences regarding the market dynamics and the market actors behaviour. One of the learning lessons of the recent political changes in the RES-E support mechanism in Germany, is that operators do not take long period to adapt changes in the support mechanism structure (estimated 68% of all on and off shore wind power production in 2012 was reimbursed according to the Market premium scheme) [GP13a]. Such experiences with the market dynamics and actors behaviour towards change will be build over time, and it is needed in-order to reach the objectives of considering renewable energy sources as a main source of energy in Germany. However, the existence of parallel mechanisms place a doubt of whether the change happened in certain levels, like in the production behaviour change toward integration RES-E in the market in a narrow sense (through voluntary curtailment of production in case of high negative prices) , will be further developed and permanent or not.

Sixth, defining a fixed remuneration for the infrequent RES-E technologies (like Wind Onshore and PV) and isolating them from the market price volatility, is a successful way to create an incentive for investment in these technologies. This remuneration can be defined by the regulator, and moving gradually toward being on auctioning bases in a competitive market environment, side by side with the maturity development of the technology. This movement toward auctioning is in order to maintain high level of subsidy efficiency and avoid over compensation. But it has to be taken into account how to discourage creating market powers in order to maximize the profit, as it will be hard for private investment in that case to enter the market. This can be done through investors categorization, by defining the level of remuneration based on the plant capacity as in the current case of the FIT, in order to make the investment in certain plant capacities unattractive for specific investors like the incumbent ones who will require a higher rate of return, but on the other hand attractive for another category of investors like the private investor. On the other side, the isolation from the market prices volatility will not solve the operation behaviour problem, the participation of operators in the balancing process and burden the costs is necessary. This can be done through involving the operators in the ancillary market by bearing the extra imbalances costs partially or totally. This will give an incentive for improving the forecasting quality of production and demand on the short-term, and fully integrating the RES-E on the market and system levels on the long-term.

Lastly, addressing the technical and economical challenges and potentials on the whole scale of the energy system, including ancillary markets, cooper plat expansion, investment in storage capacities , demand side management, smart grid and the need for a proper market design, is essential for creating a long-term electricity system with high shares of RES-E.

"Technological advances, and in some cases breakthrough, are certainly needed: but the revolution required is one of attitudes"[Gru90]. By these words Grubb since 1990 quoted in his study of modernized renewable energy technologies, the extensive view which has to be considered by a multitude of actors from policy makers to citizens, industry, investors and operators. For achieving a future where 100% of our energy is from renewable resources.

7 Outlook

The RESMIP model has lot of areas of enhancement and development potential. Starting with reducing the uncertainties related to the qualitative assessment of the support mechanisms, specially the probability of each risk factor. Such enhancement will have a reflection on the overall assessment of the risk level of each support mechanism, consequently the related assumption regarding the support mechanism risk premium will experience improvement as well. This enhancement can be done through searching for the appropriate indicators (by market surveys with investors and operators and/or literature review if relative publications are available) for each risk factor which can give an impression regarding the likelihood of having this risk under the investigated scenario. Another aspects of enhancement are the uncertainties related to the WACC calculation financial parameters (like the debt and equity requirements) , such enhancement will have a major reflection on the overall accuracy of the results, that can be done through market surveys with different types of investors. Market surveys can also help in understanding the risk perception of various investors categories. Such understanding will support the interpretation of how the evaluation for the same risk factor varies among different types of investors, and how various financial indicators (e.g NPV,IRR,LCOE and DSCR) are settled based on this evaluation. Improvement of the results can be done as well though the support mechanism structure assumptions, as making the relevant assumption to the mechanism design more applicable and economic efficient if possible, and including assumptions related to the remuneration differences under each scenario. On the operation side, improving the effects on the capacity factor assumptions under each scenario can participate as well in the enhancement of the model accuracy.

Regarding the model further development potentials. Adding a RES-E technology parameter in the quantitative assessment stage will increase the simplicity of considering other RES-E technologies in the model. Furthermore, including the investor's portfolio aspects and other behavioural factors rather than the risk perception as the perceived importance of policy type, support level and support duration, in addition to the confidence in the market efficiency and technology effectiveness and other behavioural factors as proposed in [MM12], can be taken into account in the model development. Another aspect of development is that instead of using an external model for the economic analysis, developing an economic analysis model will make it more easier to use the model as one package in case it will be integrated into a wider scope model. Moreover, the whole model concept can be implemented using a programming language like Java or python in order to optimize the scenario investigation time and support it's integration into a wider scope model.

This study is done in the "Support Schemes and Economic Aspects" group at the System Analysis and Technology Assessment department of the Institute of Technical Thermodynamics at the DLR(German Aerospace Center), and the modelling and findings of this study may be used in the future development of the AMIRIS model.

References

[bde13] bdew. Proposals for a fundamental reform of the german renewable energy sources act. Technical report, September 2013. Avaliable online: www.bdew.de/internet.nsf/res/44E1E89F7EEF4D67C1257C13004551DF/$file/Positionspapier_Vorschl%C3%A4ge%20f%C3%BCr%20eine%20grundlegende%20Reform%20des%20EEG_final_180913_en.pdf ; Accessed: December 2013.

[Bey12] Beyond(2020). Review report on interactions be-tween res-e support instruments and electricity markets. Technical report, October 2012. Avaliable online: www.res-policy-beyond2020.eu ; Accessed: November 2013.

[BME06] BME. German wind energy association, 2006. www.wind-energie.de/en ; Accessed: September2013.

[BMU12a] BMU. Renewable energy sources act (eeg) 2012. Technical report, 2012. Avaliable Online:www.erneuerbare-energien.de/en/topics/acts-and-ordinances/renewable-energy-sources-act/eeg-2012/ ; Accessed: September 2013.

[BMU12b] BMUB. Development of renewable energy sources in germany 2012 (graphics and tables), version: December2013, 2012. Avaliable Online:www.erneuerbare-energien.de/en/topics/studies/ ; Accessed: March 2014.

[BMU14] BMUB. Renewable energy sources in figures. Technical report, 2014. Avaliable Online:http://www.erneuerbare-energien.de/en/unser-service/mediathek/downloads/detailview/artikel/renewable-energy-sources-in-figures-1 ; Accessed: March 2014.

[BN08] Lucy Butler and Karsten Neuhoff. Comparison of feed-in tariff, quota and auction mechanisms to support wind power development. *Renewable Energy*, 33(8):1854–1867, 2008.

[BPAZB12] Carlos Batlle, Ignacio J Pérez-Arriaga, and Patricio Zambrano-Barragán. Regulatory design for res-e support mechanisms: Learning curves, market structure, and burden-sharing. *Energy Policy*, 41:212–220, 2012.

[CG10] Toby Couture and Yves Gagnon. An analysis of feed-in tariff remuneration models: Implications for renewable energy investment. *Energy Policy*, 38(2):955 – 965, 2010.

[DBMF12] Reid Capalin Detuche Bank: Mark Fulton. The german feed-in tariff:recent policy changes, September 2012. www.dbresearch.com/PROD/DBR_INTERNET_EN-PROD/PROD0000000000294376/The+German+Feed-in+Tariff%3A+Recent+Policy+Changes.PDF ; Accessed: November 2013.

[DLR12] DLR. Lead study. Technical report, BMU - FKZ 03MAP146, 2012. Available online: http://elib.dlr.de/76044/ ; Accessed: September 2013.

[Eco08a] Ecofys. Policy instrument design to reduce financing costs in renewable energy technology projects. Technical report, IEA-Renewable Energy Technology Deployment (RETD), 2008. Avaliable online: www.iea-retd.org/archives/publications/policy-instrument-design ; Accessed: Feb 2014.

[Eco08b] Ecofys. Policy instrument design to reduce financing costs in renewable energy technology projects - annexes. Technical report, IEA-Renewable Energy Technology Deployment (RETD), 2008. Avaliable online: www.ecofys.com/files/files/report_policy_instrument_design_to_reduce_financing_costs_in_renewable_energy_technology_pro.pdf ; Accessed: Feb 2014.

[Eco11] TU Vienna EEG Ernst &Young Ecofys, Fraunhofer ISI. Financing renewable energy in the european energy market. Technical report, January 2011. Avaliable online: www.ec.europa.eu/energy/renewables/studies/renewables_en.html ; Accessed: November 2013.

[EEG10] Fraunhofer ISI; Energy Economics Group EEG. Evaluation of different feed-in tariff design options best practice paper for the international feed-in cooperation - 3rd edition. Technical report, Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), December 2010. Avaliable online: www.feed-in-cooperation.org/wDefault_7/download-files/research/Best_practice_Paper_3rd_edition.pdf; Accessed: December 2013.

[FBH13] Riccardo Fagiani, Julin Barqun, and Rudi Hakvoort. Risk-based assessment of the cost-efficiency and the effectivity of renewable energy support schemes: Certificate markets versus feed-in tariffs. *Energy Policy*, 55(0):648 – 661, 2013. Special section: Long Run Transitions to Sustainable Economic Structures in the European Union and Beyond.

[FEL13] London. Frontier Economics Ltd. International support for onshore wind. Technical report, A REPORT PREPARED FOR DECC, June 2013. Avaliable online: www.gov.uk/government/uploads/system/uploads/attachment_data/file/205620/international_support_onshore_wind_frontier.pdf ; Accessed: December 2013.

[Fin85] Gerhard Finck. *A guide to the financial evaluation of investment projects in energy supply.* Dt. Ges. fr Techn. Zusammenarbeit (GTZ) GmbH. Rossdorf, Germany., 1985.

[FL13] Javier; Linares Pablo Fernndez Lpez, Pablo; Aguirreamalloa Arzaga. Market risk premium and risk free rate used for 51 countries in 2013:a survey with 6,237 answers. June 2013.

[Fra12] ISE Fraunhofer. Levelized cost of electricity renewable energies. Technical report, Fraunhofer (ISE), May 2012. Avaliable online: `www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere` ; Accessed: November 2013.

[Fra13] ISE Fraunhofer. Levelized cost of electricity renewable energies. Technical report, Fraunhofer (ISE), November 2013. Avaliable online: `www.ise.fraunhofer.de/en/publications/studies/cost-of-electricity` ; Accessed: Januray 2014.

[Gau08] Bernard Bekker ; Trevor Gaunt. Simulating the impact of design-stage uncertainties on pv array energy output estimation. *Paper presented at the 16th PSCC, Glasgow, Scotland*, 2008.

[GBH10] R.a Gross, W.b Blyth, and P.a Heptonstall. Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs. *Energy Economics*, 32(4):796–804, 2010. cited By (since 1996)17.

[Gil07] Paul Gilman. A comparison of three free computer models for evaluating pv and hybrid system designs homer, hybrid2, and retscreen. 2007.

[GP13a] Erik Gawel and Alexandra Purkus. Promoting the market and system integration of renewable energies through premium schemes: A case study of the german market premium. *UFZ Discussion Papers*, 2013.

[GP13b] Erik Gawel and Alexandra Purkus. Promoting the market and system integration of renewable energies through premium schemes: A case study of the german market premium. 2013. A presenation at Energy Transitions Conference, 04./05.03.2013, Joensuu, Finland.

[Gru90] M.J. Grubb. The cinderella options. a study of modernized renewable energy technologies. part 1a technical assessment. *EnergyPolicy*, 18 (6):525542, 1990.

[GX04] Green-X. Modelling risks of renewable energy investment. Technical report, Green-X project: Deriving Optimal Promotion Strategies for Increasing the Share of RES-E in a Dynamic European Electricity Market, July 2004. Avaliable online: `www.green-x.at/downloads/WP2%20-%20Modelling%20risks%20of%20renewable%20energy%20investments%20%28Green-X%29.pdf` ; Accessed: December 2013.

[Hol12] Hans. Holtrof. Renewable energy basics: Economic analysis of energy related investments lecture material, postgradute programme renewable energy (ppre). Winter Term, 2012.

[HS13a] Nouredine Hadjsad and Jean-Claude Sabonnadire. *Liberalization of Energy Markets*, pages 391–418. Wiley-ISTE, 2013. Online: `http://dx.doi.org/10.1002/9781118558300.ch17`; Accessed: November 2013.

[HS13b] Nouredine Hadjsad and Jean-Claude Sabonnadire. *Power Systems and Restructuring.* Wiley-ISTE, 2013. Online: `http://eu.wiley.com/WileyCDA/WileyTitle/productCd-1848211201.html`; Accessed: November 2013.

[IEA04] IEA. Iea wind energy annual report, 2004.

[IEA14] IEA. The power of transformation (executive summary). Technical report, 2014. Avaliable online: `www.iea.org/Textbase/npsum/GIVAR2014sum.pdf` ; Accessed: March 2014.

[Kir04] Kirschen. *Fundamentals of Power System Economics.* John Wiley & Sons, Inc., 2004.

[KNB08] Corinna Klessmann, Christian Nabe, and Karsten Burges. Pros and cons of exposing renewables to electricity market risksa comparison of the market integration approaches in germany, spain, and the {UK}. *Energy Policy*, 36(10):3646 – 3661, 2008.

[LEG12] RES LEGAL. Legal sources on renewable energy: renewable energy policy database. aninitiative of the european commission., 2012. `www.res-legal.eu` and Accessed: November 2013.

[MM12] Andrea Masini and Emanuela Menichetti. The impact of behavioural factors in the renewable energy investment decision making process: Conceptual framework and empirical findings. *Energy Policy*, 40(0):28 – 38, 2012. Strategic Choices for Renewable Energy Investment.

[MR11] Martin Meyer-Renschhausen. Investment analysis energy, investment decision making. 2011.

[Ore00] Shmuel Oren. Capacity payments and supply adequacy in a competitive electricity market. University of California at Berkeley, May 2000. A presentation at VII SEPOPE, Curitiba-Parana Brazil. Available Online: `www.pserc.wisc.edu/documents/general_information/presentations/presentations_by_pserc_university_members/`; Accessed: December 2013.

[Pfa12a] W. Pfaffenberger. *Energy Economics an introduction (PPRE2012).* Jacobs University, Bremen, 2012.

[Pfa12b] W. Pfaffenberger. *Guide to Investment Evaluation with invmodel, Economics of Energy Systems,Annex: Present value and Levelised cost.* 2012.

[REN13] RES-E-NEXT. Next generation of res-e policy instruments. Technical report, IEA-Renewable Energy Technology Deployment (RETD), 2013. Avaliable online: http://iea-retd.org/archives/publications/res-e-next ; Accessed: January 2014.

[RET05] RETScreen. Clean energy project analysis retscreen engineering & case textbook (third edition). Technical report, RETScreen International, 2005. Avaliable online: www.retscreen.net/ang/12.php ; Accessed: Feb 2014.

[RET13a] RETScreen. Retscreen international,power - case studies, 2013. www.retscreen.net/ang/t_case_studies.php ; Accessed: December 2013.

[RET13b] RETScreen. Retscreen international,power - photovoltaic - 1,000 kw /germany., 2013. www.retscreen.net/ang/case_studies_1000kw_germany.php ; Accessed: December 2013.

[RET13c] RETScreen. Retscreen international,power - wind turbine - 9,900 kw /germany., 2013. www.retscreen.net/ang/case_studies_9900kw_germany.php; Accessed: December 2013.

[SEI04] SEI. Economic analysis of res-e support mechanisms. Technical report, Energy Economics Group at Vienna University of Technology (EEG),Ecofys,Distributed Energy Company (DEC),Sustainable Energy Research Group at University College Cork (UCC), 2004. Available online: www.seai.ie/Publications/Renewables_Publications_/Energy_RD_D/Economic-Analysis-ofRES-E-EEG-ReportFNL.pdf ; Accessed: December 2013.

[Sio13] Fereidoon P Sioshansi. *Evolution of Global Electricity Markets: New paradigms, new challenges, new approaches*. Elsevier, 2013. Online: www.sciencedirect.com/science/book/9780123978912; Accessed: November 2013.

[US12] International Develoment Agency US. *Best Practices Guide: Economic & Financial Evaluation of Renewable Energy*. United States Agency for International Development, 2012.

[Win12] Deutsche WindGuard. Cost of onshore wind energy projects in germany. November 2012. Avaliable Online: www.enr-ee.com/fileadmin/user_upload/Downloads/Konferenzen/Kosten_Wind_2012/Vortraege/03_Wallasch_Deutsche_WindGuard.pdf; Accessed: December 2013.

[WM12] Rolf Wstenhagen and Emanuela Menichetti. Strategic choices for renewable energy investment: Conceptual framework and opportunities for further research. *Energy Policy*, 40(0):1 – 10, 2012. Strategic Choices for Renewable Energy Investment.

[WP98] Ryan H Wiser and Steven J Pickle. Financing investments in renewable energy : the impacts of policy design. *Renewable and Sustainable Energy Reviews*, 2(4):361 – 386, 1998. Available Online: http://www.sciencedirect.com/science/article/pii/S1364032198000070; Accessed: Feb 2014.

Appendix A

RESMIP case studies input parameters

Project informations	Reference scenario - regulated feedin-tariff		Regulatory MP ex-post	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years		Changed to:20 years	As proposed in most of the recent Wind projects
Financial assumptions	inflation rate	2.50%		
Loan	discount rate	5.86%	6.40%	Based on calculation from the current market rates for wind onshore projects
	debt ratio	70.00%	70.00%	As proposed in most of the recent Wind projects
	debt interest rate	5.20%	5.20%	Based on calculation from the current market rates for the German market risk premium rates*
	debt term	15 years		
non-debt portion	30%		30.00%	As proposed in most of the recent Wind projects*
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs	€ 277,704	€ 342,592	Due to the change In the capacity factor and production
	capacity factor	20.10%	19.10%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total electricity production per year	17422	16524	Capacity factor change

Table 7.1: Wind Regulated MPexpost case study input parameters

Project informations	Reference case - regulated feedin-tariff		Regulatory MP ex-ante	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years			
Financial assumptions	inflation rate	2.50%		
Loan	discount rate (WACC)	5.86%	7.80%	Higher risk level
	debt ratio	70.00%	65.00%	Higher risk due to uncertainty in future cash flows
	debt interest rate	5.20%	6.20%	Higher risk level
	debt term	15 years		
non-debt portion	30%		35.00%	Higher risk level
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs	€ 277,704	€ 342,592	Due to the change In the capacity factor and production
	capacity factor	20.10%	19.10%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013)
	Total electricity production per year	17422	16524	Capacity factor change

Table 7.2: Wind Regulated MPexante case study input parameters

Project informations	Reference scenario - regulated feedin-tariff		Regulatory CP	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years			
Financial assumptions	inflation rate	2.50%		
Loan	discount rate (WACC)	5.86%	10.6%	Higher risk level
	debt ratio	70.00%	60.00%	Higher risk due to uncertainty in future cash flows
	debt interest rate	5.20%	9.00%	Higher risk level
	debt term	15 years		
non-debt portion	30%		40.00%	Higher risk level
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs	€ 277,704	€ 342,592	Due to the change In the capacity factor and production
	capacity factor	20.10%	19.10%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013)
	Total electricity production per year	17422	16524	Capacity factor change

Table 7.3: Wind Regulated CP case study input parameters

Project informations	Reference scenario - regulated feedin-tariff		Auctioned FIT	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years			
Financial assumptions	inflation rate	2.50%		
Loan	discount rate (WACC)	5.86%	6.20%	Higher risk level
	debt ratio	70.00%		
	debt interest rate	5.20%		
	debt term	15 years		
non-debt portion	30%			
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs	€ 361,216		
	capacity factor	20.10%		

Table 7.4: Wind Auctioned FIT case study input parameters

Project informations	Reference case regulated feedin-tariff		Auctioned MPexpost	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years			
Financial assumptions	inflation rate	2.50%		
Loan	discount rate	5.86%	7.80%	Higher risk level
	debt ratio	70.00%	65.00%	High uncertainty in the future cash flow
	debt interest rate	5.20%	5.70%	High uncertainty in the future cash flow
	debt term	15 years		
non-debt portion	30%		35.00%	High uncertainty in the future cash flow
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs		€ 323,974	Due to the change In the capacity factor and production
	capacity factor	20.10%	18.00%	Due to quantity risk and motivation for ppo not to place the bid when negative prices effect the revenues or there is no demand need (calculations is based on the negative prices data provided by Gawel(2013))
	Total energy production MWh/year	17422	15626	Capacity factor change

Table 7.5: Wind Auctioned MPexpost case study input parameters

Project informations	Reference scenario - regulated feedin-tariff		Auctioned Mpexante	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years			
Financial assumptions	inflation rate	2.50%		
Loan	discount rate (WACC)	5.86%	8.70%	Higher risk level
	debt ratio	70.00%	65.00%	High uncertainty in the future cash flow
	debt interest rate	5.20%	6.20%	High uncertainty in the future cash flow
	debt term	15 years		
non-debt portion	30%		35.00%	High uncertainty in the future cash flow
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs		€ 323,974	Due to the change In the capacity factor and production
	capacity factor	20.10%	18.00%	Due to quantity risk and motivation for ppo not to place the bid when negative prices effect the revenues **or there is no demand need** (calculations is based on the negative prices data provided by Gawel(2013))
	Total electricity production per year	17422	15626	Capacity factor change

Table 7.6: Wind Auctioned MPexante case study input parameters

Project informations	Reference scenario - regulated feedin-tariff		Auctioned CP	reason for value change
Electricity Export Cost	0.091 €/kWh			
project life time	20 years			
Financial assumptions	inflation rate	2.50%		
Loan	discount rate (WACC)	5.86%	11.70%	Higher risk level
	debt ratio	70.00%	60.00%	High uncertainty in the future cash flow
	debt interest rate	5.20%	9.00%	High uncertainty in the future cash flow
	debt term	15 years		
non-debt portion	30%		40.00%	High uncertainty in the future cash flow
Taxes	Not applicable on Wind fame income			
Project related assumptions	feasibility study	€ 45,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Grid connection	€ 1,300,000.00		
	balance of plant	€ 700,000		
	O&M costs definition	20.733(€/MWh)		
	Total O&M costs	€ 361,216	€ 342,592	Due to the change In the capacity factor and production
	capacity factor	20.10%	18% (turbine availability 87%)	Due to quantity risk as no profits if the prices are lower than the remuneration level
	Total electricity production per year	17422	16524	Capacity factor change

Table 7.7: Wind Auctioned CP case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%		
	Debt term	15 years		
	Debt rate	4%		
	Discount rate (WACC)	4.40%	4.60%	Due to increase in the risk level
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%	8.40%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total Energy production	819.27 MWh/year	733.03 MWh/year	Change of capacity factor
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.8: PV Regulated MPexpost case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%	75.00%	Uncertainty of future cash flow
	Debt term	15 years		
	Debt rate	4%	5.00%	Uncertainty of future cash flow
	Discount rate (WACC)	4.40%	5.90%	Due to higher level of risk
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%	8.40%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total Energy production	819.27 MWh/year	733.03 MWh/year	Change of capacity factor
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.9: PV Regulated MPexante case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%	70.00%	Uncertainty of future cash flow
	Debt term	15 years		
	Debt rate	4%	8.00%	Uncertainty of future cash flow
	Discount rate (WACC)	4.40%	8.65%	Due to higher level of risk
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%	8.40%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total Energy production	819.27 MWh/year	733.03 MWh/year	Change of capacity factor
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.10: PV Regulated CP case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%		
	Debt term	15 years		
	Debt rate	4%		
	Discount rate (WACC)	4.40%	4.60%	Due to increase in the risk level
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%		
	Total Energy production	819.27 MWh/year		
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.11: PV Auctioned FIT case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%	75%	Uncertainty in cash flow
	Debt term	15 years		
	Debt rate	4%	4.50%	Uncertainty in cash flow
	Discount rate (WACC)	4.40%	5.70%	Due to increase in the risk level
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%	7.40%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total Energy production	819.27 MWh/year	646.79 MWh/year	Change of capacity factor
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.12: PV Auctioned MPexpost case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%	75.00%	Uncertainty of future cash flow
	Debt term	15 years		
	Debt rate	4%	5.00%	Uncertainty of future cash flow
	Discount rate (WACC)	4.40%	6.40%	Due to higher level of risk
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%	7.40%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total Energy production	819.27 MWh/year	646.79 MWh/year	Change of capacity factor
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.13: PV Auctioned MPexante case study input parameters

Project information	Reference case (regulated feed-in tariff)		Changed to	Reason for change
Electricity Export Cost	0.457 €/kWh			
project life time	25 years			
Financial assumptions	Share of debt	80%	70.00%	Uncertainty of future cash flow
	Debt term	15 years		
	Debt rate	4%	8.00%	Uncertainty of future cash flow
	Discount rate (WACC)	4.40%	9.30%	Due to higher level of risk
PV Modules Costs	inflation rate	2.00%		
	PV (polycrystalline)	€5,670/KWp		
Project related assumptions	BIPV (total installation cost)	€ 860.00		
	Taxes	Not applicable on PV income		
	feasibility study, planning and Engineering	€ 560,000		
	development	€ 330,000		
	engineering	€ 30,000		
	Inverters cost	€ 600,000		
	Capacity factor (including inverter losses)	9.40%	7.40%	Due to quantity risk (calculations is based on the negative prices data provided by Gawel(2013))
	Total Energy production	819.27 MWh/year	646.79 MWh/year	Change of capacity factor
	O&M costs definition	Annual increase with 2%		
	Total O&M costs increase after first year	€ 7,344		
	Annual average O&M costs	€ 15,594		

Table 7.14: PV Auctioned CP case study input parameters

Appendix B

Final Results Calculations

Wind onshore

	Support mechanism	NPV (M€)	Difference in NPV compared to ref-scenario	IRR (%)	LCOE (€/MWh)	Increase in LCOE compared to ref-scenario	DSCR (%)
Reg	**FIT (Reference Scenario)**	3.8152	0.0000	18.0%	72.12	0	1.83%
	Mpexpost	2.6975	-1.1177	15.8%	76.3	4.18	1.73%
	Mpexante	1.7507	-2.0645	13.5%	80.36	8.24	1.75%
	CP	0.0925	-3.7227	10.9%	90.31	18.19	1.69%
Auc	**FIT**	3.6120	-0.2032	18.0%	72.63	0.51	1.83%
	Mpexpost	1.3471	-2.4681	12.2%	82.35	10.23	1.71%
	Mpexante	0.8348	-2.9804	11.6%	85.27	13.15	1.66%
	CP	-1.1205	-4.9357	7.5%	100.42	28.3	1.47%
		Change in value compared to the reference scenario in (%)					
		NPV		**IRR**	**LCOE**		**DSCR**
Reg	**Mpexpost**	-29.30		-11.99	5.80		-5.46
	Mpexante	-54.11		-25.17	11.43		-4.37
	CP	-97.57		-39.35	25.22		-7.65
Auc	**FIT**	-5.33		0.00	0.71		0.00
	Mpexpost	-64.69		-32.26	14.18		-6.56
	Mpexante	-78.12		-35.58	18.23		-9.29
	CP	-129.37		-58.35	39.24		-19.67

PV

	Support mechanism	NPV (M€)	Difference in NPV compared to ref-scenario	IRR (%)	LCOE (€/MWh)	Increase in LCOE compared to ref-scenario	DSCR (%)
Reg	**FIT (Reference Scenario)**	1.9487	0.0000	9.80%	344	0	0.89%
	Mpexpost	1.0037	-0.9450	7.50%	390	46	0.79%
	Mpexante	0.1895	-1.7592	6.40%	442	98	0.79%
	CP	-1.3107	-3.2593	4.20%	590	246	0.70%
Auc	**FIT**	1.8337	-0.1150	9.80%	348	4	0.89%
	Mpexpost	-0.3224	-2.2711	4.70%	484	140	0.72%
	Mpexante	-0.6511	-2.5998	4.30%	516	172	0.69%
	CP	-1.9164	-3.8651	2.40%	691	347	0.61%
		Change in value compared to the reference scenario in (%)					
		NPV		**IRR**	**LCOE**		**DSCR**
Reg	**Mpexpost**	-48.49		-23.47	13.37		-11.24
	Mpexante	-90.28		-34.69	28.49		-11.24
	CP	-167.26		-57.14	71.51		-21.35
Auc	**FIT**	-5.90		0.00	1.16		0.00
	Mpexpost	-116.54		-52.04	40.70		-19.10
	Mpexante	-133.41		-56.12	50.00		-22.47
	CP	-198.34		-75.51	100.87		-31.46