The feasibility of the energy-only market in a highly renewable European power system

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The feasibility of the energy-only market in a highly renewable European power system

By

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SUMMARY

MAIN FINDING
This study shows that an energy-only market will not function in a highly renewable power system with a large share of wind and solar power. It is highly unlikely that renewable power sources like wind and solar will recover their capital costs during their economic lifetime. In the most extreme scenario, with a large share of unserved energy, wind and solar power will recover too less of their investment costs.

BACKGROUND
The west European power system is expected to be highly renewable in 2050, mainly due to a large contribution of wind and solar power. To reduce carbon dioxide emissions in the power sector by 95% in 2050, the call for a CO₂ neutral power system strengthens. To achieve fierce CO₂ reductions, wind and solar power are proposed as the most promising solution.

A power system with a large penetration of wind and solar requires sufficient flexibility options to match supply and demand. Since the output of wind and solar power sources in weather driven, the supply of power is variable and uncontrollable, which implies that other flexible power generators need the additional required power to match supply and demand. To maintain the high levels of generation adequacy, the continuous match between supply and demand is key.

In a power system with large shares of wind and solar power, it is to be feared that generators will not recover their capital costs in an energy-only market. The marginal generation price of wind and solar power is zero and will push the more expensive generators out of the market, thereby reducing electricity prices, which is known to be the merit order effect.

METHOD
To analyze to what extent an energy-only market will incentivise adequate investment in new generation capacity in a highly renewable European power system, a power system optimization model is used. In this study the cost minimization model PLEXOS executes two tasks, first, its investment sub model optimizes the generation portfolio and, secondly, its dispatch sub model analyses the effect of changing contextual factors on the electricity prices and security of supply for this specific generation portfolio. In the investment sub model the investment decisions for two renewable generation portfolios are determined: A highly renewable portfolio and a low carbon portfolio. The available technologies for investments in a low carbon portfolio were only limited by the absence of coal fired power plants. For the highly renewable portfolio, coal, nuclear and gas with CCS were not an option.

In the second sub model, the dispatch sub model, the performance of the energy-only market can be analyzed by means of market prices, generation adequacy (unserved energy) and net profits of generation technologies. A great advantage of this dispatch sub model concerns the hourly granularity that is needed to fully incorporate the intermittent power supply of wind and solar. This energy-only market analysis is executed through the usage of eight dispatch scenarios for both generation portfolios. The dispatch scenarios are designed on the basis of three uncertainties: weather profiles for wind and solar generation, annual demand changes, and primary fuel prices. These uncertainties have been found by means of a sensitivity analysis of the dispatch sub model.
For modelling the performance of an energy-only market for these eight dispatch scenarios assumptions have been made on the included power sources, investment costs, transmission capacity, and demand response capacity. The latter two have been fixed throughout this whole study. For both generation portfolios, coal fired power plants have been excluded as an investment option. On top of that, for the renewable portfolio, nuclear power and gas with CCS have been excluded as an investment option. For the investment costs, strong technological progress is assumed, which results in a low investment costs for especially wind, solar and storage.

**FINDINGS**

For a highly renewable power system, more than 75% of the installed generation capacity consists of intermittent renewable energy sources. Over 50% of the installed capacity is allocated to PV solar power panels. Less than 20% of the total installed capacity are thermal biomass and natural gas turbines. In addition, A limited amount of storage capacity for pumped hydro storage, CAES, and hydrogen gas turbines are constructed. The alternative to a highly renewable generation portfolio is a portfolio that consists of only 50% installed capacity for renewable energy sources. The remainder is nuclear power (25%), gas with and without CCS and biomass turbines.

A sensitivity analysis of the dispatch sub model was used to analyse which contextual factors had the most impact on market prices, unserved energy, and net profits of generation technologies. The results show high impact for demand changes, different weather profiles, and primary fuel price changes.

Wind and solar power and storage will not recover their investment costs in an energy only market. Even in the most beneficial scenario, profits for wind and solar power as well as storage technologies are small, while for all other scenarios net profits are highly negative. If climate policy on CO₂ reduction must be achieved by means of large shares of wind and solar power in the electricity mix, subsidies or other additional remuneration mechanisms are required to incentivize investment in wind and solar power.

The main trigger for high power prices is a "bad" meteorological year of low capacity factors and a one percent demand increase. This combination formed the only scenario in which all generation technologies and especially wind, solar and storage could recover their investment costs. However, the downside is clear: high power prices can only exist in the presence of unserved energy. For reasons of generation adequacy, unserved energy is not welcome.

**RECOMMENDATION**

To guarantee a high level of generation adequacy and investment costs recovery for all generation technologies in a highly renewable power system, solutions like capacity remuneration mechanisms and especially subsidies, should be investigated.
After more than two years, this master thesis will be the final deliverable of my master Systems Engineering, Policy Analysis and Management at the TU Delft. The thesis deals with the challenge of integrating renewables in the European power system. This thesis aims at policy makers in Europe and individual countries, who are interested in carbon dioxide emission reductions via the greening of the electricity production in the future.

In the last nine months, I gained help from several persons to execute my thesis. Via this preface, I would like to take the opportunity of thank those who helped me along the way. First, I would like to thank all those at DNV GL who helped me during my thesis project. For executing this thesis, I needed a power system optimization model. DNV GL gave me the opportunity to use their license of the advanced energy modelling software PLEXOS. So, in general, I am thankful that DNV GL allowed me to use their license for PLEXOS. I want to especially thank Wim van der Veen for his supervision. All the time, Wim has been very supportive throughout these months. His knowledge and advice have been a great help for me. At moment when things didn’t work out the way I planned them, Wim always convinced me that things would be alright in the end. In addition, I would like to thank Pieter van der Wijk for this help with my model in PLEXOS. His advanced knowledge about PLEXOS have been a great help.

I would also like to thank my supervisors at TU Delft. Margot Weijnen, chair of my graduation committee, always noticed the shortcomings very quickly, making the committee meeting efficient and to the point. As my second supervisor, Willem Auping, deserves some special thanks with respect to the additional supervision he was willing to provide during the summer holidays. This additional supervision helped me a lot with setting up my research design and improving my scientific writing. As my first supervisor, I would like to thanks Laurens de Vries for all the constructive personal meetings. Laurens’ knowledge of electricity markets always caused our discussions to be in depth and very interesting. You were always able to guide my research in the right direction and to help me to focus on the key aspects of my research subject.

Finally, I would like to thank all my friends and family for their open ear and interest in my thesis. They know how difficult it was for me to combine this thesis project with the personal drama I (and my friends) had to deal with. So, although this thesis project is mainly an individual performance, it does feel like a group win to me.
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<th>Abbreviation</th>
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<tbody>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>CAES</td>
<td>Compressed air energy storage</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combine cycle gas turbine</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
</tr>
<tr>
<td>CSP</td>
<td>Concentrated solar power</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current</td>
</tr>
<tr>
<td>DR</td>
<td>Demand response (same as DSM (demand side management))</td>
</tr>
<tr>
<td>ED</td>
<td>Economic dispatch</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
</tr>
<tr>
<td>FC</td>
<td>(Hydrogen) Fuel cell</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
</tr>
<tr>
<td>IRES</td>
<td>Intermittent renewable energy sources</td>
</tr>
<tr>
<td>NTC</td>
<td>Net transmission capacity</td>
</tr>
<tr>
<td>OCGT</td>
<td>Open cycle gas turbine</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operation and maintenance</td>
</tr>
<tr>
<td>PHS</td>
<td>Pumped hydro storage</td>
</tr>
<tr>
<td>PV</td>
<td>(Solar) Photovoltaics</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable energy sources</td>
</tr>
<tr>
<td>SO</td>
<td>System operator</td>
</tr>
<tr>
<td>UC</td>
<td>Unit commitment</td>
</tr>
<tr>
<td>USE</td>
<td>Unserved energy (or lost energy)</td>
</tr>
<tr>
<td>VRE</td>
<td>Variable renewable energies</td>
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1. INTRODUCTION

Anthropogenic climate change threatens society and the earth’s ecosystems. Unprecedented levels of greenhouse gases (GHG) from fossil fuels combustion caused the atmospheric temperature to increase (IPCC, 2013; UNFCCC, 2015). Consequently, land ice on the north and south pole is melting, thereby raising global sea levels. The main constituent of greenhouse gases, CO₂, causes oceans to acidify as they function as a carbon sink (IPCC, 2013). Human health and safety is impacted by flooding, heat stress, air pollution and water scarcity, in addition, food production in many places of the earth is affected and economic risks will increase as extreme weather event are likely to occur more often (IPCC, 2007, 2014). To protect the ecosystems and the people on this planet we need to bring anthropogenic climate change to a halt and alleviate its effects.

The main drivers of anthropogenic climate change are the greenhouse gases carbon dioxide (CO₂) and methane (CH₄) (European Commission, 2017; IPCC, 2013; UNFCCC, 2015). These two greenhouse gases are the largest contributors of the earth’s global warming indicator: Net radiative forcing. Approximately 50% of all radiative forcing is caused by CO₂ and 30% by CH₄ (IPCC, 2013).

Climate policies can reduce GHG emissions and the effects of climate change. Climate adaptation policies anticipate the effects of climate change (European Environment Agency, 2017a; IPCC, 2007, 2014; NASA, 2017). For example, using scarce freshwater resources more efficiently, increasing flood protection for low-lying areas, and securing human health (European Environment Agency, 2017a; IPCC, 2007, 2014). Climate mitigation policies, on the other hand, are focussed at reducing the causes of global warming (European Commission, 2011a; European Environment Agency, 2017a). Greening the energy mix by increasing the share of renewable energy sources like wind, solar, and biomass is a first policy option (BP, 2017a; ECF, 2010; International Energy Agency, 2015; Shell, 2011). Capturing and storing CO₂ by transforming fossil fuels into clean fuels, using forests to store carbon, and improving agriculture to store carbon in vegetation and soil is a second option (IPCC, 2007). Higher energy efficiency of transportation and industry is a third option (European Environment Agency, 2017a).

Of all the sectors in the energy mix, the power sector shows the highest potential for reducing GHG emissions. According to the European Commission (2011b), the power sector is responsible for 25% of all EU GHG emissions and can potentially be decarbonized to almost 100% in 2050 compared to their 1990 levels, while all other sectors in the energy mix show lower potentials. The industry sector (CO₂), emitting approximately 20% of all European Union GHG emissions in 2010, can potentially reduce GHG emissions up to 87%. Transportation (CO₂) in the EU is responsible for 20% of the total GHG emissions in 2010 and it has the potential to achieve a 54-67% reduction. Buildings and residential services (CO₂), that produced approximately 15% of all EU GHGs in 2010, can reduce their GHG emissions up to 91%. Agriculture (non CO₂) emitted more than 10% of all EU GHG emissions in 2010 and it potential reduction is moderate: 42-49%. All remaining sectors (non CO₂) together produce less than 10% of all EU GHG emissions, and are assumed to be able to achieve a potential reduction of 70-78%. Given the high potential for decarbonizing the power sector, the goal for the power sector is set at an ambitious >95% reduction of their part of all EU CO₂ emissions in 2050 compared to the 1990 level. Greening all sectors in the energy mix should reduce all GHG emissions of the energy mix in the EU by 80-95% in 2050 compared to their 1990 levels (European Commission, 2011a, 2011b). The power sector can compensate for sectors with lower potentials, to reach the 80-95% reduction for the whole energy mix in the EU.
Wind, solar, fossil carbon capture and storage (CCS), nuclear and biomass are the most promising power sources to reduce carbon emissions reduction in the power sector. Wind power does not emit CO$_2$ when producing electricity and each European country has at least some potential for installed capacity (International Energy Agency, 2016a). The wind capacity factor of each country in the EU is within a range of 15% to 30% (Staffell & Pfenninger, 2016) and all countries have land available for a minimum of 1000 MW of installed capacity (e-Highway2050, 2014). Solar power generation does not emit CO$_2$ either, and each European country has at least some potential (International Energy Agency, 2016a). The solar capacity factor of all countries is at least 9% (Pfenninger & Staffell, 2016) and all countries have land available for at least 5000 MW of installed capacity for the smallest country (e-Highway2050, 2014). Fossil power plants with carbon capture and storage (CCS) allow to continue the use of fossil fuels while emitting no CO$_2$ (ECF, 2010; European Commission, 2011a; International Energy Agency, 2012, 2015; Shell, 2011). Nuclear power generation is carbon neutral (European Commission, 2011a; International Energy Agency, 2012; Shell, 2011), however removed as an option for countries like Germany for political reasons. Biomass fuelled power generation is CO$_2$ neutral (ECF, 2010; International Energy Agency, 2012) or even CO$_2$ negative when combined with CCS (ECF, 2010; IEA and NEA, 2015; Khoshidi, Ho, & Wiley, 2014; Koornneef et al., 2012; Shell, 2011), but its full potential will most likely be shared with the industry, buildings, and transportation sectors, causing less than 50% of its potential to be available for the power sector (International Energy Agency, 2015). Hydro plants generate electricity without CO$_2$ emissions, however, new capacity is limited (International Energy Agency, 2014, p. 246). Wave, tidal, and geothermal power are other renewables that do not emit CO$_2$, but investment is costly (IEA and NEA, 2015) and potential capacity for wave and tidal is limited (International Energy Agency, 2015).

Wind and solar power generation are expected to contribute most to the decarbonization of the power sector. Solar and wind generation technologies are attractive as they have almost zero marginal costs (European Commission, 2011a). Their success has grown over past decade as costs fell by 35% for wind and 75% for solar PV (International Energy Agency, 2016a). There is a high potential for wind and solar capacity in Europe, respectively 1300 and 1000 GW installed capacity (e-Highway2050, 2014).

However, wind and solar power generation increase generation adequacy challenges for the power system. Generation adequacy is key since we do not want the light to go out (Blanco, Spisto, & Fulli, 2016; Ministerie van Economische zaken, 1998). Power generation by wind and solar is variable over time due to fluctuations in wind speeds and sunshine and are therefore known as intermittent renewable energy sources (IRES) (ECF, 2010; International Energy Agency, 2011, 2014, 2016a; Pfenninger & Staffell, 2016; Staffell & Pfenninger, 2016). A change of the weather within a few hours can cause IRES supply to drop fast and consequently require other power plants to ramp up quickly (International Energy Agency, 2011). Multiple days or weeks of low-wind and low sunshine conditions can occur, requiring sufficient backup capacity, in the worst case, for multiple weeks. Examples are wind droughts in the U.S. (Pearce, 2016) and the German winters with low wind and solar generation known as the “Dunkelflaute” (Morris, 2017).

Flexibility options can mitigate the effects of IRES on generation adequacy. Demand response (DR) can temporarily reduce, increase or reschedule load (Dragoon & Papaefthymiou, 2015; Gils, 2016; Lund et al., 2015; O’Connell et al., 2014), mainly as a short term option to deal with demand peaks (Alizadeh et al., 2016). Storing excess electricity from IRES or storing power strategically enables power to be available at moments of shortage of supply (Alizadeh et al., 2016; Beaudin et al., 2014; Dragoon & Papaefthymiou, 2015; Heussen et al., 2012; Kloess & Zach, 2014; Kondziella & Bruckner, 2016). Sharing power between regions to meet demand in regions with shortage of supply is also proposed as a flexibility measure (Dragoon & Papaefthymiou, 2015; Kondziella & Bruckner, 2016; Lund et al., 2015). Lastly, thermal plants can anticipate load changes by supplying additional power.
or decreasing their output (Alizadeh et al., 2016; Dragoon & Papaefthymiou, 2015; Lund et al., 2015; Van der Wijk et al., 2014).

In theory, the energy-only market can lead to an optimal level of generation adequacy. Perfect market competition, due to marginal pricing, should result in sufficient revenues for generators to invest in new generation capacity and to recover investment costs (P. L. Joskow, 1976). Generators do not recover their investment costs if market prices are close to their marginal costs (Knops, de Vries, & Correljé, 2013), so they prefer high prices. Consumers, on the other hand, do not prefer high prices as they have a maximum willingness to pay, so they benefit from low prices.

In an energy-only market all costs of IRES and flexibility options must be covered through the market price. The market price determines the revenues that generators receive (Sensfuß, Ragwitz, & Genoese, 2008). The marginal generator in the merit order, that is the most expensive generator that is required to run, sets the market price for all running generators at that moment in time. Generator revenues constitute of the market price multiplied by the supplied power within a certain period.

It is to be feared that all generators in a highly renewable EU power system will not recover their investment costs in an energy-only market in 2050. Due to low market prices, revenues of IRES and flexibility options will be too low to create enough profits that can recover their investment costs (Brouwer, van den Broek, Zappa, et al., 2016; Papaefthymiou & Dragoon, 2016). IRES generation lowers market prices, which is known as the merit order effect: Due to the penetration of IRES, the merit order shifts to the right, pushing out the expensive generators and lowering the market price (Hirth, 2013; International Energy Agency, 2014, 2016a; Kyritsis, Andersson, & Serletis, 2017; Sensfuß et al., 2008). IRES run first, because their marginal price is zero, plus they have priority to run according to the EU Directive on the market for electricity (European Parliament and Council, 1997, 2009).

The energy-only market will be analysed in this study by comparing the profitability of generators and market prices for a range of scenarios that are constructed by means of major uncertainties. By doing so, the main research question can be answered:

*To what extent can an energy-only market incentivise adequate investment in new generation capacity in an uncertain and weather dependent highly renewable European power system?*

To gather insights that can support an answer to the main research question, this study will discuss three sub-questions:

1. What would be the optimal generation portfolio in an energy-only market in 2050?
2. What driving forces have the most influence on the market prices and recovery of investment costs for generators?
3. Will the generation technologies recover their capital costs?

Before dealing with these sub questions, a literature study has been conducted to explain the challenges that the energy-only market is facing, specifically the challenge of intermittent renewables. Understanding the influence of intermittent renewables on producers and customers in an energy-only market will help to see the problem that is related to the energy-only market design.

In addition, literature study has been conducted to provide an overview of the status of flexibility options. The technical and economic status of the four major flexibility options are discussed as well as expectations for these in the future. This review also classifies to what extent each flexibility option is relevant for an energy-only market analysis.
To answer the first sub-question, a power system optimization model has been used to determine the optimal generation portfolio in an energy-only electricity market, given a 95% CO₂ reduction. A power system optimization model represents an energy-only market through marginal pricing, also known as spot pricing. Marginal pricing in a power system optimization model benefits both consumers and producers as it maximizes social welfare. By minimizing the total system costs, the lowest electricity price is determined at which, in theory, generators should recover all their costs (Jägemann et al., 2013). An optimization model takes accurately in account the expected opportunity costs, meaning that unserved energy is avoided as much as possible. A practical advantage of a power system optimization model is that it can guarantee CO₂ emissions to be reduced by 95% compared to 1990. The power system optimization model PLEXOS is used to create two bottom-up generation portfolios: A base policy investment scenario and a fully renewable investment scenario. Focus is on Central, West and North Europe.

For sub-question two, dispatch scenarios are designed based on the most influential driving forces that are present in the hourly dispatch optimization model. A univariate sensitivity analysis of the hourly dispatch optimization model will determine the driving forces with the highest impact on the modelling outcomes. Each variable will be tested separately to determine its impact on the model outcomes. For the energy-only market, relevant effects are the electricity market price, unserved energy and generator profits. Thus, the most influential driving forces shape the area of possible futures.

Finally, an hourly dispatch optimization model will be used to quantify the effects of driving forces on the net profits of generators in an energy-only market. A dispatch sub model in PLEXOS can take accurately, one an hourly basis, the variability of IRES power generation into consideration (Pfenninger, Hawkes, & Keirstead, 2014). Then, the net profits of generation technologies can be analysed for all the scenarios.

Once the net profits of generation technologies, unserved energy, and market prices for all dispatch scenarios are determined, a conclusion can be drawn on the scenarios under which an energy-only market can still incentivize investment in new generation capacity in a highly renewable power system.

The previously described research steps, are visualized in a flowchart (Figure 1). Chapter two explains the functioning of the current power system. This chapter is denominated as the conceptualization of the power system. In chapter three the development of the model is substantiated. The means, external factors and the criteria of the power system are defined to get a grip on the system that is to be modelled and its relations with the environment. This includes the input data for the model and a substantiation of the chosen optimization modelling technique as well as the specifics of the model itself. Chapter four presents the approach for the sensitivity analysis of the model, the accompanied results and the hereupon based scenarios for the final analysis. Chapter five will present the results of the final analysis per dispatch scenario. The implications of these results will be discussed in chapter six. The conclusions and answer to the main research question will be provided in chapter seven. In addition, some recommendations for the Dutch ministry of Economic Affairs will be added. Finally, in chapter eight, a reflection on this thesis added.
Figure 1: Flow chart of the research steps
2. **CONCEPTUALIZATION**

This chapter contains an extensive explanation of the characteristics of the 2050 power system that is to be modelled. First, the basic economics of the energy-only market are explained in paragraph 2.1. The focus will be on the influence of IRES generation on the functioning of the energy-only market. Paragraph 2.2 provides a short overview of the techno-economic status of the flexibility options. In paragraph 2.3 a system analysis will be executed to classify the factors of influential and their related uncertainty for a power system in 2050.

2.1. **THE ENERGY-ONLY MARKET**

2.1.1. **Challenges of the energy-only electricity market**

In theory, an energy-only market should lead to sufficient investments in generation capacity to provide the reliability of supply that represents the desired level of social welfare (Hogan, 2005; Joskow, 2008). Reliability of supply is key since society doesn’t want the lights to go out, which represents the social welfare problem that electricity markets face: the amount society is willing to pay for sufficient generation capacity. The theory of spot market pricing is seen as the ideal solution to solving the issue of maximizing social welfare, because other pricing techniques will produce optimal level of load and generation (Caramanis, Bohn, & Schwepppe, 1982; P. L. Joskow, 1976). Investment incentives through the interactions of all parties in the market that do so on a voluntary basis. Short term spot market prices can stimulate efficient prices to cover both short term variable costs and long term investment costs. This implies that in an energy-only market, all generators should cover all their costs through the market price (Sensfuß et al., 2008).

Ideally, such an energy-only market, without administrative interventions, should lead to market prices that incentivise investment in new generation capacity (Hogan, 2005; P. Joskow & Tirole, 2007). Five aspects should be present to incentivise investment in an energy-only market (Joskow, 2008). First, wholesale prices reflect the marginal generation costs and the social opportunity costs of generation. Second, there is an efficient dispatching of generators. Third, price-sensitive consumers are never involuntary curtailed. These consumers usually buy electricity in the spot market, with the final decision to curtail their load in their own hands (Caramanis et al., 1982). Fourth, price-insensitive consumers are involuntary curtailed by the SO to avoid a possible network collapse. Finally, investment costs should be covered by the net revenues from the market prices. In other words, a generator should get a 100% return on investment during its economic life to be. So, in an energy-only market, a power generator will be “rebuild” if all costs are recovered.

Imperfections in an energy-only market and administrative interventions cause the market to not reflect the opportunity costs through the market price (de Vries, 2003; Hogan, 2005; P. L. Joskow, 2008). Too few consumers can respond to sudden changes in market prices for the SO to keep supply and demand in balance consistent with operating reliability constraints. Most consumers have no incentive to change their behaviour as they cannot choose their individual level of reliability of supply. Reason for this is that individual consumers cannot choose their own level of reliability, because the SO cannot control power flows to individual customers, only whole regions can be curtailed. SO’s hold operating reserves to reduce the probability of rolling blackouts and network collapses low. Blackouts are rare in developed countries, causing the market to be unable to develop efficient prices during scarcity hours. To avoid blackouts, operators reduce system voltage which comes at a cost. Out of market contracts with generators that come in at the bottom of the merit order, reducing market prices. Price caps should avoid producers to exercise market power in shortage situations. Market power in situations when demand is high and capacity constraints are approached. All these measures depress market prices, while very high spot prices should be present.
from time to time in an energy-only market to reflect the willingness of society to pay for a highly secure power supply.

Administratively lowered prices during scarcity hours, which is referred to as the missing money problem, yield underinvestment in new generation capacity and reduce the reliability of supply (P. L. Joskow, 2008; Newbery, 2016; Newbery et al., 2017). The opportunity costs of generation are not reflected in the market prices in scarcity hours. That is the social costs of keeping active, the generator with the highest marginal costs that sets the investment equilibrium for the market (Knops et al., 2013). The last marginal generator in the market is depending on high price spikes to recover their fixed costs. Without these high price spikes, revenues of peak generators are too low to provide a return on investment.

Under the ideal conditions, it is however uncertain whether a highly renewable power system can function under an energy-only market design. With an increasing amount of uncertainties it is likely that investors will choose a risk averse strategy, resulting in underinvestment (Vazquez, Rivier, & Perez-Arriaga, 2002). Especially with a large share of IRES, the unpredictability of the weather-related generation pattern provides additional uncertainty for investors in highly renewable power systems to make optimal investment decisions. It is unknown how prices will develop and if there will be sufficient price spikes in a fully competitive energy-only market, causing generators to earn high amounts of revenues to recover their capital costs. If the price formation process changes, this will influence the profits of generators and they might become unable to recover their costs. In addition, will the reliability of supply change compared to the levels experienced today? The next section discusses the influence of renewables on the energy-only market to provide a better understanding of how IRES increase uncertainty in energy-only markets.

### 2.1.2. Renewables in the energy-only market

Current electricity markets in Europe are based on competition on price and quantity of generated power (Sensfuß et al., 2008). The market price for all generators is set by the generator with the highest variable costs that is required to run. This “energy-only” market is assumed to create perfect competition by means of an economic balance between the costs of generation and the consumers’ willingness to pay, the point of at which social welfare is highest (Joskow, 1976).

In the current power system RES benefit from high electricity prices. Their marginal costs are zero, which means that revenues from electricity sales can be fully used to recover their capital costs and fixed costs of operations and maintenance (O&M) (IEA and NEA, 2015). RES are allowed to enjoy these high prices as they take precedence over all other generators according to the EU directives on the market for electricity (European Parliament and Council, 1997, 2009).

A large future share of IRES lowers revenues for all generators in an energy-only market. Due to the merit order effect, RES lower market prices and reduce running hours for all non-RES plants (IEA and NEA, 2015; Keles et al., 2013; Kyritsis et al., 2017; Sensfuß et al., 2008). Merit order effect reduces market prices by shifting the merit order to the right. Renewables are added on the left side of the supply curve and expensive generators are pushed out of the market on the right. Demand and supply match at a lower price (Figure 2). The merit order effect reduces running hours of all other generators. Weather influence on IRES generation reduces load that is demanded from other generators, also known as the residual load (Figure 3). The residual load duration curve shows a reduced load that needs to be served by thermal generators (Figure 4).
It is to be feared that in a highly renewable power system, generators will not be able to recover their investment costs (Brouwer, van den Broek, Zappa, et al., 2016; Brouwer et al., 2015; Budischak et al., 2013). Base load generators, like coal and nuclear plants, will not recover their capital costs due to few running hours. For a recovery of investment costs, base load generators are dependent on capacity factors of >80% (National Energy Technology Laboratory, 2013). IRES will kill their own business case, because they reduce the market price and consequently their revenues. If prices are too often too low, IRES will not be able to recover their capital costs via the reduced stream of revenues (Steggals, Gross, & Heptonstall, 2011). Market prices could theoretically be zero in situations when IRES can fully serve demand, causing revenues to be zero. Storage and peak generators need price spikes to recover their investment costs.

A prerequisite for the energy-only market is that investors, who build new generation capacity, need to be able to recover their capital costs during the economic lifetime of a generator (Brouwer et al., 2015; International Energy Agency, 2011; Steggals et al., 2011). If generators will likely not recover the investment costs of new build plants, no investment in new generation capacity will occur. If investments in new generation capacity are not sufficient to meet the demand for electricity, generation adequacy is threatened.
The behaviour of IRES generation on the residual load is clearly visible for a random period in spring in France for a 100% RES scenario in 2050 for the eStorage project. For some hours in this period the residual load is even negative, implying a curtailment of wind and solar as their generation exceeds demand in France.

Figure 4: Hypothetical load and residual load duration curve for France

2.2. SOURCES OF FLEXIBILITY
To secure the generation adequacy for a power system with a large share of IRES, flexibility sources are proposed. Flexibility sources can mitigate the variable power supply of IRES. Studies on the large scale integration of IRES distinguish four sources of flexibility: Energy storage, thermal generators, demand response and interconnection capacity (Brouwer, van den Broek, Zappa, et al., 2016; European Commission, 2014; International Energy Agency, 2011). Hereunder, these sources of flexibility will be briefly addressed to see how they relate to each other.

2.2.1. Demand response
Demand response (DR) has a promising potential as a flexibility option to balance the variable output of IRES (Frontier Economics, 2015; Gils, 2016; Lund et al., 2015). A study by Gils (2016) shows a potential of 5 GW of power plants capacity to be temporarily replaced by demand response. Although, most DR types are only available for some hours (ranging from 1-12), they could play a crucial role in mitigating low IRES generation. Table 1 shows the specific costs and other parameters of different DR categories from an literature inventory by Gils (2016). Compared to other technologies (especially storage) DR has relatively low investment costs.
<table>
<thead>
<tr>
<th>Technology</th>
<th>DR measure</th>
<th>T (h)</th>
<th>T(_{\text{dead}}) (h)</th>
<th>Investment (k€/MW)</th>
<th>Fixed O&amp;M (%/year)</th>
<th>Variable O&amp;M (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heating residential</td>
<td>Delay</td>
<td>4</td>
<td>None</td>
<td>250</td>
<td>3</td>
<td>10</td>
</tr>
<tr>
<td>Washing residential</td>
<td>Delay</td>
<td>4</td>
<td>None</td>
<td>30</td>
<td>3</td>
<td>50</td>
</tr>
<tr>
<td>Process shift industrial</td>
<td>Advance/delay</td>
<td>3</td>
<td>24</td>
<td>0</td>
<td>0</td>
<td>150</td>
</tr>
<tr>
<td>Storage Heat resid/commercial</td>
<td>Advance</td>
<td>12</td>
<td>None</td>
<td>20</td>
<td>3</td>
<td>10</td>
</tr>
<tr>
<td>Cooling and ventilation commercial/industrial</td>
<td>Delay</td>
<td>1</td>
<td>4</td>
<td>10</td>
<td>3</td>
<td>5</td>
</tr>
</tbody>
</table>

2.2.2. Electrical energy storage

Storage technologies are extensively discussed in literature as possible sources to mitigate IRES power output (Beaudin et al., 2014; Frontier Economics, 2015; Rasmussen, Andresen, & Greiner, 2012; Weitemeyer et al., 2015). Especially the large variety of storage technologies provides space for choice. Since various publications are available on techno-economic parameters of storage technologies, an overview will be provided on the most relevant storage technologies. Storage technologies are relevant if these are suitable for long term storage. A literature study by Zakeri and Syri (2015) shows an inventory of publications for each specific storage technology. Table 2 shows a summary of the most relevant technologies for this thesis.

Pumped hydro storage (PHS) is the world largest storage technology, representing more than 95% of the world storage capacity (Beaudin et al., 2014; Chen et al., 2009). The main advantage of PHS are the large volume of stored energy and the low variable costs per unit of generated power. As a potential flexibility option, PHS will play an important role because of the large volumes and fast response time. Especially for peak shaving and IRES mitigation the PHS generators are suitable. A disadvantage is the required space for the reservoirs and the accompanied investment costs ($600-2000/kW). Suitable locations are already occupied limiting the options for new locations for PHS. Developments for locations focus on caverns and artificial PHS island in the North Sea (Klooster, 2017).

Compressed air energy storage (CAES) is the second proven storage technology at a commercial level with two function CAES plants (Zakeri & Syri, 2015). Storage units for compressed air are mostly natural reservoirs, like caverns of gas reservoirs. Aboveground options also exist, however limited in generation capacity (max. 15 MW) and storage size (two to four hours discharge). Although capital costs are high (Table 2), the total life cycle costs of CAES for bulk storage are lower than any type of battery (269-319 €/kW/year). Only PHS is slightly lower at 230 €/kW/year.

Hydrogen storage is another electrical energy storage option. Water is converted in an electrolyser to hydrogen, which can be stored and converted back to water via a fuel cell. Storing hydrogen currently is problematic, as aboveground capacity for tanks is limited and capital costs are high (Beaudin et al., 2014; Zakeri & Syri, 2015). An additional option is to convert hydrogen to ammonia. Unlike hydrogen, ammonia can be stored in large volumes. The ISPT (2017) analysed the characteristics of a realistic hydrogen/ammonia facility. The battolyser in combination with the Haber-Bosch process is assumed to be the most promising way of future ammonia production. Unfortunately, the power to ammonia to power roundtrip efficiency of the power of 31% is much lower than the power to hydrogen to power efficiency.
### Table 2: Storage costs (Source: Zakeri and Syri, 2015)

<table>
<thead>
<tr>
<th>Storage Type</th>
<th>Capital costs (€/kW)</th>
<th>O&amp;M costs (€/kW/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAES (aboveground)</td>
<td>1315</td>
<td>2.2</td>
</tr>
<tr>
<td>CAES (underground)</td>
<td>893</td>
<td>3.9</td>
</tr>
<tr>
<td>PHS</td>
<td>1406</td>
<td>4.6</td>
</tr>
<tr>
<td>Hydrogen-GT</td>
<td>1570</td>
<td>34.7</td>
</tr>
<tr>
<td>Hydrogen-FC</td>
<td>3243</td>
<td>25.1</td>
</tr>
<tr>
<td>Flywheel</td>
<td>867</td>
<td>5.2</td>
</tr>
</tbody>
</table>

#### 2.2.3. Thermal plants

Thermal plants are the third flexibility option, mainly because of the controllability of supply, which could be increased or decreased whenever needed, and their high level of reliability (Brouwer et al., 2015; Mikkola & Lund, 2016; Van der Wijk et al., 2014). Thermal plants, however, are increasingly pressured by society because CO\textsubscript{2} emissions for fossil plants and the sensitive aspect of safety for nuclear power plants. Fossil plants will become increasingly costly when carbon prices increase. Their business case deteriorates when the share of RES increases (Brouwer, van den Broek, Özdemir, et al., 2016). Still, high carbon prices increase the potential of the business case of CCS fossil plants.

#### 2.2.4. Transmission

Transmission is the last flexibility option. With increasing volumes of installed capacity of offshore wind in the North Sea, large scale solar generation in southern Europe, and decentralized generation, major expansions for the European transmission network are expected. Under all possible circumstances, for the integration renewables in Europe, expanding the transmission grid is of fundamental importance (de Joode et al., 2011; Lannoye, Flynn, & O’Malley, 2015).

#### 2.3. The Power System Environment

When modelling a power system according to an energy-only market model, first the environment of the power system must be identified. The main reason for this is to identify uncertainties that are related to a power system. Further on in this study it will be explained how these uncertainties are handled with when modelling.

Following Enserink et al. (2010), for a system demarcation, a distinction should be made between policy levers, contextual factors and criteria (Figure 5). The policy levers represent system input that can be controlled by the user, whereas the contextual factors represent the uncertain and uncontrollable system input. The output criteria will be defined by the user, to measure the systems performance.

*Figure 5: Framework for system demarcation, adopted from Enserink et al. (2010)*
2.3.1. Policy levers
Policy levers concern those aspects of the power system that can be influenced by the regulatory regime. In general, policy levers, also known as means, concern those aspects of a system that can be influenced by the problem owner (Enserink et al., 2010). Policy levers for the European power system are: The maximum CO\textsubscript{2} allowance, the value of lost load, and the phase out of nuclear energy. These are considered to be the most relevant policy levers, based on their presence in similar studies as well as their general importance due to the public attention they receive.

The absolute amount of allowed CO\textsubscript{2} emission per country per year forces investment in new generation capacity of clean generation technologies. Currently this is done via subsidies that reduce the costs of electricity of clean technologies. Permits for new generation capacity that emits CO\textsubscript{2} will not be granted, forcing investors to choose clean technologies. For example, new coal plants include CCS installations.

Another important policy lever concerns the value of lost load (VOLL). Load is lost in the event of a blackout. Since most customers prefer not to be involuntarily be curtailed, there is a value attached to the electricity that is not served: the VOLL. The VOLL is effectively the maximum price in the market. Setting the VOLL too low will reduce economic efficiency for investment incentives, while a too high VOLL will expose consumers to high market prices.

Lastly, the use of nuclear is an important policy lever, mainly due to the discussion on long term nuclear safety and the issue of radioactive waste. Germany and Switzerland decided to phase out nuclear power. Will the other European countries, likewise, adapt as phase out policy? The great benefit of nuclear power is the combination of firm capacity and zero CO\textsubscript{2} emissions. In case of a phase out in Europe, substitutes for this substantial installed generation capacity of nuclear power must be found.

2.3.2. Criteria
Power system output criteria are required for further power system modelling of this study. We need to know the performance of the energy-only market under changing contextual factors.

Common output criteria mentioned in studies in the field of modelling power systems are total system costs, installed capacities of generation technologies, and net profits of generation technologies (Table 3). Budischak et al. (2013) analysed the combination of different renewables with electrochemical storage. Goal of their model is to minimize costs, including capital costs. A study on storage by Ummels, Pelgrum and Kling (2008) explored to what extend energy storage has a reasonable opportunity to increase the integration of intermittent wind generation in the Netherlands. The dispatch was optimized to calculate the operational cost savings, excluding the investments costs. An IRES integration study for a low carbon power system by Brouwer, van den Broek, Zappa, et al. (2016) intended to find the least system costs. Investment costs are excluded from this analysis, so the generation portfolio is not optimized. The profitability of the generators. A flexibility study on highly renewable power systems by Bertsch et al. (2016) focussed on the necessity of additional mechanisms for investment incentives. The analysis included an optimization of variable and investments costs. The results, however, lack to mention the profitability of generators which is a key component for any judgement on the market design. Spiecker & Weber (2014) investigated possible development strategies for a future power system by optimizing dispatch and investment costs. Results focussed on the distribution of generated power and power prices, leaving the profitability of generators undiscussed.
The criteria for further analysis are: generation portfolios, power prices, unserved energy and profitability of generators (Table 4). The role of generation portfolios, as installed capacity per technology per country per investment scenario, is to see what the best investment decisions are given the constraints of the investment scenarios. Power prices are a criterion that can indicate the position of both producers and consumers in the market. For producers, high power prices are preferred as this incentivizes investment in new generation capacity. For consumers, low power prices are preferred since these prices are transposed in their yearly electricity bill. Too high prices are not acceptable form a social perspective. The profitability of generators is a key criterion. If generators run at a loss, they reflect an inefficient market in which generators will go bankrupt. Most of the research of the previously addressed authors focusses on systems costs, however I argue that this is of minor importance. Unserved energy (USE) as a criterion for analysis is absent in all the presented studies, but due to its importance with respect to generation adequacy it is included in this thesis. USE affects power prices and reflects the systems adequacy (blackouts). If USE is present, the market price of a whole region equals the VOLL of 10.000 €/MWh.

Table 4: Criteria for analysis of model results

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Units</th>
<th>Application in</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full generation mix per scenario</td>
<td>MW/generator per scenario</td>
<td>Investment sub model</td>
</tr>
<tr>
<td>Total generated energy and unserved demand</td>
<td>GWh/country per scenario</td>
<td>Dispatch sub model</td>
</tr>
<tr>
<td>Power price</td>
<td>€/MWh</td>
<td>Investment and dispatch sub models</td>
</tr>
<tr>
<td>Net profits per generator class</td>
<td>€/scenario</td>
<td>Dispatch sub model</td>
</tr>
</tbody>
</table>
2.3.3. Contextual factors
The effect of contextual factors on a future renewable power system is the key point of this study. Contextual factors, unlike policy levers, are uncertain; hence we want to understand their degree of uncertainty as well as their impact on a power system. This paragraph introduces the contextual factors that are related to a 2050 power system, based on future expectations of energy and especially electricity in literature. Table 5 presents an overview of contextual factors that are addressed in such literature.

First, primary fuel prices are addressed as an uncertainty for future scenarios on energy in general and electricity specifically. Fuel prices influence the competitiveness of thermal generation units in comparison with IRES generation (International Energy Agency, 2014). The higher fuel prices become, the less competitive thermal plants are.

The demand for electricity is a contextual factor that is mainly controlled by forces like population growth and GDP growth and/or economic growth. The first two forces gain much attention by The World Energy Council in their development of world energy scenarios for 2060. One of the four “critical uncertainties” addressed in this publication is economic growth (World Energy Council, 2016). Similar to economic growth is GDP growth, as denominated as an fundamental uncertainty by International Energy Agency (2014). Since GDP growth and population growth are uncontrollable from perspective of this study, future electricity demand is treated as an contextual factor.

Weather related profiles for wind and solar are only predictable in the short run. Weather predictions for 2050 cannot be made, since it is already hard to predict next week’s weather. Also, the effect of climate change is an additional cause of uncertainty for weather profiles in the long run (Greenpeace, 2012; Shell, 2011; World Energy Council, 2016). Wind and solar power generation are fully dependent on the vagaries of nature.

The carbon price for 2050 is highly speculative. Currently, the carbon price is determined via the ETS, which implies that the market basically determines its value. For that reason, the carbon price in 2050 is a contextual factor.

Investments in transmission capacity between European countries is seen as a powerful way of providing flexibility in a highly renewable power system (ECF, 2010; European Commission, 2011a). These studies argue in favour of as much transmission capacity as possible. However, it is uncertain how much new interconnection capacity will be constructed up to 2050.

Finally, investment costs of generation technologies, including storage, are mentioned in several publications as an important driving force in a renewable power system (ECF, 2010; European Commission, 2011a; Shell, 2011). The higher the technological progress will be, the lower the investment costs of renewables and storage will be, ultimately speeding lowering the total costs of a renewable power system. The rate of technological progress up to 2050 is an ongoing point of discussion, making it an influential contextual factor.

Table 5: overview of contextual factors that could be extracted from some the selected publications.

<table>
<thead>
<tr>
<th>Source</th>
<th>Uncertainties in literature</th>
<th>Translation to electricity related contextual factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>World Energy Council (2016)</td>
<td>Economic growth</td>
<td>Electricity demand growth</td>
</tr>
<tr>
<td></td>
<td>Climate change</td>
<td>Wind and solar generation profiles</td>
</tr>
<tr>
<td></td>
<td>European governance</td>
<td>International governance</td>
</tr>
<tr>
<td></td>
<td>EU Political direction on energy</td>
<td>Policy focus</td>
</tr>
<tr>
<td>Shell (2011)</td>
<td>Electricity demand growth</td>
<td>Growth world energy demand</td>
</tr>
<tr>
<td></td>
<td>EU Emission trading system</td>
<td>Carbon price</td>
</tr>
</tbody>
</table>
Technological developments
Costs of new technologies

Greenpeace (2012)
Global governance
European governance
Political view on nuclear energy
Nuclear energy
Weather influence
Wind and solar generation profiles

ECF (2010)
Technological progress
Increase in energy efficiency
Transmission capacity expansion
Integration of markets via interconnection
Technological progress
The introduction of low carbon technologies
EV use and electric heating
Fuel shift in transportation and heating
Investment security
Electricity prices

European Commission (2011)
Technological progress
Increase in energy efficiency
Transmission expansion plans
Transmission capacity
The role of gas in the transition
Price of Natural gas
Capital costs of storage in future
The need for storage
Political view on nuclear energy
The need for nuclear energy
Weather influence
Variable renewable generation
Functioning of electricity markets
Policy of member states that hinder market integration
EU Emission trading system
Carbon price

International Energy Agency (2014)
GDP growth per country
Electricity demand growth
Population growth
Electricity demand growth
Primary energy market
Fuel prices
Political view on nuclear energy
Nuclear energy
Weather influence
Variable renewable generation

Figure 6 presents an overview of all the policy levers, contextual factors and output criteria that are included in this study. Next (paragraph 2.4), the focus will be on the level of uncertainty of the before introduced contextual factors.

Contextual factors:
- Fuel prices
- Carbon price
- Wind and solar capacity factors
- Technology costs
- Demand growth
- Demand response
- Transmission capacity

Policy levers:
- VOLL
- CO₂ emissions allowance
- Nuclear policy

Criteria:
- Generation mix
- Generated power and demand
- Electricity prices
- Unserved energy
- Net profits per generator type

Figure 6: Overview of all input and output factors of the power system
2.4. **UNCERTAINTY OF CONTEXTUAL FACTORS**

All uncertainties in the 2050 power system, that are related to contextual factors, must be classified according to their level of uncertainty. This classification is based on the four levels of uncertainty as defined by Kwakkel, Walker, & Marchau (2010): shallow uncertainty, medium uncertainty, deep uncertainty, and recognised ignorance. All the contextual factors, as introduced in the previous paragraph, will be classified and for the primary fuel prices this will be done per fuel type.

2.4.1. **Natural gas price**

The future price of natural gas is categorized as a deep uncertainty, since only future price alternative can be enumerated and the likelihood of these alternative cannot be ranked. An example of the enumeration of price alternative are the fuel price estimations by the International Energy agency (2015).

Historical spread of natural gas is 3 – 12 $/MMBTU (Figure 7: Average German Import Price), which is equal to 2.85 – 11.39 $/GJ. Future gas price estimations reach up to 14 $/MMBtu in 2040 (International Energy Agency, 2015). For the sake of simplicity, we assume that the 2040 gas price can reflect the 2050 gas price. The possible spread of the natural gas price is therefore set at 3 – 10 €/GJ.

![Figure 7: Historical Natural Gas prices in $/MMBtu, source: (BP, 2017c)](image)

2.4.2. **Coal price**

Like the natural gas price, the coal price is also considered to be a deep uncertainty. The likelihood of high prices or low prices alternatives cannot be ranked. Based hereupon, the spread of the coal price is determined by the historical coal price, which is 1.5 – 3.64 €/GJ. The historical spread of the coal price, taken from Figure 8, is 40-150 $/tonne.
2.4.3. Uranium price
Uranium is considered to be a medium uncertainty, since price alternatives can be enumerated and ranked at an ordering. The main argument is that the uranium price has been more or less table. Some peaks, like in 2008, might occur due to political issues, however the price will likely revert back to the former stable level. The spread of historical uranium prices is 7 – 136 $/lb (Figure 9), which is equal to 15.6 – 302 $/kg.

2.4.4. Biomass price
Biomass supply consists of energy crops, forestry, agricultural residues and waste (European Climate Foundation et al., 2010). The uncertainty of the overall biomass price in 2050 can be classified as a deep uncertainty: merely future price alternatives can be enumerated, while the likelihood of high or low price alternatives cannot be ranked. The upper and lower bound of this ranking is characterized by the biomass price spread. The overall spread of the biomass price is equal to the future spread of the biomass price. Since wood chips from energy crops and forestry show the highest potential (European Climate Foundation et al., 2010), only these are considered in the further analysis. The future European price for biomass is estimated to range from 2.1 – 5.6 €/GJ.
2.4.5. CO₂ Emission trading system

For the CO₂ price, alternative can be enumerated, resulting in a possible range of the future CO₂ price is 0 – 150 €/tonne. Therefore, the CO₂ price is classified as a medium uncertainty. The historical carbon dioxide price in the European Emission Trading System show a price range of 0 – 17 €/tonne (Figure 11). Future CO₂ prices are estimated to grow to 140 $/tonne in highly renewable scenarios in 2040, which is 105 €/tonne (International Energy Agency, 2015). Since the 2040 price can reach up to 140 $/tonne, in 2050 values could be even 200 $/tonne (150 €/GJ).

2.4.6. Wind capacity factors

Historical chronological wind generation patterns differ per meteorological year. The capacity factor during peaks and the duration of peaks differ for meteorological years (Figure 12). The same applies to periods of low wind capacity factors. Especially these periods of low wind generation are of interest to this study.

Historical capacity factors are the best way to estimate the range of uncertainty for future wind capacity factors. It is not possible to predict future capacity factors for wind. In addition, a potential
cause of uncertainty is climate change. It is, however, unknown what the effect would be on future hourly capacity factor profiles.

Classifying chronological hourly meteorological year for wind capacity factors can be done in two simple ways: The annual capacity factor and the capacity factor distribution curve. An example for the Dutch wind capacity factors shows lower and shorter peaks for a year with a low average capacity factor (Figure 12). Peaks with higher capacity factors and longer duration show a higher average capacity factor. The low average capacity factor of 2010 corresponds with the abundance of high CF spikes for that year. Average wind capacity factors for these first 2000 hours are respectively 0.231, 0.257, 0.269 and 0.268 for the years 2010, 2011, 2012 and 2013 (Figure 12). Figure 13 provides the average capacity factor for all 13 countries since 1987. The spread of wind capacity factors for the 13 countries is 0.2 – 0.255. The historical spread of the wind capacity factors for the 21 countries in this study is 0.2 in 2010 to 0.255 in 1998 (Figure 13).

Figure 12: Example of differences in capacity factor time series for the first 1400 hours of the individual years 2010, 2011, 2012 and 2013 in the Netherlands (Data from: Staffell and Pfenninger, 2016).

Figure 13: Historical yearly aggregated capacity factors for wind generation in the Netherlands as the percentage of maximum installed capacity, calculated from data by Staffell and Pfenninger (2016).
To create more insight in the height of capacity factors during a whole meteorological year, a distribution curve could be helpful. Figure 14 provides the distribution of the wind capacity factors for eight meteorological year: 2009 until 2016. For example, 2010 (orange line) shows the lowest capacity factors in the highest 2000 hours, while being low for all others hours of the year as well. The opposite applies to 2015, showing the highest capacity factors for all sorted hours. Clearly, 2010 is a more beneficial year than 2015 for the maximum wind energy potential.

A comparison between 2010 and 2015 in Figure 15 stress the findings of the previous figures. Figure 15 shows the number of hours that at certain average capacity factor relative to the preceding 12 hours and following 12 hours. Therefore, this figure can tell us more about the number of periods with low wind speed periods (like the german dunkelflaute). For example, in 2010, almost a hundred hours of this year can be found in a 24-hour period that have an average capacity factor of 0.1, whereas in 2015 this accounts for just a few hours. The major lesson in Figure 15 is that 2010 contains much more periods of low wind speeds than 2015.

![Wind capacity factor duration curves](image)

*Figure 14: Hourly wind capacity factors sorted from high to low.*
Based on the small band of deviations in historical average capacity factors (Figure 13) and the similar capacity factor duration curves per year (Figure 14), the likelihood of future alternatives can be determined. Therefore, wind capacity factors are classified as a shallow uncertainty.

### 2.4.7. Solar capacity factors

Even more than wind capacity factors, solar capacity factors are only uncertain within a small range and can be classified as a shallow uncertainty likewise. The spread of solar PV capacity factors varies between 0.126 and 0.135 (Figure 16).

![Figure 15: The number of hours that occur exactly in the middle of a 24-hour period at a certain average capacity.](image)

![Figure 16: Historical yearly aggregated capacity factors for solar PV, calculated from data by Pfenninger and Staffell (2016).](image)

### 2.4.8. Capital costs of technologies

The investment costs of power technologies decrease over time. Technology learning causes technologies to become cheaper per unit of electrical output or storage. Storage (including power generation unit) technologies like hydrogen fuel cells and compressed air energy storage (CAES) can still be technologically improved and the economies of scale can reduce their investment price. New power generation technologies like CCS, biomass, wind, solar PV and CSP are expected to technologically improve power plants (Rubin et al., 2015). The highest reductions of investment costs are expected for new technologies. Most mature technologies like OCGT and PHS will not get cheaper as their technological progress is close to the maximum potential. Table 6 presents an
overview of the specific investment costs for the technologies that are considered in this study. Based on this table, cost alternatives can be enumerated, however, whether technological progress will be moderate, high remains to be seen: one cannot rank these different scenarios of technological progress. For that reason, capital costs are classified as a deep uncertainty.

Table 6: Investment costs related technological progress for generation technologies

<table>
<thead>
<tr>
<th>Gen. Type</th>
<th>2015 overnight investment costs (€/kW)</th>
<th>Expected 2040 overnight investment costs (€/kW)</th>
<th>Spread of uncertainty</th>
</tr>
</thead>
<tbody>
<tr>
<td>OCGT</td>
<td>375 – 700a</td>
<td>500</td>
<td>375 – 700</td>
</tr>
<tr>
<td>CCCT</td>
<td>470 – 966a</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>NGCC-CGS</td>
<td>-</td>
<td>825b – 2385e</td>
<td>825 - 2385</td>
</tr>
<tr>
<td>PC-CGS (ultrasupercritical)</td>
<td>-</td>
<td>1050b – 4320e</td>
<td>1050 - 4320</td>
</tr>
<tr>
<td>Nuclear</td>
<td>3672c – 4661c</td>
<td>4050b</td>
<td>3672 - 4661</td>
</tr>
<tr>
<td>Biomass power plant</td>
<td>2160b</td>
<td>2025b</td>
<td>2025 - 2160</td>
</tr>
<tr>
<td>Solar PV</td>
<td>703 – 1922a</td>
<td>702a</td>
<td>702 - 1922</td>
</tr>
<tr>
<td>Solar CSP</td>
<td>2675 – 6103a</td>
<td>3375a</td>
<td>2675 - 6103</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>900 – 2250a</td>
<td>1512a</td>
<td>900 - 2250</td>
</tr>
<tr>
<td>Wind offshore</td>
<td>2777 – 4300a</td>
<td>2610a</td>
<td>2777 - 4300</td>
</tr>
<tr>
<td>Geothermal</td>
<td>-</td>
<td>2340b – 20000c</td>
<td>2340 - 20000</td>
</tr>
<tr>
<td>Pumped hydro</td>
<td>375 – 3450b</td>
<td>2385a</td>
<td>375 - 3450</td>
</tr>
<tr>
<td>CAES</td>
<td>-</td>
<td>375 – 1125b</td>
<td>375 - 1125</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>-</td>
<td>1050 – 3500c</td>
<td>1050 - 3500</td>
</tr>
</tbody>
</table>

* Taken from IEA and NEA (2015) table 3.1 Summary of statistics of generation technologies
* Taken from IEA and NEA (2015) table 9.2 CCS investment costs for 2030
* Taken from IEA and NEA (2015) table 3.4, Nuclear generating technologies
* Adopted from Rubin et al. (2015)
* IEA and NEA (2015) calculated via a 2013 rate of 1$ = 0.75 euro; IEA (2016) calculated via a 2015 rate of 1$ = 0.9 euro
* Pumped, CAES and Hydrogen comprises of both power and storage costs
* For Geothermal, CAES and Hydrogen: current prices are not given since currently available installations are pilots which do not represent the costs of a large-scale project.

2.4.9. Demand

The uncertainty with respect to the demand for electricity exists of two aspects: (1) The estimation of the annual demand in 2050 as a growth process over 30 years and (2) the yearly demand fluctuations (annual growth or decline from 2049 to 2050). Both aspects are visualized for historical data for the nine countries in Figure 17: annual demand growth (blue line) and yearly demand growth (green line).

Considering the 30 year growth path of the annual demand to estimate the annual demand in 2050 is considered to be a deep uncertainty. Only some alternatives with respect to GDP growth can be enumerated, while sorting the likelihood of these alternatives is ruled out.

The yearly growth shows more fluctuation on a yearly basis. The total demand for these nine countries decreased with a maximum of 4.3% and increased with a maximum of 4%. For an energy-only market analysis, especially the price formation could be sensitive towards relative demand changes. The uncertainty of yearly demand growth can be classified as medium: growth (including negative growth) alternatives on a yearly basis are assumed to be limited by the aforementioned 4% growth/decline.
Figure 17: Total electricity generation of AT, BE, CH, DE, ES, FR, IT, NL, and PL in GWh per year. Due to incomplete data, the following countries are excluded: DK, NO, SE, and UK. Data source: ENTSO-E (2017)

2.4.10. Transmission
The total net transmission capacity (NTC) in 2050 will be classified as a medium uncertainty. Some NTC growth can be formulated and ranked according to their likelihood. The total NTC value for the selected 13 countries in 2013 was 62.5 GW. According to the TYNDP plan, this NTC capacity is planned to increase to 98 GW in 2030. The possible future NTC capacity for these 13 countries is estimated to range up to a maximum of 220 GW in 2050.
In this chapter, first the applied modelling type is substantiated in the first two paragraphs. In paragraph 3.1 the position of (power system) optimization models in the schools of energy modelling is clarified, after which the chosen power system optimization model is introduced in paragraph 3.2.

In paragraph 2.3 a system description of the western European power system is given. This system analysis intends to inventory the contextual factors that have a major influence on the power system. The inventoried factors of influence must be tested to quantify their impact on the model outcomes, by means of a sensitivity analysis. Paragraph 3.4 shows the design of the sensitivity test, containing a substantiation of the “base case” values approach for testing the impact of the influential factors on the model outcomes.

Before running the optimization model to test the sensitivity of the PLEXOS model, an explanation on the specifics of the model is given to create understanding on how the PLEXOS model functions. The results of the sensitivity analysis are given in paragraph 4, followed by a classification of the contextual factors based on their uncertainty and impact (paragraph 0). The contextual factors that point out to be uncertain and that have a high impact, form the basis of the scenarios. Paragraph 4.5.2 shows the scenario logic and the details of each scenario.

3.1. BACKGROUND ENERGY SYSTEM MODELLING
A power system with a large share of RES is expected to have an impact on the market. This in turn influences the revenues of both RES and flexibility options. To quantify this, an energy system models can be used. Literature presents several other modelling approaches. In this paragraph the different approaches are presented in literature. The modelling approach best able to quantify the effects of a high share of RES on the dispatch and investment costs is chosen. By doing so, sub question six is answered.

In the field of energy modelling, energy models can be classified by two main approaches: Top-down energy models and bottom-up energy models (Götz et al., 2012; Herbst et al., 2012). Top-down models, also referred to as macro-economic models, are used to integrate the energy in the economy at a geographic level (mostly nationally). Macro-economic models are used to quantify the effects of policies on the economy. For example, the effect of climate policy can be measured in terms of CO2 emissions and costs. For further details on macro-economic models, please read the introduction to energy systems modelling by Herbst et al. (2012). Bottom-up energy models do not focus on national economic effects, instead, they are developed in engineering to consider energy systems from a technological perspective (Götz et al., 2012). Bottom-up models have long been the standard in energy modelling because of the high degree of technical detail to accurately represent energy systems (Pfenninger et al., 2014). The high level of technical detail however makes bottom-up models dependent on input data and its corresponding quality.

With respect to choosing a top-down or bottom-up approach, two requirements for a model are set. The economic effects of a highly renewable power system on the profits of the generation technologies in 2050 should be modelled. Also, the model should be able to process a high level of temporal detail (one hour) to incorporate the variability of wind and solar energy. To satisfy both requirements, the bottom-up approach should be applied.

Within bottom-up energy models, two types can be distinguished according to Pfenninger, Hawkes and Keirstead (2014), Herbst et al. (2012), Götz et al. (2012) and Jägemann et al. (2013): Simulations
models and optimization models. Optimization models determine the cost minimized substantiation of an energy system given an objective function and constraints that result in the optimal system configuration. Two types of optimization models can be distinguished: The objective function either minimizes the system costs or maximizes social welfare (net total surplus of producers and consumers) (Götz et al., 2012; Jägemann et al., 2013). Simulation models, in contrast, describe the evolution of energy systems as a result of individual decision making and incomplete information (Jägemann et al., 2013; Pfenninger et al., 2014).

This study attempts to find the least cost solution for the power system to integrate flexibility options and RES in an energy-only market, therefore an optimizations model fits best. The social welfare maximization is a rather challenging type of optimization since it is impossible to measure the utility of consumers towards the use of electricity. For that reason, the demand for electricity is assumed to be inelastic. This simplification causes the social welfare maximization model to be replaced by a cost minimization type of optimization model.

Pfenninger, Hawkes and Keirstead (2014) define one other specific modelling type: Power system models. Power system models are based on simulation models or optimization models, however dealing with one specific form of energy: electricity. Power system models are, as opposed to energy optimization models, characterized by a high temporal resolution, which is quite relevant for power systems that continuously requires an energy balance (Pfenninger et al., 2014). Especially the influence of variable RES on the energy match between supply and demand requires a high temporal resolution, which is what the model for this study requires.

To conclude: the variability of renewables can be modelled best by means of a power system model. The optimization technique that is most suitable for this power system model is a cost minimization technique. Yet another division can be made within cost minimization models. Paragraph 3.2 will discuss the types of cost minimization that are required for the optimization problem.

Solving optimization problems for power system models can be done in two ways: an economic dispatch (ED) model and a unit commitment (UC). Economic dispatch, also called classic economic dispatch (CED), is the challenge of finding the output of the available generators that meet the
demand at least costs. The objective function aiming at the lowest system costs is constrained by the maximum capacity of the power plants and transmission lines. The idea is that power plants are dispatched according to their position in the merit order. Plants with the lowest marginal costs run before the next generator that has second to lowest marginal costs. Originally, ED models were used to schedule generation capacity for the power plants.

Unit commitment models are based on economic dispatch models, however extended with a binary value to include the status of a power plants, which could be either online or offline. This reflects start up and turn off decisions, as starting up a generator is accompanied with start-up costs. Unit commitment models can avoid situations in which, for example, a coal generator is turned on for just one hour. By including the start-up costs, which are high for a coal plant and low for a gas generator, the sum of the start-up and one hour of fuel costs are higher for a coal plant compared to a gas plant. In the classic ED model a coal power plant would be dispatched, because only fuel costs are taken into consideration. Storage technologies have even lower (or none) start-up costs compared to gas plants.

A UC model is the most suitable model to minimize total system costs. In the case of variable renewables, flexibility options are expected to get online and offline by an increasing number of times. An increasing number of start-up, stresses the importance of taking start-up costs into account.

3.2. THE PLEXOS MODEL: INVESTMENT AND DISPATCH

Several unit commitment models exist and a distinction can be made between open source models and commercial models. The main advantage of an open source model is that there is no restriction on the right to use it. All information with regard to the functioning of the model is available and makes open source models highly transparent. Disadvantages of open source models are the limited user interface and the purchase of a solver to run the model. The latter also accounts for commercial models. Plus, commercial models itself have to be purchased as well. Confidentially issue arise when it comes to information regarding the operation of these models, which reduces their transparency.

For this study, PLEXOS is a suitable optimization model. PLEXOS is a UC model that is solved via a mixed integer linear programming (MILP) technique (Papadopoulos, Johnson, & Valdebenito, 2014). It can deal with high temporal resolution dispatch and it can optimize portfolios.

PLEXOS contains the three main components that any optimization model should have: Objective function, decision variables and constraints. The objective function is predefined in PLEXOS and cannot be changed. On the contrary, to construct a power system, the decision variables and constraints must be defined by the user. All the decision variables, like the types of plants that could be build and/or dispatched, must be defined by the user. In addition, the user should also define the constraints regarding the decision variables or the whole system. Constraints on the decision variables should be in place to limit, for example, the output or ramping rate of a generator. System constraints are necessary to secure the power system, for example, a constraint should be in place that requires all demand to be supplied. Accordingly, for this study all the relevant decision variables and constraints are defined.

First, the investment optimization sub model in PLEXOS will determine the least-costs generation portfolios. Using such optimized generation portfolios is preferred over predefined portfolios of research by other authors. Drawing conclusions on the functioning of the energy-only market based on a predefined generation portfolio is not perfect since the social welfare is not optimized for a predefined portfolio. A predefined portfolio would over or underestimate investment and variable
costs and eventually the total system costs, which is undesirable for both producers and consumers. Greenfield generation portfolios are determined by means of a base case dispatch for the values of all long and short term contextual factors such as investment costs and fuel prices. The same base case dispatch is applied to the dispatch optimization sub model for consistency between the sub models.

Secondly the dispatch optimization sub model will determine the short-term uncertainty (weather, fuel price changes, etc.) of the energy-only market. This sub model calculates, at an hourly resolution, the least costs dispatch of the portfolios that are an outcome of the preceding investment optimization sub model. Based on the optimized portfolios, the impacts of contextual factors on the dispatch of generators and the consequences for the energy-only market are calculated via dispatch optimizations.

For both sub models, PLEXOS requires the user to exogenously define the following modelling objects: Load curves, load/generation centres (nodes), generation technologies that are available for investment (including storage), and transmission lines between nodes. Load curves for each country on an hourly basis are exogenous input and assumed to be price inelastic. Load/generation centres, hereafter called nodes, are defined per country. This means that for each country power generation and consumption occur at one place. A maximum of one transmission lines can be constructed between nodes, reflecting the aggregated capacity of the transmission lines between countries. The categories of discrete generation technologies are thermal generation, intermittent renewables, storage and demand response. Although these modelling objects are exogenously determined, the number of thermal and intermittent plants and storages to be built and their corresponding power output per country are endogenous. These are the outcomes of the investment optimization and dispatch sub models.

3.3. MODELLING ASSUMPTIONS
To design the model, choices must be made with respect to the model size, the level of detail and what to and what not to include. In other words, what are the assumptions for this study?

Role of contextual factors in sub models
For an energy-only market analysis, the contextual factors have diverging roles with respect to the two sub models. To determine the effect of the contextual factor on the energy-only market’s performance (electricity prices, unserved energy, and profitability of generators), they can be roughly linked to either the investment sub model or the dispatch sub model.

- **Generation technology Investment costs**: To find the most efficient economic investments in an energy-only market, the investment costs of generation technologies (including storage) are only included in the investment sub model.
- **Transmission investment costs**: Similar to the technology investment costs, the effect of transmission costs in an energy-only market is relevant in the investment sub model.
- **Primary fuel prices**: The effect of changes of primary fuel prices on the energy-only market could be measured by both sub models, however, for accurate effects of market prices and unserved energy the dispatch sub model is preferred.
- **Carbon price**: Like primary fuel price, the effect of the carbon price on the energy-only market can be best quantified by the dispatch sub model.
- **Wind and solar capacity factors**: Like primary fuel prices and the carbon prices, the effect of different yearly wind and solar capacity factors will only by quantified by means of the dispatch sub model.
- **Demand**: In this study two types of demand can be distinguished: the expected annual demand in 2050 and the relative yearly demand change from 2049 to 2050. The latter is of
special interest to determine the effects of demand on electricity prices, unserved energy and profits of generators in an energy-only market. For that reason, relative annual demand changes will be analysed by the dispatch sub model. The other type, the expected annual demand for 2050, is not directly related to the energy-only market model, but rather to the investments in an energy-only market. Moreover, this study does not aim to analyse the optimal investment, instead, the effect of contextual factors on electricity prices and generator profits is key. In other words, for an analysis of the energy-only market model, the height of the annual demand in 2050 is irrelevant, only relative demand changes are.

- **Demand response**: The effect of changes in the availability of demand response on the energy-only market model can be measured by both sub models, nevertheless, the dispatch sub model can quantify the effect of short term availability, which is of high interest with respect to the energy-only market model.

**General assumptions**
- In the investment sub model, investment decisions are taken based on an average year in terms of fuel prices, demand, the carbon price, and solar and wind capacity factors. Significant technological progress is assumed, to press investment costs of generation technologies. For carbon emissions, a simplified cap and trade system is assumed that results in a fixed price and a fixed emission allowance. For modelling purposes, however, the cap can be violated against a certain penalty to avoid an infeasible model.
- Maintenance is excluded from the model. One can argue that for an (energy-only) market model analysis, maintenance is not required. Also, the absence of maintenance reduces the time that is required to solve the model.
- The effect of climate change on weather profiles for wind and solar is ignored.

**Generation technologies**
Six categories of thermal generation technologies are expected to be suitable construction options in a power system with a 96% CO\textsubscript{2} reduction: Open cycle gas turbines (OCGT), combined cycle gas turbines (CCGT), CCGTs with carbon capture and storage (CCGT-CCS), ultra-supercritical coal plants with CCS (USC-CCS), solid biomass combined cycle turbines, and nuclear power plant. This fierce CO\textsubscript{2} reduction forces technologies such as oil fired power plants and coal power plants without CCS to be unacceptable build options. Technologies with low potential for installed capacity, like biogas power plants, solid waste incineration plants or waste gas plants, are left aside to reduce the complexity of the model.

Three IRES technologies are present in the model, generating power limited by hourly wind and solar profiles (capacity factors). IRES technologies are photovoltaics, onshore wind turbines and offshore wind turbines. Normally, IRES generate at their maximum rated capacity, however generation can be curtailed if that is required for system balance. The investment optimization and dispatch optimization sub model use historical wind and solar generation profiles that determine the hourly firm capacity of the IRES.

**Storage**
Only the most promising storage technologies are included: hydrogen fuel cells (FC), pumped hydro storage (PHS), compressed air energy storage (CAES) and hydrogen electrolysis combined with a gas turbine. The technological maturity and the corresponding investment costs make these storage technologies the best available electrical energy storage technologies. Electrical storage technologies like batteries are not taken into consideration, as batteries are mainly used for balancing purposes, which fall outside the scope of this study. Electric vehicles (EVs) are an exemption on this rule: EVs are incorporated of the consumer demand response.
Hydro power
Hydro plants are an exemption, taking the existing hydro plants over in the greenfield situation and excluding them from the build options in the portfolio optimization sub model. Because most of the existing potential is currently utilized, for simplifications it is assumed that no new hydro capacity. Existing hydro plants can be grouped in run-of-river, reservoir and pumped storage. New pumped storage plants will be constructed in the storage generation technology.

Demand response
Demand response (DR) is modelled as virtual generators that can be characterized by either load shifting and/or shedding. These are virtual, because no real power is generated, instead these DR generators mimic the reduction or increase of load to secure the match between demand and supply in the market. Without demand response measures, chances of demand and supply matches will reduce, resulting in blackouts and prices that are equal to the value of lost load. Demand shifting is modelled as a storage technology to force curtailed load to be served at another time. Demand shedding is modelled as a conventional generator.

Transmission
Exogenous transmission capacity will be used in the investment sub model, while power flows on these transmission line are calculated in both the investment sub model and dispatch sub model. Optimizing investment in interconnector capacity is a difficult topic, as it is a study on its own. Including investment decisions in new interconnector capacity in the investment optimization sub model will drive the run time to an unacceptable length. For analysing the energy-only market, it is assumed not required to optimize transmission capacities, meaning that interconnector capacities can be kept constant in this study.

Summary PLEXOS optimization
To summarize, all power flows and the dispatch of all generators and storage facilities are included in the dispatch optimization sub model, however in the investment optimization sub model, investments for demand response and transmission are excluded. Table 7 provides an overview of the decision for both the investment and dispatch sub model.

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Investment</th>
<th>Dispatch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind and solar (IRES)</td>
<td>Optimized</td>
<td>Optimized</td>
</tr>
<tr>
<td>Storage</td>
<td>Optimized</td>
<td>Optimized</td>
</tr>
<tr>
<td>Demand response</td>
<td>Exogenous</td>
<td>Optimized</td>
</tr>
<tr>
<td>Thermal plants</td>
<td>Optimized</td>
<td>Optimized</td>
</tr>
<tr>
<td>Transmission</td>
<td>Exogenous</td>
<td>Optimized</td>
</tr>
</tbody>
</table>

Geographical boundaries
The countries involved, represented as a node in PLEXOS, are Austria, Belgium, Denmark, France, Germany, Italy, The Netherlands, Norway, Poland, Spain, Sweden, Switzerland, and the United Kingdom.

3.4. MODEL IMPLEMENTATION

3.4.1. The formulation of the optimization problem
The PLEXOS model approaches optimization problems via three sub models. These sub models first differ on their time horizons and secondly on their output. As a matter of fact, these sub models also
represent the parts of the optimization process that could be separated to reduce the processing time of the solver. The three sub models are the LT plan, the MT plan and the ST plan. In PLEXOS two objective functions are defined: one for the investment optimization (LT plan) and one for the dispatch optimization (ST plan). The MT-plan does not an objective function of its own, instead it exists of constraints that are added to the objective function of the ST-plan. So PLEXOS contains two sub models, an investment optimization sub model and a dispatch sub model.

Solving the optimization problem investment sub model (LT plan) is the first task of the model. The LT plan should find the optimal solution for new generation investment that minimize the net present value (NPV) of the total system costs. In other words, LT plan decides where, when and how much new capacity is build. The objective function of the LT plan minimizes the total system costs, that is the sum of all investment costs and all generators production costs. The formal definition of the LT-plan objective function therefore is:

\[ \text{Minimize total costs of: Fixed and variable operations and maintenance costs, fuel costs, notional cost of unserved energy, and costs of new build generation capacity.} \]

The MT-plan is not formulated via an objective function. The purpose of the MT-plan is to manage medium term problems, such as the management of hydro storage levels, emission limits and fuel supply limits. Because of the MT-plan, the ST-schedule can deal with opportunity costs of hydro generators and fuel contracts. Such constraints are turned to dynamic weekly constraints that are added to the objective function of the dispatch optimization sub model of the ST-schedule.

Finally, the ST-schedule, which is a mixed integer programming tool for dispatch optimization. For modelling purposes, it is assumed that electricity markets function perfectly. A typical day ahead generation plan is optimized through the short term chronological unit commitment decision. The objective function is the minimization of the overall system costs, representing the interest of both consumers and producers. The ST-plan objective function:

\[ \text{Minimize total costs of: Fuel costs, start-up costs, variable operation and maintenance costs, CO}_2 \text{emissions costs, and carbon capture and storage costs.} \]

### 3.4.2. Mathematical formulation: Objective functions

The previous paragraph stated the objective functions of the LT and ST-plan in formal terms. These must be converted to mathematical formulation for the model.

The mathematical equation of the objective function of the investment optimization sub model (LT plan) is:

\[
\begin{align*}
\text{Min} \ (C) & = \sum_{\text{year}} \sum_{\text{gen}} DF_{\text{year}} \times (\text{BuildCost}_{\text{gen}} \times \text{GenBuild}(g, y)) \\
& + \sum_{y} DF_{y} \times \left[ FOMcharge_{g} \times 1000 \times \text{PMA}_{g} \times \left( \text{Units}_{g} + \sum_{i,y} \text{GenBuildUnits}_{g,i} \right) \right] \\
& + \sum_{t} DF_{t} \times L_{t} \times \left[ \text{VoLL} \times \text{USE}_{t} + \sum_{g} (\text{SRMC}_{g} \times \text{GenLoad}_{g,t}) \right]
\end{align*}
\]

Subject to:
- Energy balance
- Feasible build options
- Feasible dispatch

In this equation DF means discount factor, FOM refers to fixed operations and maintenance, VoLL refers to the value of lost load, USE refers to unserved energy and SRMC refers to the generator that sets the market price, which is known as the “short run marginal costs” generator.

The objective function of the ST-plan is defined as follows:

\[
\text{Min } (C) = \sum_{\text{hours}} \sum_{\text{gen}} \text{FuelCosts}_{h,g} + \text{VOMcosts}_{h,g} + \text{StartUp}_{h,g} + \sum_{\text{country}}^{13} \text{USE}_c \times \text{VoLL}
\]

Subject to:
- Energy balance constraint
- Operation reserve constraint
- Generator and contract chronological constraints: ramp, min up/down, min capacity
- Transmission limits
- Fuel limits
- Emission limits

In this equation, the fuel costs and VOM (variable operation and maintenance) costs form the marginal costs of a power plant. The generator starting costs are included, because some plants are too costly to run for like one hour. Representing the energy-only market implies that no ancillary services are delivered, therefore these are not included in the objective function.

3.4.3. Constraints

The possible outcomes of the objective function are limited by different phenomena that play a role in the power system. If, for example, transmission capacity is unlimited, then the optimal solution could transfer huge amounts of power from areas with cheap RES production to areas with high prices. Unfortunately, this would not be a possible outcome due to the capacity limitations of the transmission lines between countries. So the optimal solution can never exceed the maximum capacity of transmission lines. Besides transmission capacity, there are many other limitations, or so called constraints, to constrain the field of possible outcomes of the objective function. Hereunder the model constraints are formulated, but before this is done a crucial difference within the constraints should be explained. There are two types of constraints: hard and soft constraints.

Carbon dioxide emissions

Total carbon dioxide emissions per country in 2050 must be reduced by 96% compared to 1990. Based on data from the European Environment Agency an estimation of the total allowed CO₂ emissions per country in 2050 is provided in Table 8.

Table 8: European carbon dioxide emissions in electricity and heat production (European Environment Agency, 2017b)

<table>
<thead>
<tr>
<th>Electricity and heat production</th>
<th>1990 (Mton)</th>
<th>2050 = 4% of 1990 (Mton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>9.8</td>
<td>0.39</td>
</tr>
<tr>
<td>Belgium</td>
<td>21.18</td>
<td>0.84</td>
</tr>
<tr>
<td>Denmark</td>
<td>22.23</td>
<td>0.89</td>
</tr>
<tr>
<td>France</td>
<td>44.4</td>
<td>1.77</td>
</tr>
<tr>
<td>Germany</td>
<td>304.61</td>
<td>12.18</td>
</tr>
<tr>
<td>Italy</td>
<td>96.44</td>
<td>3.86</td>
</tr>
<tr>
<td>Netherlands</td>
<td>36.02</td>
<td>1.44</td>
</tr>
<tr>
<td>Country</td>
<td>Power</td>
<td>Demand</td>
</tr>
<tr>
<td>----------------</td>
<td>--------</td>
<td>--------</td>
</tr>
<tr>
<td>Norway</td>
<td>32.13</td>
<td>1.28</td>
</tr>
<tr>
<td>Poland</td>
<td>205.25</td>
<td>8.21</td>
</tr>
<tr>
<td>Spain</td>
<td>59.01</td>
<td>2.36</td>
</tr>
<tr>
<td>Sweden</td>
<td>6.96</td>
<td>0.27</td>
</tr>
<tr>
<td>Switzerland</td>
<td>1.89</td>
<td>0.08</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>175.0</td>
<td>7.0</td>
</tr>
</tbody>
</table>

**Supply and demand**
This is an equality constraint, since both supply and demand have to be equal at all times to avoid blackouts. Matching supply and demand is also known as the energy balance constraint:

\[
\sum_{T} \sum_{C} \sum_{G} P^{n=8760} = \sum_{T} \sum_{C} D^{n=8760}
\]

\[
T = \text{time step (hour)}
\]

\[
C = \text{country}
\]

\[
G = \text{generator}
\]

\[
P = \text{power}
\]

\[
D = \text{demand}
\]

If, for some reason, the energy balance constraint cannot be satisfied the model still needs an outcome, else there is no possible solution to the optimization problem. To guarantee a possible solution at all times, the energy balance constraint is softened. This implies that blackouts are allowed. To avoid a full violation of the energy balance, which is an optimal outcome if no power was generated and total variable costs would be zero euros for the whole system, a violation price is attached to this soft-constraint. This violation price is denominated as the value of lost load (VOLL). Estimating the value of the VOLL is a comprehensive and difficult task. A value of 10,000 €/MWh for lost load is chosen for both sub models.

**Transmission**
Transmission lines in PLEXOS are modelled as aggregated lines between two countries to represent the total transmission capacity between countries. On each line, there is a predefined maximum capacity for the flow of electricity that is assumed to be equal in both directions:

\[
P^{D \leq C_L}
\]

\[
L = \text{line}
\]

\[
P = \text{powerflow}
\]

\[
D = \text{demand}
\]

\[
C = \text{max capacity}
\]

**Maximum installed capacity generation technologies**
For each country, the maximum builds for certain technologies are defined by a maximum installed capacity per country. Main reason for this is to comply to for example the maximum wind power potential per country.

**Hydro storage level**
Storages should be managed over a period of multiple days. To avoid that the dispatch sub model will use the hydro storage power inefficiently, for example for a small shortage in the market while a larger shortage is expected two days later, the MT-schedule will create pre-analysed constraints. This is known as a gamed equilibrium, that is defined in the PLEXOS MT-schedule and turned into a weekly constraint in the ST-plan objective function.

**Generator Ramping**
Uniform ramping constraints are applied to each generation technology. Once a plant has fulfilled the start-up process, ramping is defined as follows. OCGT plants can ramp up and down at a rate of 1.5 MW/min, CCGT plants at 20 MW/min, coal plants 25 MW/min and nuclear plants 30 MW/min.

3.4.4. Construction details
Model runs for western Europe and some central European countries, which are the following: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Ireland, The Netherlands, Northern Ireland, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom. For simplicity reasons and model calculation time reductions we defined six core countries: France, Germany, Austria, Belgium, Switzerland and the Netherlands. Only these include reserve constraints and DR measures. The final analysis of the model results will be on all the countries. The implications on policy however are only considered for the six core regions and especially the Netherlands. Each of these countries is presented as a node in the model. The nodes are connected via transmission lines that represent existing connections between countries.

3.5. Input data
This paragraph discusses the data that is used in both the PLEXOS sub models. This includes the values for each contextual factor. Based on the given range of uncertainty for each contextual factor from paragraph 2.4, the “base case” values are established. These base case values are used in both the investment sub model and the dispatch sub model. Additional attention with respect to the uncertainty of the contextual factors is dealt with via scenarios in the dispatch sub model. Lastly, some data on some other technical aspects, like maximum potentials for wind and solar are provided.

3.5.1. Commodity prices
There is one price for all European countries, since there is no approach available that can predict primary fuel price differences between countries in 2050. The natural gas price will increase to 9.0 €/GJ in 2050. A decreasing demand for gas causes the economics of the gas production to be worsened and the breakeven point for this capital intensive industry pushes up the gas price (International Energy Agency, 2015). The coal price is expected to increase to almost the maximum value of the spread: 3.8 €/GJ. Stringent climate mitigation policies will ban coal plants in the EU which will strongly reduce the demand for coal and increase the price of coal (International Energy Agency, 2015). The biomass price will likely increase to 5 €/GJ. Demand for biomass wood pallets will likely increase, because CO₂ neutral thermal generators are convenient flexibility options. Uranium will be priced at the same level as current values: 1.5 €/GJ. History shows only abnormal prices for special political circumstances and since these are unpredictable in the future a low uranium price for 2050 is assumed. Carbon price for Europe is set 50 €/tonne for 2050. It is expected that the EU ETS will remain in place throughout the next decades. The EU ETS is expected to become increasingly effective from 2019, therefore increasing the price of CO₂ gradually (International Energy Agency, 2015). Fuel costs of wind, solar, hydro and geothermal renewable power sources are all equal to zero. There is a price attached to CO₂ that is captured by an CCS unit, since it costs these units to operate. Like a normal CO₂ price, captured CO₂ has a price as well equal to the costs of the CCS unit to capture one ton (or kg) of CO₂.

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>9.0 (€/GJ)</td>
</tr>
</tbody>
</table>
3.5.2. Demand

The electricity demand profile for 2050 are adopted from e-Highway2050 (2014). The demand profile is based on 1% annual demand growth per year from 2017 up to 2050, resulting in the annual demand per country as provided by Table 10. The load datafiles contain the load per hour for each one of the 13 countries. This demand growth includes: Growth of current electricity use and the expected size of new uses of electricity. The three main categories of new uses of electricity are electric vehicles, residential heating and non-residential heating. In Figure 19, a flow chart of the process to get to a demand time schedule in 2050 (or any other year) is presented.

![Figure 19: Methodology flow chart for the demand time schedule for 2050. Source: e-HIGHWAY 2050 (2014).](image)

Table 10: Electricity demand per country in 2050 (Source: e-highways)

<table>
<thead>
<tr>
<th>Country</th>
<th>Annual (GWh)</th>
<th>Peak (MW)</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT</td>
<td>84,825</td>
<td>14,329</td>
<td>9,591</td>
</tr>
<tr>
<td>BE</td>
<td>121,255</td>
<td>21,029</td>
<td>13,929</td>
</tr>
<tr>
<td>CH</td>
<td>77,330</td>
<td>15,669</td>
<td>10,847</td>
</tr>
<tr>
<td>DE</td>
<td>665,705</td>
<td>107,769</td>
<td>76,043</td>
</tr>
<tr>
<td>DK</td>
<td>42,667</td>
<td>7,578</td>
<td>4,910</td>
</tr>
<tr>
<td>ES</td>
<td>498,020</td>
<td>81,537</td>
<td>56,861</td>
</tr>
<tr>
<td>FR</td>
<td>649,447</td>
<td>124,732</td>
<td>73,988</td>
</tr>
<tr>
<td>GB</td>
<td>425,891</td>
<td>77,957</td>
<td>47,073</td>
</tr>
<tr>
<td>IT</td>
<td>431,389</td>
<td>84,475</td>
<td>59,486</td>
</tr>
<tr>
<td>NL</td>
<td>160,723</td>
<td>25,357</td>
<td>18,496</td>
</tr>
<tr>
<td>NO</td>
<td>102,015</td>
<td>17,251</td>
<td>11,645</td>
</tr>
<tr>
<td>PL</td>
<td>172,220</td>
<td>30,472</td>
<td>19,639</td>
</tr>
<tr>
<td>SE</td>
<td>131,557</td>
<td>20,013</td>
<td>13,701</td>
</tr>
</tbody>
</table>
3.5.3. Wind and solar capacity factors
Historical wind and solar capacity factor profiles are the only realistic and available data on wind profiles. Simulated capacity factors also exist; however, these are less accurate and reliable.

Open source wind and solar capacity factors by Staffell & Pfenninger (2016) are used as input for the wind and solar generation in the PLEXOS model. Hourly wind and solar profiles are available for all European countries. For wind capacity factors, a distinction is made between onshore and offshore.

3.5.4. Transmission
For this study one transmission scenario is designed based on the TYNDP for 2030 and DNV GL’s expectation of the network growth from 2030 to 2050. In 2013 the total net transmission capacity (NTC) between the included countries was: 62.5 GW. The TYNDP shows a total of 99 GW interconnection capacity for the lines between the 13 countries. In 2050 the interconnection capacity is assumed to grow up to 198 GW. These assumed capacities for the aggregated transmission line are given in Figure 20.

3.5.5. Properties of generation technologies
Two types of data on thermal plants are required for the model: Investment costs and technical specifications. For thermal plants, investment costs (Table 11) are taken from IEA and NEA (2015). Most of the IEA projections on emerging technologies focus on 2030.

Offshore wind costs will drop fast, due to economies of scale and reduced risks (Bloomberg New Energy Finance, 2017).
Table 11: techno-economic parameters of thermal units and renewable technologies in 2030 (Source: IEA and NEA, 2015)

<table>
<thead>
<tr>
<th>Gen. Type</th>
<th>Max capacity per unit (MW)</th>
<th>Investment costs ($2013/kWe)</th>
<th>Fixed O&amp;M ($2013/MWh)</th>
<th>Var. O&amp;M ($2013/MWh)</th>
<th>Efficiency (%)</th>
<th>Economic lifetime (years)</th>
<th>Start-up time (hours)</th>
<th>Ramp rate (%/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OCGT</td>
<td>100</td>
<td>500</td>
<td>10000</td>
<td>1.0</td>
<td>40</td>
<td>25</td>
<td>1</td>
<td>15</td>
</tr>
<tr>
<td>NGCC</td>
<td>400</td>
<td>1000</td>
<td>15000</td>
<td>1.5</td>
<td>56</td>
<td>30</td>
<td>2</td>
<td>5</td>
</tr>
<tr>
<td>NGCC-CCS</td>
<td>400</td>
<td>1400</td>
<td>23000</td>
<td>1.9</td>
<td>50</td>
<td>30</td>
<td>2</td>
<td>5</td>
</tr>
<tr>
<td>USC-CCS¹</td>
<td>625</td>
<td>2850¹</td>
<td>30000</td>
<td>3.3</td>
<td>41</td>
<td>40</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1000</td>
<td>4400</td>
<td>83000</td>
<td>2.0</td>
<td>40</td>
<td>45</td>
<td>8</td>
<td>3</td>
</tr>
<tr>
<td>Biomass</td>
<td>100</td>
<td>2000</td>
<td>35000</td>
<td>4.0</td>
<td>38</td>
<td>30</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Geothermal</td>
<td>50</td>
<td>7000</td>
<td>44000</td>
<td>0</td>
<td>-</td>
<td>20</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Solar PV</td>
<td>1</td>
<td>700</td>
<td>19000</td>
<td>0</td>
<td>-</td>
<td>20</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>1</td>
<td>1200</td>
<td>37000</td>
<td>0</td>
<td>-</td>
<td>25</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Wind offshore</td>
<td>1</td>
<td>2000</td>
<td>70000</td>
<td>0</td>
<td>-</td>
<td>25</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Hydropower</td>
<td>1</td>
<td>3000</td>
<td>52000</td>
<td>95</td>
<td>60</td>
<td>0</td>
<td>0</td>
<td>-</td>
</tr>
</tbody>
</table>

¹Total investment costs include the total overnight costs and 7% interest during construction
²Fixed O&M is taken from IEA table 6.1, 6.2 and 6.3 (OCGT, Biomass and Geothermal and offshore wind are taken from Brouwer et al. 2016)
³Investment for NGCC-CCS and USC-CCS are taken from EIA (2014) table 9.2. For nuclear, IEA table 6.3. For biomass investment is taken from IEA table 9.8.
⁴USC-CCS is an ultra-supercritical coal plant with post carbon capture.
⁵Biomass internal combustion gas turbine (BICGT).

3.5.6. Demand response
Demand elasticity is limited in electricity market. For reasons of modelling simplicity, modelers assume that demand is fully inelastic. However, in both sub models DR is included by means of virtual generators. Table 12 provides the key data all the DR measures. A detailed configuration of the residential demand response of consumers can be found in appendix B.

The max capacity differs per country and is dependent on: Growth of EVs in transportation, demand, house insulation, and responsiveness of consumers and industry to market price changes.
The industrial DR options show prices of 600 and 1000 €/MWh, shaping the demand curve as given below (Figure 21).

Table 12: Demand response potentials per category of load shifting or shedding. Data based on Gils (2014).

<table>
<thead>
<tr>
<th>Category</th>
<th>Type</th>
<th>Max shift time (h)</th>
<th>Max load reduction (h)</th>
<th>Max interventions per year</th>
<th>Variable O&amp;M (€/kWh)</th>
<th>Max potential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential – EV</td>
<td>Shifting</td>
<td>16</td>
<td>0</td>
<td>-</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Residential – Heating</td>
<td>Shifting</td>
<td>8</td>
<td>0</td>
<td>-</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Residential – Electric appliances</td>
<td>Shifting</td>
<td>48</td>
<td>0</td>
<td>-</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Industry – Cooling</td>
<td>Shifting</td>
<td>24</td>
<td>0</td>
<td>-</td>
<td>600</td>
<td>2000</td>
</tr>
<tr>
<td>Industry – Paper</td>
<td>Shedding</td>
<td>-</td>
<td>3</td>
<td>365</td>
<td>600</td>
<td>4500</td>
</tr>
<tr>
<td>Industry – Cement</td>
<td>Shedding</td>
<td>-</td>
<td>3</td>
<td>365</td>
<td>600</td>
<td>2400</td>
</tr>
<tr>
<td>Industry – aluminium</td>
<td>Shedding</td>
<td>-</td>
<td>4</td>
<td>40</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>Industry – zinc</td>
<td>Shedding</td>
<td>-</td>
<td>4</td>
<td>40</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>Industry – steelmaking</td>
<td>Shedding</td>
<td>-</td>
<td>4</td>
<td>40</td>
<td>1000</td>
<td>3900</td>
</tr>
<tr>
<td>Industry – Chlorine</td>
<td>Shedding</td>
<td>-</td>
<td>4</td>
<td>40</td>
<td>1000</td>
<td>1200</td>
</tr>
</tbody>
</table>
3.5.7. Storage

In paragraph 2.2.2 three electrical storage technologies were expected to be the most economically efficient: Pumped hydro storage (PHS), Compressed air energy storage (CAES) and hydrogen storage combined with a simple (multifuel) gas turbine.

The pumped hydro storage potential is geographically limited. The maximum installed capacity per country are taken from a study on hydro storage potential by Gimeno-Gutiérrez & Lacal-Árántegui (2013).

**Table 13: Expected characteristics and economics of storages technologies in 2050**

<table>
<thead>
<tr>
<th>Gen. Type</th>
<th>Investment PCS costs (€/kW)</th>
<th>Investment storage section (€/kWh)</th>
<th>Total capital costs per unit of output (€/kW)</th>
<th>Fixed O&amp;M (€/kW-yr)</th>
<th>Var. O&amp;M (€/MWh)</th>
<th>Roundtrip Efficiency (%)</th>
<th>Economic lifetime (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PHS</td>
<td>600</td>
<td>70</td>
<td>1400</td>
<td>4.6</td>
<td>0.22</td>
<td>77</td>
<td>60</td>
</tr>
<tr>
<td>Underground-CAES</td>
<td>800</td>
<td>40</td>
<td>900</td>
<td>3.9</td>
<td>3.1</td>
<td>80</td>
<td>30</td>
</tr>
<tr>
<td>Aboveground-CAES</td>
<td>800</td>
<td>110</td>
<td>1300</td>
<td>2.3</td>
<td>2.2</td>
<td>80</td>
<td>30</td>
</tr>
<tr>
<td>Hydrogen fuel cell</td>
<td>2300</td>
<td>3.7*</td>
<td>3000</td>
<td>25</td>
<td>-</td>
<td>38</td>
<td>20</td>
</tr>
<tr>
<td>H2/Ammonia gas turbine</td>
<td>1400</td>
<td>3.7*</td>
<td>1700</td>
<td>32</td>
<td>-</td>
<td>35</td>
<td>30</td>
</tr>
</tbody>
</table>

PCS = power conversion system

*Data taken from Zakeri (2015)

*Underground storage

*Storage is unlimited because of underground storage, plus in the model an equilibrium causes the extracted H2 to be replaced.

3.5.8. Installed capacity potential wind and solar power

There is an economical maximum on the installed capacities for wind and solar for each country. Available space, suitable terrain and wind speeds limit the options for installed capacities. e-Highway2050 calculated the maximum potential for installed capacities for wind and solar for all countries, excluding the North Sea offshore potential. Table 14 contains the installed capacities for wind and solar per country. The Windspeed Project explored the potential for offshore wind power, for which the maximum potential per country is given in the column North Sea Wind in Table 14.
(Windspeed Project, 2011). The following IRES generation types will be part of the model: Solar CSP, Solar PV, wind power offshore and wind power onshore.

Table 14: Wind and solar potentials per country (e-Highway2050, 2014)

<table>
<thead>
<tr>
<th>Country</th>
<th>Economical Onshore Wind</th>
<th>Corrected Onshore Wind</th>
<th>Offshore Wind</th>
<th>North Sea Wind</th>
<th>Total Offshore Wind</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT</td>
<td>8</td>
<td>8</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>43</td>
</tr>
<tr>
<td>BE</td>
<td>12</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>3</td>
<td>22</td>
</tr>
<tr>
<td>CH</td>
<td>2</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>19</td>
</tr>
<tr>
<td>DE</td>
<td>110</td>
<td>25</td>
<td>6</td>
<td>41</td>
<td>47</td>
<td>141</td>
</tr>
<tr>
<td>DK</td>
<td>24</td>
<td>10</td>
<td>2</td>
<td>60</td>
<td>62</td>
<td>16</td>
</tr>
<tr>
<td>ES</td>
<td>71</td>
<td>25</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>214</td>
</tr>
<tr>
<td>FR</td>
<td>180</td>
<td>40</td>
<td>20</td>
<td>0</td>
<td>20</td>
<td>205</td>
</tr>
<tr>
<td>GB</td>
<td>118</td>
<td>30</td>
<td>24</td>
<td>120</td>
<td>144</td>
<td>70</td>
</tr>
<tr>
<td>IT</td>
<td>32</td>
<td>12</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>166</td>
</tr>
<tr>
<td>NL</td>
<td>18</td>
<td>3</td>
<td>0</td>
<td>25</td>
<td>25</td>
<td>31</td>
</tr>
<tr>
<td>NO</td>
<td>32</td>
<td>15</td>
<td>28</td>
<td>50</td>
<td>78</td>
<td>10</td>
</tr>
<tr>
<td>PL</td>
<td>126</td>
<td>35</td>
<td>6</td>
<td>0</td>
<td>6</td>
<td>81</td>
</tr>
<tr>
<td>SE</td>
<td>41</td>
<td>10</td>
<td>5</td>
<td>0</td>
<td>5</td>
<td>10</td>
</tr>
</tbody>
</table>

3.5.9. Hydro potential

The hydro potentials in Europe are limited, since most locations with natural water flow are already in use for hydro power generation. The available potential that is assumed to be economical is based on DNV GL’s in-house data (Table 15).

Table 15: Maximum economically feasible hydro potential for the 13 countries of this study.

<table>
<thead>
<tr>
<th>Country</th>
<th>Run-of-River (GWh/yr)</th>
<th>Storage (GWh/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>5700</td>
<td>1000</td>
</tr>
<tr>
<td>Belgium</td>
<td>360</td>
<td>0</td>
</tr>
<tr>
<td>Denmark</td>
<td>13</td>
<td>0</td>
</tr>
<tr>
<td>France</td>
<td>4600</td>
<td>230</td>
</tr>
<tr>
<td>Germany</td>
<td>5700</td>
<td>1000</td>
</tr>
<tr>
<td>Italy</td>
<td>4566</td>
<td>1000</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Norway</td>
<td>0</td>
<td>32000</td>
</tr>
<tr>
<td>Poland</td>
<td>1700</td>
<td>0</td>
</tr>
<tr>
<td>Spain</td>
<td>6000</td>
<td>18000</td>
</tr>
<tr>
<td>Sweden</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Switzerland</td>
<td>4500</td>
<td>230</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>1800</td>
<td>0</td>
</tr>
</tbody>
</table>

3.5.10. Biomass potential

Total European potential for biomass consumption is set at 9 EJ primary energy. Total world potential for biomass is 19,000 TWh, of which 16,500 TWh from wood chips (European Climate Foundation et al., 2010). 40% of 16,500 TWh is consumed in the EU, which is 6,600.00 TWh or 23,760 PJ of primary energy. 80% of this potential will be consumed the 13 countries of this study involved. De Wit & Faaij
(2010) estimated the potential for biomass in the EU-27 at 6200 – 22,000 PJ per year. The ECF potential of 19,000 PJ, falls within the range of de Wit and Faaij. However, taking the issue of CO₂ neutrality of biomass into consideration, it is doubtful whether this potential will be fully utilized. We assume that the maximum potential for biomass is 9 EJ of primary energy per year. For the countries involved this implies a potential of 9,000 PJ primary energy per year.
4. PORTFOLIOS, SENSITIVITY AND SCENARIOS

4.1. SCENARIO METHOD

To catch the effects of uncertain factors in future power systems on the energy-only market, a reasonable spectrum of possible futures should be explored. This paragraph explains the logic behind the creation of the scenarios, and especially the difference between investment and dispatch scenarios.

In the scenarios, a distinction is made between scenarios for the investment optimization sub model and the dispatch optimization sub model. Different principles drive the possible futures of the generation portfolio on the one hand and dispatch decisions on the other hand. Dispatch scenarios in an energy-only market will be most sensitive to changes of contextual factors that cannot be predicted. Factors one can think of are primary fuel prices or weather dependent power generation of wind and solar. Investment scenarios, on the contrary, differ on political choices on energy that will be taken in the future. Of course, also, contextual factors such as the natural gas price will influence the investment decisions in 2050, however when analysing the dispatch in an energy-only market, which is the main goal of this study, it is of minor importance to base these investment scenarios upon contextual factors. In other words, it is the effect of contextual factors on the functioning of the market we are interested in, not the effect of contextual factors on the investment decisions. The generation portfolios in 2050 will mainly differ on political consideration such as the phasing out of nuclear energy and reducing of phasing out coal.

The dispatch scenarios will be determined via a sensitivity analysis of the dispatch sub model. A sensitivity analysis will show the impact of contextual factors on the outcomes of the dispatch sub model. For example, if the biomass price increases by 10%, will market prices change more or less than 10%? Knowing the impact of each contextual factor, together with their uncertainty, the most influential factors can be indicated.

To start the sensitivity analysis of the dispatch sub model, first, investment scenarios must be formed and the corresponding portfolios must be produced. The generation portfolios that are an outcome of the investment optimization sub model are the portfolios that the dispatch sub model will use to analyse the dispatch. The resulting generation portfolios of the investment optimization sub model for both investment scenarios will be presented in the next paragraph.

Figure 22: Structure of investment and dispatch scenarios
4.2. **Portfolio Optimization**

The investment optimization sub model optimizes the build decisions in the generation portfolios prior to running the dispatch optimization sub model. The dispatch sub model uses the generation portfolios that are the outcome of the investment sub model. We could use predetermined portfolios as input in the model as well as portfolios that are calculated by the PLEXOS investment optimization sub model.

Instead of using pre-determined power plant portfolios as input data for the dispatch sub model, the investment optimization sub model will calculate least-cost portfolios that serve a better purpose for dispatch analysis. Optimized portfolios are preferred over predetermined portfolios since optimized portfolios result from the investment optimization sub model that uses the same input data as the dispatch sub model, hence both models are consistent in data usage. It is prerequisite that the investment sub model determines all investments based on a situation in which the European electricity market functions according to an energy-only market. The dispatch sub model thereafter intends to find the effects on the energy-only market when certain market conditions change. When trying to find effects of influential factors in the energy-only market, it does not make sense to make use of a portfolio that is not based on investment decisions of an energy-only market.

The resulting portfolios of the investment optimization sub model are based on two investment scenarios that differ on including or excluding specific generation technologies. Reason is that some political considerations are quite relevant to include when establishing portfolios. Examples are a nuclear phase outs in several countries or a ban on new build coal plants. Two investment scenarios will be used: The base policy scenario and the renewable scenario. The base policy investment scenario limits nuclear options to France, the United Kingdom, Italy, Spain, the Netherlands, and Poland. The other countries have announced or implemented a nuclear phase-out. The renewable investment scenario excludes almost all fossil fuelled generation technologies. Coal with and without CCS, nuclear and gas with CCS. Only a small amount of gas turbines is allowed for flexibility purposes.

The investment optimization sub model’s main indicator of run time as well as the quality of the solution is the load slicing granularity, which is set at 70 steps per week. Ideally, load that is sliced at 168 hour per week would result in the most detailed solution. Running the dispatch optimization sub model hereafter would result in an equal dispatch of plants and equal market prices. At a granularity of 70 steps per week, the duration of one run is approximately 24 to 30 hours. Solving the investment puzzle at for example 80 steps per week would increase the run time to approximately 32 to 38 hours. Clearly, there is a dilemma on run time versus quality of model results that resulted in the choice of 70 load slices per week, mainly because test runs at 50 of 60 steps per week resulted in generation portfolios and market prices comparable with 70 steps. At 70 steps per week, the original load curve of 8760 hours is sliced into 3700 blocks of approximately 1 to 6 hours.

The two model runs that will determine the generation portfolios for the two investment scenarios, both use the same input data. The investment sub model uses the input as presented in paragraph 3.5. In addition, the 2013 weather profiles for wind and solar have been used, because this year is a representative “average” year for wind and solar capacity factors.

4.2.1. **Base Policy Scenario Portfolio**

This paragraph presents the results of investment optimization sub model for both investment scenarios.
Geothermal and coal CCS plants are never built because of their low competitiveness. The main competitor of coal CCS is CCGT-CCS, especially when the majority of the base load is generated by nuclear and biothermal plants.

IRES investments are limited to approximately 25% of total installed capacity. When it comes to competing with other generation technologies, IRES are only constructed in countries with the highest capacity factors for solar and wind. Solar PV is constructed in Spain, where the yearly solar capacity factors is about 20%, the highest of Europe. Wind turbines are mainly constructed in the UK, the Netherlands, Denmark and Sweden.

![Figure 23: Generation Portfolio - Base Policy Investment Scenario](image)

Carbon dioxide is only produced for the power production of OCGT (12 GWh) and CCGT plants (102 GWh) (Figure 24). The energy mix consists for almost 50% of nuclear energy. The share of wind, solar, and hydro in the generation mix, compared to the share of installed capacity, is low due to lower capacity factors. A detailed overview of the share per technology per country, for both installed capacity and power generation are provided in Appendix D.
The demand response (DR) capacities given in Figure 25 apply to both investment scenarios. Consumer DR is only available for France, Germany, Austria, Belgium, the Netherlands and Switzerland. Establishing these demand responsive load curves is quite a challenge, so only these core countries in the model were included. The large demand in Germany and France logically also results in the largest consumer capacity for demand response.

Market conditions with respect to power prices are about 100-110 €/MWh. Unserved energy is not present in the base policy portfolio.
Table 16: Market prices per country in the base policy investment scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Average yearly electricity price (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>110</td>
</tr>
<tr>
<td>Belgium</td>
<td>109</td>
</tr>
<tr>
<td>Switzerland</td>
<td>110</td>
</tr>
<tr>
<td>Germany</td>
<td>108</td>
</tr>
<tr>
<td>Denmark</td>
<td>110</td>
</tr>
<tr>
<td>Spain</td>
<td>105</td>
</tr>
<tr>
<td>France</td>
<td>113</td>
</tr>
<tr>
<td>Italy</td>
<td>105</td>
</tr>
<tr>
<td>Netherlands</td>
<td>107</td>
</tr>
<tr>
<td>Norway</td>
<td>100</td>
</tr>
<tr>
<td>Poland</td>
<td>91</td>
</tr>
<tr>
<td>Sweden</td>
<td>109</td>
</tr>
<tr>
<td>UK</td>
<td>106</td>
</tr>
</tbody>
</table>

4.2.2. Renewable scenario portfolio

The resulting generation portfolio of the renewable investment scenario is special for two reasons, first more than 80% of the installed capacity is renewable, and second, the generation mix contains a large installed capacity of gas turbines (Figure 26). The large share of renewable in this portfolio can easily be explain by the phase-out of nuclear power, coal plants and most gas plants. Only gas turbines are constructed for flexibility measures.

Compared to the base policy investment scenario, the total installed capacity for the renewable investment scenario increases approximately 1 TWh from 802 GWh to 1844 GWh.

A quarter of the generation mix can be denominated as flexible generation. Biomass, gas turbines and hydro power can provide flexibility. Solar PV and wind power are inflexible generation technologies, except for curtailment in case the IRES supply exceeds total demand.

![Generation Portfolio - Renewable Investment Scenario](image)

*Figure 26: Installed Capacity of thermal, hydro and IRES generation technologies in the Renewable investment scenario.*

The generation technologies are distributed according to the geographic advantages of the western European countries (Figure 73). Solar PV is not present in north European countries, mainly due to low solar capacity factors. Countries without solar PV rely mainly on a large share of wind turbines or hydro; the UK, Denmark, Norway and Sweden.
When comparing the generation mix (Figure 27) with the installed capacity for each generation technology (Figure 26), it must be noted that biomass plants have the highest capacity factor (196 GW producing 900 GWh), while solar PV the lowest (909 GW producing 1096 GWh).

![Figure 27: Total power generation for thermal, hydro and IRES generation technologies in the Renewable investment scenario](image)

Storage facilities are only built in the Renewable investment scenario. The large amount of firm generation capacity in the Base Policy investment scenario reduce the need for storage, resulting in an uneconomic business case for all storage technologies.

Mainly CAES and PHS are built in the renewable investment scenario. Above ground CAES is economically not an efficient investment due to the limited storage size of 2 MWh per 1 MW of power output. The investment costs for a hydrogen fuel cell, of 3000 €/MW, are simply too high to be competitive with underground CAES and pumped hydro storage.

![Figure 28: Installed capacity of storage technologies in the Renewable investment scenario.](image)
Mainly because of the absence of unserved energy, market prices are on average 100 €/MWh for all countries. The high costs that are attached to blackouts of 10,000 €/MWh caused the investment optimization sub model to establish a portfolio that is able to serve all demand at all times, given the load slicing granularity of 70 steps per week.

Table 17: The market prices in the renewable investment scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Price (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>101.47</td>
</tr>
<tr>
<td>Belgium</td>
<td>102.29</td>
</tr>
<tr>
<td>Switzerland</td>
<td>101.95</td>
</tr>
<tr>
<td>Germany</td>
<td>101.50</td>
</tr>
<tr>
<td>Denmark</td>
<td>84.25</td>
</tr>
<tr>
<td>Spain</td>
<td>98.54</td>
</tr>
<tr>
<td>France</td>
<td>103.37</td>
</tr>
<tr>
<td>Italy</td>
<td>99.76</td>
</tr>
<tr>
<td>Netherlands</td>
<td>101.11</td>
</tr>
<tr>
<td>Norway</td>
<td>64.88</td>
</tr>
<tr>
<td>Poland</td>
<td>102.76</td>
</tr>
<tr>
<td>Sweden</td>
<td>102.15</td>
</tr>
<tr>
<td>UK</td>
<td>78.93</td>
</tr>
</tbody>
</table>

Figure 29: Net profits of all generation technologies that result from the investment optimization in the renewable investment scenario.

4.3. VALIDATION OF DISPATCH SUB MODEL

After obtaining the three portfolios from the investment optimization sub model, the dispatch model must be tested before establishing the dispatch scenarios. Dispatch scenarios are key determine how driving forces in the power sector will influence the energy-only market.

Verification and validation are key components of the modelling procedure. Model validation to check whether the model is suited for what is intend to achieve with it. The validation of the model takes place via an extensive sensitivity test that has been carefully created in the next paragraphs. Verification is assumed to be almost fully dispensable, since coding mistakes cannot occur in PLEXOS.
PLEXOS has a user-friendly interface that does not provide the user with options to change the model code. Conflicting inputs and settings will be detected by the solver, since this will present the solver from running the model. The only mistakes that could be made during the construction of the model are either wrong data input or by not selecting the conforming settings. Through an iterative process of running the model for over approximately 200 times, most of these mistakes have been repaired.

4.3.1. Overview of sensitivity tests

The sensitivity of the dispatch sub model will be tested to determine the impact of short-term contextual factors on the modelling outcomes.

First, before the sensitivity tests, the dispatch optimization model will run a base case dispatch to determine market prices in a base case on an hourly granularity. This is done to observe differences of the market outcomes (price, profits and unserved energy) of optimization sub model and the dispatch optimization sub model. It is expected that the market outcomes of the dispatch sub model will deviate from the market outcomes of the investment sub model. The slicing of the load curve limits the investment sub model to accurately calculate hourly market prices, and consequently the yearly market prices per country. The investment sub model dispatches plants on load slicing intervals of 1 to 6 hours whereas the dispatch optimization sub model accurate determines hourly market prices. Furthermore, it provides insight in how the dispatch sub model should be changed subtle, to produce market outcomes comparable to the investment sub model market outcomes.

Some constraints in the dispatch model are relaxed, to avoid an unsolvable optimization problem. The emissions constraints are relaxed to allow gas turbine to generate more power and CO₂. Also, the potential for biomass fuels is increased by 5%. After implementing these changes into the dispatch optimization sub model, the market results of the base case run should be within the range of the investment sub model market results. The results of the two base runs of dispatch sub model are presented in appendix C.

Secondly, all short term contextual factors (variables) in the dispatch sub model are tested to determine their impact on the model outcomes. The modelling outcomes of a run with different values for compared to the base case dispatch. Each variable is tested univariate to quantify its impact on the power system while keeping all other variables equal. For the meteorological is tested ordinal. All fuel prices and the carbon price are tested for a ratio of 10% increase and decrease relative to the base case values. Load changes are tested for a one percent increase and decrease relative to the base case values. Since coal CCS plants are absent in both generation portfolios, the coal price is not included in the sensitivity analysis.

Table 18: Overview of the variables, their possible range, the base case value choice and the sensitivity values.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Range, lowest value</th>
<th>Range, highest value</th>
<th>Base Case value (X)</th>
<th>X*0.9</th>
<th>X*1.1</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Price</td>
<td>3.02</td>
<td>9.7</td>
<td>9.0</td>
<td>8.73</td>
<td>10.67</td>
<td>€/GJ</td>
</tr>
<tr>
<td>Coal Price</td>
<td>1.5</td>
<td>3.64</td>
<td>3.6</td>
<td>3.24</td>
<td>3.96</td>
<td>€/GJ</td>
</tr>
<tr>
<td>Uranium Price</td>
<td>2.08</td>
<td>5.6</td>
<td>5.0</td>
<td>4.5</td>
<td>5.5</td>
<td>€/GJ</td>
</tr>
<tr>
<td>Carbon Price</td>
<td>0</td>
<td>150</td>
<td>47</td>
<td>42.3</td>
<td>51.7</td>
<td>€/tonne</td>
</tr>
<tr>
<td>Demand*</td>
<td>-</td>
<td>-</td>
<td>3660</td>
<td>3623</td>
<td>3697</td>
<td>GWh</td>
</tr>
<tr>
<td>Meteorological solar</td>
<td>Ordinal</td>
<td>Ordinal</td>
<td>2013</td>
<td>2011 and 2016</td>
<td>Year</td>
<td></td>
</tr>
<tr>
<td>and wind pattern</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*The Base Case value is the sum of the expected yearly demand of the 13 countries included in the study.
4.3.2. Summary of outcomes of sensitivity tests
A complete overview of all the results of the sensitivity tests can be found in Appendix C: Sensitivity analysis.

The most sensitive contextual factors are fuel prices, demand and weather influence on IRES capacity factors.

The Base case: Results of the base case runs differ from the results of the investment sub model runs. The presence of unserved energy causes power prices to be higher than in the investment model outcomes. The investment decisions, for both investment scenarios, in the investment sub model results in a very thin system that is highly sensitivity to minor changes. The high, hourly, granularity of the dispatch sub model causes unserved energy to be present for multiple days. Remarkably, the market outcomes in terms of prices and unserved energy (USE) are more stable in and lower in the Renewable portfolio. Against expectations, a higher share of wind and solar in the generation portfolio does not lead to a higher sensitivity and consequently higher amounts of unserved energy and higher prices.

For fuel prices, the following is of interest:
- The price of natural gas mainly influences the power prices for the renewable portfolio.
- A biomass price changes force power prices to decrease and increase in both generation portfolios, whereas the effect on unserved energy remain minimal.
- Uranium price changes have almost no effect on unserved energy, power prices and the profitability of generators.

The impact of the carbon price is especially noticeable in the base policy portfolio.

Demand changes directly influence all the output criteria in the expected way; a decline lowers unserved energy, power prices and profitability, whereas growth pushes USE, power prices and profitability.

Especially for the renewable portfolio, the weather profiles for solar and wind capacity factors for the meteorological years 2011 and 2016 reduce unserved energy and power prices compared to the base case of 2013 capacity factors.

4.4. Classification of Driving Forces
To classify the driving forces, impact and uncertainty are the key criteria. The impact of these driving forces is derived from the sensitivity analysis of the previous paragraph, while the uncertainty of these driving forces is determined in paragraph 2.4. The driving forces are: Primary fuel prices, the carbon price, demand, and weather.

It is highly uncertain what the value of primary fuel prices will be, but the impact of primary fuel prices is the lowest compared to the other driving forces. The results of the sensitivity analysis point to a high effect of primary fuel price changes in some cases, mainly in the base policy scenario. The uncertainty spreads of chapter 2 show that primary fuel prices can be volatile, resulting in a wide spread for fuel prices most fuel prices.

The carbon price is classified as highly uncertain, however with a low impact. In the base policy portfolio, the impact of the carbon price on the model output criteria seems strong, however interest in this study lean more towards the renewable portfolio, which shows more stability.
Demand is considered as highly uncertain and with a high impact on model output criteria. For all sensitivity runs of the dispatch model for both generation portfolios, demand showed a disproportionate impact on all the output criteria. Demand is uncertain and

Table 19: Classification of driving forces on their impact and uncertainty

<table>
<thead>
<tr>
<th>Driving forces</th>
<th>Uncertain</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
</tr>
<tr>
<td>Impact</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>High</td>
</tr>
</tbody>
</table>

4.5. **Dispatch Scenario Setup**

4.5.1. **Scenario logic**

Three “driving forces” form the basis of the scenarios (Figure 30). In total these three driving forces create eight dispatch scenarios or so called ‘futures’ (black dots in the figure below).

Figure 30: Illustration of the short-term power market scenarios based on three dimensions of driving forces.

4.5.2. **Detailed scenarios**

The two end on the demand dimension in Figure 30 are called “High demand”, representing a growth of 1%, and “low demand”, representing a decline of 1%. Although the demand fluctuations reached up to even 8% between two years, these values are not representative values for this study. High growth peaks are always preceded by a growth decline, resulting in a long run average growth that is about 1%.
Both ends of the fuel prices dimension are specified as “High fuel prices” and “low fuel prices”. High fuel prices for biomass, natural gas and uranium are 7.5 €/GJ, 10 €/GJ, and 5 €/GJ. Low fuel prices for biomass, natural gas and uranium are 3 €/GJ, 3 €/GJ, and 1 €/GJ.

The ends of the weather dimension in Figure 30 cannot be quantified by means of a maximum and a minimum value, instead two meteorological years for solar and wind capacity factors are selected on the basis of their average yearly performance. The year 2010 is chosen for its historically low wind capacity factors, while 2012 is chosen because of its average values for both wind and solar capacity factors.

The values of all other model variables are equal to the base case input data as presented in paragraph 3.5. The results of the dispatch optimization sub model for the eight dispatch scenarios will be given for both investment scenarios, resulting in 16 model runs (Table 20).

Table 20: Details of the dispatch sub model runs

<table>
<thead>
<tr>
<th>Run</th>
<th>Portfolio</th>
<th>Fuel prices</th>
<th>Demand</th>
<th>Weather profile</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Base Policy</td>
<td>High</td>
<td>High</td>
<td>2010</td>
</tr>
<tr>
<td>2</td>
<td>Base Policy</td>
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<td>Renewable</td>
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</tr>
</tbody>
</table>
5. RESULTS

The first paragraph presents the results of the dispatch sub model for the eight dispatch scenarios in the base policy generation portfolio. The second paragraph presents the results for the same dispatch scenario for the renewable generation portfolio.

5.1. DISPATCH RESULTS – BASE POLICY

To compare the scenarios, the main output criteria that will be analysed are the power price, unserved energy, and net profits of generation technologies. Since storage is absent in the base policy scenario, net profits for storage technologies will only be analysed for the renewable portfolio in the next paragraph.

An analysis of the power price in the base policy portfolio provides three clear patterns in the result of the eight scenarios (Figure 31). A higher demand always results in a higher power price, independent from fuel prices and the weather profiles for solar and wind. The power price for the dispatch scenarios with low fuel prices show a larger difference than the power price of the scenarios with high fuel prices. The power price in the dispatch scenarios that use 2010 wind and solar capacity factors always exceed those that use 2012 wind and solar capacity factors.

![Wholesale power price - Base policy portfolio](image)

*Figure 31: Average power price in the dispatch scenarios for the base policy portfolio.*

The results of total unserved energy show similarities with the power price results: high power prices are linked to higher levels of unserved energy (Figure 32). Large quantities of unserved energy are present in the two scenarios that have in common an increased demand and the wind and solar capacity factors of 2010.

For two scenarios, unserved energy is entirely absent and four scenarios contain only a small quantity of unserved energy. An obvious explanation is that the reduced demand in these scenarios is causing the dispatch sub model to be increasingly flexible with respect to the match between supply and demand, thereby preventing unserved energy to be present.
Net profits of the thermal, hydro, and IRES generators of the eight scenarios show consistency with the corresponding power prices. The scenarios with a high-power price and a high demand (Figure 31) result in high net profits for all generators (Figure 33). Net profits, just like power prices, in the scenarios that use 2010 solar and wind capacity factors are higher than those using 2012.

Net profits are especially low in dispatch scenarios with low demand, compared to dispatch scenarios with high demand. In these scenarios with low demand, prices are low and consequently some generators run at a loss while other generators make just a small profit.

Generation by biomass, OCGT, CCGT, gas CCS and hydro benefit most from high power prices and show the greatest resilience against lower prices. These five power sources show positive net profits in six of the eight dispatch scenarios and their losses/profit in the other two scenarios are close to the break-even point. Nuclear power runs at a loss in six of eight scenarios, whereas net profits in the other two scenarios with extremely high prices is small compared to the large profits of the other five generation technologies. The profitability or losses of wind and solar PV are small in all eight scenarios.
5.2. DISPATCH RESULTS – ALL RENEWABLE

On average, low power prices are present in the dispatch scenarios with low fuel prices, while high price are linked to the scenarios with a high fuel price (Figure 34).

In addition, the historical capacity factors for wind and solar of 2010 show higher power prices than the scenarios with the 2012 capacity factors.

The presence of unserved energy is accompanied with high energy prices for the dispatch scenarios with a high demand and the historical solar and wind capacity factors of 2010 (Figure 35). For the dispatch scenarios with high demand and historical weather data of 2010, the average power price is higher than 300 €/MWh (Figure 34). At the same time these unserved energy is present in these two scenarios, causing these power price to be high.
In for scenarios in which unserved energy is present, market prices are high and consequently net profits (Figure 36). Except for hydro, all generation technologies run at a loss in the other six scenarios.

Especially the biomass, OCGT and hydro plants show better resistance against low prices. When prices are high, their profits are high and when prices are low their losses remain smaller than solar PV and onshore wind. Solar PV, wind onshore and wind offshore however show just small profits when prices are high and relatively large losses when prices are low.

For storage, positive net profits are present in the two scenarios with demand growth and for the historical capacity factors of 2010 (Figure 37). In scenarios without unserved energy, the storage technologies never recover their costs.

The price duration curve shows that price for two dispatch scenarios with unserved energy (Figure 35) increases up to 10.000 €/MWh at the lower end (Figure 38). High prices are absent for the other six scenarios due to the absence of unserved energy.
Because the price duration curve of the other six dispatch scenarios seems flat in Figure 38, a more detailed view of the part up to 400 €/MWh presented in Figure 39. At the lower end of the graph, the market price for the six scenarios without the presence of unserved energy reaches up to approximately 300 €/MWh.
6. DISCUSSION

6.1. INTERPRETATION OF RESULTS

In general, both portfolios show similar results: the dispatch scenarios with the combination of high demand and the 2010 wind and solar profiles result in high amounts of unserved energy.

The dispatch scenarios for the base policy portfolio show diverging model outcomes for the two scenarios that combine a 1% demand growth and the 2010 meteorological year. Most generation technologies in the base policy portfolio show a positive business case, implying that a generation portfolio with large shares of controllable generation that is exposed to short term uncertainties (fuel prices, yearly demand change, and yearly weather profile) can secure the profitability of generation technologies. For consumers, however, there is a substantial risk of high prices. Low IRES output can push up market prices, although IRES make “just” 27% of total installed capacity. The power output of IRES can be vulnerable to different wind and solar capacity factors of another meteorological year.

Negative net profits in the renewable portfolio are much larger compared to those in the base policy portfolio. High investment costs are the main cause of this higher losses in some dispatch scenarios for the renewable portfolio. The installed capacity in the renewable portfolio is the main cause for these high investment costs, as the renewable portfolio exceeds the installed capacity of the base policy portfolio by over more than 100%.

The dispatch results for the renewable portfolio are characterized by a substantial amount of unserved energy in the same dispatch scenarios as in the base policy portfolio. The dispatch scenarios with a 1% demand growth and the 2010 wind and solar capacity factors results in enough unserved energy to push up the market price to several hundred euros per megawatt hour per year. The price duration curve (Figure 39) shows that prices in scenarios without USE never go higher than approximately 300 euros, while in the two dispatch scenarios that contain USE, prices go up to 10,000 €/MWh (Figure 38). This implies that for the latter two scenarios, there is an large price risk for consumers.

Unserved energy is the main cause of high power prices as well as a lower security of supply. The match between supply and demand is missing for too many hours per year in those two scenarios, which means that the lights simply go out in thousands of households for more than a hundred hours per year.

Above all other parameters, the VOLL is the most critical parameter that determines the market price and consequently the profitability of generation technologies. To recover their investment costs, generators are dependent on price spikes that occur during a shortage (unserved energy). The volatile prices are caused by the large step from low prices, set by the most expensive marginal generator (100 €/MWh), to scarcity prices at 10,000 €/MWh when demand cannot be met. In-between those two prices, there are no (virtual) generators available that can set the power price.

For the renewable portfolio, the scenarios with high a yearly market price show positive net profits for some generation technologies (Figure 36) that provides more than 50% return on investment for some technologies in just one year. Biomass plants and gas turbines show high profits relative to their installed capacity, covering up to 75% of the total capital costs in one year. On the contrary, wind and solar generators do not benefit from high prices in these two scenarios. Their net profits are only small. High market prices mainly appear when the output of solar and/or wind power drops to a minimum: Solar PV generators cannot benefit from high market prices during nights, while wind power cannot benefit from high market prices when wind speeds are low.
The market outcomes for the dispatch scenarios do suggest that the energy-only market is not functioning well: Either the energy-only market produces low power prices in combination with a high generation adequacy, or power prices are high and generation adequacy is low. A fully and healthy functioning energy-only market should produce relatively low prices that still incentivize investment, while at the same time keeping generation adequacy high. The results presented in this study do not combine low prices and a high level of generation adequacy.

Also, in an energy-only market with a large share of wind and solar power, one would expect a high number of hours per year with an electricity price of zero euros per megawatt hour. Figure 39 shows approximately 500 hours at a power price of zero, which might be interpreted as too few hours at a zero power price. For these 500 hours, the electricity price in each of the 13 countries is exactly zero. Since the given electricity price in Figure 39 represent the average European price, for some countries prices are zero in the part for 7400-8200 hours.

High power prices in scenarios with large amounts of unserved energy are mainly caused by one policy lever: the value of lost load (VOLL). Currently in spot markets, a similar policy lever known as a price cap is installed. These values are usually much lower than 10,000 €/MWh. The model outcomes in terms of profits and market prices are to a great extent steered by this VOLL. In both sub models, the estimated value of lost load was set at 10,000 €/MWh. There is an ongoing debate about the value of lost load, which ranges from approximately 6000 to 20,000 €/MWh (London Economics, 2013). Lowering the VOLL to a value equal to price caps in current electricity markets will automatically lower power prices and net profits for generation technologies in the model. In other words, the investment decision for investors in an energy-only market are highly dependent of the value of lost load or the price cap. A lower VOLL, for example 6000 €/MWh, would imply that even more hours of shortage are required for power plants to recover their capital costs. These additional hours of shortage reduce the generation adequacy in an energy-only market even more, which is undesirable.

Furthermore, the policy lever of CO₂ allowance is also an influential factor. The maximum allowed emissions for CO₂ limit investments in cheap gas fired power plants for the provision of flexibility. Instead, more capital expensive flexibility options must be build, thereby increase the overall system costs. If CO₂ emissions were reduced by 90% instead of 95%, prices would be more stable and expensive storage facilities would not have been constructed.

Lastly, a somewhat general remark, the wide variety of the market results for the scenarios show that investment decisions in an energy-only market are highly sensitive. Making optimal investment decisions is challenging, because there is no representative starting point or base case scenario. Especially for an increasing share of renewable power by wind and solar power generators, an investment optimization is sensitive to the applied meteorological year for solar and wind capacity factors as well as demand forecasts. In the investment sub model, the optimization of investment decisions for both investment scenarios was also limited by the temporal detail of 70 steps per week, since an hourly granularity would increase the run time of PLEXOS to infinity.

6.2. COMPARISON TO LITERATURE

Other studies focus much on total system costs, as an ultimate criteria for a judgement on energy-only market performance (Brouwer, van den Broek, Zappa, et al., 2016; Budischak et al., 2013). However, excluding the criteria of profitability of generators, unserved energy, and power prices limits the analysis of the energy-only market, since these are criteria that can explain to what extent both producers and consumers benefit in an energy-only market.
Studies on the modelling of highly renewable power systems do not agree on the recovery of all costs for generation and storage technologies. The cost-effectiveness of storage show negative results in most studies. In accordance with the results of this study, profits of storage technologies are negative in similar studies (Brouwer, van den Broek, Zappa, et al., 2016; Budischak et al., 2013; Ummels et al., 2008). However, a study by Bertsch et al. (2016), shows that storage technologies can be profitable. When comparing the results for gas plants to other studies, there is an agreement on positive net profits (Bertsch et al., 2016; Brouwer, van den Broek, Zappa, et al., 2016). For intermittent RES, the results of this study are in accordance with other studies: net profits are in general negative in an energy-only market (Budischak et al., 2013; Hirth, 2013; Steggals et al., 2011).

Other studies do not stress the need for scarcity prices in cost-minimization models to recover investment costs (Bertsch et al., 2016; Brouwer, van den Broek, Zappa, et al., 2016; Budischak et al., 2013; Mikkola & Lund, 2016; Spiecker & Weber, 2014; Ummels et al., 2008). This study found a strong link between the presence of unserved energy and the profitability of generators.

There is a broad agreement on the need for controllable generation and demand response for flexibility. In this study, the investment sub model constructed as much controllable generation capacity as was allowed by the model constraints. Brouwer, van den Broek, Zappa, et al. (2016) stress the benefits of gas fired power plants to reduce system costs and provide firm flexibility capacity. Likewise, Bertsch et al. (2016) argue that the most cost-efficient source of flexibility is gas fired power plants with CCS.

The investment optimization in this study differs from the approaches in other studies. Except hydro power, this study fully optimized the generation portfolio, including storage. Likewise, (Bertsch et al., 2016; Gils et al., 2017; Spiecker & Weber, 2014) fully optimized the generation portfolio to obtain the most cost efficient generation portfolio. Some studies choose to partly optimize investments (Brouwer, van den Broek, Zappa, et al., 2016), and others avoided an investment optimization by simply creating top down generation portfolios (Budischak et al., 2013; Ummels et al., 2008).

Lastly, Bertsch et al. (2016) argues that there is no need for additional incentives for investment in flexibility, while Brouwer, van den Broek, Zappa, et al. (2016) and Spiecker & Weber (2014) argue that capacity payments are required for generators to finance their investments. In this study, the investment costs recovery in most scenarios requires a capacity payment for a 100% return on investment. To the contrary, in some rare scenarios generators can make huge profits, causing capacity payments to be undesirable. This reflects the difficult investment risk: Either wait for a bad meteorological year in combination with demand growth to harvest huge profits, or implement a capacity mechanism to obtain additional revenues.

6.3. REFLECTION ON ASSUMPTIONS

For this study, assumptions on a large variety of issues have been made that could in some way affect the modelling outcomes and consequently the lessons learned from these outcomes. In this paragraph provides a reflection on the relevant assumptions in this study.

The generation portfolios, as calculated in the investment sub model, would possible be different if the annual demand for electricity in 2050 would be higher or lower. The annual demand for electricity in 2050 is merely and assumption that is fixed for both the investment and dispatch sub model. Only in the dispatch sub model a 1% increase or decrease are included in the scenarios. Since we cannot predict the demand for electricity in 2050, the generation portfolios might be forced to construct to much CO₂ polluting power plants when demand is for example 20% compared to what
we assume in this study. In such a situation, European policy makers must be willing to accept the fact that a 95% CO₂ reduction compared to 1990 is should be relaxed to for example 90%.

Demand response (DR) is not fully included in all the involved countries. Consumer DR is only taken into consideration for six countries (FR, DE, NL, BE, AT and CH), so there might be an underestimation of demand elasticity in the market, resulting in lower flexibility and higher power prices. Modelling the demand shift is far more complicated for millions of individual consumers per country and because it is continuous type of DR. Consumer DR is assumed to be available 24/7, whereas industrial DR is available for a limited number of shifting/shedding periods per year. Assumptions on the industrial demand response potential, both shedding and shifting, are assumed to be the best available in literature. It can, nonetheless, never be excluded that these estimations will be representative by the time we get to 2050.

For electrical power storage, the relation between the size of the storage section and the capacity of the power output is fixed. The model only taken a fixed amount of capacity into consideration with a rate of 8 MWh storage per 1 MW of power output. The explanation for this is that the model cannot invest in these two components separately. This rate could be economically inefficient, resulting in too high investment costs and consequently underinvestment.

For the investment costs of storage, a reduction would stimulate investments in storage even further. Additional storage capacity would provide additional flexibility to the power system. Logically, one could argue that this would lower the number of hours of unserved energy, thereby improving the generation adequacy in the whole power system. Nonetheless, to recover their investment costs via a market price steered stream of revenues, these storages are dependent on shortages (unserved energy) to increase the market price towards the VOLL. A higher amount of generation adequacy will reduce revenues for storages likewise, which is unfavorable for their capital costs recovery.

Investment costs are highly uncertain since these depend on technological learning and economies of scale. In this study assume significant technological progress is assumed to reduce investment costs of all generation technologies, especially for wind turbines and solar PV panels. If investment costs would be more conservative, then the business case of mainly wind and solar PV would become unsound. We expect the investment sub model to construct more generators with firm capacity since their costs can easily be covered through increased revenues that are the result of generating more power.

The model is based on a simplified nodal power system of one node per country and aggregated transmission lines between countries with fixed capacities. Leaving distribution networks and real interconnection lines aside might cause an overestimation of flexibility in the whole system. The aggregated capacity for transmission lines in this study is fixed, because for an analysis of energy-only market sensitivity of short term uncertainties the transmission capacity can be fixed. Nonetheless, a detailed transmission grid with more centres of load and supply are expected to improve the model outcomes.

The total demand and the shape of the demand curve for 2050 are highly uncertain. This study includes one demand curve that is used throughout all model runs. The effect of yearly demand changes is included in the dispatch scenarios by means of a total increase or decrease of the total demand curve, thereby preserving intra temporal difference in the demand curve.

For the renewable investment scenario, it is assumed that the availability of biomass reaches up to approximately 50% of its theoretical potential. It is however doubtful whether this will be truly
achieved, because biomass is a politically sensitive issue in terms of its CO₂ neutrality and the required land for production crops and forests. A lower share of biomass plants in the mix would reduce the flexibility of the system.

For this study a time scale of one year for a greenfield optimization is chosen, rather than multiple years. So, the results of this study only focus on the functioning of the energy-only during the snapshot of the year 2050. However, to what extent an energy-only market is able function well throughout the whole transition period cannot concluded by means of the result of this study. Finally, the gas price in 2050 excludes any additional costs that are linked to gas supply from storage instead of pipeline gas. A low utilization of the pipeline gas network can force gas plants to organize gas supply via storage tanks.
7. CONCLUSION AND RECOMMENDATIONS

A highly renewable power system, with large shares of wind and solar power, will very likely not incentivize investment in an energy-only market. Without subsidies, wind and solar generators and electrical energy storage in an energy-only market, even under the most beneficial scenarios, are expected not to recover their investment costs. Even in the most beneficial scenario, wind and solar power generators will recover too less of their investment costs.

To obtain this conclusion, the investments of two power systems that emit 95% less carbon dioxide in 2050 have been optimized: A base policy portfolio and a highly renewable portfolio. The main difference between the generation portfolios is that 75% of the installed capacity in the renewable generation portfolio exists of wind and solar power, against 25% in the base policy generation portfolio. For both generation portfolios, the energy-only market’s performance under a variety of conditions was measured. The key criteria for this analysis concern electricity prices, unserved energy, and net profits of generation technologies.

A sensitivity analysis of the PLEXOS dispatch sub model showed that demand changes, different weather profiles, and primary fuel price changes are the driving forces in a power system. An increase or decrease of each of these three driving forces resulted in relatively higher fluctuations on the key criteria.

This study shows high market prices and high amounts of unserved energy in some scenarios. For most scenarios, moderate prices are observed (40-70 €/MWh), however, for some scenarios prices reached 500 €/MWh per year. Logically, net profits for generation technologies are high for the scenarios with a high power price. Still, mainly gas plants, biomass plants, and hydro plants benefit from high prices. IRES generators and nuclear power show only small profits for the scenarios with high total profits.

Both a highly renewable power system (renewable portfolio) and a power system of 25% IRES capacity (base policy portfolio) are not able to power the system up to a 100% of the time under all likely changes of weather profiles, demand, and fuel prices. Such uncertainties cause the renewable power system in this study to involuntary curtail load (unserved energy). The presence of unserved energy is mainly due to the enhancing combination of a growth of demand and a specific “bad” meteorological year.

When profits are extremely high, unserved energy reduces system adequacy. The causal relation is simple: the presence of unserved energy (lost load) pushes up the market price, resulting in high net revenues for all generators during these hours of scarcity. One hour of unserved energy sets the price of a country during that specific hour at 10.000 €/MWh.

The conditions that cause a mismatch between supply and demand are the presence of both a 1% demand increase and a meteorological year of low capacity factors for wind. The chance on such a scenario is low however. Based on historical records, a meteorological year with such low capacity factors for wind, occurred only once since in 30 years. Since 1987, the year 2010 contained the lowest average capacity factor for wind. In addition, the chance on such a scenario is further reduced because a demand increase is required on top of a meteorological year with a low capacity factor. So, for the specific dispatch scenario like the one in this study with the combination of the 2010 capacity factors and a one percent demand increase are not likely to occur often. Market results for less extreme meteorological years tend to result in negative net profits for all generation technologies in a highly renewable power system. Only under extreme meteorological conditions and a demand
increase, market prices go up to the VOLL, resulting high profits for generators to recover a large part of their investment costs. A lower share of IRES in the generation mix, like the base policy portfolio, shows a large certainty for investment costs recovery for all generation technologies. Results of the model indicate a lower chance on negative net profits compared to a highly renewable generation portfolio.

The presence of unserved energy is the main condition under which generators perform cost-efficient in both a highly renewable power system, and a power system with nuclear and gas CCS, like the base policy portfolio.

Climate mitigation policies that aim at reducing CO₂ emissions in the power sector via a wind and solar powered west-European power system will have to focus on additional incentives for investments in new generation capacity to secure generation adequacy. Without additional incentives, the energy-only market model will not be able to create a sufficient investment in new generation capacity as well as low prices and a high level of generation adequacy for consumers.

With respect to private and public policy in the electricity sector, some recommendations can be drafted. Firstly, look at the effect of a capacity mechanism on market prices and profitability of generators, especially in a highly renewable power system. Normally, authors propose the implementation of capacity mechanisms to solve the missing money problem. Since the missing money problem is not an issue in this study, a capacity mechanism would suit another purpose: additional revenues for wind and solar generators to cover their investment costs. Policy makers as well as private firms that aim as analysing investments in renewable energy of any other market analysis that includes renewables, are advised to choose meteorological years with low capacity factors for their quantitative models.

Lastly, some options for further research will be proposed. A first option would be to expand the dispatch scenarios by means of additional meteorological years for solar and wind capacity factors. A second option would be to run a ten-year period model to discover if the profitability of generators will incentivize investment in new generation capacity. The one year that is analysed in this study is only a snapshot that might differ from a ten-year net profit for a generator. Thirdly, the effect of a fluctuating VOLL on generator profits and market prices could be analysed and compared to the outcomes of this study. Since the VOLL is never equal for all countries and all days per year, market outcomes could differ from those presented here.
8. REFLECTION

This study focused on the behavior of the energy-only market in a highly renewable power system in 2050. I tried to reflect a theoretical energy-only market in a power system optimization model. However unavoidable limitations in the model cause the results to be lower than the theoretically maximum efficient model outcomes. Limitations for this study are: hydro capacities are not optimized, the VoLL is fixed, the temporal granularity of the investment sub model. Still, I am convinced that the results of this study

All trades of electricity in the wholesale market cannot be expected to be based on spot pricing. Most electricity is currently traded via bilateral contracts. Only a small portion of approximately 20% is traded via the spot market. Whether investments via a combined wholesale market of bilateral trade and spot market can result in a social welfare maximization cannot be concluded based on the findings of this study.

The available build options for the investment optimization sub model do not include combined heat and power plants (CHP), concentrated solar power plants (CSP) and coal fired power plants without CCS. Including CHP plants in the model would only make sense if the heat sector was integrated and co-optimized in the model likewise. CSP plants are excluded in a later stage of the modelling process because their behaviour could not be replicated sufficiently in the model. Coal plants without CCS are excluded from the list of build options in 2050, since it is expected not to be constructed due to high emissions costs.

Initially, I planned on using top down formulated generation portfolios for the analysis of the energy-only market. However, then dispatch results for such a predefined power system will never fully reflect a competitive energy-only market. The available solution was a bottom up approach of a full optimization of the electricity generation portfolio for all countries. The full optimization of generation portfolios in has been an enormous time consuming and difficult task. Several causes for this can be addressed. First, predicting the investment costs (and other costs) for generation technologies in 2050 is challenging. Data for investment costs was gathered from multiple sources. However, publications show a wide range of investment costs for generation technologies. The costs used in this study, are therefore the combined result of extensive research. Second, additional data is required to limit the installed capacities of technologies. The maximum potential of all individual generation technologies per country must be included in the model. Third, testing the influence of data plus the model properties and validating the investment sub model in PLEXOS consumed approximately two to three months, which explains the delay of this thesis project. Each model run for testing purposes consumed about six and up to 48 hours, even though I was at the disposal of desktop with a 3.5 GHz multicore processor. The size of the formulated optimization task caused this long run time per model run.

Next time, I am planning on building my own model from scratch. The model I constructed was based on an existing model of DNV GL, of which I 98% rebuild. This rebuilding process however allowed old components of the model to remain in place from time to time, influencing the model outcomes. It took a substantial amount of time to remove all these mistakes via a process of trial and error.

In the end, this master thesis project has been quite challenging. I enjoyed the knowledge I gained about electricity markets and the conversation with people about this topic. Also, building such a detailed and extensive power system model has been a great experience. I am happy that I had the opportunity to produce as small contribution to the large world of science.


energy challenges. Renewable and Sustainable Energy Reviews, 33, 74–86. https://doi.org/10.1016/j.rser.2014.02.003


## APPENDIX A: EXCHANGE RATE $/€

### Table 21: Exchange rate from American dollars to euros

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</table>

APPENDIX B: DETERMINATION OF CONSUMER DEMAND RESPONSE

A certain amount of the total load each hour is a candidate for demand response (DR). The portion of DR is proposed to be found in three categories: Electric heating, electric vehicles and electricity consumption of appliances. For each category, the expected load profile is taken and multiplied by a certain percentage that is expected to be responsive. For example, in the case of electric heating the share of responsive/active residents in the 100% RES scenario (equivalent of the e-Highway2050 x-7 scenario) is 26% (Table 22). This results in an hourly DR profile for electric heating. Next, this hourly profile is transformed to a cumulative electric heating graph. To create the maximum (t-4) and the minimum (t+4) electric heating load lines, the original cumulative graph is shifted 4 hours to the left and 4 hours to the right. The difference on each hour between the maximum and minimum line are the delta area that will be considered in the optimization. EVs and electric appliances undergo the same approach. The cumulative graphs are calculated for six of the involved countries for 2050. Hereunder the assumptions on the DR will be explained, since there quite some uncertainties on DSM in the future.

*Table 22: Share of passive, semi-active and active electric heating per e-highway2050 scenario. Note: The data from the x-7 scenario is used in this study, as it represents a 100% RES market situation in 2050 (Source: e-highway2050 (2014)).*

<table>
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<tr>
<th></th>
<th>x-5</th>
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<th>x-10</th>
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<tr>
<td>Share of semi-active residential heating</td>
<td>20%</td>
<td>20%</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
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<td>Share of fully-active residential heating</td>
<td>20%</td>
<td>26%</td>
<td>15%</td>
<td>15%</td>
<td>22%</td>
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<tr>
<td>Share of semi-active non-residential heating</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
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</tr>
<tr>
<td>Share of fully-active non-residential heating</td>
<td>0%</td>
<td>5%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>

Assumptions with respect to consumer DR:
- DSM only applies to Austria, Belgium, Switzerland, Germany, France and the Netherlands to reduce the optimization duration of PLEXOS.
- Electric heating, electric vehicles as well as electricity consumption of appliances are assumed to be demand responsive load categories.
- The time constant for electric heating, EVs and appliances consumption are respectively 4, 8 and 24 hours (e-Highway2050, 2014). This means that the total DSM capacity of electric heating in hour t can be transferred to any hour on or in between hour t-4 or hour t+4.
- Regarding electric heating we assume:
  - Residential heating is dependent of hourly temperature.
  - Residential heating is only considered when average temperatures per month drop below 10°C.
  - A flat load profile for heating water for each month.
  - Industrial process heating profile is always flat.
- Electric Vehicles:
  - Although there might be seasonal differences in the charging pattern, EVs are assumed to charge in the same way throughout the year (e-Highway2050, 2014). During winter time a higher share of EVs might be charged during the night. This effect is assumed to be nullified by a charging shift during summer time to mid-day, because of higher solar generation.
- Unresponsive EVs are characterized by a flat demand profile.
- Responsive EVs are characterized by a load profile that is expected to be flat, with the exemptions for weekends. Part of the daily demand on week days is distributed to the weekends.
- The proposed correction factors for the availability of EVs are shown in Figure 40 and subsequently used to determine the charging capacity that is available for DSM (Table 22).

- Electric Appliances: Although no information is available on the use of appliances in the future, it would not seem unlikely that a certain share of appliances could be subjected to DSM. The assumed percentages per country are taken over from e-Highway2050 (2014). Note that in Table 23 the x-7 scenario is the equivalent of the 100% RES in this thesis.
- All the assumptions on DSM are determined for 5 e-Highway2050 scenarios. Only two scenarios (40% RES and 100% RES) are taken over in the DNV GL database. The DSM assumptions for the 80% RES scenario are extrapolated values from the 40% and 100% values.

Figure 40: The proposed correction factor (CF) for the availability of EVs. Source: e-HIGHWAY2050 (2014).

Figure 41: Expected charging pattern of Electric Vehicles during the first 32 days (760 hours) of 2050.
Table 23: Shares of fully active demand per country. Source: e-HIGHWAY2050 (2014).

<table>
<thead>
<tr>
<th>Country</th>
<th>X-5</th>
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<th>X-10</th>
<th>X-13</th>
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<td>4%</td>
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<tr>
<td>Belgium</td>
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<td>8%</td>
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<td>2%</td>
<td>4%</td>
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<tr>
<td>Bosnia and Herzegovina</td>
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<td>5%</td>
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<tr>
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APPENDIX C: SENSITIVITY ANALYSIS

Base case runs
In this paragraph the resulting market outcomes of the dispatch optimization sub model are presented. The output criteria for this analysis are market prices, unserved energy and net profits of generation technologies. First the output criteria of the dispatch sub model for the base policy portfolio are discussed and secondly those of the renewable portfolio.

The power prices in the dispatch model, using the base policy portfolio, result in relatively high power price of at least 300 €/MWh on average per country per year (Figure 42). These high prices can be explained by the high amounts of unserved energy that remain present in the dispatch sub model outcomes, even after the additional capacity is added and emission constraints were relaxed. An example is given in Figure 43, in which a few moments of shortage in January leads to price of 10,000 €/MWh for multiple days, increasing the yearly average Spanish price easily to 360 €/MWh. Although unserved energy is only present in Spain and Italy (Figure 44), high prices in other countries can be explained by the full utilization of all available capacity leading to marginal prices in these countries that are equal to the costs of meeting an additional MW of load, which is the VoLL.

Figure 42: Electricity prices in the base run of the dispatch sub model for the base policy portfolio.
Although there is more unserved energy in the dispatch base case run of the renewable portfolio, market prices are lower. For most countries, the average power price reaches up to 200 €/MWh (Figure 45). Compared to the power prices in the investment sub model run of the renewable scenario, prices in this dispatch sub model run are two times higher. Main cause of these higher power prices is 874 GWh of unserved energy (Figure 46). Cheap hydro power in Norway causes the power price to be lower than all other countries.

The high level of flexibility in the renewable portfolio is illustrated in Figure 47. Solar generation is the only active power generation technology during the day, while each night hydro and biothermal are required generate power.

Power prices of the base case runs for both generation portfolios in the dispatch sub model differ much from the power prices of the investment sub model run for the renewable investment scenario. The power prices outcomes for both the investment sub model and the base case run of the dispatch sub model should more or less be equal. However, this sensitivity analysis (including the base case runs) are unfortunately dated. I have not been able to update this sensitivity analysis, since I did not have access to the PLEXOS license for the last month of my thesis.
Figure 45: Electricity prices in the base run of the dispatch sub model for the Renewable generation portfolio.

Figure 46: Unserved energy in the base run of the dispatch sub model, using the Renewable generation portfolio.
Impact natural gas price
The first variable for which the impact on the power system is tested is the price of natural gas. In the base case, the price of natural gas is 9.0 €/GJ, resulting in 8.1 and 9.9 €/GJ for a 10% increase and decrease.

The effect of a 10% price decrease of natural gas results in a decrease of more 50% unserved for the base policy portfolio (Figure 48). An increase in the gas price does have almost no impact on unserved energy for the base policy portfolio. For the renewable portfolio, the impact of a decrease or an increase of the gas price on unserved energy is only subtle.

The effect of a 10% decrease of the gas price pushes down the market price for the base policy portfolio by more than 40% (Figure 49). No clear impact on the power price can be distinguished in the case of a 10% gas price increase. For the renewable portfolio, the impact of gas price changes is very little at less than 3% decrease of the power price.

The profitability of generation technologies shows great sensitivity for a 10% decrease: total profits of all generation technologies decreases by more than 55% (Figure 50). The impact of a natural gas price increase does not influence the profitability. The net profits of generators do not change more than 3% for the renewable portfolio.

The system costs of DR decrease over more than 50% under a gas price reduction that is as little as 10% (Figure 51). For the renewable portfolio, a 10% gas price decrease reduces the net profits of storage technologies by approximately 10%.

Figure 47: The base case dispatch profile of Spain in January for the Renewable portfolio.
Figure 48: The impact of a 10% increase and decrease of the price of natural gas on unserved energy.

Figure 49: The effect of natural gas price changes on the average power price for all countries.

Figure 50: The effect of the natural gas price on the net profits of the thermal, hydro and IRES generation technologies.
Figure 51: The effect of changes in the price of natural gas on the net profits of DR and storage technologies.

The impact of the gas price, especially a decrease, on the power system output criteria is strong. A 10% reduction of the natural gas price leads to a large reduction of unserved energy, the average market price, net profits of generation technologies, and the costs of demand response.

Impact biomass price
In this paragraph, the impact of a 10% change of the biomass price on the output criteria is quantified. A 10% increase and decrease lead to a biomass price of respectively 5.5 and 4.5 €/GJ.

In the base policy portfolio, the impact of biomass price changes on unserved energy is disproportionately low for a biomass price decrease and higher for a biomass price increase (Figure 52). A 10% price increase pushes unserved energy up by more than 15%. A 10% price decrease reduces unserved energy by more than 25%. The impact on unserved energy for the dispatch of the renewable portfolio is limited to less than 5% for both an increase or decrease of the biomass price.

The power price is quite sensitive for biomass price changes in both generation portfolios. For the base policy portfolio, a 10% biomass price decrease reduces the power price by 18%, however a 10% biomass price increase only leads to a minor power price increase of 7% (Figure 53). For the renewable portfolio, a 10% biomass price increase forces the average power price to grow 33% (Figure 53).
Net profits of thermal, hydro and IRES generation is also affected by disproportionately due to a 10% increase and decrease of the biomass price (Figure 54). For the base policy portfolio, a 10% reduction shrinks the total net profits of these generator classes by 20%, while a 10% increase leads to an increase of net profits by just 8%. For the renewable portfolio, only a biomass price increase has impact on the net profits of these generator classes. A 10% increase of the biomass price results in more than 20% increased total net profits.

A 10% biomass price causes positive net profits for CAES storage, instead of the net loss in the base case (Figure 55). Since no storage plants are constructed in base policy portfolio, only the costs of DR are given below.

In general, the costs of demand response decrease for the base policy portfolio by 20% if the biomass price reduces and for the renewable portfolio the costs of demand response increase more than 40% if the biomass price increases by 10%.
Biomass price changes have a clear influence on the power price, unserved energy and net profits of the power system as calculated by the dispatch optimization sub model. A biomass price increase in the renewable portfolio drives up net profits, unserved energy and the power price. For the base policy portfolio, a biomass price decrease reduces the power prices disproportionally and consequently presses net profits.

Impact Uranium price
The impact of an increase or decrease of the uranium price does only affect unserved energy. An increase as well as a decrease of the uranium price reduces unserved energy slightly by 2% and 8% (Figure 56). Average power prices and net profits of generation technologies show no effects (Figure 57 and Figure 58).
Figure 57: The impact of uranium price on the power price in comparison with the Base Policy dispatch run.

Figure 58: The impact of uranium price changes on the net profits of thermal plants, IRES and hydro plants.

Impact carbon price

To quantify the impact of a change of the carbon price, a 10% decrease and increase of the carbon prices is analysed: one run for each portfolio with a carbon price of 42.3 €/ton CO₂ and one run for each portfolio with a carbon price of 51.7 €/ton CO₂.

In a market where the carbon price affects only 5% of all generated power directly, total unserved energy still is influenced (Figure 59). Most striking is the fierce reduction of unserved energy in the base policy portfolio due to a 10% carbon price growth. In the renewable portfolio, the impact of the carbon price on unserved energy remains below 10%.

The power price shows great sensitivity for a carbon price increase for the base policy portfolio. When the carbon price increase by only 10%, market prices plummet for 380 €/MWh in the base case to almost 150 €/MWh. A carbon price decrease, on the contrary does seem to have no effect on the power price whatsoever. For the renewable portfolio, effects on the power price are limited to a 15% power price increase relative to a 10% carbon price increase.
The effects of the carbon price on net profits of generation technologies is strong, especially for the base policy portfolio: total net profits drop by 70% if the carbon price increases 10% (Figure 61). For the renewable portfolio, the effects are less explosive. A carbon price increase of 10% stimulates total net profits by 15%. No effects are observed because of a 10% carbon price decrease.

Overall, the net profits for thermal, hydro and IRES plants are positive for all the sensitivity test. Only solar PV shows a small loss for a carbon price decrease in the renewable portfolio.

In general, a 10% increase or decrease of the carbon price never leads to positive net profits for storage technologies, while the costs of DR are affected disproportionally in some cases. The effect on the profitability of storage technologies and DR show similar effects as thermal, hydro and IRES plants. For the base policy portfolio, only the costs (or net profits) of DR are reduced over more than 50% (Figure 62). The costs of DR increase proportionally by 10% when the carbon price increases 10% in the renewable portfolio.
Although one might expect the carbon price to be not impactful, overall, a strong impact is shown for a carbon price increase for both generation portfolios.

**Impact demand**

To quantify the effect of demand growth or reduction, the yearly load curve of the base case is increased by 1% to represent demand growth and it is reduced by 1% to represent a decline of demand.
The strong impact of these one percent demand changes on unserved energy in both portfolios is undeniable (Figure 63). For the base policy portfolio, a load decline of one percent reduces unserved energy for more than 70%, while a one percent load growth leads to a doubling of unserved energy. For the renewable portfolio, a load decline reduces unserved energy to a null, whereas load growth does not change total unserved energy.

Load growth or load decline results in great power price volatility, especially for the base policy portfolio (Figure 64). A one percent load decline for the base policy scenario results in a power price drop of 80%. A one percent load increase forces the power price to increase 25%. The impact on the power price for load changes in the renewable portfolio show less extreme results. The power price increases by approximately 50% if load grows one percent. The power price drops 40% when demand declines one percent.

Consequently, low power prices press net profits of all generator classes and for some generators net profits drop below their breakeven point (Figure 65). In the base policy portfolio net profits of most generator classes become negative if load declines one percent, while net profits increase when demand grows one percent. Also in the renewable portfolio, a one percent decline in demandpresses net profits for most generator classes, while solar PV and offshore wind run at a loss. A demand increase has the opposite result as net profits of all technologies increase by 50% compared to the base case dispatch situation.
For DR, a demand decline of one percent in the base policy shows that DR is almost dispensable, while a demand increase of one percent in the renewable portfolio leads to positive net profits of CAES and PHS storage technologies (Figure 66).

Figure 65: The effect of a 1% increase and decrease of demand on the net profit of thermal, hydro and IRES generation technologies.

Figure 66: The effect of demand increase or decrease on DR and storage net profits.

Demand changes of one percent do have a disproportionate impact on unserved energy, power prices and net profits of generators. This sensitivity can be easily explained because the investment optimization sub model determines the least cost portfolio, without uneconomic reserve capacity. No investor is willing to construct a power plants without a profitable business case. Though, for reasons of security of supply, such plants could be constructed although and protecting the power system to be vulnerable to short term uncertainties like fuel prices and other solar and wind profiles. However, in a fully competitive energy-only market the construction of these uneconomic reserves is not considered to be necessary. Scarcity pricing will automatically lead to investment in new generation capacity to avoid any further unserved energy.

Impact meteorological solar and wind pattern
Lastly, the impact of wind and solar capacity factors of a different meteorological year on the model outcomes is quantified. The base case dispatch runs for both portfolios use the wind and solar profile of the meteorological year 2013, which will be replaced by 2016 for this analysis.
The impact of other wind and solar capacity factors is limited for unserved energy in the renewable portfolio, but for the base policy portfolio unserved energy is reduced 80% compared to the base case dispatch (Figure 67).

Power prices for the dispatch of the base policy portfolio show great sensitivity when the solar and wind capacity factors of 2013 are replaced by those of 2016 (Figure 68). In the base policy power prices drop almost 55 percent, while the impact of the 2016 weather profile on the dispatch of the renewable portfolio is less, but still 19%.

![Unserved energy - Weather sensitivity](image)

*Figure 67: The impact of another historical profile (2016) for wind and solar capacity factors on total unserved energy.*

![Power price - Weather sensitivity](image)

*Figure 68: The effect of another wind and solar profile (2016) on the average power price.*
Figure 69: The sensitivity of net profits of thermal, hydro and IRES generation to a different historical wind and solar profile (profile of 2016).

Figure 70: The effect of another wind and solar profile on the profitability of DR and storage.
APPENDIX D: INSTALLED CAPACITY AND GENERATION PER COUNTRY

**Figure 71:** The distribution of installed capacities per country for the Base Policy investment scenario.

**Figure 72:** Produced power per generation technology per country for the Base Policy investment scenario.
Figure 73: The share of installed capacity of generation technologies per country in the Renewable investment scenario.

Figure 74: Produced power per generation technology per country for the Renewable investment scenario.
Figure 75: The share of generated power per storage technology per country in the Renewable investment scenario.