Towards a cost-optimal European power system for a renewable future

An assessment of the best planning scale, complementary options and policy implications

T.H.J. de Pater
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by

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Summary

Over the past decades, the scientific certainty about human influence on climate change through anthropogenic emission of greenhouse gases, mainly CO₂, increased strongly. Worldwide, the awareness that it results in negative effects on societies and ecosystems, has instigated many countries to reduce these emissions. As greenhouse gases mainly originate from the burning of fossil fuels, alternative sources of energy are required. For the European Union (EU) aspects on energy security provide additional grounds to decrease dependency on fossil fuels. Domestic resources are insufficient, and currently about 50% of the energy demand has to be imported. This import dependency threatens the security of supply and might result in price fluctuations and spikes, which, in turn, threaten energy affordability. Renewable Energy Sources for Electricity (RES-E) are seen as a possible solution for both problems, as it decreases the dependency on fossil fuels. The electricity sector in particular is regarded to have more potential for a short term transition than other main energy consuming sectors.

Two main, promising RES-E technologies, wind and solar PV power, are completely weather dependent for their (potential) output. Their generation profile is uncertain, location specific and intermittent. The current European power systems are built for conventional power plants, with well adjustable outputs (dispatchable), like Combined Cycle Gas Turbines (CCGT), hard coal plants and with more sustainable fuels, like biomass plants. RES-E have high fixed costs, but very low Variable Operations & Maintenance costs (VOM). Therefore, they come early in the merit order of day ahead markets, distorting the business case of conventional generators. Due to their intermittency, RES-E cannot completely replace fully dispatchable generation technologies, while the need for flexible generators increases accordingly with RES-E integration levels. Large scale integration of RES-E threatens the security of supply, grid stability and, in the long term, affordability of electricity.

Aside from the desired decarbonisation of the energy sector, and resulting RES-E integration, another trend is visible within the EU. Ever since the founding of the European Coal and Steel Community (ECSC, precursor to the EU) in 1952, a joint approach of European energy policy has been on the agenda. With the recent adoption of the Energy Union package, in February 2015, a step has been taken towards a more integrated European power system and centrally coordinated policy. Because the European energy sector was privatised, and the ownership of different power system elements unbundled in the 1990s, generation planning is organised by the market and can only be steered, not directly controlled by governments. This makes it harder to reach energy goals, and especially to impose them from higher, centralised levels. On top of that, European Member States remain hesitant to hand over autonomy regarding the energy sector to the EU, mainly because energy security is regarded as a crucial national interest. Currently, the only EU-wide energy policy with binding national targets are the 20-20-20 goals, which specify emission reduction and energy efficiency goals, to be achieved by separate Member States in 2020. Hence, apart from some regional cooperation and bilateral agreed upon interconnection lines, a centrally organised and optimised European power system has a long way to go.

Measures that can support the integration of RES-E in the current power system, and possibly prevent distortions or even outages, might profit from a more centrally coordinated power system design. Technical solutions, like backup capacity, Electrical Energy Storage (EES) and Demand Side Management (DSM), are available but come at a price. The costs of these additional measures can be incorporated in the total system costs. A good measure of comparison for systems with different levels of RES-E integration is the system Levelised Cost Of Electricity (system LCOE). These can be minimised if additional measures for RES-E integration are applied on a larger geographic scale and combined with optimal mixes of complementary wind and solar PV power, strategically located generation capacity and a sufficient electrical transmission grid.

This thesis is set out to investigate the system LCOE for increasing shares of RES-E in the European energy mix, under several power system planning scales. The difference in system LCOE between several possible planning policies is the most direct form of comparison. The composition and origin of these costs differences provides insight in mechanisms driving power system costs, and the added value of complementary options for RES-E integration. However, different planning policies also have consequences for current, national energy security goals, electricity interdependencies and generation portfolio diversities, for which the results need to be considered as well. This leads to the following main research question: 'What is the effect
of different levels of centralisation for European power system planning, on cost, design choices and energy policy objectives, taking increasing shares of intermittent renewable electricity into account?".

To find the theoretical optimum, and research the effects of several planning scales, a model was developed. This system costs minimisation model represents the European power system, where Member States form the different nodes. Historical potential output data for wind and solar PV power, with an hourly resolution, was used to model the RES-E. Other generation options that were added are CCGT, hard coal plants and biomass plants. The model was run over a set of 52 days, one from each week of the year 2012, equally distributed over all days of the week. The required share of RES-E in the generation mix was subsequently increased from 20%, to 50% and ultimately 80% for each investigated scenario. EES options consisted of Flow Batteries (FB), Pumped Hydro Storage (PHS) and Hydrogen storage (H2). Furthermore the construction of a electrical transmission grid was included in the optimisation, where interconnections between neighbouring countries, or nearby overseas countries were given as optimisation options. A greenfield situation was taken as point of departure, in which no energy infrastructure is present, and the model was used to find an optimal design for the lowest total system costs. By dividing the total system costs (€) by the total demand (MWh) the system LCOE (€/MWh) was calculated, which are presented, for all scenarios, in Figure 6.2.

To validate, and give insight in deviations of optimised system designs from current lay-out, two reference scenarios were created. The first uses all currently installed capacities per technology (REF2015), while the second assumes expected installed capacities around the year 2050 (REF2050). The experiments were run with four different policies:

1. **National (NAT);** The first scenario represents a national planning policy, where countries plan their installed capacities to fulfil demand and RES-E requirements separately. In the dispatch phase the use of currently installed interconnection capacity is included. This policy scenario closely resembles the system design under current policy.

2. **Regional (REG);** The second policy scenario assumes a regional coordination of both generation planning, transmission planning and RES-E requirements, but does not allow for interaction between regions. Regional here stands for a group of countries, on average three, working together in the planning and dispatch.

3. **Continental (CON);** A third scenario increases the planning scale to continental level, for which all elements can be optimised. The RES-quota has to be met with all countries together, which allows for the most favourable locations to be used.

4. **Country goals (CG);** For the fourth scenario (CG-scenario) the continental planning scale was used, but additional country goals were added, which constrain the minimal amount of installed flexible generation (CCGT, coal and biomass) to the peak load.

Three types of results can be derived for the investigated policy scenarios: the involved costs and composition of those costs; the origin of these costs from installed capacities, the generation portfolio and resulting dispatch; and effects of different scenarios on national energy security and RES-E policies. From the experiments it was found that a continental scenario provided the lowest system LCOE, which proved to be significantly lower than the current system LCOE, even for larger RES-E shares. For all scenarios the energy costs would rise for increasing levels of RES-E integration. This increase in costs was found to be the smallest for the continental scenario and the largest for a national planning policy. The differences between scenarios are the most extreme at the 80% RES-E integration: 21% higher for NAT80 than CON80. Although the variable costs decrease for increasing shares of RES-E, the fixed costs increase more, which leads to the higher system LCOE. The costs from storage and transmission, generally, form only a small percentage of the costs. The differences between the NAT and REG scenario are only marginal, especially at lower RES-E integration levels. The central coordinated CG scenario only finds lower costs than the NAT and REG scenario for 80% RES-E integration. It is concluded that a European policy, aiming for central coordination of power system design, is increasingly economic beneficial for higher shares of RES-E integration, where it can save up to 8€/MWh.

In none of the policy scenarios there was any use of biomass, while CCGT was only used marginally. The use of solar PV is almost negligible for lower shares of RES-E, but was found to play an increasingly important role as RES-E requirement increased. For a 100% centrally planned scenario installed capacities consist for 90% of wind and 10% of solar PV. The use of storage was found to be almost exclusively PHS. Only in the NAT50, NAT80 and REG80 scenario some use of H2 was found to be beneficial. The effect storage has on the price is small, only up to 3% for the CON scenario. It was found to result in reduced need for solar PV
Figure 1: The system LCOE per scenario, given in €/MWh for increasing shares of RES-E integration (20%, 50% and 80%). The reference scenario for 2015 was found to have a maximum RES-E integration of 15%, while the reference scenario for 2050 is given for a maximum of 45% RES-E integration. VOM = Variable Operations & Maintenance

and CCGT, with a sensitivity analysis. The absence of transmission has a much more significant impact on the price, and resulted in a larger share of CCGT in the generation portfolio, but no such increase on solar PV. In the optimal design the CON and CG scenarios required up to seven times more transmission capacity than currently installed, but no increase in installed length is needed. It can be concluded that the effect of transmission on a power system design is more important than the effect of EES. Optimal designs, especially from a centralised power system planning policy, result in a multitude of currently installed transmission capacity. Most EES technologies and biomass plants are not economically competitive with other solutions, hence are not, or only marginally, used in an optimal design.

The last type of conclusions regards implications of the optimal design for national energy security, investment and energy policy, which was found to be ambiguous. On the one hand it shows an increasing energy interdependency among Member States as consequence of centralised coordination scales. In terms of energy security centralising power system planning policy is disadvantageous for some Member States, because they become completely dependent for their flexible generation capacity. On the other hand, as European RES-E goals can be achieved by using only the most favourable weather locations for wind and solar PV, not all countries have to include RES-E in their generation mix: some countries are merely used for flexible backup generation. However, other countries have neither RES-E or conventional generation and are thus completely dependent on neighbouring countries. At the same time a large share of generation capacity also results in high investment costs for a particular nation. It can be concluded that increasing the planning scale favours some countries in terms of energy security by assigning large amounts of generation capacity, but at the same time requires high investment costs, with all risks involved. It is difficult to determine whether a country thrives or is disadvantaged as a more central coordination is applied. Interestingly, the CG scenario finds a relatively distributed installed capacity, but only becomes economically favourable compared to a NAT or REG scenario at 80% RES-E integration levels.

For policymakers it is interesting to see that a significant cost reduction can be realised if the power system planning scale, including generation, storage and transmission planning, is done from a more central perspective. High shares of RES-E can then be integrated without significant increases in system LCOE. Increasing the planning scale inevitably creates a system which is heavily reliant on an extensive transmission grid. It also results in strong concentrations of generation technologies, leaving some Member States completely dependent on neighbouring countries, while others have to invest heavily in generation, transmission and/or storage capacity. The willingness of countries to give up energy independence within the EU, in order to achieve high levels of RES-E integration without unacceptable costs increase, is uncertain. Regarding historical resistance against the handover of autonomy it is expected not to be very realistic on the short-term. Policy options for which the planning is done from a central perspective, but with respect for national energy security goals and a certain distribution of generation capacity over Europe, might prove to find more acceptable solutions.
Preface

This report, lying here before you, is the result of seven months of studying, modelling and writing in order to obtain the title of Master of Science. Those seven months, however, are preceded by almost eight more years of learning, sometimes at the Delft University of Technology, but, equally important for this end product, in other places, from other experiences.

This research focusses on a sustainable energy future, which is something, I believe, is extremely valuable and should be safeguarded as good as possible. This fascination with the way humanity is both dependent on power but also faces serious problems obtaining it, grew during my study. It led to taking up courses besides the normal study path that were relevant and increased my knowledge about this topic. After several false starts of graduation projects which were much less focussing on the renewable energy sector, it proved worth the wait for this project, which allowed me to combine all knowledge and interests I have for this topic. Even though I had to learn how to model in Matlab in a few months, not very common for students at the Technology, Policy and Management faculty, up to today I have no regret at all.

I am truly proud to present this final thesis as crown piece of my studying life so far, but realised increasingly during the process of writing it, that this could not have been accomplished without the help of some people around me. The people that helped me realise this thesis, in particular, and supported me while I was learning lots of new things, have been extremely important.

First, I would like to thank Petra, for giving me the opportunity of performing a much more quantitative research than I was used to by granting me the assignment. Her support with getting all modelling equations in order was indispensable. Even more important, her fast response to all my questions and requests, as well as her availability during my graduation resulted in some envy among fellow, befriended graduate students. They had to find rare gaps in the agenda of their supervisor and were often granted just a few minutes to discuss their problems.

Secondly, I want to thank Mark. He has been a great support for his detailed commenting on written work and his thoughts on how to place my modelling outcomes into a broader perspective. Moreover, I am grateful for his supportive attitude during the half year preceding this project, in which multiple other graduation projects, smothered in early phases.

I also like to thank the chair and professor of my committee, Paulien. The opportunity she provided me to have one more week before final greenlight was greatly appreciated.

The last person of my committee deserves at least as much credits as the aforementioned members. His enthusiasm for this project and the results were really motivating. His knowledge of modelling and all sorts of additional computational questions saved me more than once. The ‘loan’ of his University computer, by allowing me to ‘break in’ from distance gave me the much needed computational strength during a period of time pressure and sleepless nights.

Aside from those who helped me from an academic perspective I would like to thank some people who devoted incredible amounts of time on reading, correcting and suggesting my research and written work in particular (so thanks Sophie, Yorick, Hustinx, Koen, Ad, Daan, Chris and Lei). Especially Brody deserves lots of gratitude for improving my English writing to a minute level of detail. My brother Bas can be seen as the ‘creative director’ of this piece of work, as he helped me to visualise the sometimes overwhelming amount of results. At last, this thesis means that an end has come to my student life. This period, it must be said, would not have allowed me to acquire so much knowledge, both academic and about life, friendships and happiness without the boundless trust and support of my parents. I hope they are glad the first of their offspring is now, finally, independent.

Tim de Pater
Delft, March 2016
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## Acronyms and Abbreviations

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<td>AC</td>
<td>Alternating Current.</td>
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<tr>
<td>ACER</td>
<td>Agency for the Cooperation of Energy Regulators.</td>
</tr>
<tr>
<td>BU</td>
<td>Bottom-up.</td>
</tr>
<tr>
<td>CAES</td>
<td>Compressed Air Energy Storage.</td>
</tr>
<tr>
<td>CapEx</td>
<td>Capital Expenditures.</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined-Cycle Gas Turbine.</td>
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<tr>
<td>CCS</td>
<td>Carbon Capture and Storage.</td>
</tr>
<tr>
<td>CF</td>
<td>Capacity Factor.</td>
</tr>
<tr>
<td>CSP</td>
<td>Centralised Solar Power.</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current.</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed Generation.</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand Side Management.</td>
</tr>
<tr>
<td>DSO</td>
<td>Distribution System Operator.</td>
</tr>
<tr>
<td>ECSC</td>
<td>European Coal and Steel Community.</td>
</tr>
<tr>
<td>EES</td>
<td>Electrical Energy Storage.</td>
</tr>
<tr>
<td>ENTSO-E</td>
<td>European Network of Transmission System Operators for Electricity.</td>
</tr>
<tr>
<td>ESM</td>
<td>Energy Sector Models.</td>
</tr>
<tr>
<td>EU</td>
<td>European Union.</td>
</tr>
<tr>
<td>EV</td>
<td>Electric Vehicle.</td>
</tr>
<tr>
<td>FB</td>
<td>Flow Battery.</td>
</tr>
<tr>
<td>FIT</td>
<td>Feed-In-Tariffs.</td>
</tr>
<tr>
<td>FLH</td>
<td>Full Load Hours.</td>
</tr>
<tr>
<td>FOM</td>
<td>Fixed Operations &amp; Mainentance costs.</td>
</tr>
<tr>
<td>GEP</td>
<td>Generation Expansion Planning.</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gasses.</td>
</tr>
<tr>
<td>HVAC</td>
<td>High Voltage Alternating Current.</td>
</tr>
<tr>
<td>IEM</td>
<td>Internal Energy Market.</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelised Costs of Electricity.</td>
</tr>
<tr>
<td>MEM</td>
<td>Macro-economic Models.</td>
</tr>
<tr>
<td>MILP</td>
<td>Mixed-Integer Linear Problem.</td>
</tr>
<tr>
<td>NTC</td>
<td>Net Transfer Capacity.</td>
</tr>
<tr>
<td>PCI</td>
<td>Project of Common Interest.</td>
</tr>
<tr>
<td>PHS</td>
<td>Pumped Hydro Storage.</td>
</tr>
<tr>
<td>PTDF</td>
<td>Power Transfer Distribution Factors.</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic.</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable Energy Sources.</td>
</tr>
<tr>
<td>Acronym</td>
<td>Definition</td>
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<tr>
<td>---------</td>
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</tr>
<tr>
<td>RES-E</td>
<td>Renewable Energy Sources for Electricity.</td>
</tr>
<tr>
<td>RLDC</td>
<td>Residual Load Duration Curve.</td>
</tr>
<tr>
<td>SEP</td>
<td>Storage Expansion Planning.</td>
</tr>
<tr>
<td>TD</td>
<td>Top-down.</td>
</tr>
<tr>
<td>TEP</td>
<td>Transmission Expansion Planning.</td>
</tr>
<tr>
<td>TGC</td>
<td>Tradable Green Certificates.</td>
</tr>
<tr>
<td>TSO</td>
<td>Transmission System Operator.</td>
</tr>
<tr>
<td>TYNDP</td>
<td>Ten Year Network Development Plan.</td>
</tr>
<tr>
<td>U.S.</td>
<td>United States of America.</td>
</tr>
<tr>
<td>UCTE</td>
<td>Union for the Co-ordination of Production and Transmission of Electricity.</td>
</tr>
<tr>
<td>UNFCC</td>
<td>United Nations Framework Convention on Climate Change.</td>
</tr>
<tr>
<td>VOM</td>
<td>Variable Operations &amp; Maintenance costs.</td>
</tr>
</tbody>
</table>
Introduction

In February, 2015, the European Union (EU) adopted the European Energy Union package, which aims at a more integrated energy system and market. It is illustrative for the pursuit of a more coordinated European energy policy by the EU, and combines multiple fields of current collaboration. Energy has been one of the central pillars throughout the development of the EU. Recently, issues about climate change and energy security affected the national and European energy policies strongly and gave rise to renewed attempts on a centralised energy policy (Helm, 2014, 2015). However, despite all efforts made by the EU to come to a more coordinated approach of energy related challenges, most of these policies are still made at nation state level. The supply of energy is a vital national interest and governments are hesitant to give up autonomy (Müller-Kraenner & Langsdorf, 2012). The effect of different coordination scales for energy policy, especially under increasing shares of renewable energy, is currently uncertain. To give insights as to the implications of current policy and EU goals, this thesis describes a study into the effects of different power system planning scales. The chapter below describes context and explains the problem and approach of this research.

1.1. An energy system under pressure

Two major drivers for the desire to transform the European energy system can be identified. First, global effects of climate change make decarbonisation of the energy supply an international ambition. Secondly, in the strongly import-dependent EU, energy security combined with geopolitical instabilities from the main oil and gas suppliers strengthens the will to find other sources of energy.

1.1.1. Anthropogenic contribution to global warming

Since the mid-1950s, evidence has increasingly been found, linking the rising concentration of Greenhouse Gasses (GHG) in the earth's atmosphere, most importantly carbon dioxide (CO$_2$), to an increase of average global surface temperature. Further research unveiled increasing evidence that human activities are the source of these rising CO$_2$-levels and the Intergovernmental Panel on Climate Change (IPCC) now officially states this as "extremely likely" (IPCC, 2014a, p. 5). The temperature increase is expected to have serious negative effects on ecosystems and human societies. There are more and heavier extreme weather events, such as floods, heat waves, droughts and cyclones. These natural disasters alone could already cause life-threatening situations, but indirect impacts, especially on the developing world, are potentially disastrous. Crops, vulnerable infrastructures and livelihoods can be destroyed and waterborne diseases easily spread, especially damaging poorer people and countries (Hallegatte et al., 2016; World Bank, 2013). The problem is not only serious, but also urgent, as a delay in responding could have several irreversible consequences (Lenton et al., 2008; Luderer et al., 2013; Riahi et al., 2015; United Nations, 2015).

Economic growth and global increase in population are seen as the most significant instigators for the rise in CO$_2$ emission-levels, especially from fossil fuels (IPCC, 2014b). Burning these fuels already causes over 60% of the global GHG emissions and consequently is the main driver for climate change. Global energy usage has increased steadily in recent decades and continues to do so according to most economic scenarios (IEA, 2012b). The first political recognition on international scale for the anthropogenic cause of climate change, and the conviction to act came in 1992. In that year, 175 nations adopted the United Nations Framework Convention on Climate Change (UNFCCC). Ratifying countries committed themselves to the development of
a legally binding instrument, that could limit human impact on global warming. Five years later, in 1997, the first result of this commitment was signed in Kyoto, known as the Kyoto Protocol, where most industrialised countries agreed on limits to their emissions. The EU signed as one party, and agreed on distributing the emission cutbacks amongst themselves internally (Grover, 2008).

1.1.2. Economic and geopolitical concerns about fossil fuel dependency

The second major reason to change the energy system, consists of regional concerns about energy security. Humanity, especially the developed world, has become increasingly dependent on energy (Höök & Tang, 2013). In modern society energy is crucial to our economy and many other commodities, such as transportation of all kinds, ICT services, water supply and sewage systems. Not meeting energy demand is extremely costly and sometimes even dangerous (Larsson, Björkman, & Ekstedt, 2013). This indirect dependency on fossil fuels could have negative effects on the EU in two ways. First, most domestic fossil fuel resources are insufficient, while the majority of global resources is owned by a small number of suppliers, which inevitably creates geopolitical tensions. Figure 1.1 shows an example of the typical worldwide fossil fuel trade movements, where the European dependence on external suppliers is evident. In its latest European Energy Security Report the EU couples the risk of heavy price spikes for fuel supply and disruptions of energy supply to multiple factors, including “suppliers, transport modes, market structure and regulatory framework and supply points, and the commercial stability in the countries of origin” (European Commission, 2014, p. 3). Heavy reliance is thus considered a severe risk under current geopolitical developments, as it might be used for political pressure according to the European Commission (2012, 2014). A second negative effect of a carbon energy system comes from the fact that resources are finite; possible scarcity results in concerns about future security of supply, which also threatens energy prices (IPCC, 2012). Additionally, an approaching depletion of fossil fuel reserves is likely leading to higher prices and greater price fluctuations (Bardi, 2007).

1.2. The European energy transition

Both climate change and energy security considerations motivate European governments to take action and reform their energy sector. The EU and its Member States have committed themselves to reduce CO₂ emissions, both in the Kyoto Protocol and more recently during the Paris summit (European Commission, 2016). Also the increasing dependency on fossil fuel import has incited the EU to set energy targets for the coming decades (European Commission, 2014). To address the aforementioned problems, the approach should be twofold: requiring both a decarbonisation of energy supply and an increase in energy efficiency (Chu & Majumdar, 2012). A stabilisation of EU import dependency already has been noticed since 2006, because of an increasing share of Renewable Energy Sources (RES) on the one hand, and energy efficiency measures on the other hand (European Commission, 2014). Most of the further decarbonisation is expected to come from the
introduction of RES, and electricity sources in particular (European Commission, 2014; IEA, 2015). The goals are set on a continental level, but since electricity markets are organised on lower levels, national policies, laws and regulations are still needed to effectuate real change.

To understand why electrical energy sources are often the centrepiece of sustainability policies, the current role and the potential of this form of energy for the European society has to be clear. Currently, most known and developed RES are power-generating technologies, such as wind turbines and solar Photovoltaic (PV). These sources, on the short-term, have the highest potential of fulfilling the demand in a sustainable way, which becomes clearer upon closer examination of the energy consumption figures. In 2012, 18.1% of total energy consumption worldwide was delivered directly by electricity. The other sources are mainly fossil fuels, oil in particular, and some biofuels (see Figure 1.2a). Looking at the most emitting sources, we find that the largest single source actually is the power-generating sector (see Figure 1.2b). If only the power generation could be made more sustainable, a large part of Europe’s CO\textsubscript{2} emission could be prevented and fossil fuel dependency could be decreased. The reduction potential further increases when a future trend is taken into consideration. Electrical engines have a realistic opportunity for electrifying (parts of) the transport sector (Dyke, Schofield, & Barnes, 2010; Valsera-Naranjo, Sumper, Lloret-Gallego, Villafafila-Robles, & Sudria-Andreu, 2009). The most used fossil fuel, oil, can mainly be attributed to transport and the CO\textsubscript{2} emission from this sector is notable (see Figure 1.2b). Combining the two sectors gives a significant potential for sufficient CO\textsubscript{2} emission reduction, as well as mitigating the risks of fossil fuel use. Since the focus of this research will be on the renewable energy sources generating electricity, a separate abbreviation is used for Renewable Energy Sources for Electricity (RES-E) to avoid confusion.

Sustainable energy supply is not the only and arguably not the most important EU goal for the energy sector. Three main goals for energy supply can be identified: sustainability, affordability and security (these terms are defined in table 1.1). The introduction of RES-E, especially at larger shares and in the long-term, threaten the latter two goals. Their characteristics are incompatible with the current power system design, as will be explained below.

1.2.1. Intermittency of RES-E
Although RES-E harbours a great potential, some characteristics make them very hard to integrate in our current power system. The most promising RES-E, wind power and solar PV, are highly weather dependent for their power output (Lund, 2007). The weather conditions can differ significantly over time (temporal) and per location (spatial). This means that potential production from both wind and solar power knows strong spatial and temporal variances, which is called ‘intermittency’. These variances are not random, but certain periodic patterns, such as day-night and seasonal, can be observed. Deviations from the standard patterns often occur, which limits the reliability of output predictions. Additionally, more and less favourable locations for certain RES-E types can be defined, which do not always correspond with demand centres (Heide et al., 2010). Dependence on the weather conditions means that the amount of electricity produced from RES-E is, to a certain extent, unmanageable and offers little flexibility to regulate power output. The intermittency of
<table>
<thead>
<tr>
<th>Criterium</th>
<th>Definition</th>
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<tbody>
<tr>
<td>Sustainability</td>
<td>“Meeting the needs of present generations without jeopardising the ability of future generation to meet their own needs” (European Commission, 2015b, para. 1)</td>
</tr>
<tr>
<td>Affordability</td>
<td>Ensure the availability “of energy products and services on the market, at a price which is affordable for all consumers (private and industrial)” (European Commission, 2010, p. 2).</td>
</tr>
</tbody>
</table>
| Security of supply| Consists of two categories with multiple dimensions according to the OECD (2010):  
1. External:  
   (a) Geopolitics, access to primary fuels;  
   (b) Safety and adequacy of international infrastructures;  
   (c) Unanticipated resource exhaustion;  
   (d) Resilience to changes in climate policy;  
2. Internal:  
   (a) Adequacy of generation capacity;  
   (b) Adequacy of domestic transport infrastructure;  
   (c) Adequacy of market design and regulation;  
   (d) Price stability;  
   (e) Operational reliability; |

Electrical RES-E is incompatible with the current power system design. It was designed built for centralised power sources, with controllable outputs. Large-scale integration of RES-E poses multiple issues, both for security of supply as well as for affordability of power (Schaber, Steinkel, Mühlich, & Hamacher, 2012; Ueckerdt, 2015). To understand the underlying mechanism for issues with RES-E integration, a closer look at the electricity markets is required.

### 1.2.2. European power markets

At European electricity markets, power plants are dispatched based on the lowest operational costs (marginal costs). Power suppliers offer the amount of electricity, that they are capable of producing, for marginal costs at day-ahead markets, whereas power consumers bid the price they are willing to pay for a certain amount of electricity. The suppliers’ bids are sorted in increasing order of prices, which is called the ‘merit order’ and results in the creation of a supply curve (Deane et al., 2015). On the other side of the market, the bids of consumers are sorted in decreasing order, creating a demand curve. The final price is then determined at the equilibrium where these two curves cross, which in most markets is done on an hourly basis for one day ahead. During this so-called market-clearing process, the price and the amounts of electricity bought and sold are determined. The highest accepted bid then sets the price: all consumers pay and all producers receive this price per unit of electricity (see Figure 1.3a) (Hildmann, Ulbig, & Andersson, 2015; Ueckerdt, 2015). National markets already have some commercial and physical coupling to neighbouring markets via interconnection transmission networks. This should essentially integrate them to form one larger market, but the current use of the interconnection capacity prevents that. Most cross-border lines are currently explicitly auctioned, and thus separate from the power trading process itself. The transmission capacities are auctioned before the actual day-ahead market. After the market-clearing process it might be the case that a producer has more booked interconnection capacity available than needed, leading to inefficiencies. Also, transmission capacities can be sold for opposite directions at the same time, as it is unclear where the day-ahead market price will be higher. Capacity sold in one of those directions will eventually be superfluous, leading to less use of the transmission capacity than would be possible (Böckers, Veit; Haucap, Justus; Heimeshoff, 2013). This flaw in the market coupling is likely to lead to higher electricity prices and prevents the emergence of a fully integrated system.

The combination of this common market design and integration of large-scale, intermittent RES-E, threatens EU energy goals. Especially concerns regarding affordability and energy security considerations pose some issues with an increasing share of RES-E, as will be explained below.
1.2.3. RES-E as risk to affordability

Since RES-E have very low operational costs, they often come early in the merit order, making them the first to be put in production (Klessmann, Nabe, & Burges, 2008). This distorts the market and the business model of conventional generation plants in three different ways. First of all, it decreases the amount of time in which fossil fuelled power plants are dispatched, which decreases their market revenues (Brouwer, van den Broek, Seebregts, & Faaij, 2014). Secondly, the need for more flexibility from the total energy system increases, because of the high variability in output from RES-E. Conventional generators will have to adapt more to the capricious power generation of RES-E, resulting in more change in output, called ramping. It will lead to a lower mean time between failures, more maintenance and a decrease of efficiency, thus needing more fuel per amount of output. Overall an increase of operational costs is to be expected (Griffes, 2014; Van den Bergh & Delarue, 2015). Thirdly, since RES-E has such low marginal costs, the average market clearing price is likely to decrease as well. Support schemes worsen this effect by shielding RES-E from market signals, resulting in prices that become zero, or even negative (Klessmann et al., 2008). Hence, conventional power plants will be in operation less often, with higher operating costs and lower market prices, resulting in even lower revenues (see Figure 1.3b).

At short-term this effect is beneficial in terms of affordability: prices are decreasing because of the low operational costs of RES-E. In the long term, however, it does pose a threat. Flexible generation plants, which are much needed considering the intermittent nature of RES-E, will have a harder time becoming economically viable. To become profitable the conventional, flexible power plants will have to increase prices during periods of production shortage from RES-E or sell more capacity on imbalance markets, resulting in price spikes (Nicolosi & Fürsch, 2009). Negative outlooks for conventional generation capacity leads, in the long-term, to lower investments or even divestment (explained further in Section 2.2.2) (Klessmann et al., 2008). Other measures to keep the system stable, when competitive flexible generation capacity falls short, are costly or even unavailable in the current design. It can thus be concluded that the market distortions as described above lead to a higher price volatility and, in the long term, to increasing energy costs (Moreno et al., 2012).

1.2.4. RES-E as risk to security of supply

With the integration of RES-E, the fossil fuel dependency decreases, solving external security of supply issues for fossil fuels (see Table 1.1). However, a whole new aspect of internal issues, like adequacy and operational reliability, comes into play. The technical stability of a power system is defined as its ‘grid stability’. For this it is important to balance the production and consumption at any moment in time and keep frequency and voltage levels within certain boundaries (see also Section 2.2.1 for more detail on the latter two) (Donker, Huysgen, Westerlea, Weterings, & Bracht, 2015). The intermittency of RES-E, as was shown in Section 1.2.1, causes fluctuations in output over time. Although electricity demand can be seen as fluctuating over time as well, it follows more predictable patterns on a daily basis, a weekday as compared to weekend day basis, and on a seasonal basis (Hekkenberg, Benders, Moll, & Schoot Uiterkamp, 2009; Schaber, Steinke, Mühlisch, & Hamacher, 2012). These output and demand patterns are often out of sync, creating a need for other solutions

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**Figure 1.3:** (a) Annual supply and demand curve in the electricity market. Reprinted from EWEA (2009) (b) The RES-E effect on wholesale market prices. Reprinted from Moreno, López, and García-Álvarez (2012)
1. Introduction

to balance the grid. The most used solution nowadays is flexible back-up power capacity (ECF, 2010). From the affordability issues it was concluded that RES-E will push conventional power plants out of the market, within the current market design. In the long term, a structural decrease in revenues results in lower new capacity investments or, in more extreme cases, a divestment in fossil fuel plants. Without the conventional power plants the system will experience a lack of flexibility in generation, increasing the risk of disruptions (see also Section 2.2.1) (Ninghong Sun, Ellersdorfer, & Swider, 2008). As long as that risk is real, the security of supply is not guaranteed, making the integration of RES-E a potential threat to both affordability and security of supply.

1.3. Approach of RES-E integration

Over the past decade, the wide variety of national sustainability policies led to a steady increase in the share of renewable energy in the EU, mostly due to the newly installed capacity of solar PV and, even more, (offshore) wind energy (Eurostat, 2014). For the coming decades, the forecast under current policies is that the share of renewable energy sources will continue to grow, becoming the largest share of load served in Europe by 2050 (ECF, 2010; IEA, 2012a). At present, around 15% of the generated power in the EU originates from intermittent RES-E (Eurostat, 2015). The expected increase of this share asks for more measures to ensure security of supply and affordability. The EU implemented multiple guidelines and binding targets over the past decade to simultaneously increase the share of RES-E and guarantee energy security. The 20-20-20 targets specify obligatory goals on national level for the year 2020. These goals are to be translated into policies on a national level. The Roadmap 2050 sketches more generic targets per decade up to 2050, but has no legislative effect and serves more as a guideline. The energy security strategy promotes resilience against shocks and disruptions, but only specifies a joint approach towards external suppliers, combined with technical grid stability recommendations towards Member States (ECF, 2010; European Commission, 2010, 2014).
All these policies only affected separate parts of the power system and often lack executive instruments. The EU already has plans for a more coordinated approach of some elements in the power system planning, by introducing an European Energy Union. It is the latest development in a long history of a joint, European energy policy.

1.3.1. The European Energy Union

On 25th February 2015, the EU adopted a 'Energy Union package'. The main goal of this package is a more integrated European energy system, with all aspects involved (for clarification, see section 1.4.2). In order to integrate increasing shares of RES-E while keeping electricity affordable and the supply secure it is the firm belief of the European Commission that competition should be fostered and the utilisation of electricity networks and generation capacities should be increased. The Commission plans to do so by integrating European wholesale markets through physical and commercial coupling of the national power systems as was emphasised by the report on a European Energy Union (Böckers, Veit; Haucap, Justus; Heimeshoff, 2013; European Commission, 2015a). It envisions “an integrated, continent-wide energy system where energy flows freely across borders, based on competition and the best possible use of resources, and with effective regulation of energy markets at the EU level where necessary” and notes that “we have to move away from an economy driven by fossil fuels, an economy where energy is based on a centralised, supply-side approach and which relies on old technologies and outdated business models” (European Commission, 2015a, p. 2). It aims to unlock the national energy islands, by physically and institutionally connecting them to one large European system. The physical aim lies in upgrading and extending the energy infrastructure, mainly in terms of the transmission capacity between countries. Institutionally the market design is to be adjusted and national markets should be integrated more, to provide security for investors and affordable energy prices across Europe.

Up to now, three separate and distinct directions can be distinguished in the European energy policy. Since 1992, the completion of an internal European market is being extended towards the field of energy, which led to the, ongoing, development of an Internal Energy Market (IEM). Furthermore, the energy security of Europe is seen as a common European interest, mainly induced by Russian gas supply distortions over the past decade. It gave rise to the European energy security strategy. The last direction of joint policy regards sustainability goals. These were set on a European level, which resulted in binding emission targets per Member State for 2020 as stipulated in the 20-20-20 goals. A more central approach of aforementioned policy areas is believed to have, in particular economic, benefits (Helm, 2014, 2015). Especially regarding current exogenous developments, like climate change and geopolitical instabilities, the last two policy areas are important components of a European energy transition.
The Energy Union Package tries to integrate the multiple policy areas and builds on a long history of a joint energy approach, which started with the very founding of the European Coal and Steel Community (ECSC) and the importance of coal to Europe's power supply. However, with many preceding attempts to unify the energy policy, a recurrent trend became visible. Member States preferred national interest over the joint European benefit, as they saw no way to internalise shared advantages (Helm, 2015). The analogy with the emergence of national power systems is striking. France and the UK imposed the national electricity system upon the already present regional and local systems around the 1950s. The result was much more well-designed and efficient than that of European countries allowing lower level governments to maintain control. It appears that very few attempts have been made to design a top-down guide for Europe, showing the benefits it could result in for different Member States (Helm, 2015).

The only technical field of current collaboration within the power system is the bilateral transmission capacity. Within the Energy Union package, the European Network of Transmission System Operators for Electricity (ENTSO-E) is expected to take up planning and managing of cross-border power flows on a regional level. This organisation has been a platform for collaboration between national Transmission System Operator (TSO)s and was given legal mandates with the Third Energy Package of the EU from 2009 (Section 2.2.3 gives further explanation on the role, power and responsibilities of ENTSO-E) (European Commission, 2015a). They have concrete and ambitious investments planned in Europe's transmission network, which are executed as Project of Common Interest (PCI), an instrument allowing the EU to perform infrastructural projects if it achieves a common European interest (ENTSO-E, 2014b; European Commission, 2014). At this moment, the intra-European interconnection capacity is relatively small and at most national borders congestions of the grid are already a real problem. As the share of RES-E increases, addressing this problem is becoming increasingly urgent (Schellekens, Battaglini, Patt, Lilliestam, & McDonnell, 2010). Various research studies have looked into the role of grid extensions for a future European power system with large amounts of intermittent RES-E. These studies demonstrated that, with the use of an extensive transmission grid, total system costs could indeed be drastically lowered while maintaining grid reliability (Fürsch et al., 2013; Schaber, Steinke, Mühlich, & Hamacher, 2012). However, these studies also showed that using only grid extensions will likely lead to incomplete solutions and unnecessary high prices. Other technical measures, like electrical energy storage, can complement grid extensions to even further reduce integration costs of RES-E (see also chapter 3) (Brouwer, Van den Broek, Zappa, Turkenburg, & Faaij, 2016; Ueckerdt, 2015; Weitemeyer, Kleinhans, Vogt, & Agert, 2015). These technical measures will be elucidated in the Section below.

1.3.2. Technical solutions for large-scale RES-E integration

As was shown in Section 1.2, the largest problems arise from the fact that RES-E is temporally intermittent. A range of readily available technical measures to reduce the risks while integrating large shares of RES-E is available. These mostly try to reduce the effects of the aforementioned intermittency (see Table 1.2). The extra costs involved with additional measures are often seen as RES-E integration costs. To have a fair comparison of costs between systems with RES-E and with more conventional power plants, some researchers suggest to look at system costs rather than solely the costs per technology (Barth, Weber, & Swider, 2008; Schaber, Steinke, Mühlich, & Hamacher, 2012; Ueckerdt, 2015). The results of earlier studies all suggest that lower system costs can be reached with a combination of measures than with each of them individually. They show that a combination of measures is more likely to reach a carbon-free future with costs to society that would be more acceptable. Additionally, an increase in planning scale is found to be beneficiary as well (see Chapter 3). This research will focus on the combination capable of a fully renewable electricity future from the generation side perspective and incorporates an 'optimal RES-E mix', 'Electrical Energy Storage' and looks at 'Grid Design and RES-E Distribution'.

1.4. This investigation

This section will give an overview of the research that was performed based on the identified problems. First the problem and research are discussed, followed by the difficulties surrounding power system design. Following this, the expected insights of the study and concrete research questions are outlined. The last section shows the layout of this report.

1.4.1. Problem statement

As has become evident, a transition of the European power system towards a low-carbon and fossil fuel independent future is required. EU policies have been developed to move toward a more integrated European
Table 1.2: Measures for dealing with RES-E integration temporal intermittency problems

<table>
<thead>
<tr>
<th>Measure</th>
<th>Effect of measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flexible generation as described by Steinke et al. (2013)</td>
<td>Flexible generation can generate electricity at moments where RES-E does not produce enough to fulfil the demand, due to weather circumstances. The combination of RES-E and flexible generation can produce a constant output, dealing with the intermittency.</td>
</tr>
<tr>
<td>DSM as described by Weitemeyer et al. (2014)</td>
<td>By making electricity demand more adjustable to RES-E output, there is less need for constant production, which will decrease intermittency problems.</td>
</tr>
<tr>
<td>Optimal RES-E mix as described by Heide et al. (2010)</td>
<td>By finding an optimal mix between installed capacity of different RES-E, with complementary intermittency profiles, the total output of all sources at a certain moment in time can be made more constant, decreasing the intermittency.</td>
</tr>
<tr>
<td>EES as described by Heide et al. (2011)</td>
<td>Storing electricity during moments of overproduction (when more is produced than demanded) and releasing this energy during moments of production shortage, increases the ‘flexibility of RES-E’, decreasing intermittency.</td>
</tr>
<tr>
<td>Grid design and RES-E distribution as described by Becker, Rodriguez, et al. (2014)</td>
<td>Temporal fluctuations of RES-E generation pose problems to the national electricity system, which in turn has an impact on the interconnected European system. However, the spatial intermittency (intermittent in space) might help to reduce the temporal intermittency. If seen over larger areas the weather is almost never the same over the whole surface. With smart distributed RES-E and abundant transport capacity electricity generated anywhere in Europe gives a much more stable production level and could be transported to every demand location, decreasing temporal intermittency.</td>
</tr>
</tbody>
</table>

Energy Union, mostly by encouraging Member States to integrate large amounts of RES-E. However, the current power infrastructure is not designed for the intermittency of most common, sustainable generation technologies. Integrating large shares of RES-E in current power systems threatens affordability and security of supply goals. To counter these threats, the measures now taken by the EU involve physical and institutional integration of the national markets, with a more central coordination of transmission investments and power flows between countries by the ENTSO-E. Other technical solutions for the integration of variable RES-E have not yet been incorporated in European policy, but are left for coordination on a national scale. This is likely to cause unnecessary high integration costs of RES-E. Additionally, the available technical measures are quite scale dependent and results from some research studies suggest that a better techno-economic design is possible with a central coordinated approach of all involved options. Such a central approach is complicated, both from a technical perspective as from an institutional point of view. Currently each nation has an only marginal connection to, and cooperation with neighbouring systems, which makes the current European power system very fragmented. Besides, the attempt to organise a more joint European approach to energy policy was always frustrated: national interests often prevail over shared European benefits. It remains unclear what such a coordinated design would look like, or what consequences it would have for national energy policy.

In order to gain more insight into added value and best scale of a more central coordinated electricity infrastructure, this thesis reports quantitative research. Based on the availability of technical solutions for the integration of large shares of RES-E, this study searches a system costs minimisation for the design of a possible European power system in the far distant future. For this research, a simplified model of the power system comprises the elements of generation/conversion, electrical energy storage and interconnection capacities. It determines both the best (least-cost) infrastructure (location and capacity of considered technologies an the transport network) as well as the operation of the system (economic dispatch and transport flows). The potential output for intermittent RES-E is based on real-time weather data with an hourly resolution. The mismatches in RES-E output and historical hourly demand are solved by additional technologies, like storage, transmission and dispatchable back-up generation. In this way, a fair representation of short-term dy-
namics can be combined with a longer-term planning horizon. The nodes of the system will consist of the EU Member States, as current active policymakers on power system level. The optimal design will be discussed for multiple planning levels: national, regional (as a small group of countries) and continental. This provides information on the added value of centralising design policy and the composition of costs. The underlying mechanisms for the differences in costs will also give a first indication on which elements of such a system are worth including. The implications of such a design on national energy goals will also be presented.

1.4.2. Designing power systems
Designing a power system is challenging, due to a few typical characteristics. Infrastructures are often very capital intensive and have a very long lifetime (Donohoo-Vallett, 2014; Melese, Heijnen, & Stikkelman, 2014). They have also been defined as socio-technical systems. This means that designing them not only includes technological components, but also institutional and organisational ones, and is often dependent on external factors, like fuel prices and public acceptance of certain technologies (Geels & Kemp, 2007; Hughes, 1987). Decisions regarding the infrastructure design have a large impact on society and need to be carefully planned by policy-makers. When researching the techno-economic aspects of the European power system, considerations on institutional aspects will also be taken into account, for the sake of completeness.

The technical part for the model of a power system consists of all technological, physical parts needed to get electricity from producer to consumer. For this study a rough division into three parts was chosen:

- **Generation:** All electricity generating facilities, such as fossil fuel and nuclear power plants, but also RES-E, like wind turbines and solar panels.

- **Storage:** All types of storage facilities, used to store electrical energy (EES), such as pumped hydro, compressed air, batteries or hydrogen. Although at present the installed capacity is relatively small, it is expected to fulfil a greater role in future electricity systems (Steinke et al., 2013).

- **Transport:** A transportation system is needed to transport electricity from the source, power generation or storage, to the consumers. This sector can be divided into multiple levels. The top level is the transmission grid, transporting large amounts of high-voltage electricity over longer distances. The lowest level is the distribution grid, where electricity is distributed towards end consumers on lower voltage levels.

1.4.3. Research Objective
The objective for this research is to develop a method for finding the cost-optimal power system design for the EU, when high shares of intermittent renewable energy sources have to be integrated. The study should give EU policymakers an indication of the optimal planning scale, but also which elements are valuable to include and what conflicts with institutional and technical elements arise from a more centrally planned system design.

Motivated by the research objective and the problem statement above the main research question can be formulated:

'What is the effect of different levels of centralisation for European power system planning, on cost, design choices and energy policy objectives, taking increasing shares of intermittent renewable electricity into account?'

In order to answer the main research question, several sub-questions must also be answered. They are formulated as follows:

1. Which aspects of a power system are influencing the design?
2. Which model type and modelling tool are best for modelling and optimising the European power system?
3. How can model computation times and quality of the results be balanced for large-scale weather-data driven models?
4. How can the future European electricity infrastructure be approximated under current policy?
5. Which elements should be included when optimising the future European power system?
6. What consequences and effects will a more central coordination of the system have for national energy policy?

7. What is the influence of separate elements on the cost-optimal design for the European power system, considering several planning scales?

To research the above questions, a model was used, which was constructed via several steps. These steps are shown in Figure 1.4.

1.4.4. The starting point

The model investigates the differences in cost-optimal designs of a power system for different planning scales, which does not require the incorporation of existing infrastructures. To capture the current system adequately in a model, and optimise from that point of view, would result in an incredibly large model, where not all outcomes are relevant for this research. It is better to accept that historical developments have led to an, up to now, sufficient network design. The current power system emerged part by part, as it was shaped by a combination of investment decisions, demand development and regulatory measures (see also Section 2.1). The system created in that way might be optimal considered over the smaller national or regional areas, but is likely to be less than optimal seen over the whole EU power system. The only way now to find an optimal system is to step back and look at it from a greenfield situation (in which no infrastructure is in place yet, allowing for a complete new design). This starting point restricts the potential to draw direct policy conclusions from the results. However, as was pointed out by Zerrahn and Schill (2015, p. 2), such a model can be used for some other interesting learning points:

- First, a comparison of the 'optimal' system design with the current one gives an insight into how far away the optimum is. Conclusions on what building costs ensue, both in the past and for future extensions, can be derived. Comparisons between different policy planning scenarios can be made;
• A second insight that can be acquired is the effect of power system optimisation on total costs of a power system, so determining the importance of optimisation in future cases;

• As a last, and maybe more applicable goal, the research aims on the long-term future, in which little or none of the current infrastructural system is still in place, simply due to its lifetime. If it appears that great added value exists if power systems are optimised, policymakers might consider taking that design into account when deciding on future adaptations.

1.4.5. Structure of this thesis
The described research is documented in this thesis. This thesis shows both (parts of) the process as the actual research deliverables. Chapter 2 gives some further information of the European power sector. It gives some technical background, an overview of relevant actors involved and some economic aspects that need to be considered. This information helps to understand certain choices, that were made during the modelling process, but also gives additional information for the final conclusions and the reservations made with regard to omitted elements. The background information is followed by an investigation into the current state of power system modelling and explains the added value of this research from a scientific perspective. Chapter 3 presents an overview of commonly used methodologies, positions the model for this research in that environment and looks at the most relevant and recent researches from this field. The knowledge from this investigation is than taken along in Chapter 4. This chapter explains the theoretical model and shows the made assumptions and choices for the modelling process. Subsequently the conceptual model is followed by a formalisation, in which the model is translated from a theoretical description into a working computer model. In this chapter, Chapter 5, also the used data is evaluated and the resulting model is verified. Once a working and verified model is obtained, in Chapter 6 the experimental design is presented, in which several scenarios are explained. These scenarios are chosen in such a way that the comparison of results from these scenarios gives information, required to answer the research questions. The description of the scenarios is directly followed by the presentation of the most important results. A short description of what can be concluded from the results can be found here as well. Chapter 7 continues with a validation process, to determine whether the model functions as was intended, and to what degree the results are representative for the real world. This validation is accompanied by a sensitivity analysis to determine the impact of certain parameters, variables, choices and assumptions have on the results. As a prelude to the final conclusions, Chapter 8 discusses the results in the light of their validity, and interprets the underlying meaning and design implications for policymakers. Any reservations and relevant choices or assumptions that seem to influence the results strongly will be discussed here. The final conclusions and recommendations can be found in Chapter 9. This chapter answers the research questions, for as far as possible, based on the obtained results. It provides recommendations both for the scientific field of research in power system studies as to policymakers facing difficult challenges and choices for the design of a future European power system. The outline of the described thesis is visualised in Figure 1.5.
Figure 1.5: Overview of how this thesis is build up. In between the introduction and the conclusions a 'qualitative stream' and a 'quantitative stream' can be distinguished, where most chapters fall in the modelling part.
A European power system, the background

The current European power system emerged over the course of many decades. The transition from small, local systems, connecting one power source to single consumers, to the continent-spanning European Energy Union, took more than a century. Parallel to this emergence of the power system, energy policy developed, both on a national level and from the centralised EU perspective. In order to model this power system, optimise it and draw relevant conclusions for policymakers, some background knowledge about the emergence and system functioning, as well as energy policy is needed. It is especially important to understand the developments of the last two decades, which led to the upcoming RES-E integration issues and energy security concerns. In this chapter some of the historical, technical, economic and institutional aspects of our current European electricity system will be discussed, in order to draw more comprehensive conclusions from the techno-economic cost optimisation. The results can also be better placed in context with an understanding of elements that were not involved in the model, but do play a role in the real world.

2.1. The emergence of the present-day power system

The current European electricity network started developing from the end of the 19th century onward, and has not stopped developing since (G. Verbong, 2006). The infrastructure that emerged is therefore very well-established, both in technical and institutional terms. At the start of this process, no master plan was developed to build the best possible system. The first electrical networks were only created due to the necessity of a connection between a local power source and nearby consumption centres. In the period from 1915 to 1951 the planning of these systems shifted more and more from local, to incidental cooperation with neighbouring infrastructures, and eventually to a national scale (G. P. J. Verbong & Vleuten, 2002). In 1921, the International Council on Large Electric Systems (CIGRE) was established for sharing knowledge and joining forces to improve electric power systems, but all planning stayed within national boundaries (CIGRE, n.d.). First ideas of a pan-European electrical network stemmed from the 1930s, when engineers were planning to make the Mediterranean sea a large reservoir. By letting water in from the Atlantic ocean through turbines, electricity for the whole of Europe would have been created, which was to be transported through a Europe-wide network (Badenoch & Fickers, 2010). A decade later, during the Second World War, Germany initiated the construction of interconnection capacity to supply their war industry. This marked the start of a influential change in perspective (G. Verbong, 2006). In 1951 the Union for the Co-ordination of Production and Transmission of Electricity (UCTE) was established, which had the goal of connecting the French, German and Swiss grids. At the same time, all over Europe similar regional cooperation was established. This period continued until the 1990s where a more interconnected grid slowly developed, but within national institutional boundaries. It was only after the 1990s that these institutional boundaries were also crossed (G. P. J. Verbong & Vleuten, 2002).

2.1.1. Unbundling and liberalisation

Until the 1990s power systems had mostly been "vertically integrated geographic monopolies that were either state-owned or privately-owned and subject to price and entry regulation as natural monopolies" (Joskow, 2008, p. 10). This system had grown this way due to the specific characteristics of electricity, making it hard to let the system be organised by the market. Since electricity was seen as a vital commodity for the soci-
14 2. A European power system, the background

Figure 2.1: Conceptual, unbundled market design. The institutional layer (upper half) shows how the different actors trade on the wholesale market, what the role of the system operator is and how this is all connected to the physical layer (lower half). Reprinted from de Vries (2013).

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2.1.2. Integration of RES-E

The EU actively started making policy on RES-E in 2001, with the Directive on renewable energies in the electricity sector. It determined national goals for the increase of RES-E shares from a measured 12% in 1997 up to 21% in 2020. Later Directives and packages have broadened the view to the whole energy sector and are legally binding (Haas et al., 2011). When Directive 2009/28/EC was adopted, mandatory national targets were set, and in order to monitor the progress Member States have to submit National Renewable Energy Action Plans to show their planned trajectory (European Commission, 2009). The share of RES-E has steadily increased, also because of promotion schemes, providing subsidies and support for developing projects (see also section 2.2.2). The policies paid off, but concerns remain that it is not going fast enough. However,
2.1. The emergence of the present-day power system

production from RES-E came from a few TWh/year in 1990 to somewhere around 200 TWh/year in 2007, without hydropower (Haas et al., 2011). The installed capacity increased, reaching more than 500 TWh without hydropower in 2013, as can be seen from figure 2.2. The share is only predicted to rise, as national targets for 2020, and further into the future, oblige countries to take measures (Jäger-Waldau, Szabó, Scarlat, & Monforti-Ferrario, 2011). By 2020, a production of around 7000 TWh/year is expected, which may even increase to between 10,000 and 15,000 TWh/year in 2035 (IEA, 2013). It can be noted that these developments are expected to take place much faster than the time it took for the current power system to emerge. With the added complexity of many independent actors, the transition of such a large system will be hard to control. A thorough planning, and approach to deal with all different stakeholders, will have to be developed in order to design a power system capable of meeting the governmental energy goals.

2.1.3. Distributed generation and electric transport

Besides a shift towards integrated, competitive markets and large shares of RES-E, the power sector also experiences other trends, mostly on a smaller scale. Nowadays, the power sector is still organised unidirectional: Large-scale power producers on the one end deliver their electricity to multiple large, medium and small consumers on the receiving side. Where the bulk amount of energy is transported via the transmission grid, a lower voltage distribution network is used to serve retail consumers. However, the development of several small-scale power generation technologies, especially RES-E, has given consumers the possibility to provide shares of their own electricity demand. As these power generation units are distributed close to their points of consumption, they are also referred to as Distributed Generation (DG).

Another trend, the growth in usage of Electric Vehicle (EV), is also likely to have an impact on the power system. The share of EVs has increased over the past decade and is expected to keep growing. The charging of EVs is a potential threat to the system when creating large demand peaks. However, they also have the potential to create extra flexibility for the grid, if they are deployed as storage units during the period they are not actively used and connected to the grid (Clement-Nyns, Haesen, & Driesen, 2010; Verzijlbergh, 2013). The precise implications of this trend for the future power system remain to be seen, but definitely add to the already complex environment in which this system evolves.

Looking at the emergence of the current power system, it’s noticeable that the regime established over more than a century has experienced some quite profound developments, particularly over the past decades (see also figure 2.3). However, current trends and developments are likely to lead to even bigger changes. Planning and designing in such a dynamic and complex environment will pose many issues for policymakers. The future of power systems is probably subject to study for many years to come.
2.2. Technical, economic and institutional aspects of a power system

From the history of the power system, already the complexity of the environment in which the system exists became clear. External trends push certain changes, while policymakers and system operators are mostly occupied facilitating political or societal developments. The unceasing growth of the system, combined with the required transition, make it ever harder to keep grid balance and stability. To realise which aspects of the system need to be considered and which can be left out when planning a future network, we must examine the technological, economic and institutional components in more detail.

2.2.1. Technical components

The technological components of the power system have been roughly divided in generation, transport and storage. The straightforward important aspects of the generation part are quite well-known: mechanical energy is converted into electricity by a turbine (dynamo). The mechanical energy is created by burning fuels, or, as is the case with, for example, a wind turbine and hydropower, using forces of nature. Solar PV energy is an exception, as it translates electromagnetic energy (solar energy) to electricity. For more information on the exact workings of generation technologies, the book of Breeze (2014a), ‘Power Generation Technologies’ is recommended, which gives quite extensive and understandable explanations on the working of different technologies and the system as a whole. The transmission, and additionally the balancing component, have more interesting features, relevant for this research. First of all, electricity has a few characteristics that make it difficult to operate the system safely. The balancing of production and consumption is a tricky business. If a deviation from the equilibrium occurs it can lead to variations in frequency and eventually system disruptions. The unpredictability of demand, production from renewable sources and distortions in generation and transportation units make the operation of the system surrounded by uncertainties (van Staveren, 2014). In essence a disturbance in the system leads to a need for either one of three balancing control types, within three different time frames (NERC, 2011):

1. **Primary control**: From directly after the disturbance to a few seconds later, the frequency of the grid will deviate from the set point. The already spinning generators will increase or decrease their output to stabilise the frequency. These adjustments are made fully automatically by generators.

2. **Secondary control**: Within the time frame of a few minutes after the disturbance, manual actions from the power plant operators restore the frequency balance to the set point. This service is often delivered by spinning generators, but some generators can respond quickly enough to start in the meantime.
3. **Tertiary control:** Within minutes to hours, a definitive solution for the original disturbance is put in place. Either the reason for the disturbance is repaired, or new dispatching distributions have been agreed upon.

Although this mechanism often prevents the system from larger failures, not all generator types are suitable for power control. The adjustment of output (ramping), can be very time consuming and costly for some technologies. From Figure 2.4 it can be seen that conventional nuclear and coal fires power plants are slow in ramping up or down. Although they can deliver primary response to around 60% of their output at that moment, structural ramping, as is needed for secondary response, can only be done for 0%/min and 6%/min of their rated output, respectively. The two classes of Combined-Cycle Gas Turbine (CCGT) perform better for both types of responses, and even have a manageable start-up time if they were not committed yet (Van den Bergh & Delarue, 2015). These differences in characteristics are decreasing and modern coal plants are more and more capable of performing the same balancing duties as were performed by CCGT before (Henderson, 2014). When large shares of variable renewable energy are introduced to the system, the need for primary and secondary control increases. This is not only due to the fact that these sources are incapable of providing the required control mechanisms by themselves, but also because the prediction for hourly feed-ins is highly uncertain and within that hour the output experiences variations.

To prevent interruptions due to a lack of response options, European system operators have determined amounts of spinning reserves and stand-by back-up capacity, needed to operate the system safely. Spinning reserves are flexible ramping power plants that are already ‘on’ (spinning) so that their response mechanisms are available to the TSO. The ENTSO-E gives an overview and recommendations, as to what percentages of spinning reserves are needed, in their latest report on the issue (ENTSO-E, 2015d). In the EU, RES-E is not often curtailed, as their position in the merit-order gives it priority on the grid (see also Section 2.2.2). The RES-E can therefore be subtracted from the load curve to create a ‘residual load curve’. This represents the load that has to be delivered by the adjustable generators. It is likely to be more volatile as the share of RES-E increases, which can be seen in Figure 2.4. This increasing volatility requires even more control mechanisms and makes a system harder to balance (Bertsch, Growitsch, Lorenczik, & Nagl, 2012; Ueckerdt, 2015).

Besides issues regarding the generation technologies, the transmission element also beholds technical elements that warrant further examination. Electricity is a commodity with very peculiar characteristics. First of all electricity can be transported in two forms: Alternating Current (AC) and Direct Current (DC). Both forms have specific characteristics and obey physical laws which have to be taken into account when used in an electricity network. In more detailed power system operation, the effects on active and reactive power flows, Kirchoff’s laws and Power Transfer Distribution Factors (PTDF) have to be considered when electricity is transported on the grid (Seifi & Sepasian, 2011). Representing AC power flows is difficult and results in non-linear equations, with demanding computational requirements (see also Section 3.1). In network modelling an often-used replacement is the DC power flow. It is “a linearisation of the AC power flow and combines computational simplicity - since it is a set of linear equations - with an acceptable level of accuracy” according to Van den Bergh, Delarue, and William (2014, p. 2). For further introduction to the workings of power transmission the working paper of Van den Bergh et al. (2014) and the book by Seifi and Sepasian (2011) are recommended, which provide an comprehensible explanation on the matter.

Although some of the mentioned technical considerations for modelling a power system are not integrated in the rest of this research, the exclusion of these elements create limitations to applicability of a found
solution. Technical elements that are involved in the model are further elaborated on in Chapter 4.

2.2.2. Economic considerations

The aim of this study, to investigate a lowest cost solution for a future European power system, is strongly influenced by the economic aspects. Three aspects are particularly interesting: how the costs and earn-back of electricity production are calculated, the exact influence of RES-E integration on the electricity market and how support schemes for RES-E work and influence investment decisions.

**Levelised Cost of Electricity**  First of all, to understand how investments in the energy sector come about, one needs to understand the business plan of a power plant. The general workings of the electricity market have been explained in Section 1.2.2 and shows the mechanism of how power plants receive revenues. The market clearing price is however not the ‘real price’ of electricity, as all producing actors bid against marginal costs. The investment costs, Capital Expenditures (CapEx), and Fixed Operations & Maintenance costs (FOM) are not included in these marginal costs, but instead have to be earned back in addition to the marginal costs. The real costs of electricity are often measured as the Levelised Costs of Electricity (LCOE), which can be seen as the "discounted life-time fixed and variable costs of a generation technology in €/MWh" (Edenhofer et al., 2013, p. S17). For instance, a wind turbine has marginal costs of (nearly) zero, but during its lifetime has to earn back the high fixed costs. To do so, it earns money when the market clearing price is higher than its marginal costs. Power plants, with marginal costs close to the average market clearing price and with high fixed costs (RES-E, nuclear and coal plants for example), need many Full Load Hours (FLH) to earn back. The gap between their marginal costs and market clearing price is often small. Other plant types (like gas turbines) are designed for less spinning hours, have lower fixed costs and higher variable costs, but are flexible to dispatch and can thus optimally benefit from high market clearing prices (Edenhofer et al., 2013). On average each plant has to receive its LCOE for sold electricity to earn back over the complete lifetime.

In order to increase revenues, a plant requires as many FLH compared to the potential FLH it could have had. The net Capacity Factor (CF) of a power generating unit is the ratio between this potential power output and actual power output over a given period of time. If a 1MW coal plant runs for one year, constantly producing 1MWh, it has a capacity factor of 1 (Generated power/Installed capacity * Hours run)). A conventional power plant has a lower CF due to the fact that it is not always fully dispatched (not generating because of non-availability, due to outages or maintenance, is often not incorporated in the CF but in the availability factor). For RES-E, like wind or solar PV, the CF is largely determined due to meteorological circumstances. A wind turbine of 1MW will not always be able to produce 1 MWh due to a lack of optimal wind conditions. If the wind allows it to produce an average of 0.5MWh over the considered period the CF becomes 0.5. For solar PV panels this works slightly different. The rated capacity for which solar PV panels are installed is measured under certain place specific circumstances. The rated power of solar PV panels is often measured in watt-peak, which "characterises the nominal power output of a output of the PV modules at Standard Test
Conditions [...] i.e. when the irradiance in the plane of the PV modules is 1000 W/m² and the temperature of the modules is 25°C” (Šúri, Huld, Dunlop, & Ossenbrink, 2007, p. 1297).

Incorporating RES-E integration costs The effects of large-shares of variable RES-E on the market might lead to under- or even disinvestment. The conventional power plant’s LCOE basically becomes higher than their average received market prices, making the business case infeasible. To illustrate this impact, the Residual Load Duration Curve (RLDC) is introduced as extension of the residual load curve. A load duration curve is an ordination of the electricity demand, often per hour and for a year in time. The y-axis represents the amount of load, whereas the curve indicates the number of hours that that level of demand was at least present as can be seen in Figure 2.5. Three mechanisms affecting the business case of conventional generation can be distinguished from this (Ueckerdt, 2015):

1. **Low capacity credit;** The need for total generation capacity barely decreases because of installed RES-E capacity. The capacity credit of a new generator can be seen as the ratio between added capacity and the amount of fully adjustable capacity “that can be removed from the system due to the addition of the new generator, while maintaining the existing level of reliability” (Ueckerdt, 2015, p. 36). Thus, in essence, dispatchable capacity can only partially be replaced by introducing variable RES-E to the system.

2. **Reduced full load hours;** The annual FLH of dispatchable power plants are reduced (which is the same effect as the ‘decrease of time dispatched’, previously explained in Section 1.2.2). Their specific generation costs, the LCOE, will increase as fixed costs are spread over less output hours.

3. **Overproduction;** Especially with higher shares of RES-E, at some hours there will be more output than demand. If no storage options are available, market clearing prices will decrease, as power generated by RES-E is often allowed first on the grid and remains profitable due to support schemes. This results in lower or even negative prices, diminishing the revenue of conventional power plants.

Currently, the LCOE of RES-E does not represent the above effects. Three types of costs should be included to the current LCOE of RES-E to give a fair representation of the actual costs. First, there are balancing costs, which represent the uncertainty of output from variable RES-E. Since there are forecast errors and short-term variability, RES-E causes intra-day output variations, creating a need for operating reserves capable of reacting within minutes to seconds. ‘Grid costs’ are the second type and occur because of the likely ‘favourable locations’ of RES-E. They are often further away from load centres and/or located in the same area (like offshore wind), which increases required investments in transmission grid. However, also the extra costs of congestion management should be incorporated in this factor. The last cost type is ‘adequacy costs’, which reflect the need for back-up capacity due to the low capacity credit of RES-E (Ueckerdt, 2015). If these integration costs are incorporated, a more representative system LCOE can be defined (see also Figure 2.6). These costs are all difficult to determine when integrating RES-E in an existing system. If the perspective of a whole
new system is used it can be designed in such a way that all costs made for building it are incorporated in one large system LCOE. Minimising total system costs means minimising system LCOE, providing the lowest possible costs per amount of electricity.

Support schemes for RES-E investments Since a competitive energy market was created by European governments over the past two decades (see also Section 2.1.1), investments have to come from commercial and private parties. Since the LCOE of most RES-E is still higher than that of conventional generation technologies, their deployment is currently supported by governments, through all kinds of schemes (Haas et al., 2011). A differentiation can be made here for price-based and volume-driven support schemes. Two of the most applied schemes in Europe are Feed-In-Tariffs (FIT) for price-based and Tradable Green Certificates (TGC) for volume-driven schemes. These schemes are not only used to neutralise the difference in LCOE, but also to break through economic, institutional, political, legislative, social and environmental barriers. However, as the governments pay for these schemes, the costs involved are eventually paid by the consumers (Fouquet, 2013). Together with the identified RES-E integration costs, this poses a burden on the regions with higher shares of RES-E due to a supportive political environment. Currently, the level of support differs strongly over Europe, despite attempts of the EU to create more standardised schemes (Held, Ragwitz, Gephart, de Visser, & Klessmann, 2014). Since RES-E is likely to be installed in meteorological attractive locations, some regions will have heavier burdens to carry from integration costs than others. When designing a power system top-down, a solution will have to be found for the distribution of ensuing costs.

2.2.3. Responsible institutions

As was mentioned in Section 2.1.1, the power sector was heavily regulated, or even owned by governments, due to the importance of the commodity energy. Although the unbundling and liberalisation of the sector allowed for more commercial activities in the sector, governments still maintain a firm grip through all kinds of policies, regulations and goals. To understand how the conclusion of this study could be implemented and how it could have conflicting interests with national goals, it is important to understand who is responsible for which element of the sector. Five important actors can be distinguished in this sector, each with their own responsibilities. The policymakers consist of the EU, setting guidelines (see Section 1.3) and national governments, which have to make concrete applicable policies, within their country borders. Both policymaking institutions have an executive organisation below them. For the national level this is the TSO. All national TSOs are cooperating in the EU-level institution ENTSO-E. The last relevant party, which is involved in the sector, consists of the companies that own or manage power plants, storage technologies or lower level electricity grids. For each of the above-mentioned institutions, their current role will be briefly discussed and their powers and responsibilities will be listed. Figure 2.7 provides a visual overview of the relations between the actors.

Role of the EU The treaty of Lisbon, which was signed in 2007, gave the EU an active legislative role on the energy policy. Until then, only indicative targets were set for which Member States had to express their intentions regarding national energy policies. The treaty was directly followed by a ‘Renewable Energy Road Map’ which specified binding targets, both EU-wide and nationally, on the shares of renewable energy in the total energy mix for 2020. Member States are also obliged to create National Renewable Action Plans, although the Commission has no control over the content (European Commission, 2007). The European Directorate-General (DG) for Energy already created strategies for further ahead, with the 2030 and 2050 Energy Strategy. In addition to the strategies containing renewable goals, an ‘Energy Security Strategy’ was also developed, which contains goals for the amount of domestic production and transmission capacities. With the introduction of the European Energy Union in 2015, the EU is aiming for a coordinative role in the continental energy policy. A more active role is envisioned for the ENTSO-E regarding the European physical and institutional coupling of national markets (European Commission, 2015a). Additionally, in 2015 the EU adopted a list of 195 Project of Common Interest (PCI)s. These projects can be supported with funding from the EU, which gives a instrument which is particularly helpful in designing the European transmission network. The instrument lacks real executive power, as still cooperation with relevant national governments and investors is needed to implement the projects (Egerer, Lorenz, & Gerbaulet, 2013). Aside from binding targets for renewable energy the EU has no real power overruling national policies on this matter. All strategies formulated thus far depend on the own initiative from Member States and can not be enforced. The national governments still remain ultimately responsible for concrete energy policies. To achieve progress, the EU will have to continue negotiating with different Member States to achieve common goals (Braun, 2011).
Role of national governments  As has become clear, the national governments are the actual policymakers in the energy sector of the EU. However, while these national governments develop the policies, the responsibility for operations and planning of power systems is often fully transferred to a TSO. Several policy aspects are normally decided upon from a governmental level:

1. Market design;
2. Responsibilities TSO, Distribution System Operator (DSO) and private companies;
3. Mechanisms for energy security;
4. Support schemes for renewable energy;
5. Cooperation with neighbouring countries;

The market designs have grown increasingly close together over the past few decades, and the recently launched Energy Union aims to make them fully compatible. The cooperation and interconnection between countries is also regulated in the Energy Union Package, as well as in the Ten Year Network Development Plan (TYNDP) by the ENTSO-E. The role of TSOs and other actors in the energy sector is more and more standardised over Europe, mainly due to guidelines provided by the ENTSO-E and the Agency for the Cooperation of Energy Regulators (ACER) (Neuhoff et al., 2015). It seems that on these aspects, Member States are following EU strategy. However, the support schemes for renewable energy and energy security mechanisms are still organised nationally without much cooperation between countries. In particular the current energy security focus has mainly been national, for multiple reasons (Jewell, Cherp, & Riahi, 2014). It has been argued that uncoordinated national policy initiatives in exactly these two areas are a serious risk to the integration of European electricity markets (Glachant & Ruester, 2014). Nonetheless, if a more coordinated approach of the future European power system is to be achieved, at least these national policies have to be aligned, if not fully transferred to be coordinated from a more central point.

Role of the national TSO  On executive levels the TSO plays an important role. The term 'national TSO' is somewhat misleading, as sometimes a country can have multiple TSOs or one TSO can be responsible over an area crossing country borders. Since the regulations imposed on a TSO are determined within country borders, this study will consider the national TSO as an aggregation of all TSOs active within that countries borders and disregards potential border crossing activities. The European definition of a TSO was given by the ENTSO-E and states that "...[TSOs] are entities operating independently from the other electricity market players and are responsible for the bulk transmission of electric power on the main high voltage electric networks. TSOs provide grid access to the electricity market players (i.e. generating companies, traders, suppliers, distributors and directly connected customers) according to non-discriminatory and transparent rules. In order to ensure the security of supply, they also guarantee the safe operation and maintenance of the system. In many countries, TSOs are in charge of the development of the grid infrastructure too.” (ENTSO-E, 2015b, par. 1). This is regarded an adequate description of their role and will be maintained for this research. In addition, the TSOs are often checked in their operations by some governmental institution. This is done to assure that the TSO follows national guidelines.

Role of the ENTSO-E  The ENTSO-E is a cooperation of 41 separate electricity TSOs, spread over 34 countries across Europe. The EU’s Third Legislative Package for the IEM, adopted in 2009, gave the organisation legitimacy and mandates. Their founding was deemed necessary to have one central institution that could coordinate the following EU goals:

- Ensuring Europe-wide security of supply and system reliability;
- Integration of RES-E, like wind and solar power, into the power system;
- Completing the internal European energy market.

The instruments available to the ENTSO-E are for example standardised network codes, a biennial published TYNDP for the development of a pan-European network, coordinating the technical coordination between TSOs, including cross-border flows, coordination of R&D plans and the publication of electricity generation or adequacy outlooks for upcoming seasons. Although their actual power is minimal, the ENTSO-E is regarded as a valuable partner for many TSOs in the transition and integration of their power systems (ENTSO-E, 2015a).
Role of private companies  Since the energy sector is liberalised, private companies are the actual entrepreneurs on the electricity market. Power generation, possible storage, retailing and sometimes distribution system operation are performed by this actor. They can additionally provide all kinds of power balancing services to the TSO as extension to the straightforward procurement and sales of energy. This is all facilitated and regulated by the TSO, but producers make their own investment decisions. This means that neither a government nor system operator can impose actions on these independent actors. To stimulate them to invest in the technologies needed often support schemes are developed by national governments. In the real world, the government must not only determine targets for RES-E, but also find a way to persuade these actors to invest in it. This was already briefly explained in Section 2.2.2.

Now that the full scale of the European power system, including the development it underwent over the period of many decades has been clarified, potential modelling choices can be better understood. The next chapter will take a closer look at methods in which the aforementioned system can be modelled. Subsequently, it will present some relevant research studies that looked at such a system with a similar goal in mind. After that, in Chapter 4 and Chapter 5, the actual model is described.
Current state of power system modelling

A quantitative investigation is performed in order to find answers to the research questions as were stated in Section 1.4.3. The system under consideration is, however, incredibly large and complex. The amount of data, as well as the number of parameters and variables make it near impossible to find a cost-optimum by hand and impossible, or at least too expensive, to experiment in the real world. This is where the combination of mathematical modelling and computer simulation offers an adequate solution. Engineering models can eliminate "certain impractical, expensive or restricted tests" (Oberkampf & Roy, 2010, p. 4) and "allow investigation of performance limitations that would not be permitted in more direct ways" (Murray-Smith, 2015, p. 2). As the modelling of a power system is a well-defined field of research, this investigation can use and build upon the experience from other researchers as a starting point. However, the number of research studies performed in this subject is so incredibly large, that first a delineation of the most relevant field of research within power system modelling is given. In this chapter the field will first be narrowed to the type of model that will be used for this research. Subsequently, an overview of relevant and recent investigations will show the state-of-the-art technology in that sector of power system modelling.

3.1. Model approach

Power systems have often been modelled, with all kinds of goals and purposes. While there are many different characteristics of these models, two main categories of characteristics can be observed: the methodology and the scope. Between the two categories some interdependencies exist, but the concepts will be explained separately in more detail.

3.1.1. Typical methodology

The modelling of power systems is typically done from either one of two levels: by considering the whole macro-economic playing field, with interactions between different economic sectors, or by focussing only on the energy sector itself. In recent literature the classifications 'top-down' and 'bottom-up' are used for these types of approaches, respectively (Herbst, Toro, Reitze, & Jochem, 2012). However, since those classifications can help distinguish the level of perspective within each methodology, the original terms (Macro-economic Models (MEM), and Energy Sector Models (ESM)) will be used for this research. A Top-down (TD) model is then defined from the perspective of one actor, who oversees the whole system with complete information and is the only decision maker in the model. A Bottom-up (BU) model is then regarded as a model in which several agents with fragmented knowledge, own decisions, and specific behaviour shape the outcomes.

A MEM often works from a full equilibrium framework, in which the effects of the energy system on the rest of the economy are captured. A high level of aggregation is applied here, as well as "low sectoral and technological details of energy conversion" (Jägemann, Fürsch, Hagspiel, & Nagl, 2013, p. 623). These models are strictly built from a top-down perspective (Götz, Blesl, Fahl, & Voß, 2012). The ESM generally have a very technical or techno-economic approach and are "characterized by an explicit techno-economic parametrisation and a high degree of technological detail, which allows for a comprehensive analysis of technological adjustment processes induced by policy interference" as was stated by Jägemann et al. (2013, p. 623). As they normally do not link with other sectors of the economy they are also called 'partial equilibrium models' and use a more economic, business approach to the used technologies, which are very functionally modelled.
3. Current state of power system modelling

(Götz et al., 2012; Herbst et al., 2012). They can roughly be divided into two model categories: simulation and optimisation. In simulation models on the one hand, often a BU-perspective is used, where the outcome is the result of "individual decision-making processes" (Jägemann et al., 2013, p. 623). The input information is "based on exogenously defined scenario assumptions" (Götz et al., 2012, p. 25). These models try to give a quantitative and descriptive illustration of energy conversion and demand, "based on exogenously determined drivers and technical data with the objective to model observed and expected decision-making that does not follow a cost minimising pattern", as was added by Herbst et al. (2012, pp. 121-122). The elements of strategic behaviour and incomplete information can then be captured by both an agent-based model or a more general system dynamics approach (Jägemann et al., 2013). An optimisation model on the other hand calculates the optimal configuration of any power system, determined by an objective function, (in)equality constraints and bounds. The constraints represent for example technical limitations, parameter assumptions or political objectives like shares of RES-E in the energy mix. The objective function is either a representation of the costs a certain configuration entails, which has to be minimised, or a display of the total surplus for actors involved, which has to be maximised. The first type is called a 'systems costs minimisation' and assumes that demand is price inelastic. The second type is often described as 'social welfare maximisation' and uses both price elastic as inelastic assumptions (Herbst et al., 2012; Jägemann et al., 2013). The categorisation of power system models is illustrated in Figure 3.1.

Within each of the above methodologies, the spatial aspect is often modelled in either one of two ways: some important locations/institutions (cities, nations, grid operating systems) within the area are defined, or the area is divided into equal cells. The temporal aspect has, in essence, three different classifications. Steady-state models do not consider temporal aspects, but look at an average or peak-situation. Multiperiod models basically look at several steady-states where each period is a different scenario, but the solution must fit to all periods. The multiperiod model is often used for investment decisions. The last classification is a dynamic model, which uses a fine time resolution. It is often used to study the operational elements of the power system (Samsatli & Samsatli, 2015).

By way of a final remark on methodologies, it is important to note that the main input data for the above model types consists of fuel prices, demand data and potential production data (RES-E). A first option for the latter two is to use historical data, which can also be adapted for future scenarios if substantiated assumptions about relevant developments can be made. The second approach is to create probabilistic or stochastic representations of that data. The second approach accounts better for uncertainties, but is more time-consuming (Barry et al., 2013; Ventosa, Balló, Ramos, & Rivier, 2005; Wallace & Fleten, 2003). Wallace and Fleten (2003, p. 651) give an often-found difference that results from the approach used for a power-system model: "A priori we can state that deterministic solutions will be characterized by extensive use of large plants with high startup costs, with relatively few starts. SP [stochastic/probabilistic] solutions on the other hand, will typically use smaller units and will involve more startups of flexible but possibly high marginal cost plants such as gas fired units. Deterministic models will know exactly how much power is needed at any time and can thus plan to run low fuel cost plants at high output for long periods of time. The gains that the model sees from such scheduling will outweigh the high startup costs that typically come with such plants." When choosing the input data type the possible effects of this should be be kept in mind. The implications of choices made will be discussed in the discussion, which can be found in Chapter 8.
3.1. Model approach

3.1.2. Typical scopes

Aside from the methodology used to model a power system, some typical scopes can also be determined. The scope for power system modelling consists, in essence, of three different dimensions:

1. **Power system time-horizon & resolution:** The time scale at which the problem is considered, ranging from a few nanoseconds to multiple decades. As the horizon respectively grows or declines, the temporal resolution within the considered time-horizon often becomes less or more granular respectively.

2. **Power system elements:** Elements of the power system that are involved in the model, for example generation technologies, transmission lines or investment decisions.

3. **Power system size:** The geographical area covered by a model, ranging from very small stand-alone systems (for instance a single household) to global networks or developments.

The different time-horizons that can be considered have been adequately discussed by Seifi and Sepasian (2011, pp. 4-7). At the lowest levels, power system transients can be examined, having a very short-term time resolution of nano- to microseconds. This includes sudden events and their impact on a power system, such as a lightning strike. One time-horizon higher are the power system dynamics, which look at milliseconds to seconds. The primary control mechanism, as discussed in Section 2.2.1 for example, acts on this time-horizon. The next step brings a set of different types of studies: the power system operations. The most common time-horizon here is a few minutes to a full week. It looks at, for instance, the way generation units are dispatched and committed, but also at maintenance schedules and optimal power flows. Important aspects in this time-horizon can be ramping times and limits, availability levels and capacity factors, but also grid reliability and bidding strategies. The highest level involves power system planning, which includes foresights of anywhere from one to many years. New infrastructures, but also the generation capacity, type and network connections are typically considered in this scope and are often used for investment decisions (Seifi & Sepasian, 2011). An overview of the different time-horizons, and the typical scope of models using such a time resolution, can be found in Figure 3.2. A model is not necessarily bound to one of these scopes, as often the interactions between them can give valuable information. However, it is very computationally demanding to have a fine time resolution in a model spanning relatively long periods. To be able to capture the advantages of both large horizons and fine resolutions, hybrid frameworks have been developed. They combine multiple resolutions, for example, by creating structured feedback loops between two models with different time-horizons (Pina, Silva, & Ferrão, 2013).

![Figure 3.2: Time-horizon perspective of power system model types. Reprinted from Seifi and Sepasian (2011).](image-url)
The second scope direction is the number of elements involved in the model. As was described in Section 1.4.2, a power system can be divided into multiple physical elements. When looking at models with expansion planning, often only one or two elements are considered. The elements can then be defined as Generation Expansion Planning (GEP), Storage Expansion Planning (SEP) and Transmission Expansion Planning (TEP). However, institutional elements can also be modelled. For example, the effect of electricity markets, governmental support schemes and commercial investment decisions are often distinguished and implemented in power system models (Després, Hadjsaid, Criqui, & Noirot, 2014; Poncelet, Delarue, Six, Duerinck, & William, 2015).

One final distinction can be made for the size of the power system considered. Some models are only built for much smaller scale purposes, like a stand-alone system (single household) or the management of a single power plant. At a level one step higher, portfolios or distribution grids are often considered, but this level ranges all the way up to global energy forecasts and simulations (Baños et al., 2011; Pfenninger, Hawkes, & Keirstead, 2014).

With regard to the scope, an approach to the problem that is too narrow might lead to overlooking important elements which would have had significant influence on the outcomes. An approach that is too wide could make the problem computationally infeasible and is probably unable to grasp all interrelations within the different elements of a model. When defining the scope and methodology to be used, one should look at the purpose of the research more closely to determine what is needed in order to find an answer to the important questions.

### 3.2. Relevant literature on power system optimisation

The type of model for this research can now be defined. Discussed literature will have multiple overlapping facets in order to be relevant for this study. From the combination of Section 1.4.3 and the knowledge obtained in the previous Section it follows that the model will be:

- A System Costs Minimisations methodology, which:
  1. considers both some ‘Economic dispatch and Optimal Power Flow’, as Power System Planning aspects. An hourly resolution will be needed, but the possible computational difficulties with a long-term time frame for this fine resolution have to be considered as well.
  2. involves elements of Generation, Storage and Transmission Expansion Planning, while ignoring effects of electricity markets, governmental support schemes and commercial investment decisions. Within GEP an increasing share of RES-E will be considered.
  3. looks at the continent of Europe, more specifically the EU, as a system.

From existing literature two important directions were distilled. The first one worth looking into is the existence of generic models and modelling tools. The second consists of research studies, with or without a model, that look into a similar type of power system.

### 3.2.1. Modelling tools

Over the years, many different institutions have developed a variety of generic tools, for many different purposes in power system modelling. There are numerous examples and for a thorough description of most models the reviews by Pfenninger et al. (2014) or Sinha and Chandel (2014) are recommended. The review by Connolly, Lund, Mathiesen, and Leahy (2010) is a bit older, but focusses more on modelling tools for the integration of RES. For a clear overview of the aspects incorporated in the most important tools nowadays, the research by Després et al. (2014) may also be of value. The most relevant tools to this study are probably the energy system optimisation models which focus on normative scenarios. Looking through these reviews, one tool in particular fits this description, which is probably the best known and comes from the International Energy Agency (IEA). In 1976 they launched the Energy Technology Systems Analysis Program (ETSAP), intended to develop a model, fit for large-scale energy system analysis. After many decades, additions, transitions and merges with other models the group of models they developed is known as the MARKAL/TIMES-model family (Pfenninger et al., 2014). The documentation on these models is extensive and the way other models simulated certain elements of the power systems is used as a source of inspiration. However, none of the mentioned models proved to be available or suitable for this particular problem.
3.2. Relevant literature on power system optimisation

3.2.2. Relevant researches

From the extensive list of literature 18 relevant researches have been selected, published between 2010 and now. These papers have firstly been gathered from the academic search engines Scopus and Google Scholar. The search query contained either one or a combination of the following search terms:

- 'power system' OR 'power network' OR 'energy system' OR 'electricity network'
- 'optimization' OR 'modelling' OR 'cost-optimization'
- 'RES' OR 'RES-E' OR 'VRE' OR 'VRES' OR 'renewable energy'
- 'intermittent' OR 'variable' OR 'fluctuating'

From the found papers that appeared to be relevant, additional papers and reports were gathered from their references. Also the suggested studies by publisher Elsevier, based on read articles, were considered. The most important findings from this literature review are discussed, as well as a brief overview of the modelling approach. All papers and reports discussed are categorised in Table 3.1.

A first interesting sub-field in the examined research studies uses the model to find a technical optimum rather than a cost-optimum, for example as was performed by Heide et al. (2010). They studied a seasonal optimal mix between the two largest sources of RES-E, wind and solar PV. With a combination of the two the potential output is more likely to follow the demand curve, reducing the need for short-term balancing. When the pattern over multiple seasons is considered, the two sources are also complementary, which allows for a stable production with less installed capacity. They find an optimal mix of around 55% of wind and 45% of solar PV for a 100% renewable Europe. A similar study, but with a more cost-optimal focus, was performed by Rodriguez, Becker, and Greiner (2015). Incorporating the costs for wind (onshore and offshore), solar PV and CCGT as a back-up option, they find rather different optimal percentages, which is mostly due to the consideration of only a 50% renewable scenario. According to this study, the cost-optimum can be reached when 94% of the renewable energy comes from wind and the rest from solar PV. Around half of the installed wind capacity would then be needed, additionally, from flexible generation as back-up capacity. Both studies mentioned look only at the generation mix and assume either - respectively - a copper plate or a given transmission capacity. Becker, Frew, et al. (2014) try to incorporate the transmission grid in the cost-optimisation. They look at the United States of America (U.S.) and divide it in different regulatory regions to see how a ideal mix of wind and solar PV (80% and 20%) can reduce the need for storage and back-up capacity. They also allow for transmission grid extensions in order to transport power from more favourable places to demand centres. However, the model does not reach an overall system optimum, but finds optimal mixes between wind and solar PV with regard to the lowest storage, backup capacity or transmission requirement.

The grid is often seen as a solution to integration issues and costs for RES-E. Schaber, Steinke, Mühlich, and Hamacher (2012) compare the costs for electricity, under increasing RES-E scenarios. They allow the grid to be optimised in capacity, but not in lay-out, in order to drive costs down. A detailed level of the European power system is taken as a point of departure. A more electro-technical research perspective is demonstrated by Egerer et al. (2013), who used the PRIMES EU-wide energy model to investigate the technically preferred option, where specifically the difference between AC and DC is considered, and a preference for a High Voltage Alternating Current (HVAC) grid was found. Rodríguez, Becker, Andresen, Heide, and Greiner (2014) built a model with less granularity, but managed to find a solution for a 100% RES integration. By penalising a mismatch between production and demand, with optimal mixes of production capacity per country given, and by allowing the model to increase the transmission capacity, they find that current interconnection capacities should be increased about 11.5 times. The same order of magnitude for grid extensions was found by Becker, Rodriguez, et al. (2014), who looked at the need for back-up capacity under increasing shares of RES-E, with either no Net Transfer Capacity (NTC) between countries, with current levels of capacity, with the current levels doubled and even quadrupled. They also found that increasing NTC leads to a higher share of wind (from 70% to 80% wind). The study by Fürsch et al. (2013) specifies, in a similar kind of research, that about 228,000 km of extra grid would have to be built between now and 2050, which is roughly 80% of the present-day grid. The advantage then would be that almost no RES-E would have to be curtailed. The basis used for this study was a cost-optimisation with dispatch and investment decisions. These investment decisions, together with a carbon pricing scheme were also researched by Schaber, Steinke, and Hamacher (2012). They found that conventional generation technologies will not be profitable without significant increases of grid extensions, based on a model taking the current lay-out and certain grid extension profiles in account. They looked at
Another often-included element, briefly mentioned in the above research, is electrical energy storage. The least-expensive design for a hypothetical power system with different generation, transport and storage facilities was researched by Samsatli and Samsatli (2015). To account for both short-term dynamics as well as a long-term planning horizon, they have developed an iteration method between multiple sub-models. From the results they conclude that, especially in a small system with large shares of RES-E, storage is very beneficial. For a system representing Europe, Steinke et al. (2013) found that even with a significant amount of storage and a large grid, much of the capacity of dispatchable power plants is still needed as back-up capacity. They used four scenarios for increasing amounts of storage and transport capacities, from which the lowest total systems costs for that scenario were examined. In a comprehensive study by Brouwer et al. (2016), three scenarios of increasing RES-E demand were researched. They found that increasing the share of RES-E leads to increased total system costs, although the increase can be kept between 10% and 15% if options, like Demand Response, Electricity Storage and Interconnection, are applied optimally. Each added option lowers the costs for Europe, but they also point out that the current high costs for electrical storage technologies are an important reason for why installed capacities remained marginal in the optimisation. While comprehensive hypothetical systems, but also Europe and the U.S. have often been the subject of study, even larger power system studies have also been performed. An example is the study by Pleßmann, Erdmann, Hlusiak, and Breyer (2014), where a global 100% renewable solution is investigated. It looks at 160 countries on a quite detailed scale and finds a possible system for a total system LCOE of around 80-200 €/MWh. A combination of solar PV, onshore wind energy and concentrated solar power, combined with three different storage options is needed for such a global system.

From most of the current research, it can be concluded that the increasing shares of RES-E in the power system lead inevitably to higher system costs. However, measures like storage, increasing interconnection capacity and the right mix and geographical distribution of RES-E can prevent a situation where the electricity becomes all too expensive. More specifically, the combination of multiple measures leads to acceptable costs. Most studies only allow one or two elements to be variable, and define the other element(s) with exogenously scenarios. The computational complexity and capacity, in particular, are named as barriers to researching a full scale system. Several investigations have used ways to decrease the number of hours that need to be researched, often by ‘smarter’ solutions for that specific time series. None of the studies allows all generation technologies, both conventional and renewable sources, to be optimised in combination with an optimal grid or additional storage facilities. In this research a contribution will be made to the available research, by showing the effects of allowing all these elements to be optimised simultaneously.

A second lacking element from current research arises from the assumption of a powerful central planner. All studies look for an optimum where one policymaker, often with (semi-)perfect knowledge, optimises the power system design. In the real world this is not the case, and the system emerges more from the interaction between multiple developments and actor interests, as has been explained in Section 2.1. The added value of a central optimisation to the real world, or differences for different planning scales and policies has only marginally and indirectly been investigated up to now, as far as this author’s knowledge goes. The conclusions regarding the optimal planning scale, loss of value for lower planning scales, as well as policy implications arising from a central planning scale are major contributions of this study to both the scientific field as to policymakers.
### Table 3.1: Overview of relevant literature and their modelling characteristics. SCM = System Costs Minimisation; GAMS = General Algebraic Modeling System; MILP = Mixed-Integer Linear Problem; ED = Economic Dispatch; UC = Unit Commitment; SS = Support Schemes; DSM = Demand Side Management; GEP = Generation Expansion Planning; SEP = Storage Expansion Planning; TEP = Transmission Expansion Planning; RES = Renewable Energy Sources.

<table>
<thead>
<tr>
<th>Research</th>
<th>Methodology</th>
<th>Data type</th>
<th>Scenario</th>
<th>Resolution</th>
<th>Elements</th>
<th>Area covered</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECF (2010)</td>
<td>SCM</td>
<td>Exogenously given parameters</td>
<td>The pathway to 80% renewable Europe</td>
<td>Quarterly hour to hourly resolution for short periods</td>
<td>UC, ED, SS</td>
<td>Europe, 9 nodes</td>
</tr>
<tr>
<td>Heide et al. (2010)</td>
<td>Technological optimisation</td>
<td>Meteorological, deterministic</td>
<td>Several mixes of solar PV and Wind power</td>
<td>Hourly, 6 weeks per year for 8 years</td>
<td>SEP, RES-mix</td>
<td>Europe, 83 nodes</td>
</tr>
<tr>
<td>Bertsch et al. (2012)</td>
<td>SCM</td>
<td>Meteorological, deterministic</td>
<td>Exogenously given capacities</td>
<td>Daily time-step, 12 days per year for blocks of 10 years</td>
<td>UC, ED, investment</td>
<td>Europe, 13 nodes</td>
</tr>
<tr>
<td>Schaber, Steinke, Mühlich, and Hamacher (2012)</td>
<td>SCM - GAMS</td>
<td>Meteorological, deterministic</td>
<td>Impact of grid extensions on RES-E integrations issues</td>
<td>Hourly, 6 weeks per year for 8 years</td>
<td>TEP</td>
<td>Europe, 83 nodes</td>
</tr>
<tr>
<td>Schaber, Steinke, and Hamacher (2012)</td>
<td>SCM - GAMS</td>
<td>Meteorological, deterministic</td>
<td>RES-E integration of several levels, starting point current lay-out</td>
<td>Hourly, 6 weeks per year for 8 years</td>
<td>ED, SS, GEP, TEP</td>
<td>Europe, 83 nodes</td>
</tr>
<tr>
<td>Barry et al. (2013)</td>
<td>SCM</td>
<td>Random/Stochastic pattern</td>
<td>Vast shares of RES-E production</td>
<td>1 time-step, multiple runs</td>
<td>ED, UC</td>
<td>Stand-alone power system, 9 nodes</td>
</tr>
<tr>
<td>Egerer et al. (2013)</td>
<td>SCM - MILP</td>
<td>Deterministic</td>
<td>Vast shares of RES-E production</td>
<td>Hourly, 18 representative hours</td>
<td>ED, TEP</td>
<td>Europe, 224 nodes</td>
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<tr>
<td>Fürsch et al. (2013)</td>
<td>SCM</td>
<td>Meteorological, deterministic</td>
<td>Increasing RES-E quotas</td>
<td>Hourly, 10 days, multiple runs</td>
<td>ED, investment, TEP</td>
<td>Europe, 224 nodes</td>
</tr>
<tr>
<td>Steinke et al. (2013)</td>
<td>SCM</td>
<td>Normalised generation</td>
<td>Increasing Uniform distribution of capacity, grid lay-out determined</td>
<td>Hourly, 8 years</td>
<td>ED, SEP, GEP</td>
<td>Europe, 224 nodes</td>
</tr>
<tr>
<td>Wu et al. (2013)</td>
<td>SCM</td>
<td>Normalised generation</td>
<td>Multiple capacity scenarios</td>
<td>Hourly, 24 hours</td>
<td>ED, UC</td>
<td>Stand-alone, 1 node</td>
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<tr>
<td>Becker, Rodriguez, et al. (2014)</td>
<td>Technological optimisation</td>
<td>Meteorological, deterministic</td>
<td>RES-E growth scenario</td>
<td>Hourly, 8 years</td>
<td>TEP</td>
<td>Europe, 27 nodes</td>
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<tr>
<td>Research</td>
<td>Methodology</td>
<td>Data type</td>
<td>Scenario</td>
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<tr>
<td>Becker, Frew, et al.</td>
<td>SCM and Technological optimisation</td>
<td>Meteorological, deterministic</td>
<td>Optimal Solar PV and Wind power mixes, different transmission extension levels</td>
<td>Hourly, 32 years</td>
<td>SER, TEP</td>
<td>U.S., 10 nodes</td>
</tr>
<tr>
<td>Pleßmann et al. (2014)</td>
<td>SCM</td>
<td>Meteorological, deterministic</td>
<td>Fully RES-delivered demand</td>
<td>Hourly, 1 year</td>
<td>SEP, RES-mix</td>
<td>Global, 160 countries, long/lat nodes</td>
</tr>
<tr>
<td>Rodríguez et al. (2014)</td>
<td>Minimise generation, storage and transmission capacity</td>
<td>Meteorological, deterministic</td>
<td>Optimal Solar PV and Wind power mixes</td>
<td>Hourly, 8 years</td>
<td>TEP, RES-mix</td>
<td>Europe, 30 nodes</td>
</tr>
<tr>
<td>Rodríguez et al. (2015)</td>
<td>SCM</td>
<td>Meteorological, deterministic</td>
<td>Chosen RES-E penetration levels and mixes</td>
<td>Hourly, 8 hours</td>
<td>ED, SS, RES-mix</td>
<td>Fictional, 30 nodes</td>
</tr>
<tr>
<td>Samsatli and Samsatli (2015)</td>
<td>SCM</td>
<td>Meteorological, deterministic</td>
<td>Optimal Solar PV and Wind power mixes</td>
<td>Hourly, daily, seasonal and yearly</td>
<td>ED, TEP, SEP, RES-mix</td>
<td>Fictional, 14 nodes</td>
</tr>
<tr>
<td>Zerrahn and Schill (2015)</td>
<td>SCM - GAMS</td>
<td>Historical demand and production</td>
<td>Optimal RES-mix, DSM and back-up capacity, linear expansion of capacity</td>
<td>Hourly, 1 year</td>
<td>ED, investment</td>
<td>Fictional, 30 nodes</td>
</tr>
<tr>
<td>Brouwer et al. (2016)</td>
<td>SCM</td>
<td>Stochastic patterns</td>
<td>Given generation capacities</td>
<td>600 periods within 1 year</td>
<td>ED, UC, Maintenance, SEP</td>
<td>Fictional, 14 nodes</td>
</tr>
</tbody>
</table>
The next four chapters concern the model used to answer the research questions. The structure that was used in the modelling process can be found in Figure 4.1. First the requirement analysis was conducted, based on the problem description, after which a conceptual model is build. In the next chapter (5) the model approach, model structure and parameters will be chosen, after which the translation into a computer model is explained. Subsequently, the quality of the model and the used data will be determined via a verification and evaluation process. The experimental design and ensuing results are then presented in Chapter 6. Finally in Chapter 9 the validation and sensitivity analysis process will determine the validity of the results.

This chapter describes the model that will be used to find answers on the research questions. It is basically a theoretical overview of how the model should work and how relations between different variables are established. It consists of "a collection of statements, assumptions, relationships and data that describe the reality of interest. From this conceptual type of description a mathematical model can eventually be constructed, and information useful in the design of experiments to test that model can be derived" (Murray-Smith, 2015, p. 4). Consecutively, the general workings and elements of the model will be explained in words and mathematical equations.

4.1. Model in words

The model has to reflect a realistic optimisation scenario and give an indication of which elements are useful to include in such a study. However, the number of options for generation, storage and even transmission are numerous. Including all of them in the model would lead to an incredibly large and complicated model. Choices have been made on which specific technologies are incorporated, while keeping the model manageable. Two considerations played a role here. First, the composition of different technologies should give an adequate reflection of the actual power system. Second, the model and its results are to give insights in which type of technologies are relevant to include in a model for this type of power system optimisation problem. To achieve that within each considered element of the power sector (generation, storage, transport) the incorporated technologies will be chosen to have typical, distinctive features. Different cost- or efficiency-characteristics will make them suited for other types of usage. When certain technologies are used more often in the optimisation, these are valuable to look into in further studies. In this section the model will be described in words. Mainly, the choices that have been made in this stage will be explained. These choices determine the scope of the model and delimit the considered time-frame, time-horizon, type of costs included and geographic limitations. At the end a summary of the optimisation model that follows from the choices in this section will be given in text box 4.1.4.

4.1.1. Model type and scope

From Section 1.4 it follows that the aim of the model is to find a cost-optimal design for a European power system, indicate the financial benefit of increased planning scales and give an indication of which elements and technologies are worth incorporating in such an optimisation. The hypothesis is that RES-E integration costs can be minimised if the power system design is coordinated on a higher scale, for example the EU-level, with all relevant elements involved in the optimisation. This asks for a power system planning approach, as was defined by Seifi and Sepasian (2011) and can be found in chapter 3. The scope for this research is defined,
Figure 4.1: Block diagram of the modelling process as will be done in the modelling chapters to come. Within the red dotted lines the focus of this chapter can be seen. Adapted from Murray-Smith (2015, p. 21)
4.1. Model in words

per dimension (see Section 3.1.2 for the difference between dimensions) as follows:

**Time-horizon & resolution** The power system planning approach often uses a time resolution of days, weeks or even years. However, the effects of intermittent RES-E integration problems are mostly created by the variation on hourly basis, which is also the resolution at which dispatch decisions are made. The also incorporated EES is used to level out generation and demand from hour to hour. This so-called energy management has strong inter-hour dependencies (Kerckhoffs, 2015). To cover all these effects and dependencies, the model will be based on an hourly resolution, with a time-horizon long enough to capture all daily, weekly and seasonal patterns.

**Elements involved** The elements involved consist of both the generation, transmission and storage elements. From the production element the offshore possibilities, which exist mainly for wind power are not taken into consideration. Since the LCOE of offshore wind turbines is higher than that for onshore and no non-economic limitations are build, which reflect the normal reasons to choose offshore over onshore wind power, it is useless to incorporate it in a cost-optimisation. A good optimisation would always choose the lower LCOE onshore turbines over the offshore variant. The computational complexity it adds is also a reason to leave it out for this investigation. For more in depth analysis of the potential for offshore wind power, one could look into (Bilgili, Yasar, & Simsek, 2011). The author is aware that at the moment mainly offshore wind energy has this great potential and admits that incorporating it, together with non-economic considerations for onshore vs. offshore, will lead to more realistic results regarding the optimisation of a real future power system. For this research, the fixed costs for all technologies will consist of both the Capital Expenditures (CapEx) and Fixed Operations & Maintainence costs (FOM). The variable costs then only consist of variable operations and maintenance costs and fuel costs Variable Operations & Maintenance costs (VOM). These costs are both dependent on the amount of output and are calculated as one parameter: Variable Costs (VC). As the FOM are often given per year, the CapEx over the whole lifetime and the variable costs per unit of output all costs will have to be made comparable over the considered time-period.

**Model size covered** The geographic area considered will be Europe; more particular the countries of the EU. However, due to a long distance to other countries, combined with an energy generation and demand so small that it is insignificant, the choice was made to not include Malta and Cyprus. In exchange, the centrally positioned country of Switzerland is incorporated. It already is linked to the ENTSO-E and cooperates on many policies with the EU (El-Agraa, 2011).

**Chosen methodology** The model will try to find overall minimum system costs, falling in the category of Top-down (TD) optimisation models as was defined in Section 3.1.1. First of all, it will look at power system planning to see how installed capacity has to be divided over countries, in order to meet demand at all times. Next to that, it will optimise dispatch decisions, based on very rudimentary power system control workings. To keep the model manageable, both the objective function and constraints are kept linear. Although many operations of the system could best be captured by nonlinear equations, the practical disadvantage of falling into a nonlinear model are decisive. Two reasons stand out for this research (Chinneck, 2012, pp. 1-5):

1. it is very time consuming, especially in problems with large numbers of variables;

2. there is no certainty whether or not the actual optimum is found, as there are many local optima. An objective function with one variable is shown in Figure 4.2, but for a nonlinear function with many variables the solver easily gets trapped in a local optimum as a movement in any direction will provide worse solutions. This risk is significantly smaller for a linear problem.

Since this model is expected to have enormous amounts of variables and constraints, nonlinearity would not only be impossible looking at the time-horizon, but also the outcomes of the model can never be fully trusted. An option that has been investigated is to model the transmission line capacities as integer variables to approximate the cost curve. No significant difference was found with a fully linear model, but it did result in a strong increase in computation time. A short explanation on this topic is given in Section 4.1.4. The model will thus be a linear power system costs minimisation with an hourly resolution. The system consists of all EU member states and Switzerland, without Cyprus and Malta.
4.1.2. Generation technologies

When considering which generation technologies to include, a few characteristics are mainly important. First is the cost-scheme, where units with high fixed costs and low variable costs stand opposite to technologies with the cost allocation the other way around. Secondly, the production profile is distinctive, where the output of RES-E is intermittent and weather-dependent, while conventional generation offers almost full flexibility. The third characteristic to which technologies may behave different is the emission of CO$_2$. All RES-E are fully sustainable, some generation plants are hybrid, meaning they pollute only very small amounts of CO$_2$ per unit of output. Conventional plants are strong polluters of GHG.

First of all the expected largest sources of intermittent RES-E are discussed, wind turbines and solar panels. From these sources data on potential production is needed to determine the output. Other fully renewable sources, like geothermal and tidal power are too far from a feasible large-scale integration. A special case is hydro run-of-river power. The installed capacity in Europe is currently quite significant. However, hydro power capacity is not freely installable as it is completely dependent on geographical characteristics and the technical potential has limitations. It is also dependent on for instance intermittent weather conditions like rain fall and melting water (Resch et al., 2008). Including these elements would lead to a much more complicated model. For now it is left out of the optimisation, but one technique to incorporate it in future research without adding too much model complexity could be to, per country, subtract the average hourly production of hydropower from the demand. Technical potentials could than be obtained from sources like for example the report by EURELECTRIC (2011).

As for conventional generation and back-up capacity, a few fossil fuel technologies are chosen that already form a large share of the installed capacity in Europe and have different cost schemes. This is the case for natural gas turbines and fossil hard coal plants according to the database of ENTSO-E (n.d.). Nuclear power will not be considered in the optimisation, as public and governmental acceptance tends to be low in Europe and it is not completely free of controversy, which is hard to incorporate in a techno-economic model. The argument that it might support a sustainable power system is debatable (Pearce, 2012; Wittneben, 2012). For gas the nowadays often build CCGT will be used, while for coal a regular hard coal power plant is incorporated. The CCGT is often used for flexibility and hence has less FLH than the coal plant. The ratio VOM/CapEx is higher for CCGT than for a coal plant, suggesting that for less FLH a CCGT is preferable over a coal plant. This gives the model the flexibility to choose the best fit technology. The last technology that will be taken into account is a sort of hybrid form: co-combustion of biomass. It offers a possibility to produce partly sustainable electricity but is adjustable in output, offering the system possibly needed flexibility under high sustainability.
4.1. Model in words

A share of the output from this plant will be seen as sustainable, while it also contributes a share to the fossil fuel generated electricity (shares will be quantified in Chapter 5). Other options for this hybrid form would have been conventional plants with Carbon Capture and Storage (CCS). However, it is, like nuclear, not completely free of controversy, while also the existence of sufficient storage locations is doubtful (Stephens, 2015). The decision was therefore made not to incorporate these technologies, but stay with the more conventional biomass plant. The last remark that has to be made on the generation aspect is that the technical detail of inter-temporal constraints, like ramping limits and costs, spinning reserves, as well as maintenance and availability concerns will be left out. It is expected that for the overall solution these effects will have little added value, but are computationally demanding. Effects of their absence will be further discussed in Chapter 8. The complete list of generation technologies considered in the model is:

- Wind turbine (WT);
- Solar photovoltaic panel (solar PV);
- Combined-Cycle Gas Turbine (CCGT);
- Hard coal power plant (Coal);
- Biomass (BM);

An overview of the chosen characteristic parameters per technology can be found in section 5.2.1.

### 4.1.3. Storage technologies

Due to the scope of the model, where power quality and power bridging are left out, only bulk storage EES for energy management will be looked at. In an earlier study by van Staveren (2014) several of these EES technologies have already been investigated. He looked at Pumped Hydro Storage (PHS), Compressed Air Energy Storage (CAES), flow batteries and hydrogen fuel cell storage (H₂). The distinctive factor for how an
EES facility is likely to be used are the energy specific technology costs. To understand this it is important to know that a storage facility consists of two main parts. First there is the converter, which transfers electricity into the storage facility and back (expressed in Watt), which brings about ‘power costs’ (€/kW). Second there is the storage facility, which can store a certain amount of energy (Watt hour) and has energy costs (€/kWh). The ratio between these two determines the length of storage the facility is best fit for (Grünewald, Cockerill, Contestabile, & Pearson, 2011). Other characteristics, such as charge and discharge efficiency or charge and discharge rate, are also distinctive (see also Figure 4.4) (Kerckhoffs, 2015). For this research, to determine which elements can be useful to the optimisation, the exact technology is not so important, but investigating technologies with different characteristics is. Therefore, the choice has been made to investigate three types of EES facilities:

- Flow batteries; suitable for short storage durations
- PHS; in terms of cost structure between flow batteries and hydrogen storage. Per country capacities will be averaged from the scenarios of Gimeno-Gutiérrez and Lacal-Arántegui (2015)
- H₂; suitable for long storage durations

Currently not all these technologies have been applied on a large-scale. Only PHS has more than 100GW installed worldwide and can be called slightly significant (Lott & Kim, 2014). As can be seen from Figure 4.3, the flow battery technology is on the edge of maturity, while H₂ has a long way to go. As a far future model is being modelled here, the assumption is made that either the H₂ technology or a similar type will further develop and becomes available as viable option.

4.1.4. Transmission technologies
The transport element of power systems is highly complex and rather electro-technical. It consists of several subsystems, which can roughly be divided into the transmission grid, the distribution grid and several types of substations. The transmission grid is the highest level, transporting electricity on high voltages from large generators to consumption areas. The distribution grid then distributes the power to single consumers on lower voltage levels. In between the two grids a substation, mainly consisting of transformers, transforms transmission voltage into acceptable distribution levels (Seifi & Sepasian, 2011). Most of these grids use AC, however, specific transport cables between countries and to offshore sites are build for DC. Either which option is chosen depends on different characteristics, for example efficiency over certain distances and the regulation of active and reactive power flows (Morton & Cowdroy, 2006). In the real world, in order to secure grid stability, aspects like the PTDF value have to be managed carefully as was explained in Section 2.2.1. However, a combination of computational limitations and superfluity for the aim of this model, lead to the decision to ignore these highly technical complications. Even the often used substitute, DC power flow, would result in a too computational demanding model. All transmission flows will be regarded as a ‘water-flow’ model: input in a line on one side leads to output of the line on the other side. Normal transmission losses over distance will be incorporated here. This corresponds with a simplified electricity transmission simulation, where Kirchhoff’s first law (conservation of currents) is respected, but the second law (conservation of voltage) is ignored (Donohoo-Vallett, 2014).

Also, due to the aim of the model and computational limitations, all countries will be assumed as ‘copper plates’; the national transmission and distribution grids are sufficient to transport all domestic flows, electricity can flow freely from production to demand locations within a country. This leaves only interconnection lines left, which will be modelled as leading from and to the coordinates of the geographical centre of each country. This leads to distances of transmission lines shown in Figure 4.5 (all distances can be found in Appendix A). Only between neighbouring countries such a connection can exist, where connections across seas are also allowed if currently these are also present or planned.

The last assumptions that need to be made about transmission lines are the costs per length and capacity. As the length of a network line increases, all facilities have to be scaled accordingly, making it logical that costs are linearly correlated with length. However, when capacity of a line increases it does not necessarily involve an equal upgrade of all elements. The pole to hold overhead cables, excavation works and foundations for example will scale less. As was pointed out in (Heijnen, Stikkelman, Ligtvoet, & Herder, 2011, p. 372) this results in a concave relation between capacity increase and cost increase. If it were to be modelled in that way it would lead to a non-linear optimisation model, with all computational disadvantages this entails. An hybrid option would be to model each connection between countries as three different integer variables, with increasing capacities of transmission lines. The costs for higher capacity lines increases, but only with a cost
factor of 0.6 as capacity increases. This also sort of reflects reality, as transmission lines are not likely to be scalable on a continuous scale, but probably come in predetermined, integer scale capacities. The integer variable would then be the number of lines installed, making the model an Mixed-Integer Linear Problem (MILP). However, as a MILP is harder to solve than strictly linear models, the advantage of more realistic outcomes has to be carefully weighed against the added computation time. Also the higher transmission costs a fully linear problem is likely to produce might be a better reflection of actual costs, seeing the number of factors left out of the technical scope. Since no significant difference in results was found, it was decided to keep the model for further investigation fully linear. This choice is further elaborated on in Appendix D.
**TEXT BOX 4.1.5; Linear Optimisation Problem**

**Minimise**

- Total system costs for the European power system, consisting of:
  - Fixed costs for capacity of generation technologies: wind turbines, solar PV panels, gas turbines, coal and biomass plants.
  - Fixed costs for capacity of storage conversion technologies and storage capacities: Flow-batteries, Pumped hydro storage and Hydrogen.
  - Fixed costs for interconnection transmission lines.
  - Variable costs for conventional generation technologies: Gas turbines, Coal and Biomass plants.

**subject to:**

- Power balance requirements:
  - Power generated + imported + discharged - exported - charged is equal to the demand in every country at all times
  - The power charged into a storage is added to the storage-level, minus efficiency losses. The power discharged from storage is deducted from storage level, plus efficiency losses.
  - The export from country $m$ to $n$ is the same as the import in country $n$ from country $m$, minus transport efficiency losses.

- Generation limitations
  - Output from conventional generation technologies stays below the installed capacity.
  - Output from RES-E stays below the installed capacity multiplied by the potential output per capacity (due to meteorological conditions).

- Storage limitations
  - The power flowing in and out storage cannot exceed the installed conversion capacity.
  - The energy in storage cannot exceed the installed storage capacity.
  - The energy in storage at the start is the same as the stored energy at the end.

- Transmission limitations
  - The power flowing from country $n$ to $m$ can never exceed the installed capacity between country $n$ and $m$.

**with bounds:**

- Lower bounds:
  - All lower bounds are 0.

- Upper bounds:
  - Installed PHS storage capacity in any country can never exceed the technical potential for that country.
  - All other upper bounds are infinite.
4.2. Mathematical formulation

In order for a computer tool to solve the optimisation, a mathematical representation of the problem needs to be defined. In this section we will look at how the aforementioned choices of what should be incorporated in the model, translate to such a mathematical representation. The equations that will be presented in this chapter try to follow the described workings of a power system as close as possible. When building a model it is important to know which elements need to be covered by the mathematical formulation. The following items are decided upon in the Sections below, based on Seifi and Sepasian (2011, p. 15-16):

- Decisions on independent and dependent variables; in relation to this problem independent variables are for example the capacity and location of certain generation, storage and transmission technologies, as well as their dispatch for each hour.
- Constraints functions; consisting of technical, economic or environmental limitations dividing the solution space into areas that are acceptable (feasible) or unacceptable (non-feasible).
- Objective functions; a function of the decision variables to be minimised or maximised. For this model the total system costs is a function of all cost involved variables, which then is to be minimised.

4.2.1. Variables, sets and parameters

In Table 4.1 an overview is given of the notation for all variables, sets of variables and parameters. The mathematical expressions will all be given in the same fashion: Upper case letters represent variables or sets of variables, Greek letters are parameters and smaller letters are elements of sets.

4.2.2. Objective function

As has been explained before, the objective of this model is to minimise total power system costs for Europe, TC. These costs consist of the sum of the fixed costs for all technologies, FC, and the variable costs for all technologies, VC (see Eq. 4.1).

\[
\min \quad TC = FC + VC
\]  

(4.1)

The FC can be defined as the total installed capacity of generation, storage conversion (IC_{i,n} \forall i \in G \cup E) and storage capacity installed (IS_{i,n} \forall i \in S), in each nation n \in N, multiplied by the fixed costs per capacity for that technology (\omega_i \forall i \in G \cup E) and \mu_i \forall i \in S). The interconnection costs have to be added as well, defined as the total transmission capacity installed (TR_{n,m} \forall n \in N \forall m \in M_n), times the length (\delta_{n,m}) and fixed costs (C), which can be found in Eq. 4.2. Since fixed costs are made for the whole lifetime of a technology, and variable costs are calculated over shorter time spans, to make them comparable the time-cost-factor is introduced (\alpha_i \forall i \in I and \beta for transmission lines). It will be explained at the end of this section.

\[
FC = \sum_{i \in G \cup E} \alpha_i \cdot \omega_i \cdot \sum_{n \in N} (IC_{i,n}) + \sum_{i \in S} \mu_i \cdot \sum_{n \in N} (IS_{i,n}) + \zeta \cdot \beta \cdot \sum_{n \in N} \sum_{m \in M_n} (\delta_{n,m} \cdot TR_{n,m})
\]  

(4.2)

The second element of the objective function consists of the variable costs per generation technology (\nu_i). These are calculated as the sum of all power output P_{i,n,t} for technology i \in G in each country n \in N of each time step t \in T, multiplied by the variable costs for technology i \in G (in €/MW\cdot h, see Eq. 4.3).

\[
VC = \sum_{i \in G} \nu_i \cdot \sum_{n \in N} \sum_{t \in T} P_{i,n,t}
\]  

(4.3)

To guarantee a fair comparison, all costs have to be calculated over the same period of time. To do so, the runtime will be considered. This means that the fixed costs have to be brought back to hourly costs and multiplied by the number of hours of the run. This will be done by creating time-cost-factors (\alpha_i and \beta, see Eq. 4.4 and Eq. 4.5). Herein the fixed costs will be divided by the lifetime in years for that technology (\phi_i or \rho in years) and the average number of hours per year (Y = 8766 hours/year, due to leap years), multiplied by the hours of the run(R). The variable costs are already calculated over the number of hours.

\[
\alpha_i = \frac{R}{(\phi_i \cdot Y)} \quad \forall i \in I
\]  

(4.4)

\[
\beta = \frac{R}{(\rho \cdot Y)}
\]  

(4.5)
### Sets

<table>
<thead>
<tr>
<th>Notation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$G$</td>
<td>Set of all considered generation technologies</td>
</tr>
<tr>
<td>$E$</td>
<td>Set of all considered electrical storage conversion technologies</td>
</tr>
<tr>
<td>$S$</td>
<td>Set of all considered electrical storage capacity technologies</td>
</tr>
<tr>
<td>$I$</td>
<td>Set of all considered technologies, where $I = G \cup E \cup S$</td>
</tr>
<tr>
<td>$N$</td>
<td>Set of all considered nations</td>
</tr>
<tr>
<td>$M_n = {m</td>
<td>A(n,m) = 1, \forall n \in N, m \in N}$</td>
</tr>
<tr>
<td>$T$</td>
<td>Considered time steps</td>
</tr>
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### Parameters

<table>
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<th>Domain</th>
<th>Description</th>
<th>Unit</th>
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<tbody>
<tr>
<td>$ED_{n,t}$</td>
<td>$n \in N, t \in T$</td>
<td>Electricity Demands</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$GP_{i,n,t}$</td>
<td>$i \in G, n \in N, t \in T$</td>
<td>Generation Potentials, maximal output per installed MW of generation technology</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$MC_{i,n}$</td>
<td>$i \in S, n \in N$</td>
<td>Maximum installable Capacities, limited by technological potential</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$\delta_{n,m}$</td>
<td>$n \in N, m \in M_n$</td>
<td>Distances between geographical centres per connection</td>
<td>(km)</td>
</tr>
<tr>
<td>$\omega_i$</td>
<td>$i \in G \cup E$</td>
<td>Fixed Costs generation and storage conversion technologies</td>
<td>(€/MW)</td>
</tr>
<tr>
<td>$\mu_i$</td>
<td>$i \in S$</td>
<td>Fixed Costs storage capacity technologies</td>
<td>(€/MWh)</td>
</tr>
<tr>
<td>$\zeta$</td>
<td></td>
<td>Fixed Costs transmission lines</td>
<td>(€/MWkm)</td>
</tr>
<tr>
<td>$\nu_i$</td>
<td>$i \in G$</td>
<td>Variable Costs generation technologies</td>
<td>(€/MWh)</td>
</tr>
<tr>
<td>$\varphi_{i,n}$</td>
<td>$i \in I$</td>
<td>Life-times generation and storage technologies</td>
<td>(year)</td>
</tr>
<tr>
<td>$\rho$</td>
<td></td>
<td>Lifetime transmission lines</td>
<td>(year)</td>
</tr>
<tr>
<td>$\alpha_i$</td>
<td>$i \in I$</td>
<td>Time-cost-factor to calculate fixed costs to hourly costs for all technologies</td>
<td>(/hour)</td>
</tr>
<tr>
<td>$\beta$</td>
<td></td>
<td>Time-cost-factor to calculate fixed costs to hourly costs for transmission lines</td>
<td>(/hour)</td>
</tr>
<tr>
<td>$R$</td>
<td></td>
<td>Specific considered hours of a run</td>
<td>(hour)</td>
</tr>
<tr>
<td>$Y$</td>
<td></td>
<td>Average number of hours in a year</td>
<td>(hour)</td>
</tr>
<tr>
<td>$\tau$</td>
<td></td>
<td>Transmission line efficiencies</td>
<td>(%/km)</td>
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<td>$\gamma_i$</td>
<td>$i \in E$</td>
<td>Charging efficiencies</td>
<td>(%)</td>
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<td>$i \in E$</td>
<td>Discharging efficiencies</td>
<td>(%)</td>
</tr>
<tr>
<td>$\theta_i$</td>
<td>$i \in G$</td>
<td>Percentage of production considered sustainable</td>
<td>(%)</td>
</tr>
<tr>
<td>$\varepsilon$</td>
<td></td>
<td>RES-E generationquotum</td>
<td>(%)</td>
</tr>
<tr>
<td>$A(n,m)$</td>
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<td>Adjacency matrix of neighbouring countries</td>
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### Variables

<table>
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<th>Description</th>
<th>Unit</th>
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<td>Total power systems Costs</td>
<td>€</td>
</tr>
<tr>
<td>$FC$</td>
<td></td>
<td>Total Fixed Costs</td>
<td>€</td>
</tr>
<tr>
<td>$VC$</td>
<td></td>
<td>Total Variable Costs</td>
<td>€</td>
</tr>
<tr>
<td>$IC_{i,n}$</td>
<td>$i \in G \cup E, n \in N$</td>
<td>Installed Capacities of generation and storage conversion technologies</td>
<td>(MW)</td>
</tr>
<tr>
<td>$IS_{i,n}$</td>
<td>$i \in S, n \in N$</td>
<td>Installed Storage capacity technologies</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$TR_{n,m}$</td>
<td>$n \in N, m \in M$</td>
<td>Installed Transmission capacity between country $n$ and $m$</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$P_{i,n,t}$</td>
<td>$i \in G, n \in N, t \in T$</td>
<td>Produced Power</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$DP_{i,n,t}$</td>
<td>$i \in E, n \in N, t \in T$</td>
<td>Discharged Power</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$CP_{i,n,t}$</td>
<td>$i \in E, n \in N, t \in T$</td>
<td>Charged Power</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$SP_{i,n,t}$</td>
<td>$i \in S, n \in N, t \in T$</td>
<td>Power in Storage</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$IP_{n,m,t}$</td>
<td>$n \in N, m \in M_n, t \in T$</td>
<td>Imported Power, through transmission line between country $n$ and $m$</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$EP_{n,m,t}$</td>
<td>$n \in N, m \in M_n, t \in T$</td>
<td>Exported Power, through transmission line between country $m$ and $n$</td>
<td>(MWh)</td>
</tr>
</tbody>
</table>
4.2.3. Equality constraints

The constraints consists of two types:

1. Equality constraints; defining a variable or set of variables equal to a certain value or other (sets of) variable(s).

2. Inequality constraints; defining a variable or set of variables less than a certain value or other (sets of) variable(s).

First the equality constraints will be covered per subject.

**Power balance** In the power system the electricity demand has to be matched with the supply in any node \( n \in N \) at each time-step \( t \in T \). This can either be done by power generation from each production technology \( (P_{i,n,t} \ \forall i \in G) \), discharging \( (DP_{i,n,t} \ \forall i \in H) \) and charging \( (CP_{i,n,t} \ \forall i \in H) \) of each storage technology or total import \( (IP_{n,t}) \) and export \( (EP_{n,t}) \) from interconnections in- and outgoing country \( n \). The sum of all has to be equal to the demand in that country at that time-step \( (ED_{n,t}, \text{see Eq. 4.6}) \).

\[
ED_{n,t} = \sum_{i \in G} P_{i,n,t} + \sum_{i \in S} (DP_{i,n,t} - CP_{i,n,t}) + \sum_{m \in M_n} (IP_{n,m,t} - EP_{m,n,t}) \quad \forall n \in N \quad \forall t \in T
\]  

(4.6)

**Storage equality constraints** The amount of energy in storage \( (SP_{i,n,t} \text{ for } i \in S) \) is dependent on the energy in storage the time-step before \( (SP_{i,n,t-1}) \), the charge and discharge, but also on the efficiencies with which electricity is charged \( (\gamma_i) \) and discharged \( (\eta_i) \), see Eq. 4.7. The energy in storage at the start \( (SP_{i,n,t_0}) \) is the same as the stored energy in the end \( \text{(SP_{i,n,t_{max}} \text{, see Eq. 4.8})} \).

\[
SP_{i,n,t} = SP_{i,n,t-1} + \gamma_i \cdot CP_{i,n,t} - \frac{1}{\eta_i} \cdot DP_{i,n,t} \quad \forall i \in S \quad \forall n \in N \quad \forall t \in T
\]

(4.7)

\[
SP_{i,n,t_{max}} = ST_{i,n,t_0} \quad \forall i \in E \quad \forall n \in N
\]

(4.8)

**Transmission equality constraints** The import from country \( m \in M_n \) to country \( n \in N \) is equal to the export in country \( m \in M_n \) to country \( n \in N \). In this transport there are some transmission losses, determined as a certain efficiency over length of line \( (\tau \text{ as } \%/km \text{, see Eq. 4.9}) \). Also, to assure that the model builds the same transmission capacity from the perspective of countries at both ends, these capacities have to be kept equal (see Eq. 4.10).

\[
IP_{n,m,t} = \tau \cdot EP_{m,n,t} \quad \forall n \in N \quad \forall m \in M_n \quad \forall t \in T
\]

(4.9)

\[
TR_{n,m} = TR_{m,n} \quad \forall n \in N \quad \forall m \in M_n
\]

(4.10)

**Help variables** To understand better what is going on in the model, some help variables are given. This also prevents very long equations that need to be understood. First is the total supplied power from RES-E, which is the sum of all produced power from generation technologies, multiplied by there sustainability factor \( (\theta_i) \), see Eq. 4.11. The other help variable is the total generated electricity \( (P_{GEN}) \), which can be calculated as the sum of electricity from all power generation technologies (see Eq. 4.12)

\[
P_{RES} = \sum_{i \in G} \theta_i \cdot \sum_{n \in N} \sum_{t \in T} P_{i,n,t}
\]

(4.11)

\[
P_{GEN} = \sum_{i \in G} \sum_{n \in N} \sum_{t \in T} P_{i,n,t}
\]

(4.12)

4.2.4. Inequality constraints

The inequality constraints are all written as ‘less than’ equations.

**Dispatch inequality constraints** The generation output from each technology \( i \), in each country \( n \), at any time-step \( t \), is always smaller than the installed capacity of that technology multiplied by the generation potential per installed capacity \( (GP_{i,n,t}) \text{ in MWh/MW}) \) of that technology. For conventional generation this potential is equal to 1, for RES-E it depends on the weather conditions (see Eq 4.13).

\[
P_{i,n,t} \leq GP_{i,n,t} \quad \forall i \in G \quad \forall n \in N \quad \forall t \in T
\]

(4.13)
**Storage inequality constraints** For storage technologies, no more electricity can be stored than the installed storage capacity in each country $n$ at each time step $t$ (see Eq. 4.14). Also, no more electricity can be charged or discharged than the converter capacity in each country $n$ at each time step $t$.

\[
SP_{i,n,t} \leq IS_{i,n,t} \quad \forall i \in S \quad \forall n \in N \quad \forall t \in T
\] (4.14)

\[
DP_{i,n,t} \leq IC_{i,n,t} \quad \forall i \in E \quad \forall n \in N \quad \forall t \in T
\] (4.15)

\[
CP_{i,n,t} \leq IC_{i,n,t} \quad \forall i \in E \quad \forall n \in N \quad \forall t \in T
\] (4.16)

**Transmission inequality constraints** The total power transported between country $n$ and $m$ should never exceed the installed transmission capacity (see Eq. 4.17).

\[
IP_{n,m,t} + EP_{n,m,t} \leq TR_{n,m} \quad \forall n \in N \quad \forall m \in M_n \quad \forall t \in T
\] (4.17)

**RES-E requirement constraint** The goal of the model is to optimise under high levels of RES-E integration. To do so, the EU sets goals for the amount of electricity from sustainable sources. To be able to model this a variable is created that can be used to set a minimum of renewable energy, the RES-fraction ($\varepsilon$). The constraint in the model prevents the share of RES-E supplied, compared to the total generation, to come below this fraction (see Eq. 4.18)

\[
\varepsilon \cdot P_{generated} \leq P_{RES}
\] (4.18)

**4.2.5. Bounds**

All variables are larger or equal to 0, so the lower bounds are all set to 0. The upper bounds are all infinite, except for the storage capacity of PHS. These are limited to their technical potential, or maximal installable Capacity ($MC_{i,n}$) as was defined in Gimeno-Gutiérrez and Lacal-Arántegui (2015) (see Eq. 4.19).

\[
0 \leq SP_{i,n,t} \leq MC_{i,n} \quad \forall t \in T \quad \forall n \in N \quad \forall i = PHS
\] (4.19)

**4.2.6. Equations listed**

In the text box 4.2.6 all relevant equations for the optimisation are given. Help variables are left out.
TEXT BOX 4.2.6: Equations for the Optimisation Problem

**Minimise**

- \( TC = FC + VC \)
  - \( FC = \sum_{i \in G \cup E} \alpha_i \cdot \omega_i \cdot \sum_{n \in N} (IC_{i,n}) + \sum_{i \in S} \alpha_i \cdot \mu_i \cdot \sum_{n \in N} (IS_{i,n}) + \zeta \cdot \beta \cdot \sum_{n \in N} \sum_{m \in M_n} (\delta_{n,m} \cdot TR_{n,m}) \)
  - \( VC = \sum_{i \in E} \sum_{n \in N} \sum_{t \in T} P_{i,n,t} \)

**subject to:**

- **Equality constraints:**
  - \( ED_{n,t} = \sum_{i \in G} P_{i,n,t} + \sum_{i \in S} (DP_{i,n,t} - CP_{i,n,t}) + \sum_{m \in M_n} (IP_{n,m,t} - EP_{m,n,t}) \quad \forall n \in N \quad \forall t \in T \)
  - \( SP_{i,n,t} = SP_{i,n,t-1} + \frac{1}{\eta_i} \cdot DP_{i,n,t} \quad \forall i \in S \quad \forall n \in N \quad \forall t \in T \)
  - \( SP_{i,n,0} = ST_{i,n,0} \quad \forall i \in E \quad \forall n \in N \)
  - \( IP_{n,m,t} = \tau \cdot EP_{m,n,t} \quad \forall n \in N \quad \forall m \in M_n \quad \forall t \in T \)
  - \( TR_{n,m} = TR_{m,n} \quad \forall n \in N \quad \forall m \in M_n \)

- **Inequality constraints:**
  - \( P_{i,n,t} \leq GP_{i,n,t} \quad \forall i \in G \quad \forall n \in N \quad \forall t \in T \)
  - \( SP_{i,n,t} \leq IS_{i,n,t} \quad \forall i \in S \quad \forall n \in N \quad \forall t \in T \)
  - \( DP_{i,n,t} \leq IC_{i,n,t} \quad \forall i \in E \quad \forall n \in N \quad \forall t \in T \)
  - \( CP_{i,n,t} \leq IC_{i,n,t} \quad \forall i \in E \quad \forall n \in N \quad \forall t \in T \)
  - \( IP_{n,m,t} + EP_{n,m,t} \leq TR_{n,m} \quad \forall n \in N \quad \forall m \in M_n \quad \forall t \in T \)
  - \( \varepsilon \cdot P_{generated} \leq P_{RES} \)

- **Bounds:**
  - \( 0 \leq SP_{i,n,t} \leq MC_{i,n} \quad \forall t \in T \quad \forall n \in N \quad \forall i = S \)

The model is now fully described, but only in theory. The next chapter explains how this conceptual model is translated into an actual working model. All parameter values are given there as well.
Model formalisation and verification

Now that the goal of this model and its theoretical operation are clear, a more thorough description of how the model was actually ‘modelled’ will be given. In the formalisation, the used modelling tool, the model code, choices and techniques will be explained, as will be the data and parameters used as input. It basically shows the translation of mathematical equations into computer modelling language. The steps taken in this Chapter follow the structure as was defined by Murray-Smith (2015) and can be found in Figure 5.1. Subsequently, the data is evaluated and corrected for outliers and strong deviations with reference studies. In the end, the built model is verified to check whether a proper translation of the conceptual model into a working modelling tool was achieved.

5.1. Choice of computer modelling tool

When solving optimisation problems with the size and scope of the European power system, it is almost inescapable to use a mathematical computer modelling tool. There are several tools available, of which probably the best known comes from the Microsoft Office package: Microsoft Excel. However, as it is the case with Excel, not all mathematical modelling tools are fit for each problem type and size. Although this specific case consisted of a linear optimisation, it was likely to have a large number of variables, for which Excel is less suitable. Often used tools in research for large numerical and mathematical problems are programs like Matlab, Python, Octave or numerous tools built around the programming languages of java, php or C/C++. Little to no experience with these programs was present and the time constraint was quite strict. Learning programming languages would take longer than working with more intuitive programs such as Matlab, Python or Octave, so a first separation could be made. From the remainder three, the one with the best documentation and online help-tools was found to be Matlab. The existence of a NetCDF-toolbox (Network Common Data Form), a database language in which the majority of the input data was stored, made the difference: the tool to use for this optimisation would be Matlab. For more reasons, strengths and weaknesses of all different modelling tools, many discussions on the Mathworks online forum can be found (Stackoverflow, 2009). To solve the problem, a more powerful solver than the custom linear solver of Matlab (linprog) was used, which was developed by IBM: cplex (IBM, 2016).

5.2. Defining parameters

The technical properties, applied in the model, have been taken from multiple researches and reports, to approach the real-world operation as good as possible. One of the most important factors are the costs, which can be divided in three main categories: Capital Expenditures (CapEx), Fixed Operations & Maintainance costs (FOM) and Variable Operations & Maintenance costs (VOM). These costs are likely to change over time and between countries. The differences in costs between countries are chosen to be ignored. During the sensitivity analysis, presented in Section 7.2, the effects of future parameter developments will be investigated. The parameters will be discussed per power system element. A full oversight of the parameters found in research can be found in Appendix C.
5. Model formalisation and verification

Figure 5.1: Block diagram of the modelling process; Model formalisation is shown within the red dotted lines. Adapted from Murray-Smith (2015, p. 21)

Table 5.1: Overview of chosen generation technology parameters. CapEx = Capital Expenditures; FOM = Fixed Operation & Maintenance costs; VOM = Variable Operation & Maintenance costs; $\eta$ = fuel to electricity conversion efficiency; Lifetime = average lifetime of the installed technology; Pollution = ton of CO$_2$ emission per generated MWh. Figures are averages taken from Bertsch et al. (2012); Brouwer et al. (2016); ECF (2010); Fürsch et al. (2013); van Staveren (2014).

<table>
<thead>
<tr>
<th>Generation technology</th>
<th>CapEx ($\text{€/kW}$)</th>
<th>FOM ($\text{€/kW/yr}$)</th>
<th>VOM ($\text{€/MWh}$)</th>
<th>$\eta$ (%)</th>
<th>Lifetime (yr)</th>
<th>Pollution (tCO$_2$/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind onshore</td>
<td>1080</td>
<td>34</td>
<td>0</td>
<td>100</td>
<td>25</td>
<td>0</td>
</tr>
<tr>
<td>Solar PV</td>
<td>1870</td>
<td>27.50</td>
<td>0</td>
<td>100</td>
<td>25</td>
<td>0</td>
</tr>
<tr>
<td>CCGT</td>
<td>800</td>
<td>20</td>
<td>46</td>
<td>60</td>
<td>30</td>
<td>0.28</td>
</tr>
<tr>
<td>Coal plant</td>
<td>1600</td>
<td>28</td>
<td>30</td>
<td>47</td>
<td>42.5</td>
<td>0.48</td>
</tr>
<tr>
<td>Biomass plant</td>
<td>2640</td>
<td>90</td>
<td>84.5</td>
<td>35</td>
<td>33</td>
<td>0.035</td>
</tr>
</tbody>
</table>

5.2.1. Generation parameters

Since technical constraints, like ramping-times, -limits and -costs, are not considered, the only used parameters for the generation technologies are CapEx, FOM and VOM. There are many sources available, together providing a wide range of these parameters. The five sources that provided the most complete set of information for the used technologies were chosen, and parameters were defined based on their findings. The information used comes from (Bertsch et al., 2012; Brouwer et al., 2016; ECF, 2010; Fürsch et al., 2013; van Staveren, 2014). Only the figures for solar PV panels have been estimated differently, since a dual-axis tracking system was used for the calculation of potential production data (see also Section 5.3.2). It is both more expensive than normally incorporated PV systems, as it has a higher output level. As the output is expected to be 10% higher than regular solar PV systems, the costs were also increased with 10%. According to a recent study in the U.S. by Simon and Mosey (2013), the price of a dual-axis tracking system is even higher, but is not regarded cost-competitive to simpler PV options. To keep different technologies comparable higher output is thus only corrected for with an equally higher price. The chosen parameters can be seen in Table 5.1. The generation technology specific LCOE can be found in Appendix B.
5.2. Defining parameters

Table 5.2: Overview of chosen storage technology parameters. CapEx_conv = Capital Expenditures for the converter; CapEx_storage = Capital Expenditures for the storage capacity; FOM = Fixed Operation & Maintenance costs; VOM = Variable Operation & Maintenance costs; $\eta_{in}$ = electricity to storage efficiency; $\eta_{out}$ = storage to electricity efficiency; Lifetime = average lifetime of the installed technology. Figures are averages taken from Brouwer et al. (2016); Steinke et al. (2013); van Staveren (2014); Zakeri and Syri (2015).

<table>
<thead>
<tr>
<th>Storage technology</th>
<th>CapEx convert (€/kW)</th>
<th>CapEx storage (€/MWh)</th>
<th>FOM (€/MW/yr)</th>
<th>VOM (€/MWh)</th>
<th>$\eta_{in}$ (%)</th>
<th>$\eta_{out}$ (%)</th>
<th>Lifetime (yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow battery</td>
<td>150</td>
<td>450</td>
<td>50</td>
<td>0</td>
<td>90</td>
<td>90</td>
<td>10</td>
</tr>
<tr>
<td>Pumped Hydro Storage</td>
<td>1900</td>
<td>58</td>
<td>0</td>
<td>0</td>
<td>90</td>
<td>90</td>
<td>50</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>1600</td>
<td>60</td>
<td>40</td>
<td>0</td>
<td>62</td>
<td>62</td>
<td>20</td>
</tr>
</tbody>
</table>

Table 5.3: Overview of chosen transmission technology parameters. CapEx = Capital Expenditures per kilometer of line (Capacity costs are already incorporated); Line capacity = specific capacity for the size of interconnection line; $\eta$ = transmission efficiency per 1000km; Lifetime = average lifetime of the installed technology. Figures were interpreted from ENTSO-E (2014a); Fürsch et al. (2013); Schaber, Steinke, and Hamacher (2012); Schaber, Steinke, Mühlich, and Hamacher (2012).

<table>
<thead>
<tr>
<th>Transmission technology</th>
<th>CapEx (€/MWkm)</th>
<th>$\eta$ (%/1000km)</th>
<th>Lifetime (yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection line</td>
<td>1000</td>
<td>96</td>
<td>40</td>
</tr>
</tbody>
</table>

5.2.2. Storage parameters

As was earlier defined in Section 4.1.3, a few characteristics of storage technologies are needed to model them. For the financial aspects, the technology consists of both a conversion and a storage unit, each with separate costs. For hydrogen ($\text{H}_2$) only from one source plausible variable costs were found, for Flow Battery (FB) and PHS these costs were mostly absent. They were thus assumed negligible or incorporated in the efficiency losses, which forms the second important characteristic for storage. However, mostly round-trip efficiencies were found, where the model works with in- and out-flow efficiencies. The assumption was made that both efficiencies are equal. The square root of the round-trip efficiency was taken for both the in- and out-flow efficiencies, so that the round-trip efficiency stays the same. For the mentioned storage parameters many sources exist, providing a wide range of values. Again, the choice was made to average the four sources that provided the most complete information on the used technologies. Their values were in the same order of magnitude, suggesting that the incorporated costs were roughly the same. The chosen characteristics are given in Table 5.2.

For PHS additional information is needed. The availability of this storage type is geological determined. Each country has a maximum technical potential that can be installed. A investigative research, issued by the EU, calculated these national technical potentials. Their figures will be used as upper bounds (see Section 4.2.5) and can be found in Table C.1 in Appendix C.

5.2.3. Transmission parameters

Since the transmission system is seen as a water-flow model, only costs and efficiencies are relevant. The sources specifying costs and capacities of transmission lines are limited. Literature, specifying costs per length and capacity, range between €400,- and 2500/€kW·km (Fürsch et al., 2013; Schaber, Steinke, & Hamacher, 2012; Schaber, Steinke, Mühlich, & Hamacher, 2012). The efficiency of 96%/1000km is quite consistent however, as is the lifetime of 40 years. Eventually average costs over the literature are around €1000,-/€kW·km. All parameters are depicted in table 5.3.

5.2.4. Manageability of the model

Now that the model is formalised, the full extent becomes clear. The sheer size of the model, due to an extremely large dataset for electricity demand and RES-E production (spanning two years with an hourly resolution), results in extremely long computation times, therefore making the model less manageable. In the previous Chapter also the choice for a fully linear model instead of a MILP was mentioned, to keep computation times more manageable. In Appendix D, these issues have been addressed by running the model and perform additional tests with it. It was even found to be impossible with the computational memory available.
to solve the problem on an hourly resolution over two complete years.

A good balance was found between the manageability of the model and the quality of the model outcomes. This manageability was achieved by not running the model over the whole dataset, but by picking specific time series. The solution from this run was capable of finding a solution with input data from other time series as well. Running the model as a MILP had little effect on the results, but enormous effects on the computation times: on average these were 10 times higher. By keeping the model fully linear and performing a run with one day from each week of the year 2012 representative results for the whole dataset were obtained. It is concluded that the model will consist of one run of 1248 hours, or 52 days, which represents roughly 7 weeks. What the effects will be for the results and conclusions will be discussed in Chapter 8.

5.3. Data evaluation

The model and results strongly depend on the input data used. Two types of data are required: electricity demand and potential production per location for wind and solar PV. This data was obtained in different ways, as will be explained below. The reliability of the data is determined with an evaluation process.

5.3.1. Electricity demand data evaluation

The electricity demand data is taken from ENTSO-E (2015d). They publish hourly demand data for each Member State per month. The data for 2012 and 2013 have been used, as these are the same years for which the RES-E production data is available (see section 5.3.2). The data is freely available and all involved parties are obliged to deliver and update it in the same way, as a result of the European Commission Regulation NO 543/2013 of 14 June 2013 on submission and publication of data in electricity markets (ENTSO-E, 2014c). This indicates that the data is reliable. However, since also some data for other countries than considered in this study was found to be missing, a short verification and validation of the data will be performed. The data was downloaded as Excel database files and transformed with the use of Matlab into large demand arrays per country.

A comparison will be made to former research, as well as to other official sources of demand data. For the demand data some country-specific patterns are known, which can be used to validate the data as well. Since it would take a lot of time and space to make a comparison of all 27 countries considered, only 5 countries spread over Europe are evaluated, as shown in Appendix E. The five countries considered are Portugal, Switzerland, Ireland, Sweden and Greece. After the data had been modified to be fit for input it firstly was tested for missing numbers, ‘NaN’ (not a number) in Matlab jargon. The few found were replaced by the average of the value the time step before and the time step after.

**Demand curve** The demand pattern is expected to change during a day, within a week with respect to weekend-days and over a year, due to seasonal effects. Interesting to notice here, is that the amount of demand per capita in economically comparable regions looks very much alike, but in warmer areas, such as Northern-America and Southern-Europe, the seasonal pattern is different from colder areas, which can be ascribed to the difference in use of heating (Bessec & Fouquau, 2008). These differences in patterns will show
5.3. Data evaluation

Figure 5.3: Weekly average electricity demands for Europe, 2012 and 2013. Each deep valley represents a night, starting on Monday morning 00:00h on the extreme left.

whether the used demand curves could indeed be representative for the actual demand curves in these countries. As can be seen from Figure 5.2 the total demand for Europe behaves as could be expected from a colder regime. High demand in the colder winter period, low demand during the warmer summers. Both the plots for 2012 and 2013 look very much alike what was found by Heide et al. (2010) over the years of 2002 up to 2008 for Europe (see also figure 5.7). From the analysis of the country-specific demand profiles it follows that especially Greece has a different inter-seasonal pattern, with high demand spikes during summer. Portugal and Ireland have less inter-seasonal variation in demand, which could be explained by their neighbourhood to the sea, which accounts for a more maritime-climate, in which the temperature differences are less extreme. Switzerland and Sweden, at last, show a more extreme seasonal change, with high demands during the winter months and lower demands during the summer, which corresponds well with the average weather type in each of the seasons: cold winters and mild summers. The expected profiles and patterns were all found back in the used data, so based on the yearly patterns, the data seems reliable.

As a last check, looking at shorter periods in the same dataset the data seems to produce quite representative outcomes as well. In Figure 5.3 the weekly average demand for 2012 and 2013 shows both the inter-daily as the inter-weekly variations. According to research by (Rasmussen, Andresen, & Greiner, 2012) and (Brouwer et al., 2016), the weekend days indeed show structural lower demand, and each Sunday has the lowest demand. Also, the daily curves, with a morning and evening spike, seem rather accurate to actual occurring profiles in, for example, a central-European country like France (Dordonnat, Koopman, Ooms, Dessertaine, & Collet, 2008).

National and European total demand The total demand figures found from the ENTSO-E data are compared to the data from another research, performed by EURELECTRIC. This organisation "represents the common interests of the electricity industry at pan-European level" and performs its own research towards electricity trends (EURELECTRIC, 2015). As can be seen from table 5.4, the values of yearly demand are not exactly the same in the two databases, but are certainly in the same order of magnitude. Several reasons could be underlying for the found differences. For instance, ENTSO-E looks from a perspective of the transmission system operator, while EURELECTRIC gets its data from national generators. Imported and exported energy might be considered ‘demand’ for one of them while it is not considered in the same way by the other. In any case, since all scenarios work with the same input data, a deviation from actual values is not considered a vital inconsistency.

5.3.2. RES-E production data evaluation

Both potential production datasets have been taken from earlier research by Wijnja-Vlot (2015). This study describes the computer model build to transform weather data into potential production data. It divides the world in 1760 longitude by 880 latitude points, resulting in 1548800 nodes. For each node the potential output is given on an hourly resolution. It corrects the wind data for weather measurements at 10m to wind speeds at hub height and for surface roughness. The used turbine is a E82-3MW wind turbine, of which the potential output at each node for each hour is given in watt. This data was calculated to output per MW to make it comparable to other generation technologies in this study. The data has been verified, outliers
Table 5.4: Yearly demand data from ENTSO-E (2015d) database (left) and EURELECTRIC (2015) figures (right).

<table>
<thead>
<tr>
<th>Country</th>
<th>ENTSO-E database</th>
<th>EURELECTRIC figures</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2012 (TWh)</td>
<td>2013 (TWh)</td>
</tr>
<tr>
<td></td>
<td>2012 (TWh)</td>
<td>2013 (TWh)</td>
</tr>
<tr>
<td>Portugal</td>
<td>49</td>
<td>49</td>
</tr>
<tr>
<td></td>
<td>47</td>
<td>47</td>
</tr>
<tr>
<td>Switzerland</td>
<td>47</td>
<td>47</td>
</tr>
<tr>
<td></td>
<td>59</td>
<td>59</td>
</tr>
<tr>
<td>Ireland</td>
<td>26</td>
<td>26</td>
</tr>
<tr>
<td></td>
<td>26</td>
<td>24</td>
</tr>
<tr>
<td>Sweden</td>
<td>142</td>
<td>140</td>
</tr>
<tr>
<td></td>
<td>132</td>
<td>130</td>
</tr>
<tr>
<td>Greece</td>
<td>50</td>
<td>46</td>
</tr>
<tr>
<td></td>
<td>54</td>
<td>52</td>
</tr>
</tbody>
</table>

Table 5.5: National averaged capacity factors compared for 5 countries and the European average. The still somewhat higher capacity factor for solar PV can partly be explained by the difference between fixed and dual-axis panels.

<table>
<thead>
<tr>
<th>Country</th>
<th>Wind CF</th>
<th>Solar PV CF</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Raw data</td>
<td>Average reference</td>
</tr>
<tr>
<td>Germany</td>
<td>0.35</td>
<td>0.19</td>
</tr>
<tr>
<td>Greece</td>
<td>0.20</td>
<td>0.27</td>
</tr>
<tr>
<td>Portugal</td>
<td>0.21</td>
<td>0.26</td>
</tr>
<tr>
<td>Sweden</td>
<td>0.40</td>
<td>0.25</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>0.40</td>
<td>0.27</td>
</tr>
</tbody>
</table>

have been removed and it is validated by comparing the output to an existing windfarm (Wijnja-Vlot, 2015). The solar PV data was calculated looking both at direct and diffuse radiation on the panel. The potential production was calculated for solar panels of 1 m² with a reference efficiency of 17% and an inverter efficiency of 96%, resulting in an overall efficiency of 16%. The potential output is calculated for a dual-axis installation, meaning that the panel will follow the optimal angle towards the sun over two angles. This increases the output by roughly 10%, but also entails extra costs (Bolinger & Weaver, 2014). To compare costs for a solar PV panel with the other generation technologies it has been assumed that 1 m² equals 160W, as was found as average in the report from 2012 by IRENA (2014). Both datasets were stored via Matlab in a NetCDF-file. This data is read via Matlab again and country averages for all considered countries were created per hour. These were stored in arrays of the same form as the demand data.

The production data consists of both the solar PV output and wind power output. The area that will be looked at are the countries that are considered in the model. For visual checks, however, a slightly larger area around the whole of Europe will be showed in order to see whether extreme and unexpectedly large differences with the direct surroundings occur. Two characteristics of the production data will be evaluated: the CF and the production curves. Both the general patterns and ratios as some absolute values will be compared with references.

Capacity factor Although the pattern of CFs projected on a map looked similar to reference studies, the absolute CFs per country, as well as comparisons between countries, were found to differ significantly from values found in comparable studies. Some extreme outliers are Ireland and Denmark, which have a wind CF of 0.51 and 0.45 respectively. The CF of solar PV for Belgium, the Netherlands, Poland and Italy appeared to be unrealistically high as well. This creates too favourable RES-E positions, which would allow the model to come up with an overly optimistic estimation of the value of RES-E. Since this was deemed unrealistic, a correction factor was applied, per country, to the data. A range of reference reports and studies was used to create national correction factors, which were applied to the potential hourly output (Boccard, 2009; Breeze, 2014b; European Commission, 2013; IEA, 2013; IRENA, 2015; Mears, 2014a, 2014b; WEC, 2013). An aggregation of found CFs in other reports was averaged with the factors from the dataset. All hourly outputs were multiplied with the correction factor.

After the corrections have been applied, the CFs and profiles were compared with references again. In Figure 5.4 we see the map of Europe twice, with in the left figure (a) the wind data CFs for 2012 and 2013 and the solar PV CFs for the same years in the two maps below figure to the right (b). From references, a CF pattern that was projected on the map of Europe was found as well. This can be found in Figure 5.4, which
5.3. Data evaluation

Figure 5.4: Yearly capacity factors for wind and solar PV over Europe from used dataset. (a) Capacity factor for wind power. (b) Capacity factors for a dual-axis solar PV panel. These are compared with the yearly capacity factors for wind and solar PV over Europe from reference sources. (c) Hourly load factors for wind power. Adapted from (EEA, 2009). (d) Potential production for 1 m$^2$ of a fixed solar PV panel. Adapted from (Energy, 2013).
Figure 5.5: (a) The found potential production curve for wind and solar PV in Europe over 2 years, from the used dataset. (b) The daily potential production curve for wind and solar PV in Europe over 2 years, from the used dataset.

shows the hourly load values for a wind turbine to the left (c) and the potential production per $m^2$ of a solar PV panel to the right (d). Although the method slightly differs from the calculation of the CFs for this report, the profile is very similar. To calculate the load hours to a CF, they should be divided by the number of hours per year (8766), which leaves values between 0.10 and 0.35 for the wind map. The solar PV annual output can be calculated back to CFs as well using the same sort of technique, leaving values of between 0.09 and 0.23. Looking at the wind maps it can be seen that the CF is highest above open sea and decreases towards the inland of Europe. The maps show some strange transitions between land and sea, which can be explained due to the fact that the correction factor was only applied to onshore data.

According to IPCC (2012) the CF of an onshore wind turbine is between 0.20 and 0.40. The study of Arvesen and Hertwich (2012) shows that for Europe the average lies around 0.25 for European onshore turbines. Looking specific at the European range of CFs, IRENA (2015) has found a range for Europe of around 0.10, up to over 0.40, averaging around 0.25. All these values seem to fit both the found European average as the range of values from individual countries. For a solar PV panel the values found by Šúri et al. (2007) vary from a country average of 0.09 in Finland to 0.17 in Portugal. The fact that their values are slightly lower than those found in our dataset can be explained by the single-axis versus dual-axis set-up of the panels. Adding the 10% dual-axis has as advantage over single-axis brings the values closer together. After the correction has been applied in pre-processing, the found CFs will therefore be considered sufficient reliable.

**Production curve**  The production curve from wind and solar PV is expected to change with the seasons. For Europe, the warmer and more sunny months are from April until August, while the more cold and windy months tend to be from September until March. Logically the potential output for solar PV is on average higher during the sunny months, while the potential output from wind thrives during the windy months. From Figure 5.5a it can be seen that this expected curve indeed can be found in the data. The curve matches the shape of found production curves from studies such as performed by Heide et al. (2010) (see Figure 5.7) and Samsatli and Samsatli (2015). We can conclude that the yearly curves are rather comparable, but also see from the curves that even over two serried years, the output potential differs quite a lot, which makes the careful selection of a time-series an even more important aspect to capture all relevant interdependencies. From Figure 5.5b, it can be seen that the daily average production potential over a day behaves as might be expected. Between 20:00h in the evening and 04:00h in the morning (almost) no solar PV power output is to be expected, while there is a production peak during noon. For wind the pattern is less extreme but a slightly lower production potential during the day is perceptible. Both these patterns correspond to found curves in the research by (Hoste, Dvorak, & Jacobson, 2009), which can be seen in Figure 5.6. Overall it can be concluded that the production data follows quite plausible patterns and profiles. The production data is deemed sufficiently reliable.
5.3. Data evaluation

Figure 5.6: Hourly average production for the state of California, U.S., for different months. (a) The potential wind power output per installed MW and (b) the potential solar PV output per MW peak installed (Hoste et al., 2009).

Figure 5.7: The normalised power and demand curve from Heide et al. (2010). "Normalized wind power generation (blue), solar power generation (orange) and load (red) time series aggregated over Europe. Each series is shown in one-month resolution and is normalized to its 8 years average." (Heide et al., 2010, p. 2).
5.4. Model verification

In the previous Sections it was explained how the model was constructed, but it is not yet ready to produce reliable results. Once a model has been developed, two actions need to be performed to identify the quality of the model and results: verification and validation. During the verification, the model (or data) is assessed for a right translation from the conceptual model to a computational model. It establishes the consistency of the final model operation, with the underlying mathematical equations. It does not say anything about how the model represents the real world. The validation process, on the contrary, is used to determine to what degree the model and data are a valid representation of the real world, looked at from the purpose of the model. If the model is properly verified, the validation basically determines how accurate the conceptual model was for the application at hand. As a full representation of the reality is impossible, the validation process is also used to determine to what degree the results are valid (Murray-Smith, 2015; Oberkampf & Roy, 2010). If insuperable inconsistencies are found, the model will need to be adapted to provide better results, which creates an iterative process. In this Section the model is verified. The result is then a model, which is translated adequately from theory to working modelling tool. The next Chapter will describe the experiments performed with this model and the results obtained by those. After that, Chapter 7 will determine the validity of the results and perform an additional sensitivity analysis.

The model will be verified in three different ways. First the literal translation of the equations into Matlab will be visually checked. The structure in which Matlab solves an optimisation scenario is well suited to do so for small problems. Secondly the optimisation will be run for a strongly simplified small problem, for which the solution can be calculated by hand. The last verification will be done for making several options of the model available and unavailable to the optimisation, and subsequently check whether the model behaves in the expected way and costs move in the expected direction.

5.4.1. Logical verification: translate equations to model

Matlab uses arrays and matrices as input for an optimisation model. All columns are equivalent to the variables and all rows of the matrices are equivalent to constraints. The matrices for the full problem are so large, that the overview of the whole problem gets lost. The process of building the matrices has been automated, but during the build-up phase many test runs have been done, in order to verify the consistency with the mathematical model. Also some smaller parts have been extracted from the matrix, to see for those parts whether or not the translation happened in a reliable way. This has not only been done for the two matrices, but also for the objective function and boundaries. For a very small problem, with two countries and one time-step, the arrays and matrices are small enough to undergo a visual inspection. Although during the build-up process many errors were discovered and the process had to be corrected, in the final run no inconsistencies were found. The author is available for any questions regarding the modelling process.

5.4.2. Operational verification: known outcomes & solutions

The operational verification of the model can be done in two different ways. The first, simple way is to calculate by hand whether the solution leads to the same system costs as the model came up with, which is merely a quick check whether the objective function works as it is supposed to. In this same method, also a manual calculation whether no constraints were broken can be applied, basically checking whether the constraints work as supposed. The second way is to calculate the solution for a very small problem (two time-steps, two-countries) by hand, and see if the same results can be obtained by the model.

For the first test we take one of the smaller time-series, consisting of one day per month, considering 312 hours in total. The first run for 2012 was used (see Appendix D). The solution is filled in and total costs are calculated by hand. The different values can be found in Table E.1 in Appendix E. A difference of €0.05 on the total system costs occurred with the solution found by the model and the calculation by hand. This difference is considered small enough to be neglected. When checking the constraints, no constraints were broken. The RES-E constraint, 50% power from renewables, is the major binding constraint. Manually changing the solution either violates the constraints, or leads to more expensive outcomes, suggesting that the optimum is, at least, a local optimum.

The small problem created to test the model's operations is a situation in which the Netherlands and Belgium need to design the optimal solution for serving the load in the first two hours of January the 1st 2012. They both have no pumped hydro storage, but there is a possible transmission line between the two of them. The potential output of wind power and solar PV power, as well as the demand for both hours can be found in Table E.2. As can be observed, no solar PV power is available in the middle of the night (00:00h - 02:00h). The
5.4. Model verification

5.4.3. Functional verification

In the functional verification two different expected patterns for the functioning of the model will be explored. The first is whether the system costs will rise with an increasing RES-E requirement, as is one of the major assumptions for this study. The second major assumption states that increasing the amount of options incorporated in any optimisation is able to decrease system costs. When certain elements of the power system are set, or absent in the optimisation this should lead to higher costs.

In Figure 5.8a the system costs have been given for the model, where the required RES-E share increases from zero to a hundred with steps of 10%. As can be observed, the costs increase exponentially, but only start doing so around 40% of RES-E. This suggests that an optimal system, where all elements are optimised, will always contain around 40% of power from RES-E. Although this seems a bit high, the possibility can not completely be ruled out: the aim of the model is to find an optimum under high integration levels of RES-E, to which it clearly acted. Therefore the visible trend is deemed acceptable and shows that the model works as it was intended.

For the second check the model was run for 20%, 50% and 80% RES-E requirement, when all options are available, when storage is unavailable, when transmission is unavailable and without both storage and transmission. In Figure 5.8b the outcome of this test can be observed. Also here the increasing trend of system LCOE can be observed as options decrease. The actual value of each option will more thoroughly be discussed in Section 7.2. For now it is clear that the expected behaviour of the model is present. The model is operating as it is supposed to.

It can be concluded that both the model and the data are sufficiently reliable to run the experiments with. In the next chapter the design of these experiments will be discussed and the results of different scenarios will be shown and described.

Now that a final model is chosen and verified, experiments can be designed to formulate an answer to the research questions. These experiments, together with the results, will be presented in the next chapter (6). The final step in the modelling process is to determine how well it represents a real world situation, which will be presented in Chapter 7. In the concluding two chapters the results will be discussed and answers to the research questions will be provided.
Experimental design and Results

With the obtained model, a number of experiments is executed. The results of these tests will give insights in the aspects and costs of a future power system design, under several planning scales. The results eventually will help formulate an answer to the research questions. To do so, the optimisation will be run for multiple possible policy scenarios, which will determine the benefits of a centrally coordinated design over more local coordination. A baseline scenario, meant to represent the current power system, will be designed in order to find the gap between any optimum and the system emerging from current policy. Besides an overview and comparison of the costs, also the solution with installed capacities, dispatching of generation technologies, charging and discharging of storage facilities, as well as cross-border power flows will be presented. The results for the most optimal scenario will be shown and compared with the other scenarios. The results for the other scenarios are presented in Appendices H to K. The validation of these results, as well as a full model sensitivity analysis are performed in the next chapter (7).

6.1. Experiment set-up
The model allows for several tests to determine the least cost-option from a techno-economic perspective. These tests all reflect a possible future policy scenario and account, in varying degrees, for national energy security. First, a scenario where each country has to plan installed capacity as if it were an islanded system, which should be able to always supply domestic demand, is investigated. In the dispatch phase, currently installed transmission capacity can be used to optimally dispatch. Secondly, a scenario is tested in which nine regions have been selected within Europe, based on current integration of country’s power systems, other researches and a visual inspection of interconnectedness. Within these regions, transmission capacities are included in the optimisation: no power flows between the regions are allowed. The third scenario involves all countries and all technologies, including transmission capacities, in the optimisation. The fourth scenario that will be looked at is a central planning scenario for all elements, but with an important constraint. It requires each country to, at least, install enough domestic conventional generation capacity to serve peak load. The other elements, as well as the RES-E share, are optimised on a continental scale. This scenario assumes that a central planning scale can bring benefit without threatening national energy security goals (see Table 6.1). Furthermore, a baseline-scenario is created which optimises power dispatch based on currently installed capacities. This scenario is mainly meant to compare the current situation with optima and comes in helpful at the validation stage.

The scenarios will be run for a set of parameters as were defined for 2015. Results for three different levels of RES-E integration will be given: 20%, 50% or 80% of the generated power is required to come from renewable sources. In this section a short explanation of how the four policy scenarios are build is given. In the next section (6.2) the results from the experiments are presented.

6.1.1. National optimisation set-up
The smallest scale of power system design, that can be studied with the model, is a national one. For this scenario, national governments (or any other appropriate authority in that country) design their system in such a way, that demand is always met and the RES-E share is fulfilled within that country. No interconnection capacity is allowed in this planning phase, so no cross-border flows can exist. In the dispatch phase, currently
Table 6.1: Studied policy scenarios, for each scenario the options that are optimised and the planning scale over which they are optimised are given. Dispatch is always optimised over the given installed capacities.

<table>
<thead>
<tr>
<th>Scenario name</th>
<th>RES-E capacity</th>
<th>Complementary options</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Conventional capacity</td>
</tr>
<tr>
<td>Reference</td>
<td>Given, 15% RES-E and 45% RES-E</td>
<td>Given</td>
</tr>
<tr>
<td>National</td>
<td>Optimised national for EU 20/50/80% RES-E</td>
<td>Optimised</td>
</tr>
<tr>
<td>Regional</td>
<td>Optimised regional for EU 20/50/80% RES-E</td>
<td>Optimised</td>
</tr>
<tr>
<td>Continental</td>
<td>Optimised continental for EU 20/50/80% RES-E</td>
<td>Optimised</td>
</tr>
<tr>
<td>National goals</td>
<td>Optimised continental for EU 20/50/80% RE</td>
<td>Optimised with national peak load constraint</td>
</tr>
</tbody>
</table>

installed interconnection capacity is available to optimise the dispatch. This scenario represents the current policy in the best way, where the power system design is done nationally, and where dispatch and cross-border flows are dealt with separately on market basis.

6.1.2. Regional optimisation set-up
The regional coordination is one planning scale higher than every country for itself. In the regional coordination countries are allowed to optimise their power system together in small groups. Within that region interconnection capacity is also subject to optimisation, but between different regions no transmission capacity is allowed. The chosen regions are based on three different things:

- Already existing power system cooperation and official ENTSO-E regional groups. In these groups the Baltic States, Scandinavia, the United Kingdom, Ireland and Continental Europe are seen as separate groups. As Continental Europe is still seen as a too large group for the spatial distribution element of this study, it is split up as was done by other researches (see next item) (ENTSO-E, 2015d).
- In the research by Brouwer et al. (2016) Europe is divided in six regions. Compared to the current ENTSO-E groups, the British Isles have been grouped, Portugal and Spain form the Iberian Peninsula, France is a stand-alone node, Italy and the Alpine States (Switzerland and Austria) have been merged and the Benelux together with Germany is seen as one region. Eastern Europe is left out of this research, so an analysis of considered transmission lines is used to group these as well (see next item).
- When looking at the map in Figure 6.1 it is noticeable that some regions are more geographically grouped together and have lots of interconnections. From this an Eastern-European cluster of countries is determined, consisting of Poland, Czech Republic, Slovakia and Hungary. Two Balkan countries (Romania and Bulgaria) are merged with Greece, while the states around the Adriatic Sea are grouped with the Alpine States: Italy, Switzerland, Austria, Slovenia and Croatia.

In Figure 6.1 the grouped countries can be seen. As some regions already work together intensively, this scenario also provides a feasible new planning scale. By keeping the planning regional, cooperation does not lead to obscure interests and room for national policy adjustments is available. This scenario will need regional TSOs to balance the power system within that region.

6.1.3. Continental optimisation set-up
The highest planning scale is the continental coordination, where all 27 considered countries are incorporated in the optimisation, including interconnection capacity between them. This scenario features the most
options and thus will lead to the lowest optimisation costs. The downside of this scenario is the enormous playing field which has to be managed by a central planner, as well as the fact that national interests might not be considered. This could lead undesired situations for some and very profitable designs for others. A continental planner and TSO will be needed for such a policy scenario.

6.1.4. Central planning, country goals
The last scenario represents a situation in which every country has to satisfy national energy security goals, but the optimisation of the whole system is done from a central planning perspective. This scenario assumes that countries require a flexible generation capacity at least equal to their peak load. This flexible generation capacity may consist of coal, CCGT or biomass. The RES-E goal is to be met by a central planner. Since this scenario can still optimise the grid, storage facilities and back-up capacity, the costs will be somewhat lower than the national scenario, but the conventional generation will also have to be placed in less favourable locations, with less full load hours. Higher costs than the continental optimisation are expected. A fair spread of the generation over all countries is expected.

6.1.5. Current & future reference scenario
The reference scenario will be investigated for two situations. A first investigation uses currently installed capacities, while the second will look at expected capacities for 2050. Because the transition towards a new coordination level of power system planning is assumed to occur between now and 2050, the two levels of installed capacity are expected to form the outer boundaries of possible system development, extrapolated from the current policy and design.

The data for current installed capacities was obtained from the ENTSO-E transparency database, but to fit it to the model some aggregations had to be made (ENTSO-E, 2015c). This resulted in a simplification
of the system, especially since the model can only handle a limited amount of generation technologies. It was tried to combine technologies with the same kind of characteristics as good as possible, were on- and offshore wind were merged, as well as all coal, oil and nuclear capacity. Run-of-the-River Hydro Power was ignored, which also will affect the results quite significantly, as it is currently one of the major contributors to the renewable generated power. Very small capacities like geothermal and marine power were ignored. The currently installed PHS storage capacity was also given, but other storage technologies were optimised, which allows for a complete use of the potential RES-E generation. The used values and capacities can be found in Appendix F.

The current power system design limits the maximum amount of renewable electricity quota to somewhere around 20%, if extra FB and \( \text{H}_2 \) is permitted in the optimisation. If a higher quota of power from RES-E is required, the problem becomes infeasible. To give an indication of how the optimal system LCOE for different policy scenarios relates to the current situation the reference scenario is tested for the RES-E integration level of 2012: 15%. This percentage was obtained without the share produced by hydropower for the year of 2012, as this technology was not incorporated in the model, but generated a significant share of the RES-E in Europe. The total electricity from renewable sources in Europe (EU-28) in 2012 was 24%, of which 11% was hydropower. In 2013 the total was 26.5% of which 12% was hydropower. The average of the renewable energy produced by other sources than hydropower (mainly wind, biomass and solar PV) over 2012 and 2013 was 15% (see also Appendix G).

Installed capacities of RES-E are planned to grow. From the report ‘e-HIGHWAY 2050’ by Bruninx et al. (2015) assumptions about the installed generation capacity, per country, for 2050 are taken. This dataset needs a few remarks. It covers the same technologies that were used for this scenario, but combines thermal technologies. These consists mainly of gas in their 2050 scenario, so these figures will be used accordingly for the installed CCGT capacity. As they also incorporate nuclear power, due to similarities in the characteristics of nuclear and coal, their figures for nuclear plants will be used as coal plant capacity in our model. The incorporated Centralised Solar Power (CSP) is not distinguished from the installed capacity in solar PV. As the potential output of both sources is reliant on the same source, the aggregated capacity of solar technologies is used as solar PV capacity in our model. The demand is only given on a yearly basis, the percentage growth will be applied to the demand used for 2012, assuming no change in pattern has occurred. The data was also compared with the comprehensive study by Pfluger, Sensfuß, Schubert, and Leisentritt (2011). The trends are comparable, but the figures from Pfluger et al. (2011) are not given per country and less comparable technologies were used. However, as these two sources provide the same trends, it is deemed an acceptable level of reliability. It gives more concrete figures about the increase in storage, however, although not per country. Their found increase of about 25% is used over the installed storage capacities in the 2015 scenario. In Appendix F the used capacities for 2050 can be found for the generation technologies. The PHS storage technologies are increased with 25% compared to the reference scenario. The transmission capacities installed in 2050 are estimated to grow with 25% as well and can be found in Appendix F too.

### 6.2. Results

The results for the most cost-optimal scenario, the Continental scenario, will be presented. These results will be compared with the other scenarios, interesting differences or similarities will be discussed. The results for other scenarios can be found in the Appendices. Table 6.2 shows which Appendix to look at for each scenario. In the discussion of the results the reference to the Appendix will not be repeated, but when a scenario is mentioned this automatically refers to the relevant results in the Appendices. These scenarios are abbreviated to avoid writing them out constantly. If the abbreviation is written, the whole scenario is meant. If the figures ‘20’, ‘50’ or ‘80’ are added this specifically refers to that RES-E integration level. The abbreviations per scenario are also given in Table 6.2.

In this chapter, four different types of results are considered relevant for the aim of this research. The most important result is shown first, the costs per policy scenario. The other results both give an explanation on the difference in costs and show the resulting design of the power system, with all advantages and disadvantages involved:

1. **Costs:** To determine the economic benefit of a more central coordination of power system design, the total system costs and system LCOE will be given. The distribution of costs over the countries and regions gives insight in how countries will have to contribute to the total costs.

2. **Installed capacities:** The first system aspect that is used to explain the costs are the total installed capacities. Secondly, to compare how the actual solutions deviate from each other the installed capaci-
6.2. Results

Table 6.2: Scenarios, scenario abbreviation and Appendix in which the results for that scenario can be found.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>National</th>
<th>Regional</th>
<th>Continental</th>
<th>Country goal</th>
<th>Reference 2015</th>
<th>Reference 2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abbreviation</td>
<td>NAT</td>
<td>REG</td>
<td>CON</td>
<td>CG</td>
<td>REF2015</td>
<td>REF2050</td>
</tr>
</tbody>
</table>

ties for the different generation and storage technologies are given. This is aggregated per region and projected on the map of Europe, to simultaneously show the concentrations or distribution of certain technologies in particular areas.

3. Dispatch and energy storage; The dispatch flows will be given, which will give a perception of the use of certain technologies. Also the charging, discharging and storage level of all different storage technologies will be shown, from which the impact of storage on the system can be determined.

4. Transmission network and flows; The transmission network is given separately from other installed capacities. A heat map of net importing and net exporting countries will be shown, from which the consequences for country’s independence can be drawn.

6.2.1. System LCOE comparison

The total system costs have been divided by the total demand over the considered period, in order to get more comprehensible values. The demand over the considered period was 420 TWh. Figure 6.2 shows the different system LCOEs. The effect of a more centralised planning level on system LCOE is unambiguously: when the planning scale increases, the cost decreases. The share of RES-E has a significant impact on the difference the planning scale makes: the effect grows stronger as shares of RES-E increase. An optimal CON20 design results in an electricity price of €37.50. The optimal price for a system planned on national level would result in €38.49; roughly 3% higher. Incorporating 80% RES-E, this difference dilates to 23%; €38.92 over €47.75. Noticeable here is the relatively small cost increase within the continental planning scenario: €1.42 or 4%. This implies that under optimal planning scale energy costs could remain around the same price as current levels, while integrating more electricity from RES-E than the European target for 2050.

Moving from a national to a regional planning level is hardly beneficial: costs for 20% or 50% RES-E are almost similar, while at 80% the regional scale saves €2.12 or 5%. This automatically shows that the benefit of the European scale over regional scales is still significant: around 17% or €6.72. Interestingly, the centrally planned scenario with regard for national energy security goals, the country generation quota scenario, performs worse than the national and regional planning scale for lower levels of RES-E. It only becomes beneficial for an 80% of RES-E requirement. The final remark is that increasing the planning for the European power system results in lower energy prices. However, the effect is smaller when less RES-E is required, or when additional constraints limit the degrees of freedom of the optimisation. Additionally it can be concluded that:

- The major part of the system LCOE, for lower levels of RES-E integration, is contributed by VOM from coal. As the share of renewables increases, the major share of costs is transferred to the fixed costs. Especially wind, coal and, in the 80% scenarios, solar PV, form a large share of the costs.

- The share of costs resulting from storage facilities is almost negligible: it forms less than 1% of the costs. The share of costs resulting from interconnection lines is almost negligible in the two restricted transmission scenarios, NAT and REG. For the CON and NGQ, especially at 50% and 80% RES-E integration levels, the transmission costs contribute between 4% and 7% of the system LCOE.

6.2.2. Installed capacities - generation & storage

To determine where the differences in costs originate from, first the results for installed capacities of different technologies will be discussed. These results have been split up in generation technologies and storage technologies.
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**Figure 6.2:** System LCOE for different policy scenarios. The costs for generation technologies have been split up in fixed costs (Investment) and Variable Operations & Maintenance (VO&M). Storage costs are divided in costs for conversion and costs for the storage facility.

**Generation capacity**  The total installed capacities per generation technology for the CON scenario can be seen in Figure 6.4. For CON, a mix, consisting mostly of wind for the renewable generation and coal plants for the flexible generation, seems optimal. The total installed production capacity increases from 734GW at CON20 up to 834GW in CON50 (13% increase). When an optimum is determined for CON80 this reaches even 1106GW of installed capacity, which represents an increase of 33% relative to the CON50. Interesting to keep in mind here is that the total demand stayed exactly the same. The increase in installed capacity is realised mainly due to an increase in wind, which almost doubles. Solar PV capacities increase only marginally and at higher RES-E integration scenarios. The installed capacities of conventional generation technologies decrease as a result of higher RES-E shares, but less than the increase in RES-E. As was explained in Chapter 2, the capacity credit for RES-E is only a smaller share of the installed capacity. RES-E is thus not completely replacing conventional generation technologies, but used in addition. The same trend of increasing generation capacities can be found in other scenarios. Figure 6.3 shows the absolute installed capacities for each scenario except. The red dotted line shows the aggregated peak load for Europe. The current (REF2015) and expected reference scenario (REF2050) are shown in the left two bars. From the comparison of installed capacities a few conclusions can be drawn and some explanations, of where the costs difference originate from, can be given:

- The total installed capacity increases significantly as the RES-E integration share increases. The total installed capacity is always significantly more than the peak load. The most extreme scenario is the NAT scenario, where for the NAT20 there is around 25% excess generation and conversion capacity, which increases to 68% at NAT80. The CON20 scenario has a higher excess capacity than the NAT20, but the CON80 is much lower with 57% excess capacity. Overall it can be seen that the integration of RES-E inevitably leads to more excess generation and storage conversion capacity. The smaller the planning scale, the more excess capacity is installed, which is a major contribution to higher costs.

- Wind is, in every scenario, the main contributor to RES-E shares. With lower integration levels of RES-E, coal forms the major part of installed fossil fuel generation capacity. The use of biomass is completely absent. In the NAT and REG scenarios the use of CCGT is rather stable, which means that the percentage of it in the fossil fuel generation capacity increases. In the 20% scenarios it only accounts for 15% of the conventional generation capacity, but has increased up to 33% in the highest RES-E integration scenario. However, in the CON scenario it completely disappears. It follows that more centralised planning scales allows for better utility rates of conventional power plants, so that the overall cheaper coal plants can be used more often instead of the more expensive CCGTs (see also Section 6.2.3). This is a major reason for lower costs at higher planning scales.

- The installed capacity of solar PV is almost negligible for the scenarios with 20% or 50% RES-E integration. It is only used for the 80% scenarios. For the NAT80 and REG80 it forms 16% of the RES-E capacity, opposed to 9% for CON80. The more centralised the planning scale is, the less use for solar PV and the better the utilisation of wind turbines (see also Section 6.2.3). Since wind is overall cheaper than solar PV, this entails a cost reduction.
Another set of interesting results can be found when the distribution of technologies over Europe is regarded. Figure 6.5 shows the aggregated installed capacities per region on the map of Europe. A few interesting results stand out:

- Most installed capacity for wind power is situated in Northern and North-Western Europe, all the way West to Spain and Portugal. When the CF-map (see Section 5.3.2) is considered, this is indeed the region where wind has the highest CF. Combined with the fact that wind power is able to deliver sustainable power for lower costs than solar PV, this explains the large installed capacity in favourable locations.

- The little solar PV capacity that was installed, besides in the logical Southern regions, is installed in the Eastern part of Europe, more particularly in Poland, which has a slightly higher CF, as will be shown in Section 5.3.2 as well. Besides that it lies fairly central between the Northern Scandinavian area and the Southern Balkans and Greece, both with lots of wind power. At the same time it is also close to a fair share of flexible generation in Central and Western Europe. The assumption for this research was that these different generation technologies are complementary, which is supported by the spread of technologies over the map. Adding to the complementarity, is the moment in time solar PV produces electricity. The fact that it lies in the East also makes that the sun comes up earlier than in more Western located countries. The complementarity of solar PV to the rest of the generation mix is extra valuable when it can produce at moments where elsewhere in Europe this complementarity is not yet available.

- In Figures 6.5, minimal, average and peak demand is given in the green, yellow and red dotted lines respectively. It is clearly visible that several regions have insufficient or just enough capacity to supply their own demand, which is especially striking in CON80. Three regions have notably less generation capacity in CON80 than they have with other planning scales: Balkans & Greece, France and Germany and the BeNeLux will experience moments during which domestic generation capacity is insufficient to produce demand. If less wind power is available also Eastern-Europe will experience difficulties supplying their own demand.

More in general, the map shows a system where the most favourable locations, for several RES-E technologies, are found at the edges of the continent. Due to the variability of these sources, flexible back-up capacity is needed, but often not at the same time in all regions. The flexible generation capacity, mainly coal, is thus generated centrally, in mostly Germany, France and Eastern-Europe. Coal can reach high FLH here, as during most of the times there is demand for flexible generation in some adjoining region. The only real exception is the Balkans and Greece, which have a fair amount of domestic coal capacity. Since this region is relatively far away and isolated from other load- and production-centres, this is understandable.

When the results are compared with other scenarios, the concentration of generation technologies is not found for other planning policies. For all other scenarios the technologies are much more spread over Europe. For the scenarios with limited transmission options (REG & NAT) this is explicable since they have no options to obtain their power from more favourable regions and need to find a complementary set of production options within the available region, be it regional or national. However, in the CG scenario also a
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Figure 6.4: Overview of total installed capacity per generation and storage technology (upper half). The figures shown inside or on the edge of the pie graph indicate the GW (or GWh, for PHS storage) installed for that technology. The capacity for only generation technologies can be found in the caption per graph. In the bottom half the generation mix is given, where the contribution per technology is given as a percentage of the total generated electricity. For both the upper and lower half of the figure all outcomes are presented for a 20%, 50% and 80% RES-E integration scenario.
somewhat equal distribution of technologies over Europe can be found. Mainly the installed CCGT capacity is noticeable, but logical as is considered that this option is cheaper than coal for low FLH. Interestingly enough, for none of the scenarios a change of generation technology occurs as the RES-E share increases. Installed capacities of conventional generation technologies in general slowly decrease, while wind capacity increases.

From the solution presented on the map of Europe some interesting findings can be taken towards the discussion and conclusions:

- For increased planning scales it is clearly visible that the design is based on the optimal locations for generation technologies: overproduction and shortages can be solved by exchanging between regions with more RES-E and more flexible generation. Especially striking is the concentration of conventional capacity around Western-Europe, and RES-E in the border regions.

- Whenever the exchange of power is limited and the planning scale decreases, generation technologies are less concentrated around their optimal location. They are rather distributed over Europe, where each region, or even country, has multiple generation technologies. This leads to more excess capacities, which explains the difference in costs partly.

- In no scenario has the increasing share of RES-E generation significant impact on a choice of generation technology. The share of wind and solar PV might grow, but very little capacity from a technology that was not used before is added. Almost no technology completely disappears, in any scenario, if it was used for lower RES-E shares.

**Storage capacity** In all previously presented figures also the installed storage capacities were presented. For the CON scenario, it is interesting to see that only PHS was used as storage option. From Figure 6.4 it can be seen that the ratio of storage capacity divided by conversion capacity increases from 6.9 for CON20 up to 10.9 for CON80. This suggests that the storage is mainly used for long term storage. The maximum amount of PHS, due to a limited technical potential (see also Section 5.2.2) is 1669GWh. Around two thirds of this was used in CON80. In general, the increase of storage capacity is significant as the share of RES-E increases as well. The CON80 scenario has almost 1000GW of storage, which is an increase of over 200% compared to the CON20. Similar storage increases can be found in other scenarios as well. In REG80 even all technical potential for storage capacity was used. The more expensive H\textsubscript{2} is used for respectively the NAT80 and REG80 scenario. Apparently, the need for storage is strong enough to substitute the, in some regions or countries, insufficient PHS with H\textsubscript{2} storage. The ratio between storage and conversion is even higher in these lower planning levels than in the CON80 scenario, both for PHS as for H\textsubscript{2}. In most scenarios the installed capacities of both storage as conversion were in the same order of magnitude. From looking solely at the installed storage capacities a few interesting points can be distilled:

- The influence of availability of storage on installed generation capacity is limited. Nonetheless, enormous amounts of storage are installed for every scenario where it is available.

- The ratio between installed conversion and storage capacity suggests that most storage is used for longer periods of time.

- In scenarios with insufficient storage capacity within reach, it proves to be beneficial to install the more expensive H\textsubscript{2} storage technology. Whenever the availability of transmission allows for the use of PHS, this is always preferred over other storage technologies.

When the distribution of the storage over Europe is considered, a clear connection between the installed RES-E capacity and storage capacity becomes visible. Especially in regions with high shares of installed wind capacity, like the British Isles, Iberian Peninsula and France, a clear correlation becomes visible. Striking is that Scandinavia has only marginal storage capacities. The technical potential in Scandinavia is only 3GW, which can be an explanation for this anomaly. Interesting for CON80 is the enormous storage capacity in Italy, Austria and Switzerland, which even transcends the amount of installed generation capacity for that region. For this, the explanation can possibly be found in the high shares of RES-E in Eastern Europe and Greece. Since these regions have very limited amounts of storage capacity available, it is likely their best option to store electricity in the PHS capacity of Italy and the Alpine States.
Figure 6.5: Installed capacities of different generation and storage technologies, aggregated per region. Note that the scales are not similar, which was chosen to be able to distinguish different technologies per bar. ‘Convert’ in the legend stands for PHS conversion (in MW), while ‘Storage’ represents the PHS storage capacity (in MWh). The installed capacities are given separately for a 20%, 50% and 80% RES-E integration scenario.
Figure 6.6: Overview of installed capacities per country. Generation technologies that are presented consist of Wind, Solar PV, CCGT and Coal plants. Storage options used only consisted of Pumped Hydro Storage (PHS). The legend indicates 'Convert', which stands for the PHS conversion technology (in MW) and 'Storage', which stands for the physical PHS storage (in MWh).
When the storage capacities are compared with other scenarios, the similarities, especially the CG scenario capacities, are striking. In both CG20 as CG50 almost no storage capacity was used, which can be explained by the available domestic conventional generation. Since this capacity is constrained with a minimum, it had to be installed anyhow and it can offer the same solutions as storage could. In REG80 the installed capacity of storage is more extreme than the CON80, as almost all PHS capacity is build. It also shows peaks in capacity in the same regions. Apparently this design of storage facilities is optimal, regardless the rest of the options available. For Scandinavia the need for storage in REG80 is so strong that H\textsubscript{2} storage is installed here. The NAT80 scenario even installs large amounts of H\textsubscript{2} where larger shares of RES-E are installed, but no PHS is available, with the exceptions being Poland and the Netherlands.

From the locations of storage within Europe for all scenarios the following can be concluded:

- A clear correlation between installed RES-E capacity and the use of storage is found. Regions without RES-E have generally much less storage capacity installed.
- PHS is by far the favourite storage technology, but for scenarios where no domestic capacity is available, and none can be reached due to a lack of transmission possibilities, the more expensive H\textsubscript{2} also is used.
- When large amounts of flexible generation capacity are available, there is reduced need for storage. These two technologies are rather interchangeable.
- Locations, where enough PHS is available, will install large shares of this capacity as RES-E share increases. This capacity is used to store both domestic RES-E production as that from neighbouring regions and countries.

6.2.3. Dispatching, charging & discharging

Besides the installed generation and storage capacities, another important aspect of the optimisation’s solution is the way in which the technologies are dispatched, and how storage facilities were used. Figure 6.9 shows the averaged generation profile for one week. It was aggregated over the whole of Europe and averaged over the whole year. The graphs presented show how the dispatch of different technologies fulfils demand at any moment in time. The demand is added as a black line, the storage level of PHS can be found as a red line. A few things stand out. First of all, the way peaks in demand (one in the morning, one in the evening) are served is interesting. The morning peak is often delivered with stored electricity, while the evening peak can often be met with an increase of wind energy output.

The comparison of generation mixes per scenario, as given in Figure 6.7, shows little anomalies. The red dotted line in this Figure shows the total load over the considered period. Based on the installed capacities the generation mix meets the expectations. From this Figure it can be concluded that:

- The share of power supplied by CCGT is negligible, even for the NAT, REG and CG scenarios, where it had significant shares of installed capacity. It can be concluded that the installed CCGT capacity is
barely used and thus has few FLH. For situations with low FLH the LCOE of CCGT is lower than that of a coal plant, which explains the choice of CCGT over coal.

- The share of wind in CON20 is higher than the required power from RES-E. This suggests that a system optimum exists with more than 20% power from RES-E. To be precise, in CON20 37% of the power is generated from RES-E.

- The share of power from solar PV is marginal and ranges from only 6% in CON80 to 11% in NAT80. This corresponds well with the installed capacities and the average CF for solar PV, compared to that of wind.

The amount of output from conventional plants is very dependent on the wind energy, for CON80 there are often moments in which there is no output needed from flexible generation plants at all. This corresponds with the found Residual Load Duration Curves (RLDC), which can be seen in Figure 6.8, where the RLDC is zero or even negative for about 15% of the time in the CON80 scenario. Where the RLDC is negative the storage is used to charge for future demand. The more horizontal the RLDC, the more FLH remain for conventional generators, but as can be seen the effect of higher levels of RES-E is an increasingly diagonal RLDC. This corresponds with the decreasing FLH and higher costs for lower planning scenarios.

To understand even better where the extra costs for a lower planning scenario result from, the utilisation rates are given in Table 6.3. The utilisation rate is calculated as the total generated output per technology, divided by the theoretical maximum output. For conventional technologies this is the installed capacity multiplied by the number of hours considered. For RES-E the potential output per hour is multiplied by the installed capacity per country, after which all is summed. It is clearly visible that for more centralised planning policies the utilisation rate stays relatively high, especially in the CON80 scenario. This high utilisation rate results in a high amount of FLH, and thus effective use of installed capacity. From the RLDC it follows that the difference between the scenarios are minimal, but that the ends of the lines in NAT and REG scenarios are more extreme upwards (at 0 hours) and downwards (at 1248 hours) than those of centrally coordinated scenarios. As was shown in Chapter 2, these peaks are hard to integrate in the current power system and, hence, costly to deal with.

Table 6.3: Utilisation rates for different generation technologies per scenario.

<table>
<thead>
<tr>
<th>Generation technology</th>
<th>NAT 20%</th>
<th>NAT 50%</th>
<th>NAT 80%</th>
<th>REG 20%</th>
<th>REG 50%</th>
<th>REG 80%</th>
<th>CON 20%</th>
<th>CON 50%</th>
<th>CON 80%</th>
<th>CG 20%</th>
<th>CG 50%</th>
<th>CG 80%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>1</td>
<td>0.97</td>
<td>0.94</td>
<td>0.99</td>
<td>0.97</td>
<td>0.89</td>
<td>0.99</td>
<td>0.98</td>
<td>0.96</td>
<td>0.99</td>
<td>0.97</td>
<td>0.93</td>
</tr>
<tr>
<td>SPV</td>
<td>-</td>
<td>1</td>
<td>0.98</td>
<td>-</td>
<td>1</td>
<td>0.98</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>CCGT</td>
<td>0.02</td>
<td>0.01</td>
<td>0.00</td>
<td>0.04</td>
<td>0.04</td>
<td>0.04</td>
<td>0.04</td>
<td>0.04</td>
<td>0.06</td>
<td>0.03</td>
<td>0.02</td>
<td>0.01</td>
</tr>
<tr>
<td>Coal</td>
<td>0.74</td>
<td>0.58</td>
<td>0.38</td>
<td>0.75</td>
<td>0.60</td>
<td>0.40</td>
<td>0.74</td>
<td>0.69</td>
<td>0.47</td>
<td>0.75</td>
<td>0.60</td>
<td>0.39</td>
</tr>
</tbody>
</table>
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Figure 6.9: Generation profile for an average week. The week starts with a Sunday (00:00-01:00h) and ends on a Saturday (23:00-24:00h). The demand is given as a black line, while the level of energy in storage (MWh) is given as a red line. The charged PHS is given as a negative, while discharged is given as a positive. Due to the fact that all values are averaged, over all countries and over all separate days of a week (Sunday up to Saturday) it is possible that at same time PHS is charged and discharged. The level of energy in storage is actually constantly higher, but adapted to have the lowest point at the x-axis. The generation profile is given for a 20%, 50% and 80% of RES-E integration.
6.2.4. Interconnection & power flows - transmission technologies

The transmission grid installed can be split up in the distance it covers, dependent on which countries are connected, and the net transfer capacity of those lines. Figure 6.10 shows both the lengths and capacities per scenario. The upwards bars show the different capacities, whereas the downward bars show the various lengths. The REF and NAT scenario only use the currently installed transmission capacities, and are therefore given in the same bar. It can be derived that:

- The currently installed line length is higher than that of an optimal scenario, but the installed capacity is lower than that of almost all optimization scenarios. The installed transmission line length stays roughly the same for different integration levels of RES-E. For REG80, it is even slightly lower than it is for REG20, suggesting less lines, but with greater capacity, are required as RES-E integration levels increase.

- The installed capacities increase significantly as the share of RES-E increases. CON80 has three times more interconnection capacity than CON20, but also 7 times more installed capacity than is currently available.

Besides the installed capacities, also the lay-out and net importing or exporting countries are given in Figure 6.11. The network lay-out is showed for the network with the most installed capacity, for two levels of RES-E integration: CON20 and CON80. On the right side of the figure the map of Europe shows average level of import or export of the considered countries. From the figures it can be concluded that:

- As the share of RES-E increases, the capacity of the network connections increases, rather than that new lines are added. Only very few lines appear or disappear as a result of changing RES-E integration levels.

- The amount of connections one country could have is not necessarily influential on the final installed transmission capacity. France, Italy and Sweden all have more than five possible connections, but are not becoming more interconnected than countries with less connections. In the European electricity no focal points emerge.

- The countries that are strong net importers or exporters are connected more than others and with larger capacities to neighboring countries. For example Ireland, Denmark, which are large exporters are heav-
ily interconnected. The Netherlands, Belgium and Austria, as large importers, are also connected to one or more transmission lines larger than 10GW.

- Large exporting countries often have large installed capacities of RES-E, while net importers mostly have domestic coal plants.
- From the import-export map it seems as if Central Europe depends on the outer regions for their electricity. This corresponds well with the assumption that only the most optimal locations for RES-E are used.
Figure 6.11: Overview of the nett import or export percentage per country. The import is calculated as amount of the total demand and is given in positive figures. Net export is given as percentage of total generation and presented in negative figures. The colors on the map represent average net import or export over a 20%, 50% and 80% RES-E integration scenario.
Figure 6.12: Interconnection transmission network for Europe for a continental optimisation. Line specifications determine the installed capacities. The network is given for a 20%, 50% and an 80% RES-E integration scenario.
Validation and testing

The result of the previous Chapters is a fully operational model, which produced results to some experiments, as shown in Chapter 6. The validity of these results has to be determined through a validation process, as was explained in Section 5.4. This validation process is presented directly hereafter, showing three perspectives to determine the validity of the model’s results. The outcomes and solutions from the previous Chapter will be used as input, mainly from the reference scenario. As a last step, the sensitivity analysis will be presented. In Figure 7.1 this process can be seen, as well as the focus for this chapter within the red dotted lines. The last identification of the model quality will be given by a sensitivity analysis. It determines the degree of dependency for model variables, operation and parameters. By doing so, an insight is given in how dependent and sensitive the outcomes and results are for deviations or flaws in assumptions, data or chosen parameters (Murray-Smith, 2015).

7.1. Outcome validation

In the verification (Section 5.4) it was found, that the model was properly translated from a mathematical problem into a computational model. Now that in Chapter 6 experiments have been performed and results are available, the validity of these outcomes is to be determined. A comparison with the real world will be made on two levels, but also a comparison with outcomes from other, similar studies will be used as validation. Two aspects of the model, especially in the reference scenario, can actually be checked for resemblance with reality: the system costs, translated into LCOE, and the generation mix. Since the model was considerably simplified, it is not expected that the outcomes are exactly the same, but the same order of magnitude is expected for a proper representation, especially with the aim of this research in mind. For the comparison with similar studies, only certain elements can be compared.

7.1.1. The Levelised Cost of Electricity

One way of determining the level of validity of the model is to look at the LCOE the experiments produced. These should fall in the same order of magnitude as the real world LCOE to make the model representing it sufficiently. The reference model is used with a 15% RES-E integration level to test this. Since the information covering real world average LCOE are scarce and not available in the required form, the model outcome is also compared with two average wholesale electricity prices for 2012, which ought to reflect the LCOE of a generation portfolio (Eurelectric, 2013). Three factors make it probable that the LCOE of this model will be lower than the actual electricity price:

1. First of all, the model is an optimisation with knowledge at forehand about the expected weather conditions and demand behaviour, while the actual system did not have this knowledge, especially not when it was planned. The actual system is designed less optimal than the design from the optimisation.

2. The absence of spinning reserves, back-up capacity, availability factors and ramping limits in this model allow an installed capacity of exactly the peak demand. In the real world, all kind of uncertainties force the system designers to install excess capacity to assure grid reliability.

3. The current system mainly operates on older installed capacity, which has both higher capital as variable costs. The parameters used for this model were all based on the technology costs later than 2010.
Figure 7.1: Block diagram of the modelling process. Within the dotted lines the focus of this chapter can be seen. Also the iterative feedback loops with earlier stages can be found. Adapted from Murray-Smith (2015, p. 21).
4. In the real world, the electricity price is inflated due to many market imperfections, information asymmetry and incomplete knowledge for actors. This aspect is completely lacking from the optimisation. As can be seen from Figure 7.2 the model indeed presents lower costs than two of the references, but stays within the same order of magnitude. It even produces slightly higher costs for the third reference, which was an average wholesale market price for Western Europe in 2012. When the reasons for a lower LCOE given above are considered, the difference seems quite acceptable as a margin. The found LCOE will be considered sufficiently valid, which makes this main outcome of the model reliable enough for the intended use.

7.1.2. Generation portfolio
A second way of determining the validity of the model results, is to compare the generation mix of the reference scenario with the actual generation mix over the considered period. A comparison with the research by van Staveren (2014) is also shown. Since the model is a strong simplification and has much less generation technologies available, the ratio of wind, solar PV, gas, coal and biomass is looked at rather than actual matching amounts of output. If from the actual generation mix the low cost generation technologies - coal, lignite, nuclear and hydro power - are aggregated, many similarities with the model’s coal production can be found. The model’s generation from gas is slightly less than the actual value, but falls within the same order of magnitude and comes closer to the actual value than the reference research. Production from solar PV and biomass are almost similar. Wind generation is slightly more used in the model than it was in the actual mix. Altogether the generation mix found by the model is relatively similar to the real production mix of 2012. The comparison with the model of van Staveren (2014) also shows many similarities. It is therefore concluded that the found generation portfolio from the reference scenario is adequately valid, which suggests that the model is capable of producing realistic generation portfolios and mixes.

7.1.3. Comparable studies
The third and last way in which the validity of the model is checked, is to compare the results from this model with those of comparable earlier studies. Three aspects will be considered when a comparison with other research is made. These aspects are relatively comparable to the continental scenario for this study and objective enough to allow for a validation:

1. Costs and cost composition; The system LCOE, the differences between LCOE for increasing shares of RES-E or (un)availability of complementary options is a common returning aspect in similar studies. The composition of this cost profile, split up in a share of CapEx, VOM, storage and transmission costs, is also a frequently returning result. That information is comparable, as it is one of the direct results from this model.
7. Validation and testing

Figure 7.3: Comparison of generation mixes per generation technology as percentage of the total production over 2012. The two pie charts on the left are reference portfolios, for which the utter left is the actual production profile according to ENTSO-E (2015), and the middle chart is an earlier reproduction of the research by van Staveren (2014). The utmost right chart is the generation portfolio as result from the model for a 15% RES-E integration.

2. **Optimal wind/solar PV ratio:** Many studies work with given RES-E input scenarios, from which one of the outcomes is the optimal mix between installed wind power and solar PV capacity. This ratio can be obtained from the generation mix and/or total installed capacity of this model.

3. **Optimal transmission network:** The optimal lay-out of a transmission network for Europe is another often researched aspect. Although differences in model set-up limit the direct comparison with other researches, general trends in the transmission network can be distinguished. The lay-out resulting from this model is directly available.

**Costs and cost composition** The studies conducted by Brouwer et al. (2016) and Rodriguez et al. (2015) discuss an obtained system LCOE from their respective researches. Brouwer et al. (2016) also divides this LCOE in different aspects. The costs from this model and their model have been put together in Figure 7.4. Three similarities can be distilled from the two graphs. First of all, the cost increase as RES-E share increases is visible in both figures, while also the real increase starts only at shares of 40% or higher. In the reference study there is barely any increase from the 17% scenario up to the 40% scenario. It only starts to increase more at a 60% share of RES-E integration. This trend is also clearly visible in another study, performed by Rodriguez et al. (2015). Secondly the increasing share of CapEx can be found in both researches. If the fixed 'investment' costs from the research by Brouwer et al. (2016) are summed they increase from roughly 50% of the costs at 17% RES-E up to 90% in a 80% RES-E scenario. The last comparable trend is the share of costs that the transmission network ensues. It also increases slightly, but stays around 2% of the costs. The difference in both researches can mostly be found from the total costs. Although the patterns and ratios are similar, both Brouwer et al. (2016) and Rodriguez et al. (2015) find significantly higher costs. Two reasons can be pointed out here: First of all the two other researches include more technical detail, such as ramping-costs and -limits, which inevitably result in a higher cost profile. However, they also keep one or more elements of the power system out of the optimisation and use exogenously determined scenarios. This leads to a ‘less-than-optimal’ result. To conclude, the costs of this model are low compared to references, but since relevant patterns are present the costs are deemed sufficiently valid.

**Optimal wind/solar PV ratio** The ratio of installed wind capacity versus solar PV capacity from this model, in a fully renewable scenario, is roughly 90% wind against 10% solar PV. The share of solar PV increases as the share of RES-E integration increases. In researches from Schaber, Steinke, Mühlich, and Hamacher (2012) and Becker, Rodriguez, et al. (2014) the optimal mix between wind and solar PV was also one of the outcomes. The study from Becker, Rodriguez, et al. (2014) showed that the amount of required balancing energy decreased as the transmission capacity increased, but especially benefited from an optimal RES-E mix. With an unconstrained transmission scenario, this optimal mix was found to be 82% wind power versus 18% solar PV. The research performed by Schaber, Steinke, Mühlich, and Hamacher (2012) even finds an mix of 85% wind versus 15% solar PV at optimal grid lay-out. These figures are all pointing in the same direction. The
small difference can again be explained by the fact that both mentioned studies work with partly exogenously determined scenarios. Apparently wind is even more favourable when the composition of RES-E is also optimised. It is therefore concluded that the found optimal mix in this model is sufficiently valid. The model assesses the characteristics and values of both RES-E available adequately.

**Optimal transmission network** The transmission network for Europe, under high shares of RES-E, is researched by Rodríguez et al. (2014) and Becker, Rodríguez, et al. (2014). Especially the first of those researches has a very comparable set of nodes considered to this research. They designed a grid for unconstrained power flows under exogenously given optimal generation mixes per country and a 100% RES-E scenario. In Figure 7.5 the grid obtained by this model (a) and the grid from the study by Rodríguez et al. (2014) (b) can be found. Interesting similarities can be found in the corner of Western and Southern Europe, while especially in and to Scandinavia the network differs somewhat. The general overview shows many similarities, as, for example, almost all connections between larger countries are present in both networks. Also all connections are above 1GW capacity, while the most important connections are all larger than 10GW. The connection capacities with Great-Britain and between France and Italy are indeed much larger than 10GW, approaching the 30GW. The research studies performed by Becker, Rodriguez, et al. (2014), or by Brouwer et al. (2016) also show great similarities in the results. These similarities are sufficient to declare the network outcomes adequate for this research purposes.

Now that the results are found to be sufficiently valid, a final step to determine the value of the results, and obtain additional insights in power system design mechanisms, is the sensitivity analysis. This will be performed in the next section, after which in Chapter 8 the results will be discussed and put in perspective.

### 7.2. Testing – Sensitivity analysis

From the results it followed, that the scale on which the future power system is coordinated has great impact on both the system LCOE and on the optimal design. A few notable outcomes require further research to determine how much variables within a model depend on given parameter quantities within that same model. A well-established approach to test this is a sensitivity analysis (Murray-Smith, 2015). A few parameters that are assumed, as well as some patterns that stood out in the results, will be varied to test their influence. First, the preference for wind power and coal plants, as well as the small share of solar PV, are striking and do not completely match with comparable results from the validation process. The absence of flow batteries, and to a great extend H2, as storage options also stands out. To research how these preferences depend on the chosen parameters the VOM and CapEx will be adjusted and tested for in different combinations. Another interesting consequence of the way the RES-E target was set, is the large amount of coal capacity and the lack of biomass, while the CO2 emission from coal plants is much higher than that from a CCGT or biomass
7. Validation and testing

To test how the effect of CO$_2$ emission, rather than RES-E production, can be incorporated, tests with both an emission cap and emission pricing are performed. Furthermore, the low percentage of costs from storage and transmission options arouse curiosity about their effect in the final result. The system is tested when either of these options, or both, are unavailable. Finally, to give insights in the possibility of a 100% renewable system, a scenario where 90% and even 100% of the demand has to be delivered by RES-E is tested for. The parameters that were adjusted, how they were adjusted and why can be found in Table 7.1.

All tests are performed with a continental planning scenario. The resulting system LCOE is shown in Figure 7.6, where the bars show the deviation per adjusted parameter from the CON50 scenario. These values are given as the black vertical line. The red dotted vertical line represents the CON80 scenario costs. The composition of the installed capacity can be viewed in Figure 7.7, while the difference in generation mix is visible in Figure 7.8. The top bars in these figures show the composition and mix for CON50.

### 7.2.1. Variable and fixed costs

The cost parameters are varied in different combinations. For the VOM, runs with an equally applied percentage increase and decrease are performed (25% and 50%), as well as with the input of expected future

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Variation applied</th>
<th>Underlying reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>VOM</td>
<td>+ &amp; - 25% &amp; 50%; Expected VOM 2050; BM -50%</td>
<td>Test the preference for certain generation technologies</td>
</tr>
<tr>
<td>CapEx</td>
<td>Expected CapEx 2050 RES-E/Solar PV/Storage</td>
<td>Test the system for the far away future, relation between wind and solar PV, is there need for FB or H$_2$</td>
</tr>
<tr>
<td>CO$_2$ emitted</td>
<td>Price of 25 &amp; 50€/tCO$_2$; Emission cap of -25% &amp; -50% to emitted in CON scenario</td>
<td>Test relation between use of coal or CCGT, maybe biomass</td>
</tr>
<tr>
<td>Complementary options</td>
<td>Without storage, without transmission, without both</td>
<td>Investigate value of different complementary options</td>
</tr>
<tr>
<td>RES-E share</td>
<td>90% and 100% RES-E share</td>
<td>Investigate the possibility of a fully renewable system and curiosity</td>
</tr>
</tbody>
</table>
Table 7.2: Overview of chosen future technology parameters. CapEx = Capital Expenditures; VOM = Variable Operation & Maintenance costs; Figures were averaged from Bertsch et al. (2012); DECC (2015); ECF (2010); Fürsch et al. (2013).

<table>
<thead>
<tr>
<th>Generation technology</th>
<th>CapEx (€/kW)</th>
<th>VOM (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015 Development</td>
<td>2050</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>1080 -10%</td>
<td>980 - - -</td>
</tr>
<tr>
<td>Solar PV</td>
<td>1870 -33%</td>
<td>1250 - - -</td>
</tr>
<tr>
<td>CCGT</td>
<td>800 0</td>
<td>800 46 +45%</td>
</tr>
<tr>
<td>Coal plant</td>
<td>1600 0</td>
<td>1600 30 +25%</td>
</tr>
<tr>
<td>Biomass plant</td>
<td>2640 0</td>
<td>2500 84.5 +70%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Storage technology</th>
<th>CapEx convert (€/kW)</th>
<th>CapEx storage (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015 Development</td>
<td>2050</td>
</tr>
<tr>
<td>Flow battery</td>
<td>150 -33%</td>
<td>100</td>
</tr>
<tr>
<td>Pumped Storage Hydro</td>
<td>1900 0</td>
<td>1900 58</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>1600 -33%</td>
<td>1067</td>
</tr>
</tbody>
</table>

parameters. A separate run was done with only the VOM of biomass reduced with 50%, to see whether there might be a situation in which that specific technology is beneficial. It was found that even such a strong decrease did not result in the use of biomass as generation source. For fixed costs the reduction for RES-E as was found for 2050 is applied. To get more insight in the value of solar PV under future costs, these costs are applied separately as well, while costs for wind are kept at 2015 levels. A last run was performed in which the costs for storage were applied for 2050, while other costs were kept equal at levels for 2015.

Predictions on costs developments that are reasonably founded go as far in the future as 2050. These figures hold a high uncertainty level though. The two trends that were deemed reliable enough to distil future parameters from, are the technological development and increasing resource prices. Improvement of the technologies drives down building costs (or improving efficiency, which will roughly be approached by assuming lower costs per installed capacity) (Bertsch et al., 2012; ECF, 2010; Fürsch et al., 2013). Increasing fuel prices for natural gas, coal and solid biomass will rise due to an increased demand and rising scarcity issues. According to DECC (2015) the price for gas and coal will rise up to 145% of current prices in 2030, after which it becomes more or less steady. The rising prices are also found by ECF (2010), although their expectations for coal are slightly less extreme. Since Bertsch et al. (2012) and Fürsch et al. (2013) find even a little decreasing coal, price these expectations will be averaged. All sources agree on a strongly increasing price for solid biomass. The costs for PHS is not expected to decrease, as the technology is already quite mature. FB and H₂ however are at the beginning of their development. Their growth rate is expected to match that of solar PV, the same decrease in CapEx is also assumed for the both developing storage technologies. In Table 7.2 the chosen parameters can be found.

Results from VOM and CapEx variations The variation in VOM shows quite large differences in the results. As the VOM decrease, this only influences the costs of fossil fuel plants. Where for the normal VOM an optimal design had around 40% RES-E share, the 20% constraint is active with a 25% decrease in VOM, suggesting that the optimal design now has a much lower optimal RES-E integration level. Furthermore the system LCOE decreases strongly for the lower RES-E integration scenarios when VOM decreases, but the increase with rising VOM is limited, or even absent, at lower RES-E integration levels. This can be explained because the optimal integration level of RES-E is 77% for a 25% VOM increase and even 87% for a 50% increase. The RES-E integration constraint is thus not active for the given levels: RES-E is cheaper than conventional generation. For all integration shares the same increase in costs is applicable. It can be concluded, however, that the system LCOE is especially sensitive to decreasing VOM at lower levels of RES-E. Since the share of power from conventional generation technologies is limited at higher shares of RES-E, the impact decreases.

It is interesting to notice that the share of solar PV capacity and generation increases significantly when VOM costs increase. Apparently it becomes a more competitive alternative to mainly CCGT, which disappears almost completely, but also to coal, from which it takes a share as well. The other way around, for decreasing VOM, it can be observed that the share of solar PV installed remains roughly the same, as does the generated power, but that the share of mainly CCGT capacity increases significantly. This comes at the expense of both wind and coal capacity. The share of power generated by CCGT increases percentage wise a lot, but stays
7. Validation and testing

Figure 7.6: System LCOE resulting from sensitivity analysis. The bars all represent the deviation from the CON50 value, for several changes in different parameters. The vertical blue line represents the CON50 system LCOE, whereas the vertical red, dotted line represents the system LCOE for CON80. Deviations are given for the 20%, 50% and 80% RES-E scenario, except for the bottom two bars, which represent a 90% and 100% RES-E scenario.

marginal in absolute terms.

The CapEx adjustments mainly result in a larger share of solar PV. As CapEx for that technology is decreased the most for both tests, this appears logical. More interesting to notice is that when future parameters for both the CapEx of wind and solar PV are used, the share of wind stays roughly the same, while the share of solar PV increases mostly at the expense of coal capacity. When only the future price for solar PV is applied it increases equally, but this time the major part is at the expense of wind power capacity. This suggests that with expected future prices, wind power remains more economically beneficial to solar PV, which only becomes more competitive compared to coal plants. However, if solar PV prices are to develop at a faster rate than wind power, it firstly becomes more competitive with wind power, before becoming more attractive than coal plants. The balance between wind and solar PV is thus very dependent on the future cost developments of either one of the two technologies.

7.2.2. CO₂ emission reduction

With the current model set-up the share of generated power from RES-E is kept at levels of 20%, 50% and 80%, but variations in the amount of CO₂ emission are still possible due to the differences in emission per fossil fuel generation technology. Two policy options are applied to test their impact on the model results. First of all, emission pricing is added to the variable costs, where prices of 25€/tCO₂ and 50€/tCO₂ are used. Secondly, an emission cap is applied rather than a share of RES-E which has to be met. The emitted CO₂ at CON20 is 128Mt, at CON50 it is 102Mt, while the CON80 finds an emission of just 41Mt. For each of these scenarios the cap will be tightened by 25% and 50%. Emissions of CO₂ per technology can be found in Table 5.1.

From the system LCOE it can be seen that the effect of a CO₂ price is larger than that of an emission cap, and that the major part of this price increase is already reached at the CON20. This policy option result is very similar to that of increased VOM, and in essence pricing CO₂ emission is nothing more than an increased
price per output for conventional generators. The real striking difference with increased VOM is the added capacity of CCGT. Since CCGT emits less per MWh than coal plants, the operational expenses of these two technologies are closer together, resulting in a more similar LCOE - FLH curve: coal is only favourable over CCGT at a higher amount of FLH, so more situations in which CCGT is preferable can be distinguished.

The effect of an emission cap is less extreme than that of emission pricing. The costs only slightly increase compared to the regular CON scenarios, while the generation mix is not altered that much. A slight increase in solar PV and CCGT can be found, but remains only marginal. The effect of a 25% decrease results in 62% of power from RES-E in the CON50 scenario, while the effect of a 50% decreased emission cap results in close to 75% of RES-E in the energy mix. This is both less than the RES-E optimum in the case of emission pricing. It can be concluded that an emission cap is less favourable for the share of RES-E, than pricing. Emission pricing, however, strongly increases electricity prices, and thus impacts the affordability more.

7.2.3. Complementary options
Both storage and transmission have some effect on the results, but since the amount of costs they account for in the CON scenarios are marginal the effect of these options needs further investigation. Scenarios without storage, without transmission and without both are tested.

First of all it can be seen that the costs for every scenario where complementary options are unavailable are more expensive than CON50. The effect of storage appears to be marginal, as the cost increase when it is taken out of the optimisation, is small. The cost increase for the absence of transmission is much more severe, reaching up to 23% cost increase in CON80. When both storage and transmission are unavailable, these costs rise with 31% for CON80. It can be concluded that transmission has more impact than storage on the system costs. Transmission is, to a certain extent, a good substitute for storage, while this is less so the other way around.

Considering the installed capacities it is found that both the absence of storage and transmission result in less wind and coal capacity and an increase of CCGT capacity for CON50 (up to +340%). Especially the absence of storage has a large influence on the installed solar PV capacity (+90%). The situations in which
output capacity with low FLH is required apparently increases when transmission or storage are lacking. The complementary profiles of wind and solar PV become more advantageous as storage becomes unavailable, while apparently, with transmission, the production profile of wind can be dealt with by spreading it over larger areas. The same pattern emerges in the generation mix, but it is striking that the relatively large increase in CCGT capacity has much less increase in generation as result. It can be concluded that without either storage or transmission the optimal FLH for conventional generation capacity decreases, making CCGT more attractive.

### 7.2.4. Fully renewable power system

Partly to see the effect on the results, but also to satisfy one’s curiosity, the percentage of power from RES-E was increased. The results for a 90% and a 100% RES-E scenario are shown in the lowest two bars, black and grey respectively, in Figure 7.6. The system LCOE deviation was only given for the 90% and 100% RES-E integration.

From the system LCOE it follows that the 90% scenario results in only slightly higher costs than the CON80 scenario. The 100% scenario does impose a relatively large share of extra costs (+15% compared to CON50). The effect is slightly larger than the increase of VOM, emission pricing or caps would result in, but in return provides a fully renewable system. Interesting to see is that the share of solar PV increases, percentage-wise, more than wind power, but in absolute terms wind power supplies the major part of power from RES-E. It can be concluded that a fully renewable system is feasible, for a significant, but probably acceptable cost increase.

### 7.2.5. Concluding the sensitivity analysis

The sensitivity analysis provided some valuable insights in the influence of certain exogenously given parameters on the result. Subsequently it provided further insights in the workings of the system as a whole. The most valuable conclusions based on the sensitivity analysis are:

- The impact of chosen values for VOM are significant. A certain fuel price development might shift the
equilibrium to the advantage of RES-E, especially compared with lower RES-E integration levels. If this is not accounted for in the planning phase impacts on the optimum can be significant. All increases in VOM prices result in a higher share of solar PV, while all decreases mainly result in slightly more CCGT over coal plants. When planning a power system, the uncertainties, known fluctuations and future developments of fuel prices should be incorporated to determine an optimum.

- The impact of chosen values for CapEx is less extreme. Expected future technology costs are likely to lead to a higher share of solar PV. This share is deducted from wind capacity, if prices for wind stay similar, but are more at the expense of coal capacity when prices for wind turbines decrease as is expected.

- The result of an emission pricing system would lead to significant higher system LCOE, but also lead to higher RES-E integration levels as optimum: around 85% for a price of 25€/Mton and even 90% at 50€/Mton.

- An emission cap has no significant cost increase as result, but does increase the RES-E level. It suggests that higher RES-E levels can be achieved with emission cap policy without radical price increases.

- The absence of one or multiple elements from the optimisation shows small differences in the installed capacities, which are only slightly reflected in the generation mix. If storage is excluded, significantly higher shares of CCGT are installed, while also a slight increase in solar PV is visible. For the exclusion of transmission the increase in CCGT is about similar, but the increase in solar PV is not visible. When both are absent, the installed capacity increases in total, with the same patterns visible as for the exclusion of storage. Interesting to notice is that the exclusion of storage has thus the most influence on the required capacities per generation technology, but shows the least difference in system LCOE. If transmission is absent, the effect is much more significant, reaching a cost increase of 23% for the CON80 scenario. It can be concluded that with a somewhat adjusted generation portfolio and mix the demand can be served at almost the same costs when no storage is used, but that the absence of transmission in the optimisation has a much larger impact on the resulting costs. The effect of transmission is concluded to be more important to the system than the effect of storage.

- A fully renewable power system is feasible, even at acceptable, but higher costs than a 50% scenario (about 23% higher costs). Such a system would consist of around 85% wind power and 15% solar PV in the generation mix, with an installed capacity of 90% wind power and 10% solar PV.

The conclusions from both the previous chapter and this section will be discussed in the next chapter, 8. The results will be placed in context and implications for policy options are examined there, but also the limitations as a consequence of the assumptions and modelling choices are argued.
In this chapter the model results will be discussed, and implications for the real world are explained. Due to the assumptions and choices made, there are some limitations to the outcomes and applicability. These limitations will be discussed as well.

8.1. Policy implications of an optimal design

The results found in Chapter 6 and distilled from the sensitivity analysis in Section 7.2 show clear decreases of costs, both for an increased planning scale, as for the availability of several different options. However, the decrease in cost comes with some design consequences, that might be controversial in power system design, or conflicting with national energy goals. Other cost-optimal design effects require significant changes to current system design or power system organisation. When comparing the cost-optimal system with the present day system, as it emerged after years of development, or with national interests as were described in Chapter 2, some interesting complications are found. To determine best policy for an optimal future power system with high shares of RES-E, the following more qualitative issues come into play:

- The distribution of generation, storage and transmission technologies shows a clear concentration around most favourable locations. This trend is already visible at lower levels of RES-E integration, and is only enhanced when the level of RES-E increases. The effect of such a concentration is twofold: first of all it creates strong interdependencies within Europe. Some countries end up with less generation capacity than their peak load, which is considered disadvantageous in terms of energy security: the goal to reduce external energy dependency is fulfilled from the EU perspective, but not from a national viewpoint. Other countries might have installed capacity, but mainly or only RES-E. As was explained in Section 2.2.1 the capacity credit of RES-E is low, which means that these countries will also experience moments of external dependency for grid balancing. Even if the political confidence within Europe would be strong enough to consider the lower costs in exchange for neighbour dependency regarding electricity, other issues might cross such a system. Technical considerations, such as network disturbances or outages of crucial power plants, are strong reasons to keep the energy sector organised on more manageable, national levels.

- The energy security in an optimal design is also affected by the dependency on few energy sources. To achieve a higher energy security, the EU endeavours a far-reaching diversification of the energy supply (European Commission, 2014). The cost-optimum, seen in all policy scenarios, focusses mainly on the use of wind and coal. Only the CG scenario installs a somewhat larger share of CCGT capacity, but still produces the major part of the electricity from the aforementioned two sources. To accept cost-optimal scenarios a change of perspective is needed regarding energy security. The optimal scenario is almost entirely dependent on wind power and coal plants.

- The countries, which have to build the concentration of generation technologies, face other issues. One of them is the social acceptance of a cost-optimal design if a country has to install large shares of capacity. Currently all three technologies that are most relied upon for an optimal design, coal plants, wind turbines and overhead transmission lines, are criticised if installed in the proximity of residents. This
often results in public resistance against the planned infrastructure and remains one of the main barriers against, particularly, wind power (Batel, Devine-Wright, & Tangeland, 2013; Cain & Nelson, 2013; Cohen, Reichl, & Schmidthaler, 2014). Only if locations with minimal impact on residents can be found within the node where that capacity is needed, or if residents can be sufficiently compensated for their perceived nuisance, the suggested optimal design might overcome such barriers. Such a compensation, or deviation from most optimal locations to reduce nuisance, are outside the scope of this study, and are likely to entail higher costs as a result.

• Another disadvantage, that comes with increased energy security in a optimal design, is the mismatch in investment. Although a large share of generation capacity reduces external energy dependence, it means large investment costs for new technologies. In the current system no mechanism is in place that coordinates shared investments for energy infrastructure. If these infrastructures are to be earned back by the market, it incorporates great risks for the investors. As some countries do not have to install any capacity, they bare no financial risk at all. Some sort of compensation will be needed for the risk takers. It will be difficult to determine the monetary value involved.

• From Section 2.1.1 it follows that because of the unbundling, the options for a central coordinated generation planning have decreased significantly. This element of the power sector is nowadays completely organised by the market and, although governments can steer, for example with support schemes for certain technologies or permits for certain areas, generation planning cannot be directly implemented (see also Section 2.2.2). To come to an improved power system design, for any scenario, requires more direct options for governments to steer installed capacities. This clashes with the achieved market design and investment decisions, as was explained in Section 2.2.2. An implication for the use of power system optimisation would thus be to create policy instruments, with which generation planning can be performed, which is likely to affect the market design.

• The dependency on transmission infrastructure for most policy scenarios is large. It was also shown in the sensitivity analysis, Section 7.2, that the value of transmission is significant. However, large transmission flows assume both a fully integrated market and a system operator supervising the network, which currently are both missing. The current system of interconnection, where transmission capacity is traded separately from generation capacity, would need to be transformed. Options with either unconstrained power flows as a governmental service, or nodal pricing, as was for instance researched in (Lejarreta, 2015), can be considered to incorporate.

In general, it can be concluded that to harvest the benefits of a cost-optimal design, the current power system is to undergo major changes, not only from a technical perspective, but also in terms of market organisation and executive institutions. Some of the developments that led up to the system as we know it should be undone or altered, not to mention the effort it would take to convince countries to abandon national security policies and adopt a more central planning policy. However, although the system found in the cost-optimisation might have many infeasible elements, conclusions on the major design principles influencing the energy costs can be found and will be presented in the next Chapter.

8.2. Model limitations

All results that follow from the model have been validated and found sufficiently reliable. Nevertheless, due to some choices, assumptions and necessary adaptations made in the process, the results are not completely representative. This has influenced the results in some ways and need to be understood to draw the right conclusions based on the outcomes.

First of all, any model is nothing more than a strongly simplified representation of the very complex reality. The chosen model approach and type, a cost-optimisation from a central perspective policymaker, form a first limitation. In no real world situation is a system solely determined by one decisionmaker: many other actors with conflicting interests participate in the process and have different levels of power to influence the outcomes in their benefit. This also introduces all kinds of market failures, which were not incorporated in the model: no externalities were considered, perfect knowledge was assumed and no other factors than techno-economic were involved. This all creates discrepancies between a real world outcome and the result found with the model. These factors would probably have led to higher overall costs and an increased spread of technologies over the several market regions. It is hard to say which solution is ‘better’, even in terms of
8.2. Model limitations

Techno-economic outcome, as the emerging system from the imperfections might be more robust and serve other interests that have not been taken into account for this model.

To add to the model approach, the used model was completely deterministic. The historic weather data and demand data, that was used as input, created a form of foresight for the central planner about conditions to expect. Uncertainties, occurring regularly in the real world, are not accounted for. These are likely to have led to higher system costs, additional to an underestimation of the needed generation capacities: extreme situations would not have been foreseen and could not be planned accurately, thus requiring overcapacities to ensure grid stability. The absence of many technical elements, that are present in the current power system, is likely to lead to lower costs and a different system lay-out from the optimisation as well. Including aspects like ramping limitations, spinning reserves and start-up times are likely to lead to higher costs and more flexible generation capacity. However, including more options, currently providing large shares of Europe's energy mix as well, like nuclear power and ROR hydropower, might have led to lower costs schemes in the optimisation. One certainty is the overestimation of transmission grid in this model design. Many complicating real world factors for electricity transport have not been accounted for, which would have limited the applicability of electrical transport. However, a very extensive transmission grid was found to have little direct impact on the system LCOE. Hence, it can be questioned whether more complicated electricity transport, mostly resulting in higher costs, would have significantly changed the cost-optimal designs for any policy scenario. Although the effect cannot be ignored, it is believed that incorporating more detailed transmission constraints in the model would lead to minimal differences in the major findings. A last technical remarks concerns the storage. Due to the deterministic design of the model, the uncertainty and short term variability of RES-E was much less of influence than it is experienced in the current power system design. Storage is seen as an option that is extremely capable of dealing with these short term effects of RES-E (Castillo & Gayme, 2014). The lack of value from storage found in this model, especially that of short term storage options like flow batteries, might be due to the exclusion of these effects. To be able to determine the added value for storage in power system planning, a model with short-term effects and stochastic RES-E variability should be studied.

Again, although the influence of model limitations should not be underestimated, the effects of it influence small parts of the system design and the impact on the major results is estimated to be only marginal. The principles found in this research remain valuable, but for a full scale design that is to be implemented more investigation into both the policy implications as the model limitations is needed. Recommendations of where to start and how important these elements are will be given in the next Chapter, in Section 9.2.2.
Conclusions and recommendations

In this chapter the conclusions will be presented that were obtained from the combination of the model, prior literature research and knowledge gained during the process. Answers to the research questions are given first. This is followed by recommendations relevant to power system policymakers. The chapter will be concluded by interesting directions for further research.

9.1. Answers to research questions

This research was set out to find an answer to the main research question:

'What is the effect of different levels of centralisation for European power system planning, on cost, design choices and energy policy objectives, taking increasing shares of intermittent renewable electricity into account?'

To be able to answer the main research question several sub-questions have been drafted, to either understand the process to come to an answer, or provide elements of the answer itself. In the sections below per sub-question answers will be presented that could be drawn from relevant parts in this research. Directly after that, the answer to the main question is presented. As a reminder, the system LCOEs per scenario are shown in Figure 9.1.

Sub-question 1: Which aspects of a power system are influencing the design choices?

Aspects influencing the power system design are numerous and come from both technical, economic and institutional perspectives. The planning of power systems is done mostly based on (national) goals, regarding energy security, affordability and sustainability, which are often conflicting. These goals might also differ on different governmental levels. On top of that the planning is subject to acceptance of residents, regarding technologies in their direct surroundings. The relevant aspects are therefore mostly dependent on the perspective considered. If one is to design a robust system with little to no outages or ‘expected energy not served’ the aspects that should be included are mainly technical. Considering generation, storage and transmission efficiencies, ramping times and limits, start-up times and limits, required spinning reserves as well as electrical transport specificities, such as PTDF and active/reactive power flows, is inevitable. Although secondary considerations also affect their choices, such a technical design is the starting point for most TSOs and the ENTSO-E. Private companies active in the power sector look at the design more from an economic perspective, but also need to consider technical elements on a small scale. Relevant aspects for them range from Levelised Cost of Electricity per technology, which consists for instance of developments in fuel and material costs, specific meteorological conditions (capacity factor) for RES-E and expected FLH for a planned generation unit. The economic feasibility is strongly influenced by more institutional aspects like support schemes.

Finally, from the viewpoint of policymakers all mentioned aspects are, to a certain degree, relevant. However, since the energy sector is liberalised and increasingly unbundled their influence on developments is only indirect and policy measures should motivate other actors to execute the aimed for actions. This means that in designing policies the right technical, economic and institutional incentives have to be included. The sustainability goal is an interesting institutional example, as it leads to a policy driven transition of the power system. Due to the liberalisation and unbundling, adequate market regulation and regulators have to be
organised and empowered by governments. Energy policy will also have to deal with public acceptance of required technologies. Concluding on the sub-question: For a full scale power system design, mainly technical and economic aspects influence the design choices. From a governmental point of view institutional aspects, like market regulation, regulating responsibilities and social acceptance are influential aspects as well. Whether all these aspects should be regarded in the design process depends on the perspective that is considered and on the aim of the design.

Sub-question 2: Which model type and modelling tool are best for representing and optimising the European power system? To begin with, power system models range, on the one side, from large, macroeconomic models in which, besides the power sector, multiple other sectors are included as well. On the other side there are bottom-up models, where individual agents are used to study the emergence of behaviour in the system. For optimisation problems it can be concluded that a partial-equilibrium model, focussing only on the power sector, is most applicable. Within these types of models a system cost minimisation model was seen best fit for the purpose at hand. Secondly, the time-horizon for a system planning problem asks for a time-horizon of, at minimum, one year, to incorporate all seasonal patterns in demand and meteorological conditions. However, the operational element needs a time-resolution of hourly steps, required to represent the effect of RES-E variability and short-term interdependencies. This creates a conflict, as running models for such a long time-span with an hourly resolution is very computational demanding and therefore hard to manage. Sub-question 3 deals with this issue. A third conclusion that can be drawn here regards the type of input-data that is to be used for this problem type. Since the assumption was made that a correlation between weather conditions exists over time and space, and no stochastic data was available which could represent such weather dependencies for the whole of Europe, real-time weather data is a good alternative. The specific weather-conditions in the considered time period will always influence the results, so this data use does not allow for direct implications on new power system design. It also requires a careful selection of the time-series as a whole, to replicate the important weather interdependencies. Regarding most applicable modelling tools it can be concluded that a computational modelling tool is indispensable. The size of the optimisation problem makes it virtually impossible to find an optimal solution by hand. Therefore a numerical computer modelling tool has to be used. For problems with as many variables as were expected for this one either mathematical modelling tools, like Matlab, Python or Octave can be used, or real modelling language, like java, ph or C/C++ could be applied. For this research the Matlab tool was used.

The last conclusion regarding the model to be used for this kind of problems concerns the type of optimisation problem. A power system is best simulated as a non-linear problem, with integer variables. However, such a model is computationally hard to solve and poses all kinds of limitations on the results. The best balance between adequate model representation and computation times was found for a linear problem. It can be concluded that the model type should be a partial-equilibrium system cost minimisation, with real-time weather-data as input, which is best optimised as a fully linear problem, using a mathematical modelling tool.

Sub-question 3: How can model computation times and quality of the results be balanced for large-scale weather-data driven models? In the previous section the issue with model size is mentioned, as well as how a representative time-series can be determined upon. It was found that for modelling systems with real-time weather data, it is not necessary to use the whole dataset. It is more important that all relevant patterns and extreme situation from that dataset are used as optimisation input. Two options can be applied to decrease the dataset size without losing too much information. The first option is to aggregate hours per 2 or even more. However, specific inter-hourly dependencies might be lost this way and also extreme values will be averaged, making it likely that the outcomes are 'smoothened'.

If extreme values are not so much relevant to the objective of the study, this is still an option, but for this research the other option seemed more appropriate. More or less random days were picked from the dataset and stuck together to form an 'artificial year', consisting of fewer days. By using complete days, daily patterns were ensured. By picking these days equally from each day of the week and over the seasons, the presence of all relevant patterns in weather-conditions can be preserved, without losing extreme values. An emerging question then is how many days need to be considered to be representative. An analysis of varying amounts of hours considered shows a decreasing upward trend for the systems LCOE as the number of days increased. Since multiple time-series can be chosen of the same length, runs with different input data for the same length can be run. This showed that the variability between runs of the same length decreased as the amount of hours included increased. Larger time-series seemed to produce more uniform and robust
9.1. Answers to research questions

results. The proper balance between model manageability and result robustness was determined at a series consisting of 52 days. This proved to be long enough to have little variability in between runs, and stayed relatively manageable in terms of computation times. If the run from this series with on average the largest installed capacities in the solution is chosen, this ensures it's capability to find a solution for all other time-series as well. Both the found design, generation mix and profile seemed to be valid for this time-series in this model, so it can be concluded that this method of decreasing model size while maintaining relevant patterns and extreme values is an applicable strategy to balance quality of results and model manageability.

Sub-question 4: How can the future European electricity infrastructure be approximated under current policy? Comparing model results with the existing model can be useful for the validation process, and give valuable insights due to similarities and differences between current and optimal design. It is hard to compare the real world power system with the found optimal design: the form in which data is available on the real power system does not match with the output of the model. To overcome this a reference scenario was created with the model, which represents the current design in the same form as it does for the optimum. It was concluded that by aggregating real installed capacities and use that as input for this model, a fairly adequate representation of the current power system could be obtained. The aggregation can be done on similar fuel sources, like sun, wind or same type of fossil fuels, but this leaves still many different technologies. It proved sufficiently reliable to aggregate them based on the LCOE versus FLH curve (high fixed, low variable costs versus low fixed, high variable costs). This meant that nuclear, lignite and coal were aggregated, as well as all kinds of gas plants. Wind onshore and offshore were aggregated, as well as the small amounts of solar CSP and solar PV. The generation mix achieved by the installed capacities was found surprisingly similar to the actual generation mix for 2012, which shows that the model can, fairly adequate, reproduce the system's operation.

Sub-question 5: Which elements should be included when modelling the future European power system? The power system, as defined for this study, consists of three elements: generation, storage and transmission. The impact of each of these elements on the results differs strongly. It was assumed that these elements are complementary in the power system operations, therefore resulting in lower costs when all of them were incorporated in the optimisation. A striking result is the relatively low impact that the availability of storage has on the results. Although the installed capacity is enormous, especially at the 80% RES-E integration scenarios, the effect on the systems LCOE is only marginal. It is interesting to see how the absence or limitation of transmission is of much greater influence on the costs than storage. Although storage contributes relatively large shares of the total system LCOE, its function can be substituted, for lower costs, by a transmission network. The effect of including storage in the optimisation, without additional technical parameters, is therefore deemed doubtful, and will be discussed in Section 9.2.2. For the transmission element, the contribution to the costs is also very small, on average not more than a few percent of the total system LCOE. However, the effect it has on the solution, especially the utility and distribution of generation technologies, is enormous. Without transmission the installed capacities increase significantly, while also a more divers mix of technologies is used per land or region. A divers mix means that less-than-optimal technologies are used, therefore increasing the costs. This directly impacts the system LCOE, as it increases accordingly. This element is valuable to include, although the costs are almost negligible.

Within the generation element it is interesting to look at which technologies are used. When techno-economic parameters are used as main input for the technologies and no additional policy measures are included, the model will only base it's installed capacity on the cheapest available option. It can be concluded from the results that wind turbines and coal plants were by far the most used technologies, both in installed capacities and in the generation mix. These technologies have the lowest LCOE for many full load hours, which is something that an optimisation is able to design for as it has prior knowledge about weather-conditions and demand over the whole dataset. The share of solar PV only increased slightly, as the RES-E requirement increased up to levels of 80%. Both CCGT and solar PV shares increased as transmission and storage options became limited or unavailable. Especially when transmission was limited, the situations with a need for flexible generation, but with few FLH, increases, which creates situations more appropriate for CCGT. For storage the same trend occurred. PHS is the cheapest option, and the only option used except for scenarios where the transmission is limited or unavailable. When determining which technologies should be included in the model, one has to consider factors that might choose more expensive options over cheaper ones. If these are not included in the model, additional options will only be used marginally. For this study the extra, but expensive option of a sustainable flexible generation technology, biomass, was even found not
to be used at all, under any circumstance. Within the generation and storage element it can be concluded that not so much all available technologies have to be incorporated, but rather a mix of technologies with distinctive parameters and cost-schemes.

A few conclusions can be drawn from the elements that were not included in this study. The absence of run-of-the-river hydropower from this model did not create any issues for reaching the high shares of RES-E in a system which satisfies demand at all times. Also somewhat controversial generation technologies, such as nuclear power and Carbon Capture and Storage technologies, were not included, but still a system was found that satisfies demand for high shares of RES-E. It can be concluded that from a technical perspective these technologies are not indispensable to create a power system capable of fulfilling balancing constraints.

Sub-question 6: What consequences and effects will a more central coordination of the system have for national energy policy? It was concluded from Chapter 2 that most of the energy policy making is done on a national scale, by national governments. Security of supply is considered extremely important to individual countries, and most of them have concrete goals regarding minimal domestic generation capacity and energy diversity, as well as policies for strategic reserves or back-up capacity markets. The national policy already is influenced by European goals, regarding interconnection capacity and RES-E targets. However, the cooperation in operations of the power system is only marginal, also due to limited cross-border transmission capacity, and in the planning of the power system almost absent. The conflicting consequence of an optimal central coordinated power system, with these national goals, is twofold. First of all, the domestic capacity for many countries becomes by far insufficient to deliver average daily demand. The generation mix is very one-sided: in most countries, and even in most regions, one, or maybe two technologies are forming the major share of installed capacity. All flexible generation capacity is centred in a few countries, mostly in North-Western Europe, like Germany, France and Italy, although some capacity is also installed in Eastern Europe and the Balkans. The Northern and South-Western regions are completely dependent on this flexible generation at times, as they only have wind power as generation technologies. The import and export map shows large interdependencies between countries. The extreme values, at moments, result in complete dependence on external production. National energy goals are thus not in line with the design for an optimal power system from a central coordinated point of view.

Other consequences of the cost-optimal design are a mismatch in investment, as some countries or regions have to invest heavily where others do not invest at all. Finding a way to compensate all involved actors, or to subdue the whole system to one internal market will prove to be difficult as well. Not only the investment burden falls heavier on some countries than on others, also the social acceptance of the required amounts of installed capacities in the regions, will result in resistance. It can thus be concluded that a cost-optimal, European design clashes with the current design and national energy policies, especially because of the clustering of installed generation capacity.

Sub-question 7: What is the influence of separate elements on the cost-optimal design for the European power system, considering several planning scales? From the results it can be concluded that two aspects influence the cost-optimal design for the European power system strongly. First of all the number of elements included in the optimisation plays a role, where especially the influence of transmission is noticeable. A second important element is the planning scale that is considered: for an increase in planning scale a decrease in costs was found. As the share of RES-E increases the difference with scenarios that are planned regionally or nationally becomes larger, until a significant difference is reached at an 80% RES-E integration level. The effects of regional planning compared to national planning are much less significant. When storage is left out, the effect on costs for a continental scale is negligible. Slightly higher costs are found when each country has to have a minimal domestic RES-E production. It must be concluded that the cost-optimal design for a far distant future power system is obtained when a full scale, Europe-wide optimisation is performed with generation, storage and transmission elements included.

9.1.1. Answer to main research question
To answer the main research question, four policy scenarios were investigated. The planning scales, considered in these scenarios, increased from a national level to a continental level. The highest planning level had an additional scenario, in which national energy security goals were to be satisfied. For each of the policy scenarios an optimisation was performed, for increasing shares of electricity from renewable sources in the energy mix. The optimisation varied installed capacities of generation and storage technologies per country, transmission lines between countries and an hourly dispatch, within balancing constraints. The optimum
was determined based on the lowest total system cost, which consisted of all fixed and variable costs required to build the necessary technology capacities, and produce enough electricity to meet demand. From this study, three major conclusions can be drawn, based both on the quantitative outcomes of the optimisation model, as on qualitative analysis of the European power system and energy policies. First, a comparison between the costs, converted to system LCOE, for different policy scenarios was. The second conclusion focuses on the resulting design and design choices required to come to a cost-optimum. Additional findings on why certain elements are beneficial, or completely unused, are based on the sensitivity analysis. The third, and final conclusion shows the impact an optimal design for different planning scales has on current energy policy objectives. The analysis of the current power system planning playing field is used to determine the feasibility of such a design. The three conclusions are illustrated below:

1. **System LCOE**: The effect of a more centralised planning level on system LCOE is unambiguously: when the planning scale increases, the cost decrease. The share of RES-E has a significant impact on the difference the planning scale makes: the effect grows stronger as shares of RES-E increase. An optimal design, planned on continental scale for 20% RES-E integration, results in an electricity price of €37.50. The optimal price for a system planned on national level would result in €38.49; roughly 3% higher. Incorporating 80% RES-E, this difference dilated to 23%; €38.92 over €47.75. Noticeable here is the relatively small cost increase within the continental planning scenario: €1.42 or 4%. This implies that under optimal planning scale energy costs could remain around the same price as current levels, while integrating more electricity from RES than the European target for 2050.

Moving from a national to a regional planning level is hardly beneficial: costs for 20% or 50% RES-E are almost similar, while at 80% the regional scale saves €2.12 or 5%. This automatically shows that the benefit of the European scale over regional scales is still significant: around 17% or €6.72. Interestingly, the centrally planned scenario with regard for national energy security goals, the country goals scenario, performs worse than the national and regional planning scale for lower levels of RES-E. It only becomes beneficial for an 80% of RES-E requirement. The final remark is that increasing the planning for the European power system results in lower energy prices. However, the effect is smaller when less RES-E is required, or when additional constraints limit the degrees of freedom of the optimisation.

The higher costs for lower planning scales have multiple origins. First, a lot more generation capacity is installed, which has lower utility rates. Second, the share and use of more expensive CCGT is slightly higher, which results in increased VOM. Third, more use of storage was found, which adds extra costs both due to the investment costs of storage facilities, as due to the increased efficiency losses. These efficiency losses have to compensated by more production, which is also visible in significantly more power production than there is demand.

2. **Design choices**: For the optimal design, a few things stand out. First of all, the optimal generation portfolio is intriguing. With the incorporated options and technical limitations applied in this model, an optimal design is strongly reliant on wind turbines and coal plants. These two sources have the lowest
specific LCOE at higher FLH. When an optimisation is applied, situations are created where the installed capacity has the highest possible utility rate. Additional options, more favourable at fewer FLH, like CCGT, are only used as a last resort in the three policy scenarios without additional constraints. For the country goals scenario, a fair amount of excess backup capacity has to be installed, with few, or even zero FLH. The option with low fixed costs, CCGT, is used significantly more in such a situation. The second RES-E option, solar PV, is rarely applied for lower shares of RES-E. The complementary profile only becomes more attractive at high shares of RES-E integration, where it supplies, averaged over the policy scenarios, 10% of the installed RES-E capacity. In the country goals scenario it is not even used then, which implies that solar PV and CCGT are somewhat interchangeable options. In essence the optimal design has a strong preference for wind and coal. Only when additional constraints, like high RES-E requirement or minimal installed conventional generation capacity, create exceptional situations, the added value of CCGT and solar PV is applicable.

In terms of geographic design, the system moves from a fairly distributed generation portfolio to clusters of same technologies as the planning scale increases. On a national level each country has to fulfil the RES-E requirement, which results in quite diver mixes per country. Not surprisingly such a scenario results in more solar PV and CCGT capacity. When planned regionally, already the most favourable RES-E location is overrepresented, mainly with installed wind capacity. Flexible, conventional generation capacity is then placed in more central locations. This is most visible in the continental planning scale, where the RES-E is all moved to the outer regions and countries of Europe, while the centre contains solely fossil fuelled generation capacity, mainly coal.

The system becomes more and more reliant on transmission technology when the planning scale increases. All separate clusters are needed at different moments in time, but serve larger geographic areas, requiring large capacities of interconnection lines. The large amount of cross-border flows also results in a heavily reliant centre of Europe, which becomes increasingly dependent as the share of RES-E grows. The few countries, with favourable RES-E locations, provide most of the European power and are strong exporters.

As a last remark, although storage was used significantly when available to the optimisation, the influence it had on the system LCOE was found to be marginal. When the option of storage was made unavailable, a strong increase in transmission capacity was the result, which implies that transmission is a adequate substitution for storage. The effect was not found the other way around. Within storage, only PHS was commonly used. FB and h\textsubscript{2} were used only marginally and in extreme situations. Biomass plants were found not be used at all in the optimal design, not even when the price was decreased significantly.

Hence, it can be concluded that a more centralised planning scale results in systems with a strong clustering of generation technologies in most favourable locations. The most often used technologies are coal and wind, while solar PV and CCGT are only used in exceptional situations. The system becomes heavily reliant on a strong transmission grid as the planning scale increases, which automatically results in strong interdependencies between Member States. The effect of storage on the optimal system was found to be marginal, while more expensive, but sustainable generation technologies, like biomass, were not used at all.

3. Implications for energy policy objectives: The optimal design has several, negative implications for current European and national energy policy objectives. From a economic perspective increasing the planning scale is beneficial, but from the technical and institutional perspectives this creates issues. Technical challenges arise around the robustness and energy security of such a system. If the dependency on import and therefore the transmission network becomes too large, a minor disturbance threatens the security of supply. The strong, external energy dependency would be exchanged for a significant interdependency among Member States. This is also undesired from an institutional point of view, as most national governments regard energy as such a critical commodity that they have created guidelines for share of domestic production. On the other side, countries with clusters of generation technologies might also not experience this as advantageous. They bare great investment risks and an adequate payment or compensation scheme would be required to motivate these countries to install more capacity than they require. Additionally, social resistance, against mainly wind power and overhead transmission lines, is currently a barrier for power system planners. Implementing a more central planning perspective will face many challenges.
Finally, a more centrally coordinated power system requires adequate system planners and operators. Currently the organisational design is lacking both. The generation planning is done completely by the market and can only be steered indirectly by governments. Support schemes and local policies are used to influence the design, but can hardly be called efficient for real power system optimisation, when all elements are to be involved. The operation is mostly done on a national level, while cross-border flows are increasingly managed regionally. Although the ENTSO-E has some powers influencing the European power system, there is currently no institution capable of managing power flows in a pan-European design. Thus, increasing the planning scale is economically beneficial, but some serious barriers will need to be overcome in order to get there.

### 9.2. Recommendations

Now that the main findings of this research have been presented, some recommendations will be given. First of all the insights for policymakers will be presented, followed by suggestions for future research.

#### 9.2.1. Insights for power system planners

The optimisation shows clear indications for policymakers to use for future energy policy. Especially for the field of power system planning some valuable insights can be distinguished. First of all, power system optimisation results in significantly lower average system LCOE than the current system can offer. The costs can theoretically decrease with 50% to one third of the current costs. Although a power system optimisation is a time consuming process, the benefits are clearly present. It proves beneficial for both national and European policymakers to invest in extensive optimisation tools.

Currently the ‘power system planning’ mostly consists of transmission extension planning. Including the elements of storage and, especially, generation in the planning is leading to improved outcomes. Considering the transmission system as a European network, with continental planning scale decreases network costs and increases utility rates of installed generation capacities. A transition to a more centrally planned cross-border network can be recommended.

Thirdly, the EU already aims for a more integrated market, but still then the integration of large shares of RES-E is causing problems for the business model of conventional generators. The utility rate of coal and CCGT decreases steadily as RES-E shares increase, even at higher planning levels. The fluctuating output of RES-E has to be supported by some form of dispatchable generation capacity. To preserve system stability other mechanisms, like capacity markets, or market designs will be required.

Furthermore, for the short term, a lot can be won by regional cooperation. Even when the system is not designed centrally, dispatch decisions in cooperation with neighbouring markets can lead to a cost decrease. If a more central planning scale is adopted, optimisation without additional policy goals is likely to politically infeasible designs. The importance of energy to national governments makes it a difficult subject to transfer authority to a central planner. More likely are scenarios where the domestic generation capacity for all countries is assured, and import dependency within Europe is limited for all countries.

A fifth recommendation consists of increased the interconnection capacity. In all scenarios investigated in this research, the value of an extensive cross-border transmission grid became clear. This potential benefit is endorsed by findings from almost all other comparable studies. Extended grids give options both for the dispatch phase, as for higher utility rates. If more interconnection capacity is installed an adequate market design will be needed to optimally use this capacity.

Finally, it is strongly recommended to set the mandatory RES-E targets on higher scales, allowing countries to use more favourable locations to install RES-E capacity. Even if no joint power system planning is performed, a combination of favourable locations and transmission grid can decrease the amount of problems with RES-E integration. To prevent an unstable and overly costly system to emerge ways of cooperating on the installation of RES-E capacity should be developed.

#### 9.2.2. Future research

Obtaining and analysing the results showed that further research is necessary to understand the full implications and meaning of the outcomes. Many elements, both from a techno-economic point of view as from a more institutional point of view will need further elaboration and study before valuable conclusions can be drawn which might lead to policy adaptations. Furthermore, the limitations of the used model arouse curiosity to the influence of other technical aspects on the design.

One major assumption throughout this research has been that countries would be willing to exchange
some autonomy in their energy policy for lower energy costs. This transfer of responsibilities towards a more central planner is much less likely than it seems based solely on the economic benefit. National governments have been relatively reluctant to transfer their powers towards European policy makers, as is also the case in the current discussion and ‘exits’ of the EU. Further research has to determine to what extend national governments are willing to remit responsibility, or, as an other solution, cooperate more closely with central power system planners. This inevitably opens up another element of research topics. The question of what authority should act as the central planner and what powers are needed to fulfil this role adequately is important to answer. Currently no authority is capable of such a task. The only institutions that act on that level in this sector are ENTSO-E and ACER, but neither of them currently has the capabilities or powers to play this role.

A more techno-institutional solution that was not included in this research was the use of Demand Side Management (DSM). Many of the peak capacity found in this research was only built for very few full load hours, making it relatively costly to have these capacity. The effect of DSM on the optimal scenario is expected to show interesting results for this peak capacities.

From a more economic point of view the question arises, from this study, how costs for an optimal system could be divided. If the system is to be optimised and designed with many countries together, the optimal design and policy measures to get there ensue costs. All benefit from this better design but it is unlikely that the current fragmented market design is capable of allocating these costs in the right way. Besides that, the step from a theoretical optimal design, up to the actual installation requires investors to act accordingly. To achieve this, the mechanism behind investment decisions for such an optimised system, and profitability of business models, will need to be researched, as well as policy measures to steer the investments in the right direction. An interesting element which has been left out completely for this study are the financing costs. These costs are not necessary to include if total system costs are calculated, but appear incredibly important for private investors.

The last research direction to be mentioned here is the techno-economic element, which is very much intertwined with the modelling of power systems. For this model, knowingly or unconsciously, many techno-economic parameters have been left out. This inevitably influenced the results, as was discussed in Chapter 8. For the generation element several elements have not been included in this research, but are known to play a role in the current power system. Their effect upon the model outcomes is largely unclear, and will need further investigation, in order to determine if they can be ignored. These elements comprise:

- **Ramping elements**: Ramping of conventional power plants often knows limitations, costs and takes time. The inclusion of this in models is limiting the use of large, but log conventional coal and nuclear plants and gives incentives for more flexible plants like for instance CCGT. Including this has thus an influence on the generation mix, but is also expected to influence the total costs.

- **Start-up elements**: The same as for ramping, starting up conventional power plants takes time and includes costs. Including this is also likely to produce more realistic outcomes, influence the generation mix and influence total costs.

- **Unit commitment**: The capacity of a generation technology does not consist of a continuous scale, but rather consists of multiple units (plants) with a certain rated output. A unit is either committed, meaning it is start up and produces energy, or shut down. When a plant is committed it often has a minimum output level, making it more beneficial to run such a unit for longer periods. This is likely to influence generation mixes, but also cost profiles.

- **Availability factor**: Generation units have, besides a capacity factor, also an availability factor, that determines how much of the time it could be committed it is available for production. This factor can be influenced by planned maintenance, which is controllable, or distortions and failures, which have a certain chance of occurring. Including this in any model results in some excess installed capacity and also more extreme situations in which multiple units at once experience failures and are thus unavailable. Including this element fully allows for the design of a more robust power system.

- **Wake effects wind**: Due to the aggregation of weather data per country the installed capacity is all put in one position and has the potential output for the average weather conditions in that country. In the real world wind turbines are very much influenced by the proximity of other wind turbines. When separate units are introduced, wind farms can be researched as a unit in which the wake effects of wind turbines are incorporated.
Besides the mentioned elements of generation technologies, also the influence of some technologies that were not incorporated in this model should be looked at. Especially nuclear power and run-of-the-river hydropower currently contribute a large share of Europeans energy. Both are relatively cheap and thus favourable generation technologies, which also have no CO$_2$ emission. For nuclear power, social acceptance considerations come in to play. The inclusion of offshore wind power and maybe even CSP might be valuable to include as well. CSP is only interesting in a scenario with future parameters, as it is currently less competitive than, the already rarely used, solar PV.

From the network point of view, an interesting aspect to include is a separate cost-scheme for offshore cables. In the cost-optimal design many of the transmission capacity in Northern Europe is installed across seas (connection to the UK or SE). Including this in the research might influence the network lay-out, installed generation and storage capacities. Grid stability aspects and their effect on the optimal design and costs are interesting to research as well, by including PTDF, AC or DC cables and active and reactive power flows.

The last recommendations for further research affect the input data. For this study the used input data had to be corrected before it seemed reliable. First of all, the same study should be performed with different sets of input data to make sure the solution is less dependent on a specific data set, with all measurement errors it includes. For this model, the data was also aggregated per country, which proved to be quite influential. Furthermore, research is suggested incorporating smaller geographic area of aggregation, to determine more precise where RES-E should be situated. Other relevant questions regard the effect of stochastic data would have, instead of the deterministic approach that was used for this study. Research with stochastic determined weather conditions is also more applicable to project a new system with, as it can be designed for extreme situation that were lacking during the specific dataset considered.
Reflection

To conclude this thesis, I first would like to thank you for reaching this point. It means you managed to read through my extensively (some would say ‘long’) and complex (some might call it ‘boring’) report. Secondly some room will be taken to reflect on the process this research really was. To break with the rest of the report this will be done in a slightly more frivolous fashion.

The energy market, and renewable energy in particular, was something that has always fascinated me. From the assumption that a large energy transition was needed and large transitions are most likely to come from large, influential actors in the sector, I tried to start graduation assignments at TenneT (Dutch TSO) first. Due to several reasons and miscommunication, however, this did not result in a satisfying result in the end. Since all these assignments would have been largely qualitative it proved to be advantageous not to have started one of those assignments. Deciding that it would take too long to try and find another assignment with either TenneT or any other energy related company I choose to graduate at the Faculty. Exactly in that month some malfunctions in the graduation portal of the Faculty had pushed a few, actually expired assignments back to the front page, one of them containing the challenge to design an optimal future electricity network for Europe. On my first meeting with Petra and Remco I had no idea of what would lay ahead.

Looking back now I can honestly say that I did not expect that the majority of this project would be swallowed up by programming. I had heard friends at more technical studies talking about (read: ‘cursing’) the mathematical computing tool of Matlab. Up to a few months ago I could not have imagined myself building an extensive model in this program, but the majority of the above report results from this newly acquired skill. The stepping stones provided by Remco during the process were indispensable and provided me with a kick-start I could not have done without.

The process of modelling an extensive European energy system swung me back and forth between megalomania (“If I can model this, why not add all relevant technical elements?”) and panic attacks (“I can as well throw away all I have and start over, or better hand back the assignment.”). In the end the model proved to be as valuable as it is extensive and the endless stream of interesting results confronted me with the next challenge: what is relevant for this research?! Probably up to the last day this question will keep me struggling and will make me adjust, rewrite, or remove results, conclusions or research questions.

In the end, this project made me realise one thing: I want to use my brain capacity to help find and enable a sustainable future. I do not know yet how, where or when my contribution is useful, but that is something only future can tell us. I hope at least something in my thesis has inspired you, as reader, to think about how you can contribute to the energy transition and a brighter future. For now, I am glad that my period as a student has ended after what has been an incredible period of my life.


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Institute for Systems and Innovation Research ISI.

AG.


j.apenergy.2015.10.100

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Distances between geographic country centres

Table A.1: Geographic distances between country centres.

<table>
<thead>
<tr>
<th>Connection</th>
<th>Distance (Km)</th>
<th>Connection</th>
<th>Distance (Km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT === CZ</td>
<td>293</td>
<td>FI === SE</td>
<td>597</td>
</tr>
<tr>
<td>AT === DE</td>
<td>515</td>
<td>FR === DE</td>
<td>758</td>
</tr>
<tr>
<td>AT === HU</td>
<td>505</td>
<td>FR === IT</td>
<td>929</td>
</tr>
<tr>
<td>AT === IT</td>
<td>502</td>
<td>FR === LU</td>
<td>520</td>
</tr>
<tr>
<td>AT === SI</td>
<td>482</td>
<td>FR === ES</td>
<td>826</td>
</tr>
<tr>
<td>AT === CH</td>
<td>405</td>
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<td>244</td>
</tr>
<tr>
<td>BE === FR</td>
<td>557</td>
<td>DE === NL</td>
<td>279</td>
</tr>
<tr>
<td>BE === DE</td>
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<td>DE === PL</td>
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</tr>
<tr>
<td>BE === LU</td>
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<td>DE === SE</td>
<td>1276</td>
</tr>
<tr>
<td>BE === NL</td>
<td>221</td>
<td>DE === CH</td>
<td>451</td>
</tr>
<tr>
<td>BE === GB</td>
<td>538</td>
<td>GR === IT</td>
<td>880</td>
</tr>
<tr>
<td>BG === RO</td>
<td>334</td>
<td>HU === RO</td>
<td>398</td>
</tr>
<tr>
<td>HR === HU</td>
<td>402</td>
<td>HU === SI</td>
<td>189</td>
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<tr>
<td>HR === IT</td>
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<td>HU === SK</td>
<td>398</td>
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<td>HR === SI</td>
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<tr>
<td>CZ === PL</td>
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<td>IT === CH</td>
<td>599</td>
</tr>
<tr>
<td>CZ === SK</td>
<td>315</td>
<td>LV === LT</td>
<td>127</td>
</tr>
<tr>
<td>DK === DE</td>
<td>560</td>
<td>LV === SE</td>
<td>791</td>
</tr>
<tr>
<td>DK === NL</td>
<td>477</td>
<td>LT === PL</td>
<td>516</td>
</tr>
<tr>
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<td>726</td>
<td>LT === SE</td>
<td>841</td>
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<td>DK === GB</td>
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<td>NL === GB</td>
<td>542</td>
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<td>EE === FI</td>
<td>556</td>
<td>PL === SK</td>
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<tr>
<td>EE === LV</td>
<td>230</td>
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<td>687</td>
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</tr>
<tr>
<td>FI === LV</td>
<td>780</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure B.1: Technology specific LCOE. The LCOE is calculated as the price per MWh versus the number of full load hours, for the chosen parameters in this research.
Reference parameters for power system technologies

<table>
<thead>
<tr>
<th>Source</th>
<th>Wind onshore</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CapEx</td>
<td>FOM</td>
</tr>
<tr>
<td>Brouwer (2016) variable without fuel</td>
<td>e/kW (2015)</td>
<td>1402</td>
</tr>
<tr>
<td>Bertsch (2012)</td>
<td>e/kW (2020)</td>
<td>1220</td>
</tr>
<tr>
<td>ECF (2010)</td>
<td>e/kW (2010)</td>
<td>1000 - 1300</td>
</tr>
<tr>
<td>Fürsch et al. (2013), VOM = fuel-based</td>
<td>e/kW (2010)</td>
<td>1220</td>
</tr>
<tr>
<td>Schäfer et al. (2013), F = 0,75;2,5=1,54</td>
<td>e/kW (2015)</td>
<td>1330</td>
</tr>
<tr>
<td>iEA (2012); US estimates</td>
<td>e/kW (2010)</td>
<td>1000</td>
</tr>
<tr>
<td>Rodriguez et al. (2015)</td>
<td>e/kW (2010)</td>
<td>1000</td>
</tr>
<tr>
<td>Hirth (2013)</td>
<td>e/kW (2010)</td>
<td>1200</td>
</tr>
</tbody>
</table>

Figure C.1: Parameters for RES-E generation technologies, found in references for 2015 (or closely around that year).

<table>
<thead>
<tr>
<th>Source</th>
<th>Wind onshore</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CapEx</td>
<td>FOM</td>
</tr>
<tr>
<td>Bertsch (2012)</td>
<td>e/kW (2010)</td>
<td>1110</td>
</tr>
<tr>
<td>Fürsch et al. (2013), VOM = fuel-based</td>
<td>e/kW (2010)</td>
<td>1110</td>
</tr>
</tbody>
</table>

Figure C.2: Parameters for RES-E generation technologies, found in references for 2050 (or any other far future estimate).
Figure C.3: Parameters for fossil fuel generation technologies found in references for 2015 (or closely around that year).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value 1</th>
<th>Value 2</th>
<th>Value 3</th>
<th>Value 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameter A</td>
<td>0.1</td>
<td>0.2</td>
<td>0.3</td>
<td>0.4</td>
</tr>
<tr>
<td>Parameter B</td>
<td>5.1</td>
<td>5.2</td>
<td>5.3</td>
<td>5.4</td>
</tr>
<tr>
<td>Parameter C</td>
<td>10.1</td>
<td>10.2</td>
<td>10.3</td>
<td>10.4</td>
</tr>
<tr>
<td>Parameter D</td>
<td>15.1</td>
<td>15.2</td>
<td>15.3</td>
<td>15.4</td>
</tr>
</tbody>
</table>

C. Reference parameters for power system technologies
### Figure C.4: Parameters for fossil fuel generation technologies, found in references for 2050 (or any other far future estimate).

<table>
<thead>
<tr>
<th>Source</th>
<th>CapEx</th>
<th>FOM</th>
<th>VOM</th>
<th>η</th>
<th>Lifetime</th>
<th>CapEx</th>
<th>FOM</th>
<th>VOM</th>
<th>η</th>
<th>Lifetime</th>
<th>CapEx</th>
<th>FOM</th>
<th>VOM</th>
<th>η</th>
<th>Lifetime</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>700</td>
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<td></td>
<td></td>
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<td>3287</td>
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<td></td>
<td></td>
<td></td>
</tr>
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<td></td>
<td></td>
<td></td>
<td>3287</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Figure C.5: Parameters for Storage Technologies Found in References for 2015 (or Closest Around That Year)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value 1</th>
<th>Value 2</th>
<th>Value 3</th>
<th>Value 4</th>
<th>Value 5</th>
<th>Value 6</th>
<th>Value 7</th>
<th>Value 8</th>
<th>Value 9</th>
<th>Value 10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameter A</td>
<td>1.00</td>
<td>2.00</td>
<td>3.00</td>
<td>4.00</td>
<td>5.00</td>
<td>6.00</td>
<td>7.00</td>
<td>8.00</td>
<td>9.00</td>
<td>10.00</td>
</tr>
<tr>
<td>Parameter B</td>
<td>1.01</td>
<td>2.01</td>
<td>3.01</td>
<td>4.01</td>
<td>5.01</td>
<td>6.01</td>
<td>7.01</td>
<td>8.01</td>
<td>9.01</td>
<td>10.01</td>
</tr>
<tr>
<td>Parameter C</td>
<td>1.02</td>
<td>2.02</td>
<td>3.02</td>
<td>4.02</td>
<td>5.02</td>
<td>6.02</td>
<td>7.02</td>
<td>8.02</td>
<td>9.02</td>
<td>10.02</td>
</tr>
</tbody>
</table>

*Note: Detailed data is available in the actual document.*
### Table C.1: Pumped hydro storage, technical potential in MWh. Figures taken and averaged over their multiple scenarios from Gimeno-Gutiérrez and Lacal-Arántegui (2015).

<table>
<thead>
<tr>
<th>Country</th>
<th>Technical potential (MWh)</th>
<th>Country</th>
<th>Technical potential (MWh)</th>
<th>Country</th>
<th>Technical potential (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>98075</td>
<td>Germany</td>
<td>4700</td>
<td>Poland</td>
<td>0</td>
</tr>
<tr>
<td>Belgium</td>
<td>0</td>
<td>Greece</td>
<td>0</td>
<td>Portugal</td>
<td>22250</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>2750</td>
<td>Hungary</td>
<td>0</td>
<td>Romania</td>
<td>0</td>
</tr>
<tr>
<td>Croatia</td>
<td>0</td>
<td>Ireland</td>
<td>0</td>
<td>Slovakia</td>
<td>0</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>2325</td>
<td>Italy</td>
<td>202375</td>
<td>Slovenia</td>
<td>0</td>
</tr>
<tr>
<td>Denmark</td>
<td>0</td>
<td>Latvia</td>
<td>0</td>
<td>Spain</td>
<td>593000</td>
</tr>
<tr>
<td>Estonia</td>
<td>0</td>
<td>Lithuania</td>
<td>0</td>
<td>Sweden</td>
<td>75</td>
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<tr>
<td>Finland</td>
<td>3000</td>
<td>Luxembourg</td>
<td>0</td>
<td>United Kingdom</td>
<td>152925</td>
</tr>
<tr>
<td>France</td>
<td>152000</td>
<td>Netherlands</td>
<td>0</td>
<td>Switzerland</td>
<td>436000</td>
</tr>
</tbody>
</table>
There appear to be two aspects of the described model that result in extremely long computation times, therefore making the model less manageable. These issues will have to be addressed in order to run the model and perform additional tests with it. The first aspect increasing computation times is the mixed-integer problem set-up, the second is the use of an extremely large dataset (spanning two years with an hourly resolution) for electricity demand and RES-E production. It was even found to be impossible with the computational memory available to solve the problem on an hourly resolution over two complete years. A good balance has to be found between the manageability of the model and the quality of the model outcomes. To do so, both aspects need to be judged on their contribution to a more realistic outcome. The outcome of the model can be divided in two elements:

1. **Solution**: The design of the power system, consisting of location and capacities of chosen technologies and their dispatch and power flows.

2. **Result**: The total system costs resulting from the found solution, in the model called f-value.

Below the problems, proposed solutions and what the effect is for the reliability of the outcomes will be explained in more detail.

### D.1. Time-series from datasets

The first choice that is made regards the historic data. To understand why running over the complete datasets with an hourly resolution creates issues, a little understanding of how Matlab handles optimisation problems is needed. To begin with, linear solvers in Matlab need sets of arrays, for bounds and the objective function, and matrices, for equality and inequality constraints, as input. Each column represents a variable, were as in the matrices, each row represents a constraint. Unfortunately, ‘power flows’ (generation, storage-in or -out and transport) in the model have to be modelled as separate variables for each time-step, each country and each technology. As the considered number of time-steps increases, the size of the matrices increases exponentially (see also Table D.1). The amount of computational random-access memory (RAM) this occupies quickly becomes too large for any normal computer. This problem was solved by making the matrices ‘sparse’, in essence leaving out zeros and instead giving the size of the matrix with coordinates of all non-zero values in it. This saves incredible amounts of memory, but does not decrease the difficulty of solving a problem with so many variables, still resulting in large computation times.

There are two possible solutions for reducing computation time. The first solution is to decrease the granularity of the resolution, for instance making it two-hourly or even more hours aggregated. However, much of the inter-hourly variations and dependencies would be lost and the representation of specifically storage would constantly compromise on reality. The second solution therefore is more applicable in this case, where representative time-series are taken from the complete datasets. If these time-series are chosen carefully the different production- and demand-patterns (daily, weekly, yearly) can be preserved. In Table D.1 the time-series that are expected to deliver the same sort of outcome as a run over the whole dataset are shown. It is important to see that a The computation times and results of the different time-series for a fully linear problem can be found in Figure D.1 and Figure D.2, given for increasing shares of RES-E. Since it proved
Table D.1: Model specifications per selected time-series. Since 2012 is a leap year, both years and the even months differ between the two years. In the A-series not really 1 day per month was taken, but rather on out of every cycle of 28 days, which made it possible to look at 13/26 days per run. In between parentheses the number of runs that could be run for that specific time-series can be found.

<table>
<thead>
<tr>
<th>Time-series</th>
<th>Set-up</th>
<th># hours</th>
<th># variables</th>
<th># eq. constraints</th>
<th># ineq. constraints</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>1 day per month, over 1 year (56r)</td>
<td>312</td>
<td>204,265</td>
<td>85,385</td>
<td>126,986</td>
</tr>
<tr>
<td>A-2</td>
<td>1 day per month, over 2 years (28r)</td>
<td>624</td>
<td>407,689</td>
<td>170,249</td>
<td>253,969</td>
</tr>
<tr>
<td>B-1</td>
<td>1 day per week, over 1 year (14r)</td>
<td>1248</td>
<td>814,537</td>
<td>339,977</td>
<td>507,937</td>
</tr>
<tr>
<td>B-2</td>
<td>1 day per week, over 2 years (7r)</td>
<td>2496</td>
<td>1,628,233</td>
<td>679,433</td>
<td>1,015,873</td>
</tr>
<tr>
<td>C-1</td>
<td>Even months, over 2012 (1r)</td>
<td>4368</td>
<td>2,848,777</td>
<td>1,188,617</td>
<td>1,777,777</td>
</tr>
<tr>
<td>C-2</td>
<td>Even months, over 2013 (1r)</td>
<td>4344</td>
<td>2,833,129</td>
<td>1,182,089</td>
<td>1,768,009</td>
</tr>
<tr>
<td>C-3</td>
<td>Even months, over 2 years (1r)</td>
<td>8712</td>
<td>5,681,065</td>
<td>2,370,104</td>
<td>3,545,785</td>
</tr>
<tr>
<td>C-4</td>
<td>Odd months, over 1 year (2r)</td>
<td>4416</td>
<td>2,880,073</td>
<td>1,201,673</td>
<td>1,797,313</td>
</tr>
<tr>
<td>C-5</td>
<td>Odd months, over 2 years (1r)</td>
<td>8832</td>
<td>5,759,305</td>
<td>2,402,828</td>
<td>3,594,625</td>
</tr>
<tr>
<td>D-1</td>
<td>2012 complete (1r)</td>
<td>8784</td>
<td>5,728,009</td>
<td>2,389,772</td>
<td>3,575,089</td>
</tr>
<tr>
<td>D-2</td>
<td>2013 complete (1r)</td>
<td>8760</td>
<td>5,712,361</td>
<td>2,383,244</td>
<td>3,565,321</td>
</tr>
<tr>
<td>D-3</td>
<td>Two years, complete (1r)</td>
<td>17544</td>
<td>11,439,529</td>
<td>4,772,429</td>
<td>7,140,409</td>
</tr>
</tbody>
</table>

impossible to solve a problem with more time-steps than the C-4 time-series (4416 hours) only for the time-series with a length up to that the information is given. The computation times of the C-scenarios proved to be so large that these were ruled out immediately. Also, to make the results from time-series of different sizes comparable, they are transformed to a System LCOE by dividing the total system costs by the total supplied power. In Figure D.3 the installed capacities of generation technologies, pumped hydro storage and total transmission capacity are given. Other storage technologies and biomass plants are left out, as they were found not to be used. The solutions for all time-series are given for a 50% share of RES-E requirement. To choose from the time-series three aspects are considered:

1. Are the system LCOE’s for different RES-E integration scenario’s increasing as the renewable requirement increases? Are the system LCOE’s not increasing or declining heavily when a shorter or longer time-series was chosen?

2. Is the variability in the results between separate runs acceptably low? This could occur if shorter runs profit above average of certain favourable circumstances in a run of a time-series.

3. Are the computation times acceptable?

It can be observed from the comparisons between different lengths of time-series that the costs only slightly increase with an increasing RES-E requirement, but the time-series in which this trend is most visible is the B-series. Looking at the solution in terms of installed capacities we can conclude that with an increasing number of hours the variability in results shrinks significantly. The variability between runs in the A-series is deemed to strong, which makes it less plausible that a solution for one of the runs is representative for the whole set of data. From the B-series the highest system LCOE and the expected trend of an increasing cost profile with higher RES-E requirement was found in run 1 of the B-1 series. With a relatively small bandwidth in between the run solutions it seems to produce quite reliable outcomes for over the whole dataset. The manageability of this specific run is very acceptable, as it took only 38 minutes to solve all three RES-E requirements. Especially if this is compared with the more time consuming B-2 or C-series the consideration of quality of results versus computation time is strongly favours the B-1 series. Run 1 gives a conservative (expensive) outcome and high installed capacities as solution. It is assumed that the solution of this run would always be capable of satisfying constraints, for every run in all time-series available. For all analysis and results from now on run 1 of time-series B-1 will be used and will be referred to as ‘the model’. 
Figure D.1: Comparison of computation times for different time-series. The variation among runs for the same runtimes can be seen as well.

Figure D.2: Comparison of system LCOE for different time-series. The variation among runs for the same runtime can be seen as well.

Figure D.3: Comparison of the installed capacities per time-series. The variation among runs for the same time-series can be seen as well.
Table D.2: Overview of chosen transmission technology parameters for a MILP. CapEx = Capital Expenditures per kilometer of line (Capacity costs are already incorporated); Line capacity = specific capacity for the size of interconnection line; $\eta =$ transmission efficiency per 1000km; Lifetime = average lifetime of the installed technology. Figures were interpreted from ENTSO-E (2014a); Fürsch et al. (2013); Schaber, Steinke, and Hamacher (2012); Schaber, Steinke, Mühlich, and Hamacher (2012).

<table>
<thead>
<tr>
<th>Transmission technology</th>
<th>Line capacity (MW)</th>
<th>CapEx (€/km)</th>
<th>$\eta$ (%/1000km)</th>
<th>Lifetime (yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection Small</td>
<td>100</td>
<td>1000</td>
<td>96</td>
<td>40</td>
</tr>
<tr>
<td>Interconnection Medium</td>
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<td>2600</td>
<td>96</td>
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</tr>
<tr>
<td>Interconnection Large</td>
<td>1000</td>
<td>4000</td>
<td>96</td>
<td>40</td>
</tr>
</tbody>
</table>

D.2. Choices for model type

The second issue addressed here is the model type. From Section 4.1.4 it follows that although a non-linear cost-curve is most realistic for transmission capacity and length, a integer set of lines with increasing capacity could approach this curve. This is however, much more computationally demanding than a fully linear problem. Here again a balance has to be found between realistic and manageable outcomes. The differences in results have been tested with MILP model with the transmission line capacities as given in Table D.2. These parameters were based on the report by ENTSO-E (2014a), which gives current capacities in Europe, which range between 100MW and a few thousand MW. The capacities have been chosen based on these figures. The costs increase with a factor 0.6 per increasing capacity. The results and computation times for a LP and a MILP solving of the model can be found in Table D.3. It is clearly visible that the computation time for the MILP exceeds that of a LP for all RES-E shares. In the same table the System LCOE can be found. In Table D.4 the solution of the model solved as a MILP and as LP can be found. Since this setting is expected to particularly influence the transmission capacity, these are given separately in Table D.5.

It can be concluded from the comparison of both results that the MILP problem has a lower outcome and uses more transmission capacity with less generation or storage capacity as a solution. Since many simplifications were applied for the transmission element, the lower costs for transmission network found in the MILP solution is probably unrealistic as well. The transmission costs also form such a small element of the total system costs (< 1%) that it’s influence is negligible anyhow. When the computation time for the model with mixed-integer linear programming settings is compared to the linear programming, it is concluded that quality of results is not significantly different and the difference certainly does not outweigh the lost manageability. It was chosen to work with the fully linear model. It is concluded that the model will consist of one run of 1248 hours, or 52 days, which represents roughly 7 weeks. The problem will be solved fully linear.

Table D.3: The computation times and results of A-1 and A-2 time-series as System LCOE for a fully linear problem and for a MILP, given for increasing shares of RES-E.

<table>
<thead>
<tr>
<th>RES-fraction</th>
<th>Time-series</th>
<th>Computation times (s)</th>
<th>System LCOE (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20%</td>
<td>50%</td>
<td>80%</td>
</tr>
<tr>
<td>LP</td>
<td>A-1</td>
<td>109</td>
<td>94</td>
</tr>
<tr>
<td></td>
<td>A-2</td>
<td>321</td>
<td>356</td>
</tr>
<tr>
<td>MILP</td>
<td>A-1</td>
<td>7568</td>
<td>11335</td>
</tr>
<tr>
<td></td>
<td>A-2</td>
<td>15548</td>
<td>23476</td>
</tr>
</tbody>
</table>
**Table D.4:** Installed generation and transmission capacities for time-series A-1 and A-2 for a 50% RES-E requirement. The values for installed capacities when solving the model as LP and MILP are compared.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind turbines (MW)</td>
<td>17928</td>
<td>19478</td>
<td>6867</td>
<td>8907</td>
<td>261%</td>
<td>219%</td>
</tr>
<tr>
<td>Solar PV panels (MW)</td>
<td>578216</td>
<td>598344</td>
<td>608744</td>
<td>647753</td>
<td>95%</td>
<td>92%</td>
</tr>
<tr>
<td>CCGT (MW)</td>
<td>1110</td>
<td>1570</td>
<td>392</td>
<td>693</td>
<td>283%</td>
<td>227%</td>
</tr>
<tr>
<td>Coal plant (MW)</td>
<td>298581</td>
<td>305635</td>
<td>302214</td>
<td>301445</td>
<td>99%</td>
<td>101%</td>
</tr>
<tr>
<td>Biomass plant (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Flow battery conversion (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Flow battery storage (MWh)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PHS conversion (MW)</td>
<td>165997</td>
<td>169479</td>
<td>181099</td>
<td>188570</td>
<td>92%</td>
<td>90%</td>
</tr>
<tr>
<td>PHS storage (MWh)</td>
<td>1277132</td>
<td>1426823</td>
<td>1455813</td>
<td>1752522</td>
<td>88%</td>
<td>81%</td>
</tr>
<tr>
<td>Hydrogen conversion (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hydrogen storage (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Table D.5:** Installed interconnection transmission capacity for one run of time-series A-1. The values for installed capacities when solving the model as LP and MILP are compared.

<table>
<thead>
<tr>
<th>Installed capacity (GW) per time-series</th>
<th>LP</th>
<th>MILP</th>
<th>Difference LP/MILP</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT == CZ</td>
<td>14159</td>
<td>24899</td>
<td></td>
</tr>
<tr>
<td>AT == DE</td>
<td>27639</td>
<td>39722</td>
<td></td>
</tr>
<tr>
<td>AT == HU</td>
<td>539</td>
<td>10120</td>
<td></td>
</tr>
<tr>
<td>AT == IT</td>
<td>13702</td>
<td>23782</td>
<td></td>
</tr>
<tr>
<td>AT == SI</td>
<td>489</td>
<td>9400</td>
<td></td>
</tr>
<tr>
<td>AT == SK</td>
<td>28970</td>
<td>39161</td>
<td></td>
</tr>
<tr>
<td>AT == CH</td>
<td>8294</td>
<td>24498</td>
<td></td>
</tr>
<tr>
<td>BE == FR</td>
<td>3121</td>
<td>1524</td>
<td></td>
</tr>
<tr>
<td>BE == DE</td>
<td>8589</td>
<td>10408</td>
<td></td>
</tr>
<tr>
<td>BE == LU</td>
<td>45</td>
<td>89</td>
<td></td>
</tr>
<tr>
<td>BE == NL</td>
<td>894</td>
<td>510</td>
<td></td>
</tr>
<tr>
<td>BE == GB</td>
<td>743</td>
<td>607</td>
<td></td>
</tr>
<tr>
<td>BG == GR</td>
<td>1935</td>
<td>5477</td>
<td></td>
</tr>
<tr>
<td>BG == RO</td>
<td>4644</td>
<td>7865</td>
<td></td>
</tr>
<tr>
<td>HR == HU</td>
<td>441</td>
<td>2293</td>
<td></td>
</tr>
<tr>
<td>HR == IT</td>
<td>3429</td>
<td>7952</td>
<td></td>
</tr>
<tr>
<td>HR == SK</td>
<td>2934</td>
<td>7018</td>
<td></td>
</tr>
<tr>
<td>CZ == DE</td>
<td>4108</td>
<td>15423</td>
<td></td>
</tr>
<tr>
<td>CZ == PL</td>
<td>18594</td>
<td>40761</td>
<td></td>
</tr>
<tr>
<td>CZ == SK</td>
<td>9</td>
<td>24</td>
<td></td>
</tr>
<tr>
<td>DK == DE</td>
<td>3297</td>
<td>5074</td>
<td></td>
</tr>
<tr>
<td>DK == NL</td>
<td>230</td>
<td>115</td>
<td></td>
</tr>
<tr>
<td>DK == SE</td>
<td>639</td>
<td>1162</td>
<td></td>
</tr>
<tr>
<td>DK == GB</td>
<td>25</td>
<td>207</td>
<td></td>
</tr>
<tr>
<td>EE == FI</td>
<td>519</td>
<td>352</td>
<td></td>
</tr>
<tr>
<td>EE == LV</td>
<td>1457</td>
<td>1441</td>
<td></td>
</tr>
<tr>
<td>EE == SE</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>FI == LV</td>
<td>7288</td>
<td>9445</td>
<td></td>
</tr>
<tr>
<td>FI == SE</td>
<td>139</td>
<td>64</td>
<td></td>
</tr>
</tbody>
</table>
Table D.5: Installed interconnection transmission capacity for one run of time-series A-1. The values for installed capacities when solving the model as LP and MILP are compared.

<table>
<thead>
<tr>
<th>Installed capacity (GW) per time-series</th>
<th>LP</th>
<th>MILP</th>
<th>Difference LP/MILP</th>
</tr>
</thead>
<tbody>
<tr>
<td>FR == DE</td>
<td>49</td>
<td>3647</td>
<td></td>
</tr>
<tr>
<td>FR == IT</td>
<td>15814</td>
<td>44555</td>
<td></td>
</tr>
<tr>
<td>FR == LU</td>
<td>137</td>
<td>505</td>
<td></td>
</tr>
<tr>
<td>FR == ES</td>
<td>15503</td>
<td>27032</td>
<td></td>
</tr>
<tr>
<td>FR == GB</td>
<td>10375</td>
<td>7909</td>
<td></td>
</tr>
<tr>
<td>FR == CH</td>
<td>15010</td>
<td>28238</td>
<td></td>
</tr>
<tr>
<td>DE == LU</td>
<td>784</td>
<td>1297</td>
<td></td>
</tr>
<tr>
<td>DE == NL</td>
<td>35356</td>
<td>57535</td>
<td></td>
</tr>
<tr>
<td>DE == PL</td>
<td>51530</td>
<td>55121</td>
<td></td>
</tr>
<tr>
<td>DE == SE</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>DE == CH</td>
<td>36859</td>
<td>36501</td>
<td></td>
</tr>
<tr>
<td>GR == IT</td>
<td>19625</td>
<td>20437</td>
<td></td>
</tr>
<tr>
<td>HU == RO</td>
<td>4445</td>
<td>8332</td>
<td></td>
</tr>
<tr>
<td>HU == SI</td>
<td>668</td>
<td>2277</td>
<td></td>
</tr>
<tr>
<td>HU == SK</td>
<td>8174</td>
<td>20851</td>
<td></td>
</tr>
<tr>
<td>IE == GB</td>
<td>11414</td>
<td>5685</td>
<td></td>
</tr>
<tr>
<td>IT == SI</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>IT == CH</td>
<td>12156</td>
<td>31672</td>
<td></td>
</tr>
<tr>
<td>LV == LT</td>
<td>9684</td>
<td>11936</td>
<td></td>
</tr>
<tr>
<td>LV == SE</td>
<td>2</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>LT == PL</td>
<td>11271</td>
<td>13657</td>
<td></td>
</tr>
<tr>
<td>LT == SE</td>
<td>9</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>NL == GB</td>
<td>27287</td>
<td>44137</td>
<td></td>
</tr>
<tr>
<td>PL == SK</td>
<td>159</td>
<td>10756</td>
<td></td>
</tr>
<tr>
<td>PL == SE</td>
<td>13352</td>
<td>16435</td>
<td></td>
</tr>
<tr>
<td>PT == ES</td>
<td>70550</td>
<td>67166</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
E.1. Input data evaluation

Figure E.1: Electricity demand for Greece in 2012 and 2013 on an hourly resolution. Data taken from ENTSO-E (2015d) database.

Figure E.2: Electricity demand for Ireland in 2012 and 2013 on an hourly resolution. Data taken from ENTSO-E (2015d) database.
Figure E.3: Electricity demand for Portugal in 2012 and 2013 on an hourly resolution. Data taken from ENTSO-E (2015d) database.

Figure E.4: Electricity demand for Sweden in 2012 and 2013 on an hourly resolution. Data taken from ENTSO-E (2015d) database.

Figure E.5: Electricity demand for Switzerland in 2012 and 2013 on an hourly resolution. Data taken from ENTSO-E (2015d) database.
Table E.2: Start conditions for a small linear optimisation problem. Belgium and the Netherlands are considered for the first two hours of 2012. The potential output for 1MW of wind turbine and solar PV panel are given, as well as the demand. The ‘h1’ and ‘h2’ give the hour considered.

<table>
<thead>
<tr>
<th>Country</th>
<th>Demand (MWh)</th>
<th>Wind potential (MWh/MW)</th>
<th>Solar PV potential (MWh/MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>h1</td>
<td>h2</td>
<td>h1</td>
</tr>
<tr>
<td>Belgium</td>
<td>8762</td>
<td>8249</td>
<td>0.8654</td>
</tr>
<tr>
<td>Netherlands</td>
<td>10191</td>
<td>9818</td>
<td>0.1358</td>
</tr>
</tbody>
</table>

E.2. Model verification

The total demand is 37,020MWh, the average wind production potential in Belgium (the most favourable position for wind turbines) is 0.87. If all RES-E is to come from wind, then the installed wind power capacity, multiplied by the average production potential has to equal, at least, half of the total demand. This means that at least (18510/0.87 = 21277) 21277MW of wind power needs to be installed in Belgium, of which 17011MWh can be used in Belgium, while the rest has to be transported to the Netherlands. This requires a transmission link with minimal capacity of 1500MW. Normally a coal plant is likely to be used, but since the CF for a wind turbine in this example is extremely high and power dispatching from a wind turbine is free, it is more plausible that the full power will be served by wind turbines in Belgium after which the required demand in the Netherlands is completely imported. This requires a transmission link of more than 10000MW (when transmission losses are calculated as well).

Table E.1: Solution for run 1 of 2012 with a A-1 time-series (1 day per month) with a 50% RES-E requirement. The costs were calculated by hand to check with the system costs from the model outcome. The installed capacity from transmission lines is already a multiplication of the capacity times the distance (MWkm).

<table>
<thead>
<tr>
<th>Technology</th>
<th>Installed capacity (MW(h))</th>
<th>Costs runtime (€/MW(h))</th>
<th>Total costs capacity (€)</th>
<th>Power dispatch (MWh)</th>
<th>VOM (€/MWh)</th>
<th>Total costs dispatch (€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind onshore</td>
<td>637458</td>
<td>2747.71</td>
<td>1,751,549,108.58</td>
<td>99536328</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Solar PV</td>
<td>0</td>
<td>4819.16</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>CCGT</td>
<td>16329</td>
<td>1660.96</td>
<td>27,122,523.78</td>
<td>341694.6</td>
<td>46</td>
<td>15,717,950.72</td>
</tr>
<tr>
<td>Coal plant</td>
<td>96746</td>
<td>2336.51</td>
<td>226,049,537.52</td>
<td>10972835</td>
<td>28</td>
<td>307,239,363.91</td>
</tr>
<tr>
<td>Biomass plant</td>
<td>0</td>
<td>6050.65</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>FB converter</td>
<td>0</td>
<td>2313.48</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>FB storage</td>
<td>0</td>
<td>1210.13</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PHS converter</td>
<td>142139</td>
<td>1352.50</td>
<td>192,243,406.97</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PHS storage</td>
<td>1497456</td>
<td>41.29</td>
<td>61,825,139.79</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>H2 converter</td>
<td>0</td>
<td>7296.37</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>H2 storage</td>
<td>0</td>
<td>106.78</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>100MW line</td>
<td>8257920</td>
<td>44.49</td>
<td>367,395,489.10</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total capacity costs</strong></td>
<td><strong>2,626,185,205.73</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Total variable costs</strong></td>
</tr>
</tbody>
</table>
Table E.3: Solution with installed capacities and dispatch per hour, for Belgium and the Netherlands. As can be seen, demand is met and all constraints are satisfied.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Installed capacity (MW)</th>
<th>Belgium Dispatch h1 (MWh)</th>
<th>Belgium Dispatch h2 (MWh)</th>
<th>Netherlands Dispatch h1 (MWh)</th>
<th>Netherlands Dispatch h2 (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind onshore</td>
<td>22281</td>
<td>19282</td>
<td>18384</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Solar PV</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>CCGT</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Coal plant</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Biomass plant</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>FB converter</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>FB storage</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PHS converter</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PHS storage</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>H2 converter</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>H2 storage</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>100MW line</td>
<td>10520</td>
<td>-10520</td>
<td>-10135</td>
<td>10520</td>
<td>10191</td>
</tr>
<tr>
<td>Total</td>
<td>22281</td>
<td>8762</td>
<td>8249</td>
<td>0</td>
<td>10191</td>
</tr>
</tbody>
</table>
Reference scenario values

*Table F.1:* Installed capacities per generation technology per country for 2015. The capacities were taken from the transparency database by ENTSO-E (2015c) for the year 2015, or, if these figures were not available, from the nearest preceding year for which they were available. Many values have been aggregated, for instance all coal, nuclear and oil capacities have been summed due to their similar characteristics. Biomass and waste have been taken together for the same reason. Also wind on- and offshore were merged into wind power. Wherever there is a question mark behind the figure, this figure was assumed based on other data instead of readily available from ENTSO-E.

<table>
<thead>
<tr>
<th>Country</th>
<th>Wind (MW)</th>
<th>Solar PV (MW)</th>
<th>CCGT (MW)</th>
<th>Coal (MW)</th>
<th>Biomass (MW)</th>
<th>PHS conv (MW)</th>
<th>PHS store (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT</td>
<td>2140</td>
<td>715</td>
<td>4901</td>
<td>1561</td>
<td>315</td>
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Table F.2: Installed interconnection transmission capacity between neighbouring countries for 2015 and 2050. Data for the current situation was taken from the research by (Becker, Rodriguez, et al., 2014).

| Link | 2015 | 2050 | | Link | 2015 | 2050 |
|------|------|------| |------|------|------|
| AT === CZ | 800 | 1000 | FI === SE | 1850 | 2313 |
| AT === DE | 2100 | 2625 | FR === DE | 2950 | 3688 |
| AT === HU | 800 | 1000 | FR === IT | 1785 | 2231 |
| AT === IT | 250 | 313 | FR === LU | 100 | 125 |
| AT === SI | 900 | 1125 | FR === ES | 900 | 1125 |
| AT === SK | 0 | 0 | FR === GB | 2000 | 2500 |
| AT === CH | 835 | 1044 | DE === CH | 2150 | 2688 |
| BE === FR | 2850 | 3562 | DE === LU | 100 | 125 |
| BE === DE | 0 | 0 | DE === NL | 3425 | 4281 |
| BE === LU | 100 | 125 | DE === PL | 1150 | 1438 |
| BE === NL | 2400 | 3000 | DE === SE | 605 | 756 |
| BE === GB | 0 | 0 | DE === CH | 2500 | 3125 |
| BG === GR | 525 | 657 | GR === IT | 500 | 625 |
| BG === RO | 600 | 750 | HU === RO | 700 | 875 |
| HR === HU | 1000 | 1250 | HU === SI | 0 | 0 |
| HR === IT | 0 | 0 | HU === SK | 950 | 1188 |
| HR === SI | 1000 | 1250 | IE === GB | 1000 | 1250 |
| CZ === DE | 1550 | 1938 | IT === SI | 370 | 463 |
| CZ === PL | 1300 | 1625 | IT === CH | 3000 | 3750 |
| CZ === SK | 1700 | 2125 | LV === LT | 500 | 625 |
| DK === DE | 1815 | 2269 | LV === SE | 700 | 875 |
| DK === NL | 0 | 0 | LT === PL | 1000 | 1250 |
| DK === SE | 2210 | 2763 | LT === SE | 700 | 875 |
| DK === GB | 0 | 0 | NL === GB | 1000 | 1250 |
| EE === FI | 1000 | 1250 | PL === SK | 550 | 688 |
| EE === LV | 500 | 625 | PL === SE | 0 | 0 |
| EE === SE | 0 | 0 | PT === ES | 1600 | 2000 |
| FI === SE | 0 | 0 | | | |
**Table F.3:** Installed capacities per generation technology per country for 2050. Thermal capacity was used for CCGT, nuclear for plants, solar for solar PV. All figures were taken from Bruninx et al. (2015).

<table>
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<th>Country</th>
<th>Wind (MW)</th>
<th>Solar PV (MW)</th>
<th>CCGT (MW)</th>
<th>Coal (MW)</th>
<th>Biomass (MW)</th>
<th>PHS conv (MW)</th>
<th>PHS store (MWh)</th>
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Share of hydropower in Europe’s RES-E generation

Figure G.1: Share of Renewable electricity in the total European (EU-28) generation. Adapted from (Eurostat, 2015)
National scenario results

**Figure H.1:** Total installed capacities and the contribution of different generation technologies to the generation mix in percentages.
Figure H.2: Installed capacities for generation and storage technologies, aggregated per region. Both PHS and H2-storage are used. Scales differ from each other.
Figure H.3: Installed generation and storage capacities per country.
Figure H.4: Average weekly generation profile. The week is shown from an average Sunday (00:00-01:00h) up to an average Saturday (23:00-24:00h). Demand is given as the black line. The energy in storage is given by the red and yellow line. These lines have been adjusted so that the lowest point is 0, instead of a much higher figure.
Regional scenario results

Figure I.1: Total installed capacities and the contribution of different generation technologies to the generation mix in percentages.
Figure I.2: Installed capacities for generation and storage technologies, aggregated per region. Both PHS and H2-storage are used. Scales differ from each other.
Figure I.3: Installed generation and storage capacities per country.
Figure I.4: Average weekly generation profile. The week is shown from an average Sunday (00:00-01:00h) up to an average Saturday (23:00-24:00h). Demand is given as the black line. The energy in storage is given by the red and yellow line. These lines have been adjusted so that the lowest point is 0, instead of a much higher figure.
Figure I.5: Amount of import or export per country. Net import is given as a percentage of demand and is a positive figure, while net export is given as a percentage of domestic generation and is given as a negative figure. The color of the country corresponds with the scale on the right and is averaged over the three RES-E integration scenarios. The table in the bottom gives the exact figures per scenario.
Figure I.6: Representation of the optimal network designs for different RES-E scenarios. The line thickness represents the capacity. Only transmission within regions is allowed for.
Country goals scenario results

---

**Figure J.1:** Total installed capacities and the contribution of different generation technologies to the generation mix in percentages.
Figure J.2: Installed capacities for generation and storage technologies, aggregated per region. Both PHS and H2-storage are used. Scales differ from each other.
Figure J.3: Installed generation and storage capacities per country.
Figure J.4: Average weekly generation profile. The week is shown from an average Sunday (00:00-01:00h) up to an average Saturday (23:00-24:00h). Demand is given as the black line. The energy in storage is given by the red and yellow line. These lines have been adjusted so that the lowest point is 0, instead of a much higher figure.
Figure J.5: Amount of import or export per country. Net import is given as a percentage of demand and is a positive figure, while net export is given as a percentage of domestic generation and is given as a negative figure. The color of the country corresponds with the scale on the right and is averaged over the three RES-E integration scenarios. The table in the bottom gives the exact figures per scenario.
Figure J.6: Representation of the optimal network designs for different RES-E scenarios. The line thickness represents the capacity.
Reference scenario results

Scenario: Reference (2015&2050)
Total installed capacity

15% RES-E requirement
Total generation capacity: 705GW

45% RES-E requirement
Total generation capacity: 1059GW

Generation mix

Figure K.1: Total installed capacities (top) and the contribution of different generation technologies to the generation mix in percentages (below).
Figure K.2: Installed capacities for generation and storage technologies, aggregated per region.
Figure K.3: Installed generation and storage capacities per country.
Figure K.4: Average weekly generation profile. The week is shown from an average Sunday (00:00-01:00h) up to an average Saturday (23:00-24:00h). Demand is given as the black line. The energy in storage is given by the red and yellow line. These lines have been adjusted so that the lowest point is 0, instead of a much higher figure.
Figure K.5: Amount of import or export per country. Net import is given as a percentage of demand and is a positive figure, while net export is given as a percentage of domestic generation and is given as a negative figure. The colour of the country corresponds with the scale on the right and is averaged over the three RES-E integration scenarios. The table in the bottom gives the exact figures per scenario.
Scenario: Reference (2015&2050)
Transmission network

Renewable energy requirement: **15%**

Renewable energy requirement: **45%**

Figure K.6: Representation of the optimal network designs for different RES-E scenarios. The line thickness represents the capacity.