EUROPA UNIVERSITÄT FLENSBURG

DOCTORAL THESIS

Optimised Storage Extension and Utilisation for the Future German Power System

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"Plans are of little importance, but planning is essential."

— Sir Winston Churchill

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Abstract

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Optimised Storage Extension and Utilisation for the Future German Power System

by Lukas Wienholt

The provision of flexibility is vital in power systems shaped by weather-dependent renewable energy generation. While today power system flexibility in Germany is provided by still existing large scale thermal power plants, storage units will have to take over with rising renewable shares. This thesis aims to analyse the required storage units regarding their central characteristics. A high-resolution model of the future German power system allows an in-depth optimisation and assessment of the sizing and siting of optimal storage units. The open-source model is strictly based on open data. Demand and power grid infrastructure are kept constant at today's levels, while two future scenarios define the power generation portfolio. Under the assumption of significant wind power feed-in in Northern Germany, it is found that storage capacity is mainly required in the North and Northwest of the country. Offshore wind grid connection points trigger the installation of storage units. Bottlenecks in the power grid are another significant driver for storage. Hence, weak North-South transmission capacities lead to more storage in the North. Cross-border power exchange is highly beneficial for renewable power systems and may substantially decrease storage requirements in Germany.

Acknowledgements

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Another open source model this thesis builds upon and that requires acknowledgement is PyPSA, in its early days pushed forward by Tom Brown and Jonas Hörsch and today a leading model for power system analysis.

In the final days before the submission I enjoyed two very productive but also very pleasant week-long diss-sessions with my fellow PhD candidate Samuel Glismann.

Finally, very special thanks go out to my parents and my sister Nora for the permanent support and in Nora's case especially for proof-reading this thesis. Britta, the most important companion in my life has always been understanding for this "hobby" of mine and supported and encouraged me to bring this thesis to an end.

Contents

List of Figures

List of Tables

List of Abbreviations

CO_2 . . . . Carbondioxide

a . . . . Year

AA-CAES . . . . Adiabatic Compressed Air Energy Storage

AC . . . . Alternating Current

AG . . . . Aktiengesellschaft (Public Limited Company)

AGPL . . . . GNU Affero General Public License

AT . . . . Österreich / Austria

BNetzA . . . . Bundesnetzagentur (Federal Grid Agency)

BSH . . . . Bundesamt für Seeschifffahrt und Hydrographie (Federal Maritime and Hydrographic Agency)

C . . . . Celsius

CAES . . . . Compressed Air Energy Storage

CCS . . . . Carbon Capture and Storage

CH . . . . Schweiz / Switzerland

CHP . . . . Combined Heat and Power

COP . . . . Conference of the Parties

CSP . . . . Concentrating Solar Power

CZ . . . . Tschechien / Czech Republic

DB . . . . Deutsche Bahn (German Railway)

DC . . . . Direct Current

DE . . . . Deutschland / Germany

DSO . . . . Distribution System Operator

E . . . . Energy

EEZ . . . . Exclusive Economic Zone

EHV . . . . Extra high Voltage

ENTSO-E . . . . European Network of Transmission System Operators - Electricity

ERCOT . . . . Electric Reliability Council of Texas

ETES . . . . Electric Thermal Energy Storage

EU . . . . European Union

EUR . . . . Euro

FEP . . . . Flächenentwicklungsplan (Site Development Plan)

FR . . . . Frankreich / France

GmbH . . . . Gesellschaft mit beschränkter Haftung (Private Limited Company)

GPL . . . . GNU General Public License

Gt . . . . Gigatonnes

GW . . . . Gigawatt

GWh . . . . Gigawatthours

h . . . . Hour

HV . . . . High Voltage

HVDC . . . . High Voltage Direct Current

Hz . . . . Hertz

IPCC . . . . Intergovernmental Panel on Climate Change

km . . . . Kilometer

kV . . . . Kilovolt

LCOE . . . . Levelised Cost of Electricity

LOPF . . . . Linear Optimal Power Flow

m . . . . Meter

MVA . . . . Mega Voltampere

MW . . . . Megawatt

MWh . . . . Megawatthours

NEP . . . . Netzentwicklungsplan (Grid Development Plan)

NREL . . . . National Renewable Energy Laboratory

O&M . . . . Operation and Maintenance

ODbL . . . . Open Database License

OEP . . . . Open Energy Platform

OPF . . . . Optimal Power Flow

OPSD . . . . Open Power System Data

OSM . . . . OpenStreetMap

P . . . . Power

PHS . . . . Pumped Hydro Power Storage

PJM . . . . Pennsylvania-New Jersey-Maryland

PPM . . . . Parts Per Million

PTDF . . . . Power Transfer Distribution Factor

PV . . . . Photovoltaics

PyPSA . . . . Python for Power System Analysis

RES . . . . Renewable Energy Sources

SE . . . . Schweden / Sweden

SR . . . . Szenariorahmen (Scenario Framework)

SRU . . . . Sachverständigenrat für Umweltfragen (German Advisory Council on the Environment)

TSO . . . . Transmission System Operator

TWh . . . . Terawatthours

U.S. . . . . United States

UC . . . . Unit Commitment

UCTE . . . . Union for the Co-ordination of Transmission of Electricity

1 Introduction

The German power system is currently facing an extensive and structural shift towards clean energy provision. Weather-dependent wind and solar generation are the backbones of the future German power system. The fluctuating feed-in of these technologies requires balancing by flexible generators and storage units. In this context, power system models help to assess the shape of power systems, their measures, technologies, and their development in light of the energy transition. The motivation to assess the role and requirements of storage in the German power system is developed in the following sections. As a result, the derived central research questions of this thesis are presented.

1.1 The Energy Transition and its Implications to Flexibility Provision

More than 30 years ago, on 6 December 1988, the United Nations General Assembly established the Intergovernmental Panel on Climate Change (IPCC). The major task of the IPCC is to provide reviews on climate change and its possible impacts. The IPCC has since provided five Assessment Reports, the latest published in 2014. Apart from possible impacts, the IPCC also points out measures to tackle climate change and global warming. For instance, the IPCC expects a reduction of CO_2 emissions to below 25-30 GtCO_2 per year in 2030 and zero by 2050 to be sufficient to keep global warming below 1.5°C compared to pre-industrial levels (Rogelj et al., 2018). However, since the establishment of the IPCC in 1988 the CO_2 concentration in the global atmosphere increased from 352 PPM to 411 PPM at the end of 2019 (ESRL, 2020). Moreover, recent global data shows that 2016 was the warmest and 2018 the fourth warmest year since 1880 (NASA, 2019). As a result of the 21st Conference of the Parties (COP) in December 2015 195 countries reached the "Paris Agreement" which has the target of keeping global warming well below 2°C compared to pre-industrial levels and strive for a limitation of global warming to 1.5°C (UNFCCC, 2015). The COP 24 held in Katowice in December 2018 agreed on a "rulebook" which sets standards on how countries measure and report their efforts to reduce emissions. Still, individual targets of the countries on how the 1.5°C target shall be reached are not implemented yet (UNFCCC, 2018).

The energy sector is one of the largest CO_2 emitters with a share of more than one-third of the total CO_2-equivalent emissions, for example in Germany (UBA, 2018). Thus, the energy sector is central for measures responding to climate change. The

2018 IPCC Special Report states that the global share of electricity supplied by renewable sources must increase to 59-97 % to keep in line with the 1.5°C target (Rogelj et al., 2018, p.134). Still, the transition of the energy sector towards higher shares of renewable energy can only be the start of a transition process that also includes other sectors such as mobility and industry.

Today's power systems are mostly shaped by conventional generation, which does not only add to global carbon emissions but also heavily depends on finite resources such as oil, coal, lignite, gas, and uranium. While the IPCC considers nuclear power generation to be an emission-free and even non-fossil option for power generation (Rogelj et al., 2018), many countries, including Germany, decided to phase-out nuclear power generation (AtG, 2011). In these cases, renewable energy sources (RES) are the only source of power for an emission-free energy system. Hence, many countries have adopted policies to increase the RES shares of their energy consumption. In 2018 the European Union (EU) agreed on a target of 32 % RES share in total energy consumption by 2030 (EC, 2018). In contrast to this cross-sectoral target, the German government only recently decided on a target of 65 % RES of total electricity generation in 2030 (Bundesregierung, 2019). The appropriate capacities of different RES technologies to meet this target until 2030 have been adopted recently (EEG, 2020) The focus of policy-makers to achieving a target only in the power sector underestimates the necessary measures and capacities to reach the binding EU target in total energy consumption. While Germany achieved RES shares in power generation of 37.8 % in 2018 (UBA, 2019) and 42 % in 2019 (UBA, 2020), conventional capacities are decreasing slowly, see Figure 1.1. The red dotted line indicates a remarkable decrease only in 2011 due to the shut-down of several nuclear power plants after the Fukushima incident (AtG, 2011). The blue dotted line representing the installed RES capacities in Germany since 2000 displays a dynamic growth which is mainly assigned to solar and wind power.

Offshore wind power had not played a significant role in German generation capacities until 2017 when the number of 5 GW was reached (Durstewitz et al., 2018). The discussion on large offshore wind power capacities in German waters started at the beginning of the 2000s with more than 100 proposals for offshore wind parks submitted to the responsible authority, the Federal Maritime and Hydrographic Agency (German: Bundesamt für Seeschifffahrt und Hydrographie (BSH)) (ZfK, 2013). In 2010 the German government set the target of 25 GW installed offshore wind power in 2030 (Bundesregierung, 2010). In light of this optimistic perception, the German Council of Environmental Advisors (SRU) proposed massive offshore wind power capacities of 73.2 GW for the year 2050 in its 2011 special report (SRU, 2011). However, due to high installation costs and technical challenges, the first commercial offshore wind park "Baltic 1" was commissioned only in 2011 (EnBW, 2018). The political target for 2030 was in this context corrected to only 15 GW together with the introduction of a central auctioning system for offshore wind power in 2017 (WindSeeG, 2016). After the first auctions in this new system resulted in unexpectedly low

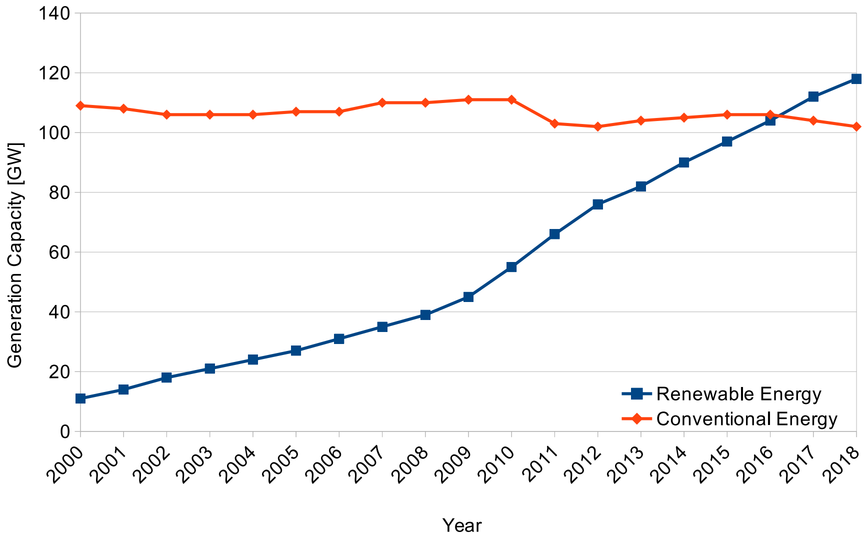


FIGURE 1.1: Installed generation capacities in Germany per end of year by renewable and conventional sources. Data source: (BDEW, 2019)

prices down to subsidy-free bids, the offshore wind industry now demands higher political targets of at least 20 GW for 2030 and 35 GW for 2035 (Philippi, 2020). While 20 GW are now the official extension target for German waters until 2030, the long-term target is 40 GW until 2040 (WindSeeG, 2020). Such targets raise the question of the capability of the onshore power system to integrate increased offshore wind energy capacities up to the high capacities proposed by the SRU.

The central challenge of all power systems is to meet the variable power demand at all times. Any fuel-based power generation technology such as coal, lignite, gas, or nuclear power plants may adjust their generation at least in a particular range through their fuel and thermal flexibility (Agora Energiewende, 2017). The significant uncertainties of these thermal generation systems are the forecast of the power demand and the availability of sufficient generation capacities. Thus, flexibility as "*the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons*" (Ma et al., 2013, p.1) has been provided by thermal generation capacities and few peak-load pumped hydro storage units (PHS) (Bessa et al., 2017). These PHS can be considered the only relevant storage technology in former power systems that are shaped by thermal generation. For instance, in Germany the installed capacity of 9.3 GW in PHS is mainly used for arbitrage between base and peak load periods (BNetzA, 2018; Bessa et al., 2017). However, the required power system flexibility is expected to grow with an increased RES generation share while the technical potential to extend the PHS capacities in Germany is limited (Gimeno-Gutierrez and Lacal-Arantegui, 2013). As the utilisation of conventional power plants decreases due to the rising RES share, their capacities remain in the system and are an advantageous means to provide flexibility in contrast to new investments in storage units.

A shift of power generation from large and central conventional power plants to a large number of small and decentral generation units induces a paradigm shift in several dimensions of power generation and flexibility provision. In power systems shaped by fluctuating renewable power generation, the central uncertainty is not predicting demand alone but also generation. Short-term flexibility provided by storage units becomes more critical since conventional capacities will decrease (Bründlinger et al., 2018). The assumption of an absence of any non-renewable generation technology in the German power system provides the baseline for the lead scenario eGo 100 of this thesis. Apart from the generation portfolio the grid as an instrument to transmit power over large distances is another critical parameter of power systems. Power transmission may effectively improve grid integration of renewable power generation (Schlachtberger et al., 2017; Weitemeyer et al., 2015b). In Germany, the Grid Development Plan (German: Netzentwicklungsplan (NEP)) is the central instrument for the construction of a power grid infrastructure fitting to the expected more fluctuating power generation characteristics (EnWG, 2011). The German Transmission System Operators (TSO) first produce the NEP and its baseline scenario study (German: Szenariorahmen (SR)). Based on this extensive scenario study, the NEP identifies necessary grid extension measures for the respective target year. Second, the Federal Network Agency (German: Bundesnetzagentur (BNetzA)) approves these (EnWG, 2011). The first NEP was set up in 2012 and focused on grid extension measures for ten years until 2022. It has been updated yearly until 2015 addressing 2025 respectively (Feix et al., 2015). The SR for the NEP 2015 provided the basis for power generation data in the intermediate NEP 2035 scenario of this thesis. Starting 2017, the NEP is produced only every second year (EnWG, 2015) and concentrates on the year 2030. From 2021 it focuses on the year 2035. Hence, a fully renewable German power system is not covered by the NEP yet. Moreover, even today the realisation lags behind the planning as out of a total additional line length of 5827 km identified by the NEP, only 361 km are completed as of October 2019 (BNetzA, 2020b).

However, not only the power grid as an instrument to shift power in space becomes more critical but also the flexibility to shift power in time through storage technologies gains significance. Especially with regards to the challenges of setting up a power grid which is fit for the energy transition, storage flexibility is expected to fill an important role. In contrast to other neighbouring countries, Germany does not have a topography that allows large scale PHS throughout the country. Still, this restriction leads to the possibility of a relatively free allocation of chemical storage units that are independent of local prerequisites. Long-term storage, in contrast, can only be provided by either underground hydrogen storage or substantial imports from neighbouring countries and their seasonal reservoirs.

On this ground, the guiding questions of this thesis address the required flexibility in the future German power system. A particular focus lies on the siting and the sizing as the central characteristics of storage units.

1.2 Research Questions

Considering the previous remarks on the energy transition, its implications to flexibility provision and its modelling, this thesis addresses the following guiding research questions:

1. How can optimal storage units be characterised in terms of their size, location, and utilisation?
2. What is the impact of flexibility in neighbouring countries to German storage requirements?
3. How does an extension of offshore wind energy capacities affect the results?

The first research question has been addressed for the status quo and an intermediate scenario of 70 % RES share in the publication "Optimal Sizing and Spatial Allocation of Storage Units in a High-Resolution Power System Model" (Wienholt et al., 2018). In this work, the optimal storage capacities for two different technologies are assessed with the consideration of today's power grid in Germany. This thesis extends the scope of Wienholt et al., 2018 and analyses optimal storage units in a fully renewable German power system. The results of this research question are presented in Section 5.2.
The second research question addresses the impact of Germany's neighbouring countries on its flexibility demand with a focus to Norwegian pumped hydro storage capacities. In this regard, several variations of possible connections are analysed for different scenarios. Section 5.5 presents the results of this investigation.
Another potential driving factor to storage units and their characteristics in Germany are capacities of offshore wind power. In this context, this thesis discourses several extension scenarios for offshore wind capacities. The typically increased utilisation rate of offshore wind power compared to other fluctuating RES may reduce the demand for storage units although the feed-in of offshore wind power is spatially limited to Northern Germany. The discussion on this inquiry is produced in Section 5.6.

1.3 Current Trends in Modelling Future Power Systems

Energy system modelling has gained impetus in the past, especially with regards to the modelling of future power systems based on RES (Wiese, 2015). The high level of interconnection of different technical assets in power systems provides a challenge for realistic models of these. The axiom of meeting the power demand at all times in combination with the challenge of storing electricity requires the consideration of all relevant assets of a power system.

Power system models and their results are important for energy policy and can provide the basis for political decisions. Thus, any model and research relevant to policy should refrain from secrecy and open code, data, and approaches for criticism and an in-depth discussion on possible results (Pfenninger, 2017b). The German NEP is an example where this is not possible. The NEP features an extensive modelling process which depicts the German power transmission system in an appropriate resolution. The model is composed of different parts, for instance a market simulation and a separated power flow model (Feix et al., 2015). Although the NEP is the basis for real-world investments, such as the routes of new power transmission lines, the baseline model is not transparent and reproducible for the public. The modelling for the NEP is carried out by consultants assigned by the German TSOs and the models themselves are not published, which impedes the assessment of its results in contrast to open-source models. In order to enable an in-depth scientific discussion of the approach and the results, the model and data for this work are fully open source. Most of the data and model setup took place within the research project open_eGo funded by the German Federal Ministry for Economics and Energy. The availability of useful data is a challenge in power system modelling as many datasets, for instance regarding the power transmission system, are not published for reasons of security or competition. Furthermore, many datasets are published but not adequately licensed, which impedes the utilisation of these in open power system modelling (Hirth, 2020).

Apart from the availability of data, the resolution of a model can be demanding due to the increased effort on handling and computational capacity. However, the consideration of assets may affect the results of a model. Within power system models, the modelling of flexibility is a complex task since demand and supply patterns have to be depicted in a high temporal resolution. At the same time, the intertemporal constraints of storage units and their filling level impede clustering methods of the temporal resolution. The previous remarks highlight the central dilemma of complex models between a high degree of detail on the one hand and an acceptable level of handling and computational effort, on the other hand.

2 The Role of Flexibility in Power System Models

2.1 Energy and Power System Models

The modelling of energy systems took a rapid development in terms of its level of detail in the past years, especially with regards to the modelling of future energy systems based on RES. With the help of such models, possible technological, political, environmental, and economic trends can be depicted in form of different scenarios (Hughes and Strachan, 2010, p.6063). The results obtained with energy system models may provide a scientific basis for public discussion and in some cases even political decision-making, for instance through the German NEP (EnWG, 2011; Feix et al., 2015). Due to the rapid development in recent years, many different modelling approaches and models exist. Approaches to classifying these models are presented by Hall and Buckley, 2016, Pfenninger et al., 2014 and Connolly et al., 2010. While Connolly et al. reviewed 37 studies in 2010 and conclude that the application or focus of a subject pre-defines the appropriate model (Connolly et al., 2010), Hall and Buckley choose a different approach and developed a framework to classify energy system models from existing models. They divide this framework into the three primary characteristics: purpose and structure, technological detail, and mathematical description (Hall and Buckley, 2016, p.612). With the help of specific, more detailed parameters for each of the three main characteristics, they provide a comprehensive review of existing energy system models that supports the choice of a model for different purposes.

The modelling of future energy systems that are entirely supplied by RES began at the end of the 1990s with first studies for a sustainable Europe. Czisch presented the first energy system with an hourly resolution in 2005 (Hohmeyer and Bohm, 2015; Czisch, 2005). In the following, many of so-called 100 % scenarios have been produced (Hohmeyer and Bohm, 2015) and in most cases try to proof the feasibility of energy systems to be based entirely on RES. In 2017, Heard et al. reviewed several of these 100 % studies and conclude that according to their assessment none of them demonstrates the feasibility of a fully RES-based power system (Heard et al., 2017, p.1125). The assessment is carried out based on four criteria of demand projections: reliability, power transmission and distribution, and the provision of ancillary services. The central critique of Heard et al. is the underestimation of technical restrictions and too optimistic projections regarding future power demand. However, Brown et al. responded to this article and state that the authors misjudge the terms feasibility and viability (Brown et al., 2018a, p.835). According to Brown et al. 100 % RES-based power systems are technically feasible. The central question of studies would be to assess how 100 % RES power systems can be viable under social, political, environmental and economical constraints (Brown et al., 2018a, p.835). In a recent publication Zappa, Junginger and van den Broek support this claim after analysing seven scenarios of 100 % RES-based power systems partly with worst-case assumptions such as an unfavourable weather year (Zappa et al., 2019). This recent discussion shows the importance of transparency and the availability of relevant data for energy system modelling. Moreover, the relevance of the spatial and temporal resolution of power system models is highlighted by both authors. A comment by Jenkins et al., 2018 and an article by Sepulveda et al., 2018 initiated another recent discussion. After reviewing 40 studies on 100 % RES power systems, they claim the step from an 80 % to 100 % RES share forms the central challenge of such power systems and induce the highest costs. The authors base this hypothesis on the finding that curtailment of fluctuating renewables increases drastically in this period and at the same time state that no long-term and large-scale storage option would be available to shift this excess production to times of need. Batteries and demand response are considered to be "fast-burst" (Sepulveda et al., 2018, p.2) which means these technologies are only available on a short-term basis and too expensive to provide long-term power supply. As a result, Sepulveda et al. and Jenkins et al. conclude that nuclear, natural gas with CCS, geothermal, and bioenergy as so-called "firm low-carbon"(Sepulveda et al., 2018, p.2) resources are the most viable option for reaching low or zero-carbon power systems. However, the findings of the authors are based on current studies that apply today's expectations on generation costs to long-term scenarios (Jenkins et al., 2018; Sepulveda et al., 2018). Due to this uncertainty a shift in generation costs – which could be observed for instance for battery systems (Curry, 2017) and PV cells (Vartiainen et al., 2019; ISE, 2019) in recent years – could rapidly change these conclusions. The previous remarks focus on energy system models that could, according to the terminology, also cover cross-sectoral models not only focusing on the power system. In this thesis, no other sectors besides the power sector are directly addressed. The following section documents the importance of considering the power transmission and distribution grid in power system models.

2.2 Consideration of the Power Grid in Models

In general terms, the integration of the power grid into power system models introduces the shift of power not only in time according to a residual load, but also in space through the interconnection of different regions. Especially concerning an increased share of weather-dependent RES in the modelled scenarios, the benefits of interconnection between regions with different supply patterns become obvious (Schlachtberger et al., 2017; Weitemeyer et al., 2015b). In this context, a detailed depiction of the power grid seems preferable since transmission requirements and real-world constraints can be identified. It has been pointed out by Wienholt et al., 2018, p.2 that several recent works, such as Brown et al., 2016, Svendsen and Spro, 2016 or the mentioned German NEP (Feix et al., 2015; Rippel et al., 2017) focus on the extra-high voltage (EHV) grid. However, due to the relevance of the subjacent high voltage (HV) grid level for the grid integration and transmission of decentral RES, the integration of this voltage level seems advantageous. While van Leeuwen recommended the consideration of the HV in 2014 (Leeuwen et al., 2014), a comprehensive implementation to power system models did not happen since. Müller et al., 2018 used the model and data applied in this thesis to show that an integration of the HV level reveals a significant impact on modelling results.

Krishnan et al. provide a very general overview of the challenges of co-optimising supply and transmission in power system models (Krishnan et al., 2016). In this context they present three types of power grid depiction: (1) non-linear AC power flow, (2) linear DC power flow and (3) simplified transshipment models. The application of these types is dependent on the focus of a model. Large-scale planning studies may sufficiently depict the power grid through a transshipment model that simplifies power transmission by transport between nodes with a certain efficiency (Krishnan et al., 2016, p.14). Examples for this approach that often consider net-transfer capacities between countries or regions can be found in Czisch, 2005; Weitemeyer et al., 2015a; Bussar et al., 2017; Schlachtberger et al., 2017; SRU, 2011. The transshipment approach is insufficient for any analyses with regards to grid planning. The studies that provide the basis for grid planning in Europe (ENTSO-E, 2018) and Germany (Feix et al., 2015; Rippel et al., 2017), on the other hand, are based on non-linear AC power flow models (1). The simulation of, for instance, voltage stability and reactive power flow increases the complexity of these models compared to the other approaches. Consequently, the applications of AC power flow models of transmission grids are rare in scientific works except, for instance, Hoffrichter et al., 2018 and Linnemann et al., 2011 who used the undisclosed transmission grid model developed for the German NEP. A more common modelling approach is the linearisation of AC power flow as described by Brown et al. (Brown et al., 2016) to a so-called DC power flow (2) (Stott et al., 2009). Non-linear equations of the AC power flow are linearised, which leads to disregarding, for instance, the reactive power flow. Thus, a DC power flow representing an AC system must make approximations regarding these non-linear parameters, which are often realised by limiting the powerline transmission capacity to 70 % (Brown et al., 2016; Hörsch and Brown, 2017). Both, Brown et al. and Stott et al. conclude that the DC approximation is relatively accurate when line loading is below 70 %, which is mostly ensured by the mentioned limitation (Brown et al., 2016; Stott et al., 2009). With regards to the high complexity in combination with common challenges concerning the convergence of non-linear power flows it seems that DC power flow is more useful for large-scale national or international planning studies as long as the approximation is carefully set. The power flow approach applied in this thesis will be elaborated on in Section 4.1.

2.3 Flexibility in Power Systems

Ma et al., 2013, p.1 describe the term flexibility as "*the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons*". Technically, the condition of reasonable cost does not necessarily define flexibility. Still, this definition highlights the central characteristic of flexibility to cope with different variabilities and achieve this through either a shift of power in time (storage) or space (grid). Although this is a very general distinction, many different technologies and parameters exist within these two classes. Especially the ability to shift power in time features several approaches while a shift in space is limited to power grid capacities. A shift of power in time cannot only be achieved by direct storage in certain technologies but also indirectly by regulatory mechanisms such as hourly market prices or comparable signals that stimulate, for instance, demand response. Thus, a pile of hard coal may also be considered a storage since the moment of its burning for power generation may be shifted according to external market signals. However, in this thesis flexibility is considered to be provided by storage units while other mechanisms such as the described coal pile are only considered indirectly through the modelling logic. The approach to model flexibility is described in appropriate detail in Section 4.3.

The German power system has been set up and developed with mainly thermal power generation units. The flexibility of thermal power plants differs according to the respective technology. While nuclear power plants operate in base load only, lignite and hard coal used to operate mainly as base load power plants until their role shifted to increasingly operate in peak hours due to the rising share of RES (Agora Energiewende, 2017). Gas-fired power plants and PHS are classic peak load generation types. From a power system perspective, such a diverse setup allows utilising low priced base load generation in combination with a more seldom use of peak load generation. In such a power system shaped by thermal generation, balancing of an inelastic demand provides the central driver for flexibility requirements. Thus, with low RES capacities, new storage technologies are neither required nor economically attractive due to the immanent power system flexibility of the combined thermal portfolio. Only a rise in fluctuating RES induces supply-side flexibility requirements and fosters the need for and the value of additional flexible capacity (Bertsch et al., 2016; Denholm et al., 2013b). Hence, today's storage units operate with arbitrage or in relatively small and increasingly competitive reserve power markets. Thermal power plants compete with storage units in both markets which reduces possible revenues for storage operators and impedes an extension of capacities (Denholm et al., 2013a; Zucker et al., 2013). The total installed storage capacity in Germany has therefore been limited to PHS and remained constant for many years despite the rising share of fluctuating RES (BDEW, 2019). Apart from the limited economic potential for further PHS, the resource potential for new plants of appropriate size is very limited in Germany (Gimeno-Gutierrez and Lacal-Arantegui, 2013). In contrast, neighbouring countries in Scandinavia (Norway, Sweden) and the alpine region (Switzerland, Austria) have well established (pumped) hydro power capacities, often combined with extensive reservoir capacities. As a result, these power systems benefit from the flexibility of their hydro power system and do not require large thermal power capacities. Only in recent years, the installation of battery storage units added to the total storage capacity in Germany. The development of battery storage systems may be subdivided into small decentral units in households, often in combination with PV systems, and on the other hand industrial MW-scale units that operate at the reserve power market. According to Figgener et al., small home storage systems in Germany accumulate to an installed capacity of around 415 MW and an energy capacity of 930 MWh at the end of 2018 (Figgener et al., 2020). Large scale battery storage, on the other hand, adds up to 400 MW and an energy capacity of 550 MWh (Figgener et al., 2020). Together, these numbers result in an average energy to power (E/P) ratio of 1.82 and underline the relatively low storage capacity of these units. Since small scale battery storage units are operated to optimise the own consumption of the owner, their operation cannot be considered to be system-oriented in a way that reduces peak loads and the overall power systems flexibility requirements. The German TSO TenneT states that small scale battery storage units can be accumulated in a virtual power plant to allow the provision of reserve power (TenneT, 2018). With regards to the scope of this thesis, where the provision of reserve power is not considered, one can assume that the impact of small decentral battery storage units to a system-oriented power arbitrage operation is rather insignificant. However, a further significant increase in both, decentral and central battery storage units seems likely for instance due to new support schemes for small scale storage units and promising market conditions for large scale plants, both in combination with decreasing technology costs (Curry, 2017). This development is not limited to Germany. Similar trends can be observed, for instance, in the United States (EIA, 2018) or China (Curry, 2017).

Hydrogen-based power-to-gas storage units are currently in operation only on a low MW-scale in several pilot projects (dena, 2019). Most of these projects demonstrate the H_2 production with RES feed-in and its material utilisation in industry, mobility or an injection to the natural gas grid. The re-electrification of the H_2, for instance through a fuel-cell to complete a full cycle power storage, has not reached an equal status yet. However, a steep increase in hydrogen electrolysis capacity is expected by several studies, especially for the period from 2030 to 2050. In a recent study commissioned by Shell GmbH, Siemens AG and TenneT TSO GmbH, Nikogosian et al. review several analyses and find a corridor of possible electrolysis capacity developments that peak at 35 GW in 2030 and 350 GW in 2050 for Germany (Nikogosian et al., 2018).

Apart from PHS, battery, and hydrogen storage, there are several other potential power storage technologies under development. For instance, Siemens Gamesa develops an electric thermal energy storage (ETES) with a test facility in Hamburg (Siemens, 2020). This ETES technology makes use of the thermal capacity of volcanic stones and can be considered a short to medium term storage technology. Similarly, the adiabatic compressed air energy storage technology is usually considered a short-term storage with an E/P ratio of a few hours. In contrast to ETES, compressed air energy storage (CAES) is a technology that has been in operation for many years in Germany and the U.S. but is limited to sites with an appropriate underground to allow the storage of compressed air (Luo et al., 2015, p.525). The improvement of making the storage process adiabatic (AA-CAES) promises higher storage efficiency. Luo et al., 2015 provide a comprehensive overview of many storage technologies.

2.4 Modelling Flexibility

In energy system analyses, flexibility in general and its provision by storage units have been subject to numerous academic works (Heide et al., 2011; Denholm and Hand, 2011; Budischak et al., 2013; Steinke et al., 2013; Huber et al., 2014; Weitemeyer et al., 2015a; Weitemeyer et al., 2015b; Bertsch et al., 2016; Andrey, C., Fournié, L., Gabay, M., de Sevin, H., 2016; Bussar et al., 2017). The expectation that flexibility demand and thus its significance grows with higher shares of RES is mentioned above. It leads to a more in-depth scientific examination and discussion in recent years. In 2011 Heide et al. analysed storage requirements for Europe based on 100 % RES depending on the generation mix of PV and wind energy. They find that when allowing excess RES generation or in other words curtailment of 50 % of the yearly production, storage requirements amount to approx. 1 % of the yearly demand. In a brief comparison with existing reservoir lakes in the Alps and Scandinavia as well as possible hydrogen storage capacities in underground salt caverns in Northern Europe, the authors expect the storage capacities to be sufficient for a 100 % renewable European power system. However, this study disregards any effects of power transmission since Europe is depicted as one copperplate (Heide et al., 2011). Later, Steinke et al., 2013 applied the optimal mix of PV and wind energy developed by Heide et al. (Heide et al., 2011) and analysed the optimal combination of grid and storage extension. Here, the authors also apply a simple model for Europe without the consideration of any real transmission constraints. Grid extension is in contrast depicted by an increase of the regarded cell by a certain distance. The authors find that the 100 % renewable European power system requires backup capacities in the range of 40 % of yearly demand. With an ideal copperplate-like grid, this value may be reduced to 20 %. The model setup and the technologies are rather abstract as neither losses for transmission or storage of power nor any other constraints are considered (Steinke et al., 2013). Other applications of such a European approach with optimal mixes of PV and wind energy are Weitemeyer et al. (Weitemeyer et al., 2015a; Weitemeyer et al., 2015b). In a first study, the approach is improved by an introduction of two representative storage technologies, namely efficient short-term storage and long-term seasonal storage with low efficiency. Considering a wind generation share of 60 % and a PV generation share of 40 %, they find that a RES generation share of up to 50 % may be reached without any storage requirement. The efficient short-term storage most efficiently accommodates RES in the range from 50 % to 80 % while RES shares beyond 80 % require a seasonal storage option (Weitemeyer et al., 2015a). The second study by Weitemeyer et al. extend the setup to a simplified transmission model without losses where first all EU-27 countries are analysed individually and compared to the fully integrated European setup. It is found that the interconnections would be used significantly in 75 % of the time with a stronger utilisation during winter months (Weitemeyer et al., 2015b, p.119).

In contrast to the highlighted studies, Bertsch et al. set up a power market model for Europe and analysed the economic optimum of different generation portfolios for up to 80 % RES share in 2050 and for several representative intermediate years (Bertsch et al., 2016). The authors find that flexibility requirements increase sharply with the RES share and identify hourly generation ramps of up to 40 GW as one of the central drivers. The power grid between the European countries is considered through net transfer capacities and a copperplate approach within each region (Bertsch et al., 2016). A similar power grid consideration for a model of 27 European countries but with unlimited interconnection capacities was applied by Huber et al., 2014. In their model, they address parameters impacting the flexibility requirements of power systems. The consideration of flexibility was limited to a timescale of 1 to 12 hours which excludes short-term flexibility below one hour and any long-term or seasonal flexibility. They conclude that flexibility requirements are dependent on three parameters: the share of RES (1), their mix (2), and the size of the balancing area (3). The latter is claimed to be mainly due to the smoothing effect of wind power generation over vast distances (Huber et al., 2014). A model to optimise generation, transmission and flexibility at the same time was introduced by Bussar et al., 2017. With the help of the GENESYS model, they consider five European countries and pre-define a trend of CO_2 reductions and hence a phase-out of conventional power generation until the year 2050. The transmission between the five regions is depicted through net transfer capacities that are variable for the optimisation. The three technologies representing storage units are pumped hydro, battery, and seasonal hydrogen storage. They are not only optimised for their capacity, but also for the (E/P) rate, which defines the required storage size. As a result Bussar et al. find that these E/P rates see a substantial change over time with peaks of approx. 200 h for hydrogen storage around the intermediate year 2035 while the charging and discharging power steadily increase up to the 100 % RES case in

2050 (Bussar et al., 2017). It is expected that this development is based on increased power generation gradients. Similar to the previously mentioned approaches, there are additional publications that consider the complete European power system with a one-bus-per-country resolution (Schlachtberger et al., 2018; Victoria et al., 2019; Child et al., 2019). Cebulla et al., 2017 have a slightly different approach as Germany is subdivided into 18 regions which allows more detailed results on storage siting.
Looking beyond Europe, Budischak et al. optimise the generation and storage portfolio for meeting certain fixed RES shares at lowest supply cost while disregarding grid bottlenecks (Budischak et al., 2013). In this 2012 work, the authors apply their model to the PJM interconnection in the eastern United States, which compromises 1/10 of the total electric demand of the U.S.. A central result is that demand can be met at 99.9 % of the time by RES in an optimal solution based on cost assumptions for the year 2030 and with total costs comparable to today's. Another interesting finding is that the relevance in terms of installed capacity of offshore wind has a strong increase when going from 90 % to 99.9 % RES share (Budischak et al., 2013, p.65). Denholm and Hand apply a similar approach to a case study with the ERCOT grid in Texas/U.S. which is almost completely isolated from neighbouring transmission grids. A central parameter of their analyses is the curtailment rate, although transmission constraints of the network are not directly considered. Thus, curtailment must be considered as a value to quantify RES integration. The authors find that with the lowest base load flexibility possible and a 50 % wind energy generation share, curtailment rates add up to 50 %. Combinations with solar power feed-in, storage installations and the reduction of must-run capacities may substantially decrease curtailment rates (Denholm and Hand, 2011, p.1822).

All studies introduced before provide a different level of detail regarding the spatial resolution or the detail of storage technologies. Since the works cover large geographical regions, a detailed model of the respective power grid is hardly possible due to handling and computational constraints. Thus, the highest degree of detail regarding the transmission grid can be found when net transfer capacities between regions are considered. In the following, studies with a more precise representation of the power grid are discussed. Compared to models with simplified grid representation, these studies are rare but growing in numbers in recent years.
The relatively small 14-bus representative IEEE fictional network is considered as a basis by Wogrin and Gayme, 2015. The authors restrict their analysis to one representative day but with the relatively high temporal resolution of five-minute timesteps. Hence, no long-term storage options are considered. They find that Lithium-Ion batteries are capable of both, the balancing of short-term sub-hourly variations, and longer-term hourly energy arbitrage. In general, they propose the consideration of different storage technologies in order to cover different power system characteristics (Wogrin and Gayme, 2015). In 2017 Hoersch and Brown presented a systematic approach to assessing the role of spatial scale in power system optimisation. They apply the free software Python for Power System Analysis (PyPSA) for a model of the

European transmission grid. The authors compare results regarding overall system cost and investment optimisation for setups with a different spatial representation and a CO_2 reduction of 95% compared to 1990 levels. Similar to Bussar et al. not only storage units but also the expansion of transmission lines and the installation of additional generation capacity is subject to the optimisation problem (Bussar et al., 2017). The original European transmission grid consists of 5586 AC lines, 26 DC lines and 4653 substations. Through a k-means clustering, this model is reduced to clusters of 37 to 362 buses. In their results, Hoersch and Brown find that for these different cluster sizes, the optimisation yields results in the same range for overall system costs with a trend towards lower costs for a higher degree of detail. They claim that the results stabilise from clusters with more than 200 buses. The authors do not explicitly present storage requirements, but a trend towards battery storage systems in PV-shaped Southern Europe and increased transmission and hydrogen storage capacities in Northern and Western Europe with high wind energy yields can be observed (Hörsch and Brown, 2017). Svendsen and Spro apply a similar optimisation approach to the Western Mediterranean transmission grid including North Africa for the year 2030. They focus on the value of storage for Spain and Morocco as a complement to Concentrated Solar Power (CSP) plants and conclude that such CSP storage units may significantly reduce overall system costs. Another central finding is the strong impact of grid bottlenecks to the benefit of flexibility (Svendsen and Spro, 2016) which supports the assumption that an appropriate transmission grid representation is vital when assessing flexibility requirements. Another study depicting the power grid in a relatively high level of detail is the 2016 NREL publication by Hale et al., 2016. Here, the authors set up a model of the Western interconnection spanning over the Western U.S. and parts of Southwestern Canada. Their model allows capacity extension of different battery storage technologies as well as PHS. Several possible applications of storage are considered, including the provision of reserve power which is limited to hourly representation due to the temporal resolution. The analyses focus on the years 2015 until 2030 and vary the RES generation shares. A central finding is that interruptible load provides an alternative to storage installations, especially in intermediate scenarios with a lower RES generation share. Storage installations are found to be highly dependent on cost assumptions and the year or RES generation share (Hale et al., 2016). One of the most detailed studies on the German power system is by Babrowski et al., 2016. Their spatial model has a relatively high resolution with data going down to NUTS-3 level and a complete depiction of the current transmission grid. Moreover, planned grid extensions until 2020 are considered. The temporal resolution, on the other hand, is rather coarse as only representative days for each season are considered which impedes the proper depiction of extreme events and of seasonal storage. Hence, only battery storage units are considered. The scope of the study proceeds in five-year steps until 2040, where a RES generation share of 60 % is reached. Their approach to storage optimisation consists of two steps. First, storage siting is determined with a linear optimisation

model with lossless storage. Second, the capacity of the obtained units is determined with a mixed integer linear programming (MILP) process where a storage efficiency of 85 % is considered (Babrowski et al., 2016).
Many of the contributions introduced above are part of a review by Cebulla et al. that analyses storage demand in dependence of the RES generation share for the U.S., Europe and Germany (Cebulla et al., 2018). A central finding of the authors is that the generation mix of a power system is an essential driver for storage demand. With rising RES generation shares, they identify a linear growth of storage power capacity and an exponential increase of storage energy capacity. Generally, PV-dominated systems reveal higher storage requirements while a stronger wind power generation leads to higher transmission requirements and, therefore, lower storage needs. Interestingly, all of the 17 studies that Cebulla et al. reviewed analyse storage demand based on relatively coarse or even copperplate-like grid models.
In contrast to the scientific works introduced above for the German Grid Development Plan (NEP), a different approach to flexibility modelling is applied. Since the NEP is set up to assess and evaluate future transmission requirements in the German transmission grid, storage and flexibility are not directly optimised, but instead defined in their capacities and characteristics ex-ante. Hence, generation, demand and storage capacities are pre-defined by a best guess and not a result of an optimisation. Furthermore, potentials for different non-grid flexibility options as alternatives to grid extension have only been considered in the scenario framework 2030 from 2016 (Feix et al., 2016). However, this and the following scenario report (Rippel et al., 2018) only quantify possible developments of flexibility options such as electric vehicles and heat pumps, without explicitly describing their role within the modelling framework and their impact on the results. Not only the numbers but also the complete model logic of the NEP is different from most of the other studies. For the NEP a heuristic process is developed which mainly consists of the three central parts *dispatch, power flow* and *redispatch*. The central motivation of this approach is to model the process that is applied in reality as detailed as possible. This process starts with the hourly day-ahead trade that leads to the dispatch of power plants. In the NEP, this step is implemented through a market simulation. Starting from this dispatch information per power plant, a power flow simulation is carried out by the respective grid operator for each hour. In the case of grid constraints produced by these power flows, the TSOs perform a preventive redispatch in order to relieve transmission bottlenecks. A prominent example of a redispatch measure is to reduce the wind power feed-in in Northern Germany in times of high production and ramp up conventional power plants in the South of the country which the Northern wind power cannot reach due to bottlenecks. Redispatch measures have seen a sharp increase in recent years and are often considered as an indicator for transmission or even storage requirements. The costs for redispatch measures added up to a total of 387.5 million EUR in 2018 in Germany and are composed of compensations for both the ramp-up (6956 GWh) and the ramp-down (7919 GWh) power plant (Bundesnetzagentur,

2019b). The three-step process of finding an optimal power flow is not only applied by the NEP but by research works (Leeuwen et al., 2014; Hoffrichter et al., 2018) from Aachen University which is an essential contractor of the TSOs for setting up the NEP. However, the general heuristic is applicable by using separate modelling tools for the individual steps where for each of these useful open-source solutions are available (e.g. PyPSA (Brown et al., 2018b; PyPSA, 2020), oemof (Hilpert et al., 2017; oemof, 2020), pandapower (pandapower, 2020)).

Another heuristic approach to find optimal locations and sizes of storage units in a network shaped by RES was introduced by Dvijotham et al., 2011. Their approach starts with the placement of battery storage units at any grid node in the fictional IEEE network model with 96 buses. Storage requirements are then assessed based on their utilisation in different RES generation patterns and the overall RES share of the network (Dvijotham et al., 2011). The authors find that relevant storage installations begin from a RES penetration of 30 %. The locations of storage are found to be oriented on critical network junctions rather than buses with a characteristic RES generation. In their interpretation, Dvijotham et al., 2011 assume these locations advantageous as storage units may directly control power flows close to critical junctions. Pandzic et al. refined this approach and introduce a three-step heuristic approach to storage siting and sizing in a transmission network. Similar to Dvijotham et al., 2011, they apply their algorithm to the 96-node fictional IEEE network and use battery storage only. In a first step, these storage units are set to all buses without any limitation of size or storage capacity. Next, a Unit-Commitment (UC) problem is solved individually for each day of one year passing on the generators', but not the storage status to the next day with resulting storage utilisation rates. According to a fixed threshold of days in use, the most beneficial storage locations are then further analysed, any storage units below the threshold are discarded. The authors then fix beneficial storage locations for the second UC run again without any limitation in storage size or capacity. In the third and final step, the ratings of the storage units are fixed and not longer optimised individually per day but with passing on the status to the next day. In contrast to Dvijotham et al., 2011, Pandzic et al. find that the location of storage units is dependent on the RES generation distribution and especially the wind resource distribution. The authors interpret the results of their heuristics to be near-optimal (Pandžić et al., 2015).

An alternative option to co-optimise dispatch and installation while taking network restrictions into account is the linear optimal power flow (LOPF) method. According to Milano, the Optimal Power Flow (OPF) method as an instrument of economic dispatch with the consideration of power flow equations has been introduced in the early 1960s (Milano, 2010). Brown, Hörsch, and Schlachtberger developed the software Python for Power System Analysis (PyPSA) which features a linear OPF that extends the economic dispatch optimisation of generators to an investment optimisation of generators and storage units (Brown et al., 2018b). The LOPF with investment optimisation has been applied by the same authors for studies on the European power system (Hörsch and Brown, 2017; Schlachtberger et al., 2017). In contrast to any heuristic approach described above, the advantage of the LOPF is its integrated character that produces an optimal result under consideration of several constraints in one optimisation problem.

2.5 Resolution and Complexity

The review of current literature on flexibility in power systems in the previous sections reveals that on a national or continental scale a close-to-reality representation of the transmission grid can be rarely found when analysing storage requirements. Apart from the availability of the corresponding data which is a central challenge in energy system modelling, the complexity of a proper power grid representation and modelling can be considered to be the central reason for the widespread disregard. In 2014, Pfenninger et al. investigated common challenges of energy system modelling and found the complexity or "resolving time and space" (Pfenninger et al., 2014, p.77) to be one of the central challenges. Regarding the spatial resolution of a model, Hörsch and Brown have analysed the impact of the spatial scale and conclude that clustering methods are necessary when working with a high spatial resolution in a comparably big network, such as Europe (Hörsch and Brown, 2017). In their article, the authors find that the amount of buses a large network is clustered to has an impact to the overall system costs. Potential explanations are decreasing grid constraints with a more coarse grid representation and the averaging and thus lowering of capacity factors of RES. Generally, they find that a careful selection of the right cluster size is required according to the effects that are to be analysed (Hörsch and Brown, 2017). The hypothesis of Hörsch and Brown that clustering methods are necessary can be regarded as scientific consensus as no contribution features the European transmission grid in its full complexity. Another supporting argument is the fact that even the ENTSO-E as the operators of the European transmission grid apply simplification methods when modelling the future European grid, for instance in the e-Highway 2050 scenarios (Anderski et al., 2015). Most of the studies on the European power system consider the EHV transmission grid at the most. Consequently, the challenge of spatial resolution and computational effort is further increased when adding the high-voltage level power grid to the model. Hinz and Möst, for instance, set up a redispatch model for the 110 kV voltage level in Germany and its neighbouring countries. The focus of their analysis is the provision of reactive power by wind power plants connected to this voltage level. In order to achieve acceptable computational efforts with such a high-resolution grid model, they reduce the temporal resolution drastically and work with 16 representative hours in contrast to a full-year simulation (Hinz and Möst, 2016). Svendsen presented a grid reduction method for large scale power grids and grid integration studies which is based on Power Transfer Distribution Factors (PTDF). The algorithm aims to provide a PTDF matrix for a reduced network that is similar to its full-scale equivalent. The algorithm is applied for power systems in Morocco and Norway with the finding that the approach may be applicable even for analysing the line loading. However, these comparisons are only carried out for a representative hour without a comparison of the effects of the reduced matrix for full-year simulations (Svendsen, 2015). The two latter described works highlight the strong dependency of the computational effort on the spatial and the temporal resolution of a power grid model. In power system modelling hourly simulations can be considered the standard temporal resolution. For models that address power system planning, any sub-hourly effects may be safely disregarded (Brown et al., 2018a; Deane et al., 2014). However, large scale power system models may need to be simulated in a more coarse temporal resolution in order to keep computational efforts manageable. Thus, several approaches to reduce the number of snapshots of a full year simulation exist. Hörsch and Brown, for instance, apply a simple method by skipping every second and third hour, which reduces the temporal resolution to one-third of the original dimension. The skipped hours are not entirely disregarded as the computed snapshots are weighted by a factor 3, which leads to a good representation of three hours by one snapshot (Hörsch and Brown, 2017). Kotzur et al. presented a more complex approach. Their motivation is to reduce temporal resolution while keeping the ability to model seasonal storage. This implies intertemporal constraints and requires dependencies, for instance of storage filling levels between several snapshots. In their algorithm, Kotzur et al. identify representative snapshots for different operation modes and create an abstract representation of a full year by these typical snapshots. According to their findings, the computational effort may be reduced by up to 90 % by this approach (Kotzur et al., 2018).

3 Hypotheses

The previous review of current academic works on flexibility in power system models indicates that a high-resolution power grid modelling has been rarely applied in storage requirement studies. Apart from data availability, the computational and general handling efforts are possibly the driving factors for this widespread disregard. In this thesis, an approach to overcome this gap shall be developed. The following hypothesis summarises the challenges of this methodological target.

A. *It is possible to develop an integrated method to realistically model the utilisation of different storage technologies in power systems with a high spatial and temporal resolution. At the same time, the optimality of installation and utilisation of storage units can be assessed.*

With the help of a successfully implemented model according to hypothesis **A.**, numerous research questions may be addressed. The central parameter of optimal storage siting may only be assessed adequately with results in a high spatial resolution. In line with the research questions set up in Section 1.2, the following hypothesis provides the guideline for the evaluations carried out in this thesis.

B. *The characteristics and optimality of the utilisation of storage units are dependent on local or regional situations regarding generation, demand, and power grid. The approach developed within this thesis helps to prove that in a renewable power system, even under detailed consideration of the electricity grid, central large storage units are necessary and meet the criterion of optimality.*

4 Method

The core of the modelling carried out in this thesis is a Linear Optimal Power Flow (LOPF) problem that allows the integrated optimisation of utilisation and additional installations of storage units under the consideration of power grid restrictions. The following section presents the details of this approach before Section 4.2 introduces the generation and processing of the required data for the model. The approach and central assumptions of optimising storage units can be found in Section 4.3. Section 4.4 compromises the implementation of the model and points out complexity reduction measures. Finally, Section 4.5 closes this chapter with a critical discussion of the applied methods.

4.1 Linear Optimal Power Flow

Power flow modelling is a common and often applied method to analyse effects in power systems. Section 2.2 introduced several ways of power flows and provided examples of their application in academia or grid planning studies. For AC power systems, the power flow adheres to

$$\bar{S_n} = P_n + jQ_n = \bar{V_n}\bar{I_n^*} \tag{4.1}$$

with n defining a given bus, S_n the injected apparent power at the bus, P_n the injected active and Q_n the injected reactive power. V_n defines the injected complex voltage and I_n^* the injected complex current. With predefined generation dispatch (for instance by an ex-ante LOPF), the injected current at a bus is dependent on the current of the lines connected to the bus based on Kirchhoff by

$$\bar{I_n} = \sum_m \bar{I_{nm}} = \sum_m \bar{Y_{nm}V_m} \tag{4.2}$$

with Y_{nm} defining the admittance between bus n and m. Considering the conductance G_{nm} and the susceptance B_{nm} between n and m, the admittance is given by $Y_{nm} = G_{nm} + jB_{nm}$ and defines the injected power at bus n as

$$\bar{I_n} = V_m e^{j\theta_m} \sum_m (G_{nm} + jB_{nm}). \tag{4.3}$$

With equation 4.1 this leads to

$$\bar{S_n} = V_n e^{j\theta_n} \sum_m (G_{nm} - jB_{nm}) \Big(V_m e^{-j\theta_m} \Big). \quad (4.4)$$

Equation 4.4 is then split into the active power part for the injected active power at bus n as

$$P_n = V_n \sum_m V_m (G_{nm} \cos\theta_{nm} + B_{nm} \sin\theta_{nm}) \quad (4.5)$$

and the reactive power part for the injected reactive power at bus n as

$$Q_n = V_n \sum_m V_m (G_{nm} \sin\theta_{nm} - B_{nm} \cos\theta_{nm}). \quad (4.6)$$

The slack bus $n = 0$ provides the balancing bus in a power flow and has a predefined voltage magnitude $|V_0|$ and voltage angle θ_0. P_0 and Q_0 are to be found by the power flow with the help of the equations 4.5 and 4.6. Any other bus in the network is defined based on its reactive power behaviour either as load bus PQ or feed-in bus PV. For PQ buses P_n and Q_n are defined while $|V_n|$ and θ_n are calculated by the power flow. PV buses, on the other hand, have a given P_n and Q_n while θ_n and $|V_n|$ are to be found (Brown et al., 2018b). The solution of the nonlinear equation system is initiated by the assumption of $\theta_n = 0$ and $|V_n| = 1$ and is found applying a Newton-Raphson algorithm. The power flow produces results for P_n, Q_n, $|V_n|$ and θ_n at all buses of a network. A more in-depth presentation of the theoretical basis of a non-linear power flow can be found in Milano, 2010.

In order to reduce complexity, a non-linear power flow may be linearised even for an AC network by decoupling active and reactive power (Brown et al., 2018b). Three preconditions must be met for such a simplification:

- a constant voltage magnitude,
- small voltage angles θ_l of branches to allow $\theta_l \approx \sin\theta_l$ and
- branch resistances R_l to be negligibly low compared to branch reactances X_l.

For the grid model used in this thesis (see Section 4.2.1), the average X_l/R_l ratio was analysed by Scharf, 2017 and found to be approximately in a range that allows for a linearisation according to Van Hertem et al., 2006.
The linear optimal power flow (LOPF) is based on such a linearised power flow and optimises operation and investment in the network. The demand must be met at all times and the objective of the LOPF is to minimise total system costs. Capacity extension of generators, storage units, or network assets is possible and considered through annualised investment costs. In this thesis, generation capacities and network assets are constant at all times and only storage capacity may be extended. Thus, the optimisation is carried out by minimising the following objective function:

$$\min_{\substack{H_{n,s} \\ g_{n,r,t}, h_{n,s,t}}} \left[\sum_{n,r,t} w_t \; o_{n,r} \; g_{n,r,t} + \sum_{n,s} c_{n,s} \; H_{n,s} + \sum_{n,r,t} w_t \; o_{n,s} \; [h_{n,s,t}]^+ \right] \tag{4.7}$$

with the optimisation variables $g_{n,r,t}$ for the generator dispatch of type r and at hour t, $H_{n,s}$ for storage investment s at bus n and the positive storage dispatch $[h_{n,s,t}]^+$. The dispatch optimisation is mainly dependent on the marginal costs $o_{n,r}$ for generators and $o_{n,s}$ for storage units. Investment optimisation, on the other hand, is defined by the capital costs $c_{n,s}$ for a storage unit. The hourly dispatch may be weighted by a factor w_t in cases where not every hour of a year is considered. In this thesis, the factor is set to $w_t = 3$, indicating that every third hour of a year is calculated and needs to be weighted accordingly to compensate for the disregard of the remaining hours.

The parameters of the objective function are subject to several constraints, considering the technical limitations of these assets. The dispatch of generators is limited by their respective capacity according to

$$\tilde{g}_{n,r,t} \cdot G_{n,r} \leq g_{n,r,t} \leq \overline{g}_{n,r,t} \cdot G_{n,r} \tag{4.8}$$

with $\tilde{g}_{n,r,t}$ and $\overline{g}_{n,r,t}$ as time-dependent constraints of the generator for instance due to a weather-dependent feed-in and $G_{n,r}$ representing the installed capacity of the generator. Constraints regarding ramping up or down of thermal power plants are not considered in this thesis but could be implemented with this constraint and to the cost of significantly increased computational effort. At least for power systems with gas-fired power plants being the major thermal generation type, such a simplification seems justifiable when operating on an hourly scale. The central scenario in this thesis is a 100 % RES scenario with biomass and minor gas capacities in neighbouring countries as the only thermal generation types. Thus, the consideration of ramping constraints is only relevant for the intermediate scenario with significant conventional generation capacities. In this case, thermal flexibility constraints are assessed by limiting the range of flexible operation for nuclear-, lignite-, and coal-fired power plants to the range above 50 % of their installed capacities (compare Section 5.4).

Storage unit dispatch is mainly dependent on its charging and discharging power in combination with the storage filling level. These constraints are defined by

$$0 \leq h_{n,s,t} \leq \overline{h}_{n,s} \tag{4.9}$$

$$0 \leq f_{n,s,t} \leq \overline{h}_{n,s} \tag{4.10}$$

$$0 \leq soc_{n,s,t} \leq r_{n,s} \cdot \overline{h}_{n,s} \tag{4.11}$$

with the storage discharging power $h_{n,s,t}$ and charging power $f_{n,s,t}$ which must comply to the installed storage power $\overline{h}_{n,s}$ which is assumed to be the same for charging and discharging in this thesis. The storage filling level $soc_{n,s,t}$ must stay within the limits of the energy capacity which is defined by a fixed E/P ratio $r_{n,s}$ for each storage type and the installed power $\overline{h}_{n,s}$.

Kirchhoff's current law as the central condition to meeting the power demand at all buses at all times is met by

$$\sum_r g_{n,r,t} + \sum_s h_{n,s,t} - \sum_s f_{n,s,t} - \sum_l K_{n,l} f_{n,l} = d_{n,t} \tag{4.12}$$

with the generator dispatch $g_{n,r,t}$, the storage dispatch $h_{n,s,t}$, storage charging $f_{n,s,t}$, the power balance of connected buses or branches $f_{n,l}$ with $K_{n,l}$ defining starting ($K_{n,l} = 1$) or ending ($K_{n,l} = -1$) buses and the demand $d_{n,t}$ at the bus.

Power flows $|f_{l,t}|$ on branches are limited by their capacity F_l through

$$|f_{l,t}| \leq F_l. \tag{4.13}$$

In addition, Kirchhoff's voltage law must be adhered which indicates that the sum of the voltage differences around any closed cycle c must be zero and may be expressed by

$$\sum_l C_{lc} \cdot x_l \cdot f_{l,t} = 0 \tag{4.14}$$

with C_{cl} depicting a matrix of passive branches and x_l the inductive reactance of branch l (Brown et al., 2018b).

An additional optional constraint that is introduced to manage the generation dispatch is the fulfilment of a certain RES share of the overall dispatch. Although the fluctuating RES wind and PV do not have marginal costs and are therefore prioritised in the dispatch, large thermal capacities at beneficial network locations may lead to a more efficient overall result. In order to make the obtained results comparable and to reduce the curtailment of RES the optional constraint of

$$\sum_{n,r,t} r_{n,r,t} \leq p \cdot \sum_{n,r,t} g_{n,s,t} \tag{4.15}$$

may be applied with $r_{n,r,t}$ representing the feed-in of RES and p the share of RES of the total dispatch $g_{n,r,t}$. The definition of p is generally flexible, but should consider the installed capacities of RES.

The constraints to storage investments are presented in Section 4.3. A more general description of the LOPF and its constraints with possible set-ups such as the investment to generators or grid assets can be found in Brown et al., 2018b.

The software PyPSA is used to carry out the LOPF. PyPSA is a GPL-v3 licensed open-source tool. Originally, the idea of PyPSA was to establish a robust open-source tool for power flow analysis. Over time, the functionalities of PyPSA were largely extended now allowing the modelling of unit-commitment problems or large-scale optimisation of power systems, even with links to other sectors. In his review, Groissböck, 2019 concludes that PyPSA is one of the top-performing open-source tools for power system modelling and optimisation.

4.2 Model Data

In general, power system modelling aims at depicting real power systems as close to reality as possible. At the same time, especially large power systems consist of millions of assets, consumers, and producers. To keep the handling of a model for such a power system in line, a compromise of a sufficient degree of detail and acceptable simplifications must be found. The approach of the open_eGo model, which is applied for this thesis, is to pursue a relatively high level of detail and respectively build a large data model. Simplifications may be applied through ex-post algorithms if the computational handling turns out to be too challenging. Thus, the approach is to use any input data in a relatively high degree of detail. In the following, the complete data model is described starting with the power grid model, which provides the basis for the spatial allocation of generation, storage and demand data.

The generation of the data is performed within the data_processing [1] package which consists of several python and SQL scripts published under the AGPL-v3 license. Since any data is open and freely accessible, a complete reproduction of the data set is possible. Central parts of the data processing are presented in Hülk et al., 2017. The resulting data is stored in a PostgreSQL+PostGIS database and published within the OpenEnergyPlatform (OEP) [2], also developed and set up within the open_eGo project.

4.2.1 Grid

A spatial power grid model can be considered a prerequisite when modelling large scale power systems. In Section 2.2, the importance of modelling the power grid is highlighted. However, the modelling of highly interconnected power grids bears two central challenges: the (spatial) resolution of the grid and publicly available data of the grid assets. Publicly available data, in this case, is understood to allow the free use of data, for instance, also tolerating the publication of results created with this data. In short, publicly available data may only be properly used for power grid modelling if it is published under an open license[3] (Müller et al., 2017). In recent years some European and all German Transmission System Operators (TSO) published static models of their transmission grid (Hertz, 2019; Amprion, 2019; TenneT, 2019; TransnetBW, 2019). While these datasets provide some helpful insights especially for validation purposes, its contents may not be applied in open power system

[1] https://github.com/openego/data_processing

[2] https://openenergy-platform.org/

[3] For a list of appropriate open data licenses see https://wiki.openmod-initiative.org/wiki/Choosing_a_license#Data

models since the data is published without any license making any further publishing illegal under German law.
Another factor impeding the setup of a power system model is the diversified structure of German power grid operation. The transmission grid is divided in four operation zones, namely those of 50 Hertz Transmission GmbH in Eastern Germany, Amprion GmbH in Western Germany, TenneT TSO GmbH spanning from the Danish to the Austrian border and TransnetBW GmbH in Southwestern Germany. Additionally, the underlying grid of the high voltage level (60 kV to 110 kV) is again subdivided into numerous regional operators. While the processing of data published by the TSOs for the transmission grid may seem possible with some effort, the same seems unrealistic for the high voltage levels due to its diverse responsibilities and no legal obligation for the operators to publish any information on their power grid structure. Thus, when setting up an open power grid model in a high resolution, the operators' data may only be helpful for ex-post validation.
The global project OpenStreetMap (OSM)[4] aims at building a detailed global map fed by its users and allowing free use under the Open Database License (ODbL) (OKF, 2019). In Hülk et al., the application of OSM data for the open_eGo model was first introduced (Hülk et al., 2017). It was pointed out that "the coverage and quality of OSM is inhomogenous, but constantly improving due to a growing community of commercial and scientific users" (Hülk et al., 2017, p.81) (see also Section 4.5).
The importance and implications of considering the high voltage level in large scale power system modelling are pointed out in Sections 2.2 and 2.5. The power grid model provides the spatial basis for such a high-resolution approach. With the help of voltage levels, a distinction between distribution and transmission grid is possible. Figure 4.1 shows the distinction made in the open_eGo project and within this thesis: The extra-high and high voltage levels are considered as the transmission grid while any voltage level below these belongs to the distribution grid. The latter is not considered in this work.

The smallest entity in the transmission grid according to this definition, is a substation of the high voltage level. Within the open_eGo project, these substations provide the interface between transmission and distribution grid and are also the basis for the so-called grid districts. These grid districts support the spatial allocation of generators and demand data. They will be elaborated on in Sections 4.2.2 and 4.2.3. The contribution Hülk et al., 2017 describes the process of identifying these substations as well as creating grid districts and load areas around these. Generation and demand data are allocated accordingly. Since substations are the basis for the spatial power grid model, the process of identifying these is presented in more detail in the following.
There are three types of data in OSM: node, way, and relation. A node is a simple point, a way can be a line or a polygon, and a relation describes a structure that is composed of nodes and/or ways. Examples for a relation can be a cycle path or in

[4] `www.openstreetmap.org`

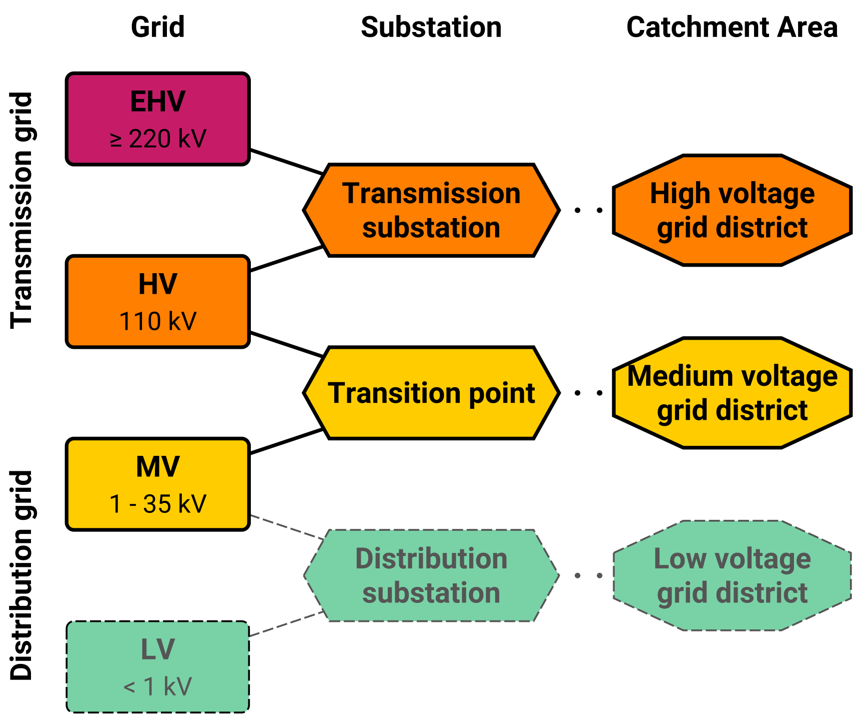


FIGURE 4.1: Simplified scheme of voltage levels. Figure by Ludwig Hülk / CC BY SA 4.0 (Hülk et al., 2017)

this context a power circuit. Each item of these data types may contain information in the format $(key, value)$. For instance, substations usually have $key = power$ and $value = substation$. Even if there are certain conventions in OSM on how to map such items, substations can be found named station, sub_station or substation and they are also commonly mapped in all three data types node, way or relation. Thus a query for substations in the OSM data set needs to consider such inconsistencies in the mapping and naming of the same item. When carrying out this query, the information on the voltage of a substation is the central value. To consider substations with incomplete or incorrect voltage information, substations at the beginning or end of a power line of a certain voltage level are assigned the same voltage. An additional convention was introduced within the open_eGo project through the consideration of assets with a voltage level of 60 kV as 110 kV. This is a rather uncritical simplification as there are only very few substations and power circuits in 60 kV in Germany and their operation will expire and shift to 110 kV in the near future according to grid operators. In the next step, irrelevant substations are filtered, which in the case of Germany are mainly substations of the separated railway power grid which is operated at 16.67 Hz and not considered here. Finally, substations situated very close $(d < 150m)$ to each other are aggregated to one substation. The complete process of generating relevant substations from raw OSM data is summarised in Table 4.1, which was first published in Hülk et al., 2017. The implementation of this process

TABLE 4.1: Process of abstraction and filtering from raw OSM data to coherent substations. This table was first published in Hülk et al., 2017.

Step	Assumption	Result
1. Raw OSM data processing	power = *	extracted open power dataset of all voltage levels
2. Filter substations	type *node* or *way* or *relation* power = substation or sub_station or station	substations of all voltage levels
3. Filter voltage levels	for EHV substations: voltage $\geq$ 220,000 for HV substations: voltage = 110,000 or 60,000 or line starts/ends at substation	EHV substations HV substations HV_{Rail} substations
4. Filter relevant substations	situated within administrative boundary frequency $\neq$ 16.7 or 16.67 operator $\neq$ DB_Energie or DB Energie GmbH or DB Netz or DB Netz AG substation $\neq$ transition or traction	EHV substations HV substations
5. Aggregate substations	aggregate substations that are situated within a distance of $75\,m$ from their boundary	Transmission substations Transition points

is part of the open_eGo data processing [5]. Applying the process to an OSM data set dated October 1st 2016 reveals 3591 HV and 424 EHV substations.

Not only the nodes of the power grid model are derived from OSM data, but also the line topology connecting these nodes. According to Medjroubi et al. and Mueller et al., the OSM power grid data covers approximately 95 % of the real extra high voltage grid concerning the line length (Medjroubi et al., 2017). Müller et al., 2017 introduced the general method of extracting the power grid topology and setting up a model ready for power flow simulations. The proper use of OSM data types node, way, and relation is essential when mapping grid topology assets. Usually, nodes can be considered single towers of power lines which are connected by a way. A relation may consist of several ways and define, for instance, a closed power circuit between two or more substations (Müller et al., 2017). The mapping of power circuits is hardly possible only based on visual inspection since information – such as the number of wires belonging to a circuit – must be known. The information on the static grid models published by the TSOs may help to identify power circuits and thus accurately

[5] https://github.com/openego/data_processing

TABLE 4.2: Voltage levels relevant in the German transmission grid, their respective coverage in the OSM database by *relations* and *ways*, and their role in state-of-the-art power flow models. In this context the distinction between *good* and *poor* can be regarded as the adequacy to use the data in power flow simulations. This table was first published in Müller et al., 2017.

Voltage level	**OSM relations**	**OSM ways**	**Integrated in grid models**
380 kV	good	good	yes
220 kV	good	good	yes
110 kV	poor	good	typically not
60 kV	poor	good	typically not
$\leq$ 35 kV	none	poor	no

map relations. Several open-source tools for the extraction of this topology data from OSM have been developed in recent years. One of the first approaches was the tool SciGRID which was the product of a funded project of the same name from 2014 to 2017. In SciGRID, only relations are extracted, which means that a good coverage and mapping quality is a prerequisite when applying the tool. For high voltage power lines, Mueller et al. find the coverage of relations rather poor with only 14 %, which disqualifies SciGRID for this work (Müller et al., 2017). Another extraction tool that could potentially be applied is named GridKit [6]. The software was developed by a student within the SciGRID project but pursues a different approach as it is a heuristic and completely geometry-based approach where no relations, but only nodes and ways are considered. In this case, the topology coverage is improved but the possibly existing information on power circuits and electrical properties in OSM is neglected. Thus, broad assumptions have to be made before utilising GridKit in power flow simulations. The third tool is named osmTGmod and was initially developed by Malte Scharf in his Master Thesis at Wuppertal Institut (Scharf, 2015). An enhancement of the initial software within the open_eGo project has become necessary due to the consideration of the high voltage level and several additional functions. Its logic lies between SciGRID and GridKit as relations, ways, and nodes are considered. The central motivation to use osmTGmod in this work is to apply a tool that is appropriate to the available OSM data and mapping quality per voltage level. Table 4.2 summarises the OSM quality per voltage level and data type. As in this work any voltage levels above 60 kV shall be considered, an extraction tool that makes use of the data type ways seems necessary. In osmTGmod, the relatively precise information from relations is used at first. Additionally, for those assets with insufficient coverage through relations, ways are considered.

The osmTGmod tool applies a PostgreSQL database extended by PostGIS. The abstraction process is mainly implemented in SQL and PostgreSQL's procedural language pl/pgSQL. The initiation and general control of osmTGmod are carried out by

[6] `https://github.com/bdw/GridKit`

a Python-environment. The resulting grid model is designed in a way that allows direct use in standard power flow software such as Matpower[7]. Initially, a PostgreSQL database is set up, which in the next step is fed with the raw OSM data filtered for $key = power$. The transition points defined within the data processing and described above are fed into a separate table. These transition points are central and need to be connected to the grid since load and generators are allocated to these substations. Once the raw data is complete, a collection of SQL queries is executed as the core of the abstraction process. In the beginning, relevant voltage levels are filtered, and in the case of this work, the voltage levels 110 kV, 220 kV, and 380 kV are selected. OSM items that are mapped in different voltage levels but are close to one of the standard levels are assigned to the closest standard voltage. Similar to the definition of the transition points, any infrastructure that can be securely assigned to the separate railway grid are disregarded. Generally, since the German power system is an AC system, three cables are assumed per power circuit which is adjusted here for poorly mapped cases. The same applies for wires where information that is available from the OSM data is adopted, while in cases of missing or incorrect data assumptions have to be made. Here, four wires are assumed standard for the 380 kV voltage level, two wires at 220 kV, and one wire at 110 kV. Apart from the electrical parameters, mapping errors also occur in the geometry; for instance, when power lines simply end without connecting to a substation. In such cases, osmTGmod checks for close substations, connects to these if available or disregards the power line if no close substation is existent. The connection of the transition points as the central unit for load and generation allocation takes place in a similar way and makes use of the Djikstra algorithm. A check for close power lines from transition points originally not connected to the grid is carried out, and the transition point is then connected through a newly added power line of the respective voltage to the power grid. Apart from power lines and substations, also complete subgrids occur that have no connection to the rest of the interconnected grid. Primarily due to the existence of 110 kV underground cables in urban areas, it is assumed that these cases occur due to missing OSM information and thus subgrids are connected to the rest of the power grid similarly to the logic for initially not connected transition points. Transformers between the present voltage levels are the central part of a substation. In osmTGmod transformers are depicted as power lines without a geometry but connecting the voltage levels present in a substation. The nominal capacity of the transformers is assumed to be the sum of the apparent power $S_{nom,l}$ of any power lines of the same voltage within the respective substations. Consequently and possibly in contrast to real power systems, the transformer capacity may not lead to congestions in power flow simulations (Scharf, 2015). The total nominal capacity per substation is the basis of the calculation of the number of installed transformers according to the apparent power S_{nom} per transformer in Table 4.3.

According to Flosdorff and Hilgarth, 2005, the impedance Z_{tran} of a transformer

[7] `https://github.com/MATPOWER/matpower`

TABLE 4.3: Electrical parameters of standard transformers within the extra-high and high voltage level. Source: based on Oeding and Oswald, 2011. This table was first published in Müller et al., 2017.

S_{nom} **in MVA**	V_a **in kV**	V_b **in kV**	v_{sc} **in %**
1,000	380	220	13.5
300	380	110	14
200	220	110	12

can be assumed to be equal to the reactance X_{tran} since in comparison Z_{tran} may be safely disregarded. With the help of the short circuit voltage $v_{sc,lit}$ and the respective upper nominal voltage given in Table 4.3 the reactance X_{tran} is determined as:

$$Z_{tran} = X_{tran} = v_{sc,lit} \cdot \frac{V_a^2}{S_{nom,lit}} \tag{4.16}$$

Based on the present geometrical information for each power line, the respective electrical parameters are assigned as a necessary prerequisite to carry out power flow simulations. The applied standard values for overhead lines and underground cables are presented in Table 4.4 and given by Brakelmann, 2004.

TABLE 4.4: Electrical parameters of standard overhead lines and underground cables for the extra-high and high voltage level. Source: based on Brakelmann, 2004. This table was first published in Müller et al., 2017.

V_{nom} in kV	type	S_{nom} in MVA	R' in Ω/km	L' in mH/km	C' in nF/km
110	line	260	0.109	1.2	9.5
110	cable	280	0.0177	0.3	250
220	line	520	0.109	1	11
220	cable	550	0.0176	0.3	210
380	line	1790	0.028	0.8	14
380	cable	925	0.0175	0.3	180

The relevant electrical parameters for power lines in power flow simulations are the resistance R_l, the reactance X_l, the capacitance C_l and the apparent power $S_{nom,l}$ according to the thermal limits of the line. These parameters are defined by the following equations (Medjroubi et al., 2017):

$$R_l = \frac{l_l \cdot R'_{lit}}{n_{circuits}} \tag{4.17}$$

$$X_l = \frac{l_l \cdot L'_{lit} \cdot \omega}{n_{circuits}} \tag{4.18}$$

$$C_l = l_l \cdot C'_{lit} \cdot \omega \cdot n_{circuits} \tag{4.19}$$

$$S_{nom,l} = S_{nom,lit} \cdot n_{circuits} \tag{4.20}$$

The input values for these equations are on the one hand given in Table 4.4 and on the other hand, mainly pre-defined by the information included in the power grid model produced by osmTGmod. The length l_l of a power line can be derived from the geometry and is given for each line in the resulting power grid database. The voltage level V_{nom} which defines the respective standard per unit length values for R', L', C' and the circuit-based S_{nom} in Table 4.4 is also defined for each power line. The number of power circuits is derived from the information on the number of conductors for each power line. With the general assumption of a three-phase AC power system in Germany (Schwab, 2012), the resulting quantity of power circuits is defined by $n_{circuits} = \frac{cables_l}{3}$. In line with the standard frequency of $f = 50Hz$ in the UCTE power system, the angular frequency is defined as $\omega = 2 \cdot \pi \cdot f$. In power flow simulations, the definition of a slack bus as the balancing bus is a necessity and is defined as the bus with the highest generation per year within this model (Rendel, 2015). The (n-1) criterion is a general rule in grid operation and specifies that the outage of one asset in a connected power system shall not harm the overall power system security and in no terms lead to a general outage. In order to consider this restriction regarding power line utilisation, the capacity is globally reduced to 70 % of the maximum capacity of each power line (Wiese et al., 2014).

The abstraction process by osmTGmod only considers power grid infrastructure within the borders of Germany but identifies cross-border power lines to other countries. In order to model the impact of neighbouring countries on power flows in Germany, the electrical neighbours of the German power system (The Netherlands, Luxembourg, France, Switzerland, Austria, Czech Republic, Poland, Sweden, Denmark) are considered through these cross-border lines. Due to handling and computational efforts, the neighbouring power systems are simplified and centred at one artificial bus in the centre of the respective country. Any generation and load of a country are assigned to this bus. The power exchange with the German and possibly also other neighbouring countries of Germany takes place via the cross-border power lines which are connected to the artificial bus. Connections between the neighbouring countries of Germany are identified via the ENTSO-E grid map (ENTSO-E, 2019) and in terms of their electrical parameters defined according to the standard values presented above. As of 2016, there are only two DC interconnectors from or to Germany, namely the Baltic Cable to Sweden and Kontek to Denmark. In these cases, a manual definition of their electrical properties and losses takes place according to ABB, 2019b; ABB, 2019a; FfE, 2014. Note that the power systems of Belgium and Norway are not directly connected to the German power system as of 2016 and are therefore not included in the basic setup.

The results of the osmTGmod grid model are saved in separate tables for buses, branches, DC lines and general metadata of the abstraction process. The software osmTGmod [8] is separated from the data processing scripts in open_eGo. The data used in this work is based on an OSM data export dated October 1st 2016. Table 4.5

[8] `https://github.com/openego/osmTGmod`

TABLE 4.5: Characteristic results for the grid topology model. Parts of this table have initially been published in Müller et al., 2017.

Parameter	Quantity
Buses	11,294
thereof	
Substations	3,702
Joints	7,592
Branches	19,605
thereof	
Overhead lines	18,221
Underground cables	869
Transformers	515
DC links	5

shows the resulting number of buses and branches for this data set. Figure 4.2 shows the resulting grid topology. Note that the number of substations presented here (3,702) includes both, EHV and HV level. After filtering the sole EHV substations (compare Table 4.1), 3591 substations or transition points remain.

4.2.2 Generation

The power generation data is another central parameter of power flow simulations. It needs to be spatially allocated to the defined transition points, and in the case of fluctuating renewable energies also their feed-in characteristics need to be pre-defined based on weather assumptions. In the open_eGo project, three generation scenarios are defined. Hence, the complete generation portfolio is pre-defined and no subject to optimisation in this model. The current situation of the German power system is defined by the status quo scenario, which is referenced to the year 2015. The second scenario, named NEP 2035, can be considered an intermediate scenario on the track towards a fully renewable power system. The NEP 2035 scenario is based on the generation portfolio as defined by scenario B2-2035 of the NEP 2015 (Feix et al., 2015). According to the authors of the NEP, this scenario considers a relatively high RES share and additional natural gas capacities while a CO_2 limit of 134 million tonnes in 2035 is met. In comparison to the latest NEP confirmed in December 2019, this scenario may be considered conservative. The current version includes a CO_2 limit of 127 million tonnes by 2035, has reduced conventional capacities of 5 GW and approximately 40 GW higher RES capacities than the 2015 version that is considered in the open_eGo project and this thesis (Bundesnetzagentur, 2019a; Rippel et al., 2019). The third scenario is named eGo 100 and does not contain any conventional generation capacities in Germany, which should allow a completely renewable power generation. The generation capacities of the eGo 100 scenario are based on e-Highway2050, 2015. The key parameters per scenario are shown in Table 4.6. The

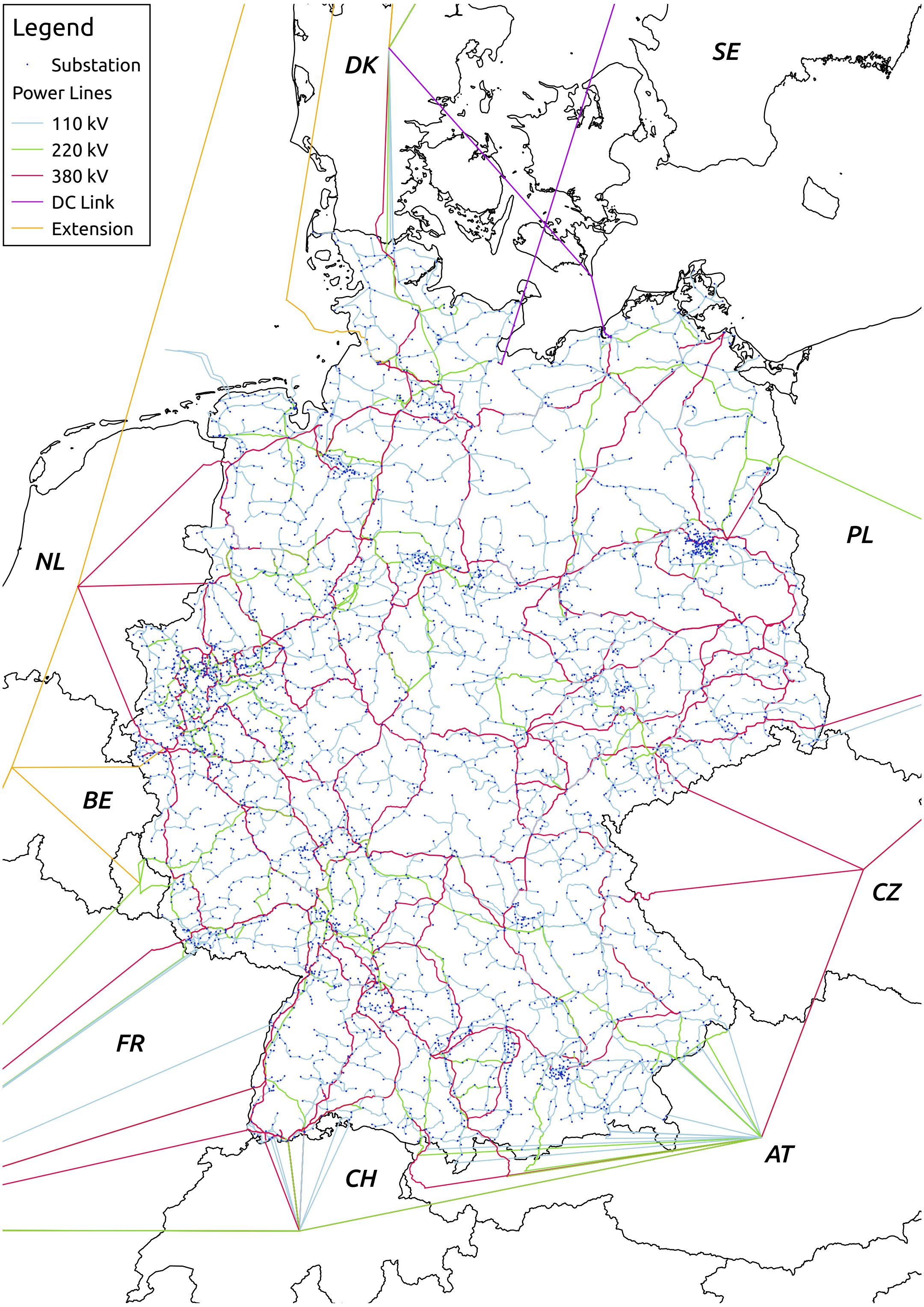


FIGURE 4.2: Spatial illustration of the final power grid model. Note:
(1) Offshore wind grid connections are not depicted.
(2) Lines in orange indicate the extension scenario connection Norway and Belgium. These lines are not included in the basic setup and only added for certain variations (compare Section 5.5).
(3) An extended view of this map can be found in Appendix B.

TABLE 4.6: Characterisation of scenarios by key parameters.

	status quo		NEP 2035		eGo 100	
	Germany	Total	Germany	Total	Germany	Total
Share of RES in installed capacity	50%	42 %	75%	67 %	100%	97 %
Net electricity consumption (TWh)	506	1569	506	1569	506	1569
Annual peak load (GW)	87	253	87	253	87	253
Share of renewable energy in el. consumption[1]	27%	–	66%	–	100%	–

[1] Statistic and report values (See: BMWi, 2017, Feix et al., 2015). May differ according to calculation.

separation between only the German and the full power system, including neighbouring countries illustrates the difference to the neighbouring power systems and their respective generation portfolio.

Installed Capacities – Generation The installed generation capacities differ according to scenario and region. For the status quo scenario, the numbers for Germany are based on data sets generated in the Open Power System Data (OPSD) project (Bunke, 2016; Gerbaulet and Kunz, 2016). The data refers to the status at the end of the year 2015. These data sets are taken from public registries of single power plants and verified. The status quo data for the neighbouring countries is aggregated per technology and country and taken from ENTSO-E, 2014 (scenario B, values at 19.00 p.m.). The data of the NEP 2035 scenario is for Germany based on scenario B2-2035 of the first draft of the NEP published 2015 (Feix et al., 2015). Minor adjustments of the numbers are made, for instance, the assignment of small CHP power plants to natural gas or biomass. For the neighbouring countries, the installed capacities are also taken from the source known from the status quo scenario ENTSO-E, 2014 (vision 3, values at 19.00 p.m.). In contrast to the other two scenarios, data for the eGo 100 scenario is taken from one source, the study eHighway 2050, which is a European study mainly conducted by the TSOs (e-Highway2050, 2015). A central manipulation of the original data is the disregard of 13 GW natural gas capacity in order to achieve a completely renewable power system in Germany (Wingenbach, 2018).

Installed Capacities – Storage Existing storage units in Germany and its neighbours are considered similar to generators in the LOPF, the main distinction is the absence of a marginal price, but instead the direct consideration of conversion losses (efficiency). For the status quo scenario, only PHS are considered as existing storage since other technologies have not been installed in relevant numbers yet. However, new technologies are introduced in the further optimisation process presented in Section 4.3. For the German power system, the existing PHS remain constant for all scenarios due to very limited additional potential (Gimeno-Gutierrez and Lacal-Arantegui, 2013). The storage optimisation covers any additional storage capacity. Reservoir hydro power plants may provide another type of storage with less flexibility compared to PHS due to the absence of pumps. Since large lake reservoirs are a natural precondition, this storage/generation type only occurs in the alpine countries Austria, Switzerland, Germany, and France as well as in Sweden and the Czech Republic. For simplicity, reservoir and run of river power plants are combined to hydro power in Figure 4.3 and Tables 4.7 and 4.8. Storage capacities in the neighbouring countries are based on ENTSO-E, 2014 for the NEP 2035 scenario and on e-Highway2050, 2015 for the eGo 100 scenario, similar to generation units. Due to inconsistencies in quantifying the pumped storage capacities in contrast to other hydro power generation capacities, a simplification has to be made. In this approach, the renewable hydro power capacity (often referred to as run of river) is subtracted from the total hydro power capacity per country to receive the pumped storage capacities. In contrast to Germany, additional hydrogen and battery storage units are installed in the neighbouring countries in the eGo 100 scenario. These capacities are predefined based on Wingenbach, 2018 and thus not part of the capacity optimisation of German storage. Although the storage in neighbouring countries might influence the optimised storage requirements in the German power system, it is expected that there will be significant storage capacities in these countries in such a RES-based scenario. At the same time, the focus of the storage optimisation in this thesis is clearly on the German power system, which is why it is not carried out for the complete system, including neighbours. In the context of strictly considering today's grid capacity not only for Germany but also to and between neighbouring countries, additional storage capacity is expected to be required to allow for feasible power systems. The impact of this approach to the resulting storage capacities is presented in Section 5.6. The total installed capacities per scenario and separated in Germany alone and in total with its electrical neighbours are shown in Figure 4.3 and Table 4.7. The difference in German hydro power generation capacity between the NEP 2035 and the eGo 100 scenario shown in Table 4.7 can be explained by a different consideration of hydro power capacity in neighbouring Austria directly connected to the German power grid. A more detailed listing of capacities per country can be found in Appendix A.

Generation Parameters Marginal generation costs are the central parameter for modelling the dispatch of existing power generators. In this work, all cost components such as fuel costs or costs for CO_2 emission certificates are included in one value. The costs for CO_2 emission certificates are set to 5.91 EUR/tCO_2 in the status quo scenario (Wingenbach, 2018; EEX, 2014), 31.00 EUR/tCO_2 in the NEP 2035 scenario (Feix et al., 2015) and 62.05 EUR/tCO_2 in the eGo 100 scenario (Wingenbach,

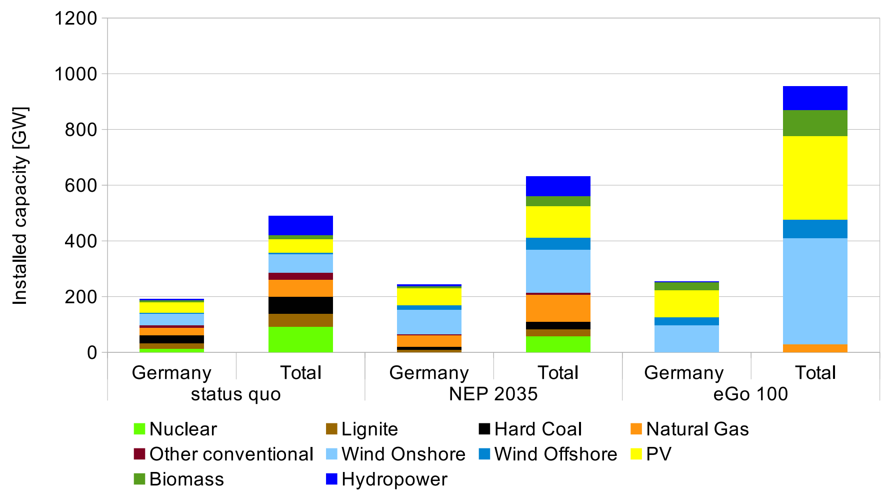


FIGURE 4.3: Installed generation capacity per scenario and separated by Germany alone and including neighbouring countries.

2018; Nitsch et al., 2012). The individual fuel costs per generation type and scenario are documented in Bunke et al., 2017. There is no distinction in countries for the cost assumptions. The resulting marginal costs per scenario and generation type are presented in Table 4.8. Apart from the marginal costs, no additional generation parameters are required for the LOPF. The individual efficiency of power plants is implicitly considered through the marginal costs, and no distinction is made for individual power plants within the same generation type. The efficiency of PHS is assumed to be 78.3 % for a full charging and discharging cycle and for all scenarios (Erlach et al., 2015). Further generation constraints such as ramp limits for thermal power plants are not considered in this work due to the increased optimisation complexity of such constraints. Thus, the dispatch of thermal power plants may fully shift within its capacity limits from one timestep to the next. The absence of nuclear- or coal-fired power plants in the central eGo 100 scenario allows this simplification. In the case of the NEP 2035 scenario, a simplified analysis of the effects of start-up constraints is conducted and discussed in Section 5.4.

Spatial Allocation The basis for the spatial allocation and model-based grid connection of power plants are the grid districts surrounding the transition points introduced in Section 4.2.1. The creation of the grid districts is described in detail in Hülk et al., 2017. The data sources for installed generation capacities as described above contain spatial information on the location of each power plant. The degree of detail in the original data is very diverse – while some power plant locations are known through a postal address, others are accumulated per postal code area and thus somewhat imprecise. Hence, all power plants are georeferenced based on the information available. Apart from the location, the information on the voltage level a plant is connected to is required. With the help of these parameters, power plants may not only be assigned to the correct transition point but also directly connected

TABLE 4.7: Installed generation and storage capacities in GW for Germany alone and in total with its neighbouring countries, separated by scenario. Source: Bunke et al., 2017

Technology	status quo		NEP 2035		eGo 100	
	Germany	Total	Germany	Total	Germany	Total
Nuclear energy	12.0	92.5	0.0	57.5	0.0	0.0
Lignite	21.2	46.0	9.1	25.7	0.0	0.0
Hard coal	27.8	62.3	11.0	27.3	0.0	0.0
Natural gas	27.5	59.4	40.7	96.2	0.0	28.5
Oil	4.4	15.8	0.8	5.6	0.0	0.0
Waste	1.7	8.0	1.6	1.6	0.0	0.0
Other conventional generation (mixed fuels)	2.5	2.5	1.0	1.0	0.0	0.0
Total conventional generation	**97.1**	**286.5**	**64.2**	**214.9**	**0.0**	**28.5**
Wind onshore	41.3	66.1	88.9	153.6	98.4	382.1
Wind offshore	3.4	5.0	16.4	42.8	27.0	65.9
Photovoltaic	38.5	48.3	60.1	113.8	97.8	300.1
Biomass	7.2	15.2	8.3	36.0	27.8	93.3
Hydro power	5.3	69.7	5.8	70.7	3.2	84.5
Total renewable generation	**95.6**	**204.3**	**179.5**	**416.9**	**254.2**	**925.9**
Pump storage	9.3	19.7	9.3	33.9	9.3	51.4
Battery storage	–	0.0	–	0.0	–	16.7
Hydrogen storage	–	0.0	–	0.0	–	39.7
Total capacity	**202.0**	**510.5**	**253.0**	**665.7**	**263.5**	**1062.2**

to the correct voltage level. In cases where the voltage information of a power plant is not given, the installed capacity may hint to the appropriate voltage level.
The spatial allocation of offshore wind parks takes place solely through their onshore grid connection point. These are given for the status quo scenario in the former Offshore Grid Connection Plan (Feix and Hörchens, 2015). In case of the NEP 2035 scenario, the more recent approval of the NEP 2019-2030 is applied for the definition of the offshore wind connection points (Bundesnetzagentur, 2019a).

Several variations of the offshore wind capacities are carried out (compare Section 5.6). In these cases, the grid connection points of the additional capacity are also defined according to Bundesnetzagentur, 2019a. The same applies to the connection of the 27 GW offshore wind planned in the eGo 100 scenario. The respective grid connections are taken from Bundesnetzagentur, 2019a (Szenario C2038). If an onshore grid connection point – as defined in Feix and Hörchens, 2015 or Bundesnetzagentur, 2019a – is only planned and thus not yet part of the grid model, the respective offshore wind park is connected to the closest substation nearby. All potential offshore wind grid connection points are illustrated in Figure 4.4.
For the scenario NEP 2035, the spatial allocation of thermal and hydro power plants

TABLE 4.8: Marginal costs per generation type and scenario.

	status quo EUR/MWh	**NEP 2035** EUR/MWh	**eGo 100** EUR/MWh
Nuclear energy	4.68	5.48	–
Lignite	10.78	17.64	–
Hard coal	14.95	24.79	–
Natural gas	32.30	41.93	56.05
Oil	41.02	68.86	–
Waste	31.65	39.93	–
Biomass and CHP < 10 MW	23.96	31.11	31.63
Other conventional generation (mixed fuels)	31.65	39.93	–
Hydropower	0.0	0.0	0.0

is realised according to the registry published alongside the NEP (50 Hertz Transmission GmbH and Amprion GmbH and TenneT TSO GmbH and Trans-netBW GmbH, 2014a). The allocation of hydro power plants and PHS in the eGo 100 scenario is assumed to remain constant at these locations. Biomass and small ($P_{nom} < 10MW$) natural gas and hydro power plants are expected to increase proportionally in capacity at their respective status quo locations. Due to the strong growth of small CHP plants in the scenario, an alternative distribution has been developed in a project by Mario Kropshofer. In this approach, small CHP plants are spatially distributed mainly according to the population density as heat demand is strongly dependent on this parameter (Kropshofer, 2017). Wind onshore and PV power plants are allocated based on their status quo distribution, too. In these cases, the number and installed capacity in the status quo scenario is analysed per municipality. Based on this, reference wind power and PV plants are defined. The given installed capacities per federal state (in case of the NEP 2035 scenario) or the whole country (in case of the eGo 100 scenario) then provide the target value for the proportional capacity increase in each municipality. The location of these new power plants is assumed to be at the centroid of the respective municipality. This approach is assumed to be sufficient when modelling the high voltage level and above while modelling power flows in the lower voltage distribution grid would require a more detailed approach. Since the open_eGo project aims at modelling all voltage levels, such a more detailed approach has been developed and described by Amme et al., 2018 but is not relevant in this work. In the case of the neighbouring countries, the spatial allocation of power plants is straightforward and assigned to the central bus of each country.

Generation Time-series The general principle of the LOPF applied in this work is introduced in Section 4.1. According to this logic, only weather-dependent time-series of wind and solar power plants are exogenously fed into the LOPF process. At the same time, any other generation units that operate on marginal costs or storage efficiency are endogenously dispatched within the LOPF without any presetting. The

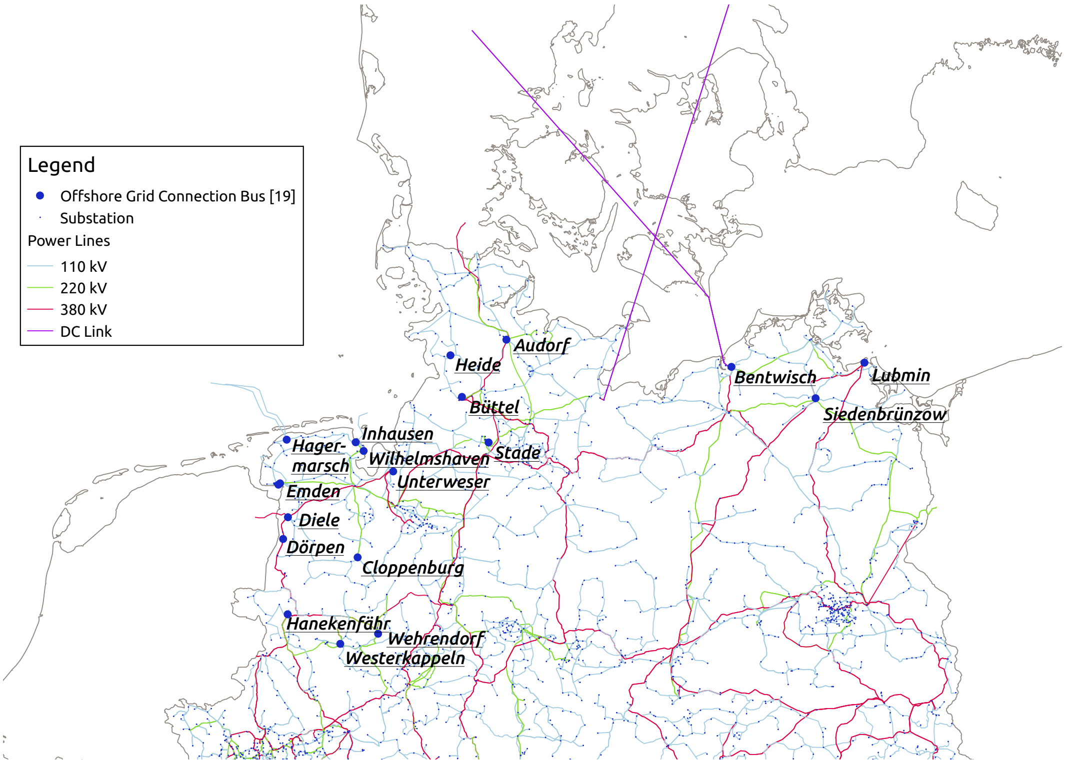


FIGURE 4.4: Spatial illustration of the offshore wind grid connection buses. Note that this Figure depicts any potential buses while not all of these are used as offshore grid connection points in the basic modeling setup.

feed-in time-series of wind and PV are dependent on the weather resources. In the open_eGo project as well as in the present work, 2011 is the representative weather year. The weather data itself is reanalysis data of the CoastDat-2 model, which is produced with the help of the climate model COSMO-CLM (Geyer, 2014; Geyer and Rockel, 2013). Out of these data sets wind speeds and values on the surface roughness measured at 10 m atop the surface and solar irradiation are used. The reanalysis data is available in a spatial resolution of approximately 22 km between each raster point in Germany. In line with the allocation of generation and demand for the neighbouring countries, in these cases, one point at the centre of each country is considered. In order to calculate feed-in time-series based on this weather data, reference wind and PV power plants have to be defined. The reference PV module is a YL210 2008 E manufactured by Yingli. The azimut angle is set to 180°, the pitch assumed to be 30°, and the reflectance 0.2 p.u. The reference offshore wind power plant is a Siemens SWT 3.6 120 with an installed capacity of 3.6 MW and a rotor diameter of 120 m. The decision to use this wind turbine as a reference is based on the relatively high market share of the manufacturer Siemens of approximately 47 % of newly installed capacity globally and 60 % of existing offshore wind capacity in Germany 2017 (Durstewitz et al., 2018). Reference onshore wind turbines are subdivided into seven separate turbine types according to their power rating and based on the registry of installed wind power turbines in Germany. Once seven separate power

TABLE 4.9: Reference onshore wind power plants and their technical parameters.

Power range [MW] from	Power range [MW] to	Turbine model	Capacity [MW]	Hub height [m]	Rotor diameter [m]
0.0	0.7	Vestas V47	0.66	65	47
0.7	1.1	Enercon E53	0.80	73	53
1.1	1.6	Nordex S70	1.50	65	70
1.6	2.1	Vestas V90	2.00	105	90
2.1	2.4	Enercon E82	2.30	108	82
2.4	3.1	Nordex N117	2.40	141	117
from 3.1		Vestas V126	3.30	137	126

TABLE 4.10: Potential full load hours after application of correction factors for the generation of hourly time-series of wind and PV.

Technology	**Potential Full load hours [h/a]**					
	status quo		NEP 2035		eGo 100	
	DE	Total	DE	Total	DE	Total
Wind onshore	2061	1931	1999	1848	2024	1773
Wind offshore	4482	4597	4389	4386	4393	4680
Photovoltaic	968	977	964	979	963	988

rating classes are found the turbine with the most installations within the respective power class is defined as the reference turbine. Table 4.9 lists the resulting reference turbines and their parameters.

The power curves of all reference plants, for PV, offshore and onshore wind are contained in the oemof feedin-lib (Krien and oemof developing group, 2016) which then calculates normalised feed-in time-series from the weather data and the reference power plant information. Since the CoastDat-2 weather data is known to overestimate the feed-in and thus the full load hours per technology, a correction factor is introduced for each technology which leads to more realistic full load hours (Wiese, 2015). The full load hours of the NEP 2015 are considered when applying the correction factors in a way that the resulting numbers are in the same range (Feix et al., 2015). The resulting full load hours per technology as well as scenario differentiated for Germany and the full system are presented in Table 4.10.

River-based hydropower plants may provide flexible feed-in with the resource limit considered through a cap of 65 % of their installed capacity (Wingenbach, 2018). Thus, the maximum power output of these hydropower plants is 65 % of their nominal capacity. Another technology with a resource limit is reservoir hydropower which only occurs in countries with the respective natural precondition as mentioned above. Wingenbach derived average availability rates of these reservoir power plants

TABLE 4.11: Full load hours of reservoir power plants in neighbouring countries. Source: (Wingenbach, 2018) based on (e-Highway2050, 2015).

Country	full load hours [h]
AT	2007
CH	2596
CZ	1603
FR	1838
SE	3878

from the e-highway results (Wingenbach, 2018; e-Highway2050, 2015). The resulting full load hours per country are presented in Table 4.11 and applied as a limitation to the respective power plants in this model.

The resource necessary to feed biomass power generation is not limited in this work but checked for plausibility ex-post (compare Section 5.7).

4.2.3 Demand

The depiction of the total power demand is relatively straightforward compared to the generation. The total power demand per year remains constant for all three scenarios. While on the one hand efficiency gains may lead to decreasing power demand, increasing electrification of transportation or heating and the establishment of more electronic devices, in general, are expected to push power demand. For 2025 and 2035 respectively, the NEP 2015 expects a constant power demand at today's level (50Hertz Transmission GmbH and Amprion GmbH and TenneT TSO GmbH and Trans-netBW GmbH, 2014b). For Germany, the 2011 total net electricity demand (disregarding railway operation) adds up to 506 TWh (Arbeitsgemeinschaft Energiebilanzen, 2019) and provides the basis in this thesis. In total considering electrical neighbours, the demand is 1569 TWh. The demand patterns per country for the neighbouring countries are taken for the same year from ENTSO-E's transparency platform (ENTSO-E, 2016).

Spatial Allocation Hülk et al., 2017 described the open_eGo approach to define grid districts and load areas and to spatially allocate the annual power demand to and within these areas. The central data sources are the published annual power demand per federal state in Germany (Arbeitsgemeinschaft Energiebilanzen, 2019), information on inhabitants, and gross value added in a high resolution, and OSM data on the utilisation of certain areas, such as industrial zones. The spatial distribution from the federal state level down to the load areas is separated by sector. For households, a direct correlation of inhabitants and power demand is assumed (Leuthold, 2009; Mackensen, 2011; Rathke, 2013; Robinius et al., 2017). Since information regarding inhabitants is known when defining load areas (Hülk et al., 2017), the spatial distribution is rather straightforward. For the industry and retail sector, a correlation between gross value added and power demand is assumed (Leeuwen et al., 2014; Rendel, 2015). Available information on the gross value added per municipality is further distributed to load areas according to the utilised area (based on OSM information, see Hülk et al., 2017) of the respective sector. The power demand of the agriculture sector is allocated based on the size of agricultural areas in OSM. The central motivation for this relatively detailed approach is the application for power flow modelling for low and medium voltage grids in the open_eGo project. Since these distribution grids are not considered in this work, the high-resolution demand information is aggregated per grid district and thus the respective HV substation. Industrial consumers, on the other hand, are assumed to be directly connected to the EHV transmission grid. In cases where an industrial area exceeds an annual demand of 130 GWh such a direct connection is assumed. The 424 known substations of the transmission grid are potential connection points, and the allocation is carried out using voronoi cells that determine the location of an industrial area to the closest transmission substation.

Demand Time-series The result of the spatial allocation described above is the annual demand per transition point, subdivided by sector. The general approach to producing hourly demand time-series based on these sums is described in Müller et al., 2017. In order to be in line with the generation time-series, 2011 as the same representative weather year is applied for the demand time-series. The basis of the bottom-up demand time-series generation are standard load profiles that are used by power utilities and grid operators to model power demand (Hayn et al., 2014; Meier et al., 1999). The association of German utilities (BDEW) publishes these normalised load profiles by sector (residential, retail, agriculture, industry) (BDEW, 2017). In case of power demand associated with the industry sector, a stairs function is assumed (Schachler, 2014). With the help of the tool demandlib developed in the oemof project (Developer Group, 2016) the sector-specific time-series are calculated per transition point.

4.3 Optimisation of Storage Units

A central requirement of the method developed for this thesis is the ability of an approach to produce optimal storage capacities in a high spatial resolution. At the same time, the respective utilisation of these storage units must be assessed. The research overview in Section 2.4 indicates several possible ways to obtain these results.

The first approach for this thesis was to develop an iterative heuristic that consists of four central steps. In a first step, the residual load as the difference between the total load and the production of variable RES is calculated for each hour and each bus. Due to the absence of any intertemporal constraints, this process can be carried out in advance for a full year. In contrast, the following steps must start with the first hour and take preconditions from previous snapshots into account. Based on the residual load for $t = 1$, a market simulation depicting the merit order creates the production of flexible power plants at each bus n for this timestep. In the third step, the power grid is added to the problem as the resulting production per bus is fed into a power flow simulation which considers the thermal limits of the power lines. In cases where this power flow simulation creates a feasible result meeting the thermal limits, the process starts over with the market simulation for $t+1$ taking into account the utilisation of assets in $t=1$ as a precondition for instance due to ramping constraints. If the power flow produces an infeasible result, another iterative process is initiated. First, a redispatch logic is added to the power flow simulation, allowing ramping up or down flexible generation behind or in front of a grid bottleneck. Cases, where this process produces feasible results, lead to the next timestep $t+1$. In cases where this redispatch may not cure the problem, a virtual unlimited storage unit is assumed at each bus. The required utilisation of each storage unit for the entire period then provides the first indication of optimal storage at each bus. In an additional step after the simulation, storage capacities need to be set up based on the utilisation and may be validated in a second simulation run with predefined storage capacities.

The described heuristic process generally may only produce near-optimal solutions to optimal storage sizing and siting (see also Pandžić et al., 2015). Thus, a solution may only provide a hint towards optimality, but cannot guarantee it as an optimisation problem does. At the same time, the heuristic process itself and hence its results are transparent and comprehensible. Due to the separated steps of the process, intermediate results can be analysed, and the impact of, for instance, the power grid constraints may be assessed. In contrast, an integrated optimisation produces a single optimal result while analyses of the impact of certain variables may only be carried out ex-post. The advantages and disadvantages were taken into account when the decision was made to apply an integrated optimisation rather than a heuristic process for optimising sizing and siting of storage.

The general method to find optimal storage units with one optimisation problem applied in this thesis was also described in Wienholt et al., 2018. Similar to the initial heuristic approach, the installation of unlimited storage capacity is allowed at any bus within the LOPF according to

$$\sum_{n,s} c_{n,s} \cdot H_{n,s} \tag{4.21}$$

as part of the overall objective function as presented in equation 4.7 with the storage annualised capital cost per storage power $c_{n,s}$ and the storage nominal power $H_{n,s}$. The optimisation allows for a limitation of the storage nominal power $H_{n,s}$ as in

$$\tilde{H}_{n,s} \leq H_{n,s} \leq \hat{H}_{n,s} \tag{4.22}$$

with the minimum $\tilde{H}_{n,s}$ and maximum $\hat{H}_{n,s}$ capacity. However, in this thesis there is no such limitation which is due to the approach of keeping restrictions of storage power as low as possible when assessing the storage requirements. Thus, equation 4.22 results in

$$0 \leq H_{n,s} \leq \infty. \tag{4.23}$$

The storage nominal power optimisation is a continuous optimisation without any predefined or standardised units. Given this approach, a mixed-integer problem can be avoided, which reduces the computational burden. The filling level $e_{n,s,t}$ of a storage unit is limited by its capacity $E_{n,s}$. For extendable storage units without a given storage energy capacity, $E_{n,s}$ is defined as

$$E_{n,s} = H_{n,s} \cdot t_{max} \tag{4.24}$$

with t_{max} representing the maximum duration of charging or discharging at full power.

In order to keep the energy of the power system in balance, the filling level $e_{n,s,t}$ must comply to

$$e_{n,s,t=0} = e_{n,s,t=T} \tag{4.25}$$

The initial filling level $e_{n,s,t=0}$ is not pre-defined. In a separate ex-post check, the realisation potential of the resulting storage units is analysed. Technical parameters such as the maximum charging/discharging duration at full load or the efficiency are predefined per technology and scenario (see Table 4.12) and thus influence the resulting flexibility demand. The cost $c_{n,s}$ per MW installed provides the central decision parameter for these installations and is defined according to the following equations. Note that in general the storage costs $c_{n,s}$ are given in dependence of the nominal storage power in MW.

$$c_{n,s} = C_{annual} + C_{O\&M} \tag{4.26}$$

with

$$C_{annual} = \frac{C_{invest}}{A_{T,r}} \tag{4.27}$$

with

$$C_{invest} = C_{power} + C_{energy} \cdot t_{max} \tag{4.28}$$

and

$$A_{T,r} = \frac{1 - \dfrac{1}{(1+r)^T}}{r} \tag{4.29}$$

and with

$$C_{O\&M} = C_{annual} \cdot c_{O\&M}. \tag{4.30}$$

The total storage costs as the central optimisation parameter are composed by the annualised storage investment costs C_{annual} and the annual costs for operation and maintenance $C_{O\&M}$. In order to obtain an annualised net present cost value based on total installation costs, the Equivalent Annual Cost method is applied assuming an operational lifetime T per technology and scenario according to Table 4.12 and a fixed interest rate of $r = 5\%$. The economic incentive to install the additional storage capacities is depicted by this interest rate. Installation costs for the power module C_{power} per MW are added to the costs of the energy storage C_{energy} per MWh taking into account the storage energy capacity in terms of the maximum charging or discharging time t_{max}. The linear ratio of storage power and storage energy capacity leads to a respective linear depiction of the costs. The charging/discharging ratio is set to be 1:1. O&M costs $C_{O\&M}$ are added to C_{annual} by applying a fixed factor $c_{O\&M}$ to C_{annual}.

It is generally possible to distinguish between various storage technologies and their respective capital costs and technical parameters such as efficiency or E/P rate. As a result, requirements for any predefined storage technology could be assessed. The computational effort, on the other hand, demands a limitation of variables and in consequence storage types. Thus, in this thesis, storage types are only distinguished by their energy capacity classifying them into long-term or short-term storage. Taking into account costs and technical parameters, representative technologies are defined for these two storage classes. Long-term storage is expected to charge or discharge at full nominal power for one week ($t_{max} = 168\ h$) to empty or fill its reservoir. PHS are only capable of this if connected to large reservoirs which cannot be found in Germany. In alpine or Scandinavian countries, on the other hand, such reservoirs allow for seasonal shifts of power. Underground hydrogen storage is considered the only alternative for seasonal power balancing in countries without large hydro reservoirs (Erlach et al., 2015). Similar to large hydro reservoirs which require a certain topography, seasonal hydrogen storage has a critical local precondition which is the existence of suitable underground salt caverns.

Several storage technologies may be considered short-term storage. In this thesis, short-term storage is assumed to charge or discharge at full nominal power for six hours ($t_{max} = 6\ h$). On a large scale, PHS fit this range but are dependent on suitable local geological preconditions. In contrast, industrial-scale battery storage units may be installed at any site given the required space and at the same time operate at a higher efficiency (Erlach et al., 2015). Taking this into account and knowing, on the other hand, the potential of additional PHS plants is very limited in Germany (Gimeno-Gutierrez and Lacal-Arantegui, 2013; eStorage, 2015), battery storage units are defined as the standard short-term storage in this thesis. Existing capacities of PHS are considered (see Section 4.2.2). Additional storage capacity may thus be provided by the long-term underground hydrogen storage or the short-term battery storage option. The technical and economical characterisation of these representative units is presented in the following.

4.3.1 Uniform Battery Storage

Battery storage units are not dependent on any local preconditions besides the necessary space, and therefore their installation is allowed at any grid bus. The Lithium-Ion technology is selected as the representative battery storage type with regards to its technical and economic parameters. Regarding these parameters, several recent publications may be considered relevant and are taken into account when assessing the final values. For instance, Budischak et al., 2013 provides general assumptions for storage parameters that have been used by numerous works (Weitemeyer et al., 2015a; Hörsch and Brown, 2017; Pfenninger et al., 2014). Other relevant studies providing relevant data on storage costs are Jülch, 2016; Fuchs et al., 2012; Fleer et al., 2016. The German publication "Energiespeicher – Technologiesteckbrief zur Analyse Flexibilitätskonzepte für die Stromversorgung 2050" from 2015 is relatively up to date and provides reviewed values on storage parameters not only for Lithium-Ion batteries and underground hydrogen storage but also for several other technologies (Erlach et al., 2015). Apart from values dated 2013 there are projections for 2023 and 2050 which distinguishes this study from the other potential sources and is considered to be sufficiently in line with the two future generation scenarios NEP 2035 and eGo 100 applied in this thesis. The storage parameters relevant for the optimisation process are collected in Table 4.12.

4.3.2 Seasonal Hydrogen Storage

Underground salt caverns are considered to be the most suitable underground formation since they allow "much higher injection and withdrawal rates and the flexibility to handle frequent cycles" (Crotogino and Donadei, 2011, p.411). According to Crotogino and Donadei, 2011, p.411, when filling depleted pore storage with hydrogen or air "the oxygen in the air or the hydrogen can react with the minerals and the microorganisms present in natural reservoirs. This can result in a loss of oxygen or hydrogen, production of hydrogen sulphide as well as the blockage of the fine pores in the reservoir rocks by the reaction products." Therefore, other formations such as pore storage are disregarded here.

According to Kruck and Crotogino, most salt caverns are suitable to store hydrogen or natural gas within wide pressure ranges of 60 – 180 bar and depths from –500 m to –2,500 m below surface (Kruck and Crotogino, 2013). Although hydrogen and natural gas have the same technical requirements, a distinctive competition of the technologies for suitable sites is not expected (Zander-Schiebenhöfer et al., 2014). The preparation of a salt cavern is mainly defined by the solution mining in a suitable salt formation. The resulting void is the future cavern. The brine is the most important waste product, and its disposal requires a location close to the sea (Keplinger et al., 2011). In this thesis, any underground salt formation is considered to be generally suitable for a hydrogen cavern. Unfortunately, there is no further public information on the site-specific suitability. A combination of the salt formations

TABLE 4.12: Storage parameters for battery and hydrogen storage units based on Erlach et al., 2015. The indicated parameters represent complete power-to-power cycles, i.e. costs and efficiency for electrolysis, storage and fuel cell.

Parameter	**status quo**	**NEP 2035**	**eGo 100**
Battery storage			
Capacity costs C_{power} [EUR/MW]	160,000	72,500	45,000
Storage costs C_{energy} [EUR/MWh]	445,000	141,000	105,500
Max. hours t_{max} [h]	6	6	6
Total Investment costs C_{invest} [EUR/MW]	2,830,000	918,500	678,000
Operation years T [a]	20	25	30
Investment costs per year C_{annual} [EUR/MW/a]	227,087	65,170	44,105
O&M factor $c_{O\&M}$ p.a.	1%	1%	1%
O&M costs $C_{O\&M}$ [EUR/MW/a]	2,271	652	441
Total storage costs per year C_{total} [EUR/MW/a]	229,357	65,822	44,546
Charging efficiency	0.93	0.93	0.95
Discharging efficiency	0.93	0.93	0.95
Standing losses [1/h]	0.00972	0.00694	0.00417
Round-trip Efficiency	0.86	0.87	0.90
Hydrogen storage			
Capacity costs C_{power} [EUR/MW]	1,215,000	815,000	575,000
Storage costs C_{energy} [EUR/MWh]	450	450	450
Max. hours t_{max} [h]	168	168	168
Total Investment costs C_{invest} [EUR/MW]	1,290,600	890,600	650,600
Operation years T [a]	25	25	25
Investment costs per year C_{annual} [EUR/MW/a]	91,571	63,190	46,162
O&M factor $c_{O\&M}$ p.a.	3.5%	3.5%	3.5%
O&M costs $C_{O\&M}$ [EUR/MW/a]	3,205	2,212	1,616
Total storage costs per year C_{total} [EUR/MW/a]	94,776	65,402	47,777
Charging efficiency	0.68	0.73	0.76
Discharging efficiency	0.38	0.43	0.57
Standing losses [1/h]	0.000694	0.000694	0.000694
Round-trip Efficiency	0.25	0.31	0.45

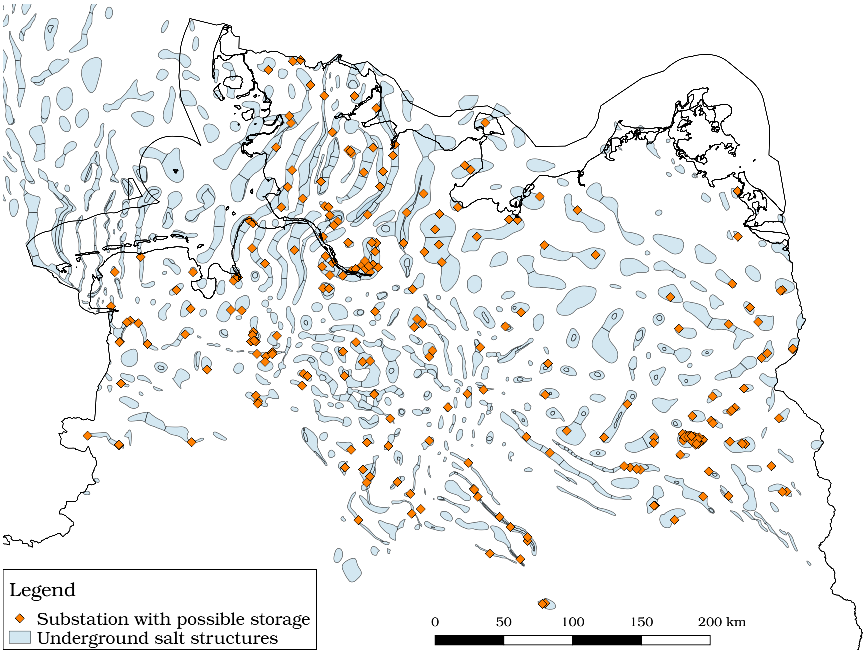


FIGURE 4.5: Salt formations in Northern Germany (light blue) and substations located on top of these (orange diamonds) as possible sites for underground hydrogen storage units with connection to the power grid. Source for data on salt formations: *Salzstrukturen* ©BGR, Hannover, 2015. Figure by Lukas Wienholt / CC BY SA 4.0 (Wienholt et al., 2018)

with the relevant transition points (see Section 4.2.1) is illustrated in Figure 4.5 and indicates 248 potential sites in Germany. Hence, an installation of hydrogen storage units is possible at these 248 buses.

4.4 Implementation and Complexity Reduction

The central software instrument for managing the optimisation runs for this thesis is eTraGo (eTraGo, 2020), which was developed within the open_eGo project. Via the interface ego.io, eTraGo imports the relevant data for an optimisation from the Open Energy Platform (OEP). The OEP is another product of the open_eGo project and was set up as a central database for open data in energy system modelling. The input data, as described above in Section 4.2, is fed into the OEP within the data-processing. For the results obtained in this thesis, the data version "v0.4.6" of September 2019, which can be obtained from the grid schema of the OEP, is applied. Any relevant specification of the optimisation is then defined in eTraGo. Starting from the period – for instance one month or one year – to the scenario or the applied linear solver and its parametrisation. Additionally, eTraGo features several data manipulation options that are mainly introduced to reduce complexity. Within this thesis, two relevant reduction methods are applied. On a temporal scale, only every third hour of a year is calculated, which leads to a depreciation of the remaining two-thirds of hours and is compensated by a weighting factor as introduced in Section 4.1.

Apart from the temporal scale, the network is also spatially reduced by a k-means clustering approach which was similarly applied by Hörsch and Brown, 2017. This approach is based on the expectation-maximisation(EM)-algorithm, which minimises the weighted sum of the squared euclidian distance between the nodes of the original network and the new cluster centres (inertia). The application of the algorithm is mainly carried out through the Python package scikit-learn (Pedregosa et al., 2011). The weight of each original node is defined by the sum of its conventional generation capacity and power demand. The basis for these numbers is the status quo scenario since the existing network was developed based on this structure. Consequently, the resulting cluster centres are also reproduced for the NEP 2035 and the eGo 100 scenario as the grid remains constant. In a first step of the EM-algorithm, a number of k random cluster centres is defined within the original network. Secondly, each node of the original network is assigned to its closest cluster centre. The location of the cluster centre is in a third step relocated to the centroid of its assigned nodes. The second and third steps are repeated until convergence. Finally, all components of the original network nodes are assigned to the cluster centre and aggregated per generation or storage type. PV and wind generators are dependent of local weather data and are therefore weighted by their installed capacity before they are aggregated. Grid restrictions within a cluster are disregarded which leads to a copperplate depiction of local grid constraints. This effect becomes more relevant with a decreasing k (see Section 5.8). Any original branches between clusters are aggregated, which leads to one synthetic connection depicting the original transmission capacity. Thus, network constraints may still occur. The algorithm is highly dependent on the original selection of cluster centres. In order to reduce this dependency, the number of runs is set to 2500 through the parameter n_init. The run with the lowest resulting inertia or weighted sum of the squared euclidian distance between the nodes of the original network and the new cluster centres is selected. Additionally, the maximum tolerance of this inertia is set to 1e-20 through the tol parameter of scikit-learn (Pedregosa et al., 2011). The application of the k-means clustering significantly reduces the network complexity and thus, the number of variables in the LOPF. Based on the number of 3591 buses in the original dataset, the network is reduced to $k = 500$ buses in the standard case. This number roughly matches the number of buses in the German EHV transmission grid. However, through the consideration of the HV level and the indirect representation of branches connecting cluster centres, these networks are hardly comparable. The selection of a lower k value would be beneficial in terms of the computational effort of the optimisation. On the other hand, grid constraints as a major driver of storage requirements are expected to be underestimated with a decreasing k value (Hörsch and Brown, 2017). Hence, the selection of $k = 500$ depicts an approach to model the power grid in a relatively high resolution despite the increased computational effort. The impact of this selection and possible other definitions of k are discussed in Sections 4.5 and 5.8.

In order to prevent stochastic results due to a large number of generators with the

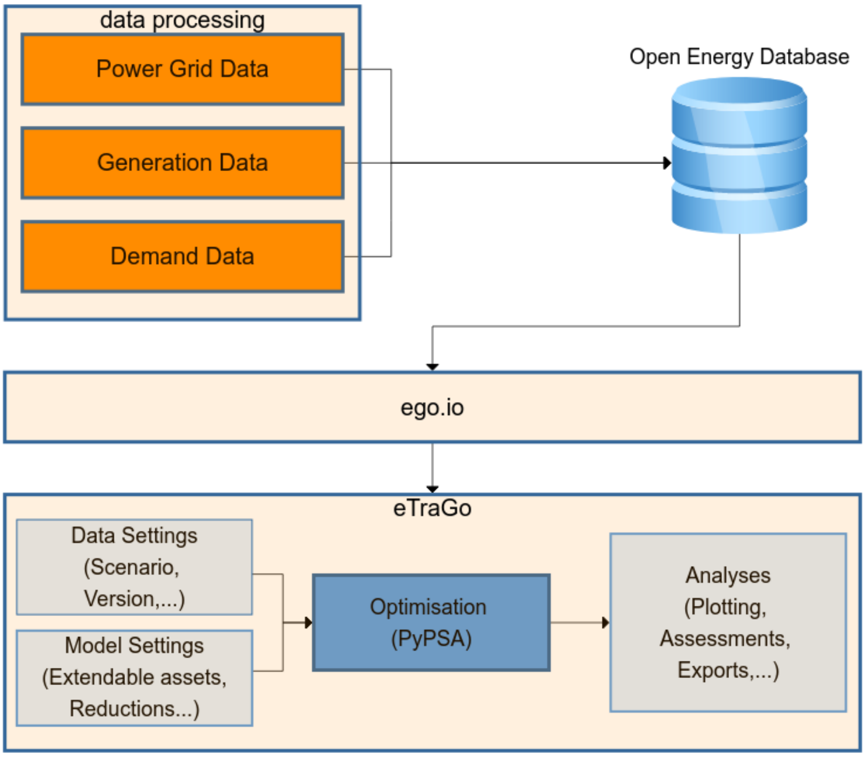


FIGURE 4.6: Abstract illustration of the implementation of the model with the applied software tools.

same marginal costs, a small noise with a standard deviation of 0.01 EUR is added to the marginal cost of each generator. The obtained marginal costs may be reproduced and thus allow comparing the results of several optimisations.

The power flow method itself does not consider the so-called (n-1) criterion, which is a standard security measure in grid operation. The criterion states that the outage of one asset – for instance, a branch or a transformer – may not harm network stability. As a global approximation of the (n-1) criterion, the extra-high-voltage branches of the network are reduced to 70 % of their original technical capacity (Wiese et al., 2014). High voltage power lines are even further reduced to only 50 % of their original capacity.

With these specifications of eTraGo in place, the LOPF itself is carried out by PyPSA as described in Section 4.1. The Gurobi Optimizer in version 8.0 is used for solving the linear optimisation problem. The calculations in this thesis are carried out on a machine with 32 cores and 282 GB RAM. Figure 4.6 depicts the model landscape that is applied to carry out the optimisation as described in this Section.

4.5 Critical Acclaim and Limits of the Model

The setup of a large-scale power system model and optimisation problem, as described in this chapter, is affected by numerous assumptions that are afflicted with uncertainty. In the following, these uncertainties are summarised and briefly discussed. While the impact of certain assumptions can be easily investigated through sensitivity analyses (see Section 5.8), the impact of others can only be discussed and needs to be taken into account when assessing the final results.

Spatial Resolution The power grid model applied in this thesis is characterised by a relatively high spatial resolution through the consideration of the high voltage level, which is rather unusual when modelling large-scale power systems. The underlying distribution grid is, however, not considered here. Such a simplification seems justifiable as the distribution grid usually transports power on local and possibly regional, but not on a national level. Structural grid constraints that occur in the transmission grid may thus not be overcome by an evasion to the distribution grid. The reduction of the original spatial resolution of 3591 buses to a reduced network with only 500 buses through the k-means clustering algorithm certainly implies a loss of detail that impacts the final results. Even though the capacity of power lines in the reduced network is defined according to the original lines, the clustering may disregard (local) grid constraints of the original network. However, it is expected that most of the significant and structural transmission bottlenecks are also represented by the reduced network. In Section 4.2.1, the setup of the grid model is described in detail. In contrast to a well-established power grid model, this model was built from scratch and is based on publicly available data within the open_eGo project. While validations of the model have been carried out to a certain extent by Medjroubi et al., 2017 and Müller et al., 2017, the general dependency of crowd-sourced open data needs to be considered, in contrast to any well-established industry model of the power grid. It is therefore expected that general and systematic effects of the power grid can be assessed by the modelling results while assertions regarding individual assets or very local effects are hardly possible.

Linear Optimal Power Flow The restrictions of the power grid in this thesis are considered through a linear power flow model. This LOPF refers to the thermal limits of the grid's assets. Compared to the non-linear power flow of AC networks, this approach is an estimate as a linearisation approximates the non-linear equations. If a general capacity reduction of power lines to approximately 70 % is applied, a linearisation seems applicable, especially for large-scale power system models (Brown et al., 2016; Stott et al., 2009). On the downside of this approach, only active power flows are considered, whereas any non-linear effects of an AC power system, such as reactive power flows, are disregarded. Nonetheless, as such effects are not the focus of this thesis on optimal storage units, the power flow here is restricted to the LOPF whereas non-linear power flows are not considered. The reduction of power line capacity to 70 % and 50 % as presented in Section 4.4 is an essential prerequisite for this simplification. Once the LOPF yields a feasible result, the respective overall power system structure is capable of coping with the resulting active power flows.

It is expected that potential additional efforts on adhering to non-linear constraints would not lead to a significantly different result. The depiction of the HV power grid is in this modelling approach the same as for the EHV transmission grid. Hence, there are no constraints on regional power grid operation, for instance, through open switches and the power grid is modelled as one large grid with different voltages. In reality, however, the German HV power grids are operated by several regional Distribution System Operators (DSO) which potentially diverges from an operation according to large-scale or national requirements. As a consequence, the HV grid depiction in this model could overestimate the transmission potential due to these operational restrictions compared to reality. Modelling of such operation patterns is, on the other hand, impossible as the status of the respective switches that could disconnect a regional HV grid from the rest is unknown to the public.

Temporal Resolution In power system modelling the temporal resolution is a critical parameter that requires a compromise of a sufficient degree of detail and the complexity of a model. The hourly resolution can be considered a standard setup for recent studies on power systems. Sub-hourly modelling is often only applied when short-term effects, e.g. reserve power, are considered. The modelling horizon in these cases is often reduced from one or more years to shorter representative periods. Especially with regards to storage unit modelling a more coarse temporal resolution than hourly possibly impedes the validity of the results. Deane et al. examined the impact of the temporal resolution from five minutes to one hour with a focus on flexibility modelling and total system costs. They apply different resolutions to a RES-shaped case study setup and find significant effects on these parameters. For instance, total system costs increase by 1 % only by reducing the temporal resolution from one hour to five minutes (Deane et al., 2014). Troy et al. conducted a similar analysis and define a model setup of the Irish power system for the year 2020 with an assumed wind power generation share of 75 %. They compare storage unit utilisation in two weeks for a temporal resolution of 15 minutes vs one hour and find that in the latter more coarse case, utilisation rates decrease by 37 % (Troy et al., 2012). Even though these results may not be representative due to the relatively short modelling period, the general effect is visible and should be acknowledged. By choice of an hourly resolution in this thesis, such uncertainties are disregarded but should be kept in mind when discussing the final results. Certainly, sub-hourly modelling would be beneficial, but storage is in this case analysed on a power system level where sub-hourly effects may be disregarded. Additionally, for a large-scale power system model as applied here, the general data handling and computational effort must be kept in an acceptable range. Restrictions in computational capacity are also the reason why for the full year only every third hour is considered, while the remaining two-thirds are disregarded and only depicted through a weighting factor. The effect of this approach on the RES feed-in is examined by a comparison of the potential full load hours per RES technology (before curtailment). While skipping snapshots has no visible effect on onshore wind feed-in, PV full load hours are decreased by 0.17 % and those of offshore wind increased by 0.29 %. Hence, the impact of the skip snapshot simplification on generation patterns can be considered acceptable. Possible effects to other essential parameters, such as the storage installations or total system costs are addressed in Section 5.8.

Weather Data Section 4.2.2 points out that within the open_eGo project and this thesis, the representative weather year is 2011. The NEP published in 2015, which is the basis for the generation scenario NEP 2035, also applied the year 2011. From 2017 on, the current NEP applies the weather year 2012, which is said to be one of the best fits with the average wind feed-in of the past ten years in Germany (Feix et al., 2016). In comparison with 2012, the year 2011 has a lower average wind feed-in across the year but features a sharp peak in December. The significant differences of wind and PV feed-in between different years are known and have been analysed in a case study for Great-Britain by Pfenninger, 2017a who recommends using not only a single year, but rather decades. However, the resulting challenges of handling the data are acknowledged and the reason for considering only one representative year in this work. Schlachtberger et al., 2018 conducted a European power system optimisation with up to four weather years from 2011 to 2014. The authors find the deviation of RES capacity factors in these four years to be below 3.5 %. Moreover, they find overall system costs to be relatively robust. Similar to Pfenninger, 2017a, the authors find a multi-year optimisation to be beneficial (Schlachtberger et al., 2018). Climate change may indeed become another long-term impact of the representative weather year and has been subject of a study by Schlott et al., 2018. Especially with regards to the eGo 100 scenario, which is expected to address the 2050s and is heavily dependent on weather-based RES generation, the uncertainty of significantly changing feed-in patterns due to climate change increases. These uncertainties regarding the weather year are not considered through the input data but should be recognised when discussing results.

Generation Projections of future power generation portfolios are hard to make due to numerous uncertainties. For instance, the scenario framework for the German NEP regularly defines scenarios for the development of the German power system in the forthcoming ten years. Even for such a relatively short horizon, the projections are uncertain and need to be adjusted regularly. In this light, long-term scenarios depicting completely renewable power systems, for instance in the year 2050, depict by definition only one possible pathway. As the results of power system models are strongly dependent on the assumed generation portfolio, these are in general hard to validate (Dieckhoff et al., 2014). However, Cao et al. point out that one central prerequisite to assess energy scenario studies is transparency (Cao et al., 2016). Hence, the model set up and applied for this thesis is completely based on open data and discussed with regards to potential critical assumptions in the following.

The German power system in the basic eGo 100 scenario is in this thesis depicted without any conventional generation technology. Even natural gas is disregarded here which could be questioned as it is a relatively clean form of generation that could also be potentially replaced by renewable gas. However, in order to set up a completely renewable power system in the first place, such a strict approach is required. The share of the different RES source is another factor with direct impact on the results. In general, the eGo 100 scenario can be regarded as a relatively strong wind scenario as it foresees around 100 GW of onshore wind capacity in Germany alone. The current political discussion in Germany in the context of reaching a 65 % RES share by 2030 shows the difficulty of reaching such a capacity. In the so-called Climate Protection Program (Klimaschutzprogramm), the German government proposes an installed onshore wind capacity of 67 GW – 71 GW (Bundesregierung, 2019). Due to possible new and strict obligations regarding the minimum distance of wind turbines to inhabited areas (Bundesregierung, 2019), this range can be considered to be close to the limit of the realisable potential. In the case of PV, on the other hand, the German government proposes the installation of 98 GW until 2030, which is precisely the number of the eGo 100 scenario for the completely renewable power system. Hence, the government sees the necessity to compensate rather low onshore wind capacities by solar and offshore wind. Regarding offshore wind, the eGo 100 scenario envisages 27 GW while the government plan is 20 GW until 2030. The eGo 100 offshore wind expansion can, therefore, be considered to be rather low, especially when compared to long-term outlooks on the German offshore wind potential. Although currently there is no detailed spatial study on the offshore wind potential in the German exclusive economic zone EEZ, a range from 45 GW (Ausfelder et al., 2017; Repenning et al., 2015) to 57 GW (Knorr et al., 2017) and even 60 GW (Gerbert et al., 2018) is assumed in recent studies on possible fully renewable German power systems. Despite the rather low 27 GW assumed for offshore wind in this thesis, the eGo 100 scenario may be considered to be rather wind-oriented which needs to be considered, for instance when discussing the storage requirements in regions with a high RES feed-in.

With an installed capacity of 27.8 GW for Germany, biomass is another relatively strong generation type. The production of biomass in terms of power produced is not limited ex-ante but needs to be considered when discussing results. In light of the dependence of biomass utilisation of sufficient fuel, the power production potential from biomass is limited. Currently, half of the biomass utilised in Germany is based on energy crops, out of which corn makes up the majority with 70 % (FNR, 2019). Hence, the production potential also has a limitation regarding the space that is available for harvesting these crops. Furthermore, there is a possibly competing use of the limited biomass potential with other sectors, such as mobility and heat, which may impede the complete utilisation of the power generation capacity in reality. Given these potential restrictions, some authors do not consider any biomass for power production (Jacobson et al., 2015; Schlachtberger et al., 2017; Brown et al., 2018c). For the results presented in this thesis, the effects of variations of the generation capacities are presented in Sections 5.6 and 5.8.

The modelling of thermal flexible power plants is rather straightforward. In the default settings, power generation can be fully shifted between zero and the nominal power of a unit. Thus, neither intertemporal ramping constraints nor start-up or shut-down restrictions are considered. It is expected that this approach is acceptable for gas-fired power plants and biomass generation. For large conventional units such as nuclear-, lignite-, or coal-fired power plants, this disregard of technical limitations is undoubtedly a simplification that facilitates generation from these units. Another factor disregarded here is the heterogeneous fleet of power plants within a technology type. While there are certainly differences in the commissioning year, the operational lifetime, and hence also of the efficiency, no such distinction is made. Instead, general but representative assumptions are made for each technology type. All these assumptions are undoubtedly beneficial for the dispatch of these conventional generation units. However, for the basic eGo 100 scenario, this effect can be safely disregarded as biomass and natural gas are the only thermal generation types in this scenario. In the case of the intermediate NEP 2035 scenario, the impact of these effects is assessed and presented in Section 5.4.
The power curves that allow the determination of the generation based on weather data for wind and PV are based on technology that is installed today (compare Section 4.2.2). In the case of offshore wind, a power curve of a 3.6 MW turbine is applied. It is recognised that even today, this turbine type can be considered small and is not expected to be installed any further. Offshore turbine development now heads towards capacities of 10-12 MW (GE, 2019; Vestas, 2019). Since the larger share of additional offshore capacity is yet to be installed the application of power curves of these modern turbines would undoubtedly be beneficial and more accurate. Through efficiency gains, it is expected that the power curves, in general, will be enhanced in order to allow improved utilisation of the respective natural potential (Hirth and Müller, 2016). Furthermore, in some cases of wind turbines, the ratio of turbine capacity to rotor diameter is decreased to allow a better yield in times of low wind speed. Such adjustments to the power curves impact the feed-in of weather-dependent RES and may, for instance, lead to a more steady output which could reduce flexibility requirements. The potential full load hours per technology as presented in Table 4.10 should be recognised in this context. While the values for offshore wind can be considered relatively high, those for onshore wind are expected to be at the lower end of possible future full load hours. Further examinations of these effects are, however, not carried out in this thesis, but should be recognised with regards to the overall results.

Demand Compared to the generation, which is varied in different scenarios, the depiction of the demand is relatively coarse and no subject to different future projections. The total power system demand remains constant at today's level for all three scenarios (Section 4.2.3). The objective function (compare Equation 4.7) introduced in Section 4.1 illustrates that meeting the demand at all times is the central objective of the optimisation process. Adjustments to the demand side of the equation are, therefore of significant importance for the obtained results. In contrast to power generation, the demand has only gained increasing attention in energy system modelling in recent times. For instance, the demand depiction in the German NEP used to be rather coarse (50Hertz Transmission GmbH and Amprion GmbH and TenneT TSO GmbH and Trans-netBW GmbH, 2014b) but gained a significant level of detail in more recent versions (Rippel et al., 2018). At the same time, the recent NEP scenario frameworks assume an increasing demand for all future scenarios which was confirmed in stakeholder consultations and mainly assigned to increasing electrification of other sectors (Rippel et al., 2018; Drees et al., 2020). In Drees et al., 2020, the authors assume a demand increase of up to 22.5 % compared to 2018. Hence, the total yearly load for Germany assumed in this model may be considered relatively low and potentially underestimates such an increase. In this light, Bossmann and Staffell analysed the changed load curves for Britain and Germany due to a shift in power demand (Boßmann and Staffell, 2015). They find a remarkable shift of peak loads and general demand patterns and recommend an according consideration in future energy system models (Boßmann and Staffell, 2015). Despite these arguments, no variations of the load curves are analysed in this thesis. Furthermore, a general flexibilisation of the demand as an alternative source of flexibility is not implemented within the optimisation process. A brief discussion regarding the impact of the demand projections is carried out based on simple variations of the overall demand. The respective results are presented in Section 5.8.

5 Results

The model described in Chapter 4 is applied to obtain the results that help to address the guiding research questions of this thesis. In the following, the modelling configuration and its relevant results for each research question are presented in detail.

5.1 Status Quo Reference

The setup and modelling of a baseline reference scenario are vital in future energy system modelling. In this matter, the status quo scenario serves as a starting point which depicts today's state of the energy system analysed in this thesis. The basic assumptions of the status quo scenario are presented in Section 4.2.2. In general, the parameters of the power grid and the demand remain the same for all scenarios, including the status quo. The generation portfolio of the status quo scenario depicts the installed capacities as of the year 2015. In terms of installed renewable energy capacity, the portfolio adds up to a share of 50 % of total installed capacities in Germany and 42 % in the overall model, including neighbouring countries. The installation of additional storage units as described in Section 4.3 is possible in the status quo scenario with the difference that the storage parameters depict today's market and technology. Thus, storage costs are significantly higher and efficiency is lower compared to future scenarios.

Results The modelling of the status quo scenario is carried out with the constraint of reaching the highest possible share of renewable generation. The obtained results show that the 2015 power system, as depicted in the model, is capable of reaching a 37.4 % share of renewable generation without the requirement of any additional storage capacity. The share for Germany alone amounts to 27.8 %. In comparison to the actual value of 31.8 % RES generation share in Germany 2015 (UBA, 2019), the modelling results are in the same range while differences to the real value may be assigned to the modelling approach and the consideration of the neighbouring power systems. In terms of storage capacity, we can conclude that especially due to large thermal generation capacities in the status quo scenario (see Section 4.2.2) no additional storage capacity is required.

The **levelised cost of electricity (LCOE)** is a simple and well-established parameter to assess the average costs of a power system. In this thesis, the LCOE are composed of exogenous and endogenous costs. The power grid costs are disregarded here. Exogenous costs depict costs that are induced by setting up the existing power generation portfolio. For any generation technology (including PHS) installation overnight costs per kW are given by Schröder et al., 2013. In the case of the eGo 100 scenario, hydrogen and battery storage in neighbouring countries are considered based on the values given in Table 4.12. The overnight costs are converted to annuity values since only one year (out of several years of a unit's lifetime) is modelled here. With an assumed lifetime T per technology, a fixed interest rate of $i = 5\%$ and the present value of an annuity (PVA) as

$$PVA = \frac{1}{i} - \frac{1}{i * (1+i)^T} \tag{5.1}$$

the annuity is defined as

$$C_{annuity} = \frac{C_{overnight}}{PVA}. \tag{5.2}$$

The endogenous costs of the power system are composed of the installation costs of additional storage units and the power dispatch costs that are mainly characterised by the marginal generation costs. In order to calculate the total LCOE, the sum of exogenous and endogenous costs is divided by the sum of the total power system load:

$$LCOE = \frac{C_{exogen.} + C_{dispatch} + C_{storage}}{\sum\limits_{t=0,n}^{T,N} w_{t,n}} \tag{5.3}$$

Note that in case LCOE are given for Germany only, the neighbouring countries are disregarded. Hence, possible costs for imports to Germany are not considered, which needs to be kept in mind, especially in cases of high import rates.

In the status quo scenario, the LCOE add up to 52.02 EUR/MWh for the complete system and 47.14 EUR/MWh for Germany alone. Since no additional storage capacity is required, these values consist of exogenous costs for the installation of the respective generation capacities and dispatch costs for these units. Exogenous costs make up the largest share of 91.2 % for the total system and 89.2 % for Germany. The modeling results of the status quo scenario indicate that Germany is a net importer of power since only 88.4 % of the total German demand can be covered by German dispatch. In this case, the result is not in line with the real German power exchange balance as Germany has been a net exporter of power since 2003 (A. Breitkopf, 2019). The optimisation of power dispatch in the model is strictly based on marginal costs while considering constraints such as line capacities. Thus, the imports to Germany may be explained by comparably low priced dispatch from neighbouring countries. The average power line loading over the entire year shows that cross-border lines to France, the Netherlands and Poland are highly utilised while the line loading within Germany and to the other neighbouring countries is relatively low. Thus, the status quo power grid in Germany seems fit to transmit the power flows of a 31.8 % renewable power system. The relatively low curtailment rates of 1.5 % for the complete system and 2.2 % for Germany are mainly induced by onshore wind and indicate that grid constraints are rather negligible in the 2015 power system.

5.2 Characteristics of Optimal Storage Units in a Fully Renewable Power System

In Short:

- **With an additional storage capacity of 7.98 GW and an import rate of 13.6 % of the yearly German demand a 100 % RES based power system is feasible.**
- **The resulting storage locations are primarily situated in the North of the country, which is characterised by strong wind power feed-in. Offshore wind grid connections seem to trigger storage locations.**
- **Substantial grid bottlenecks to the demand centres in the South lead to a clear distinction of a low-priced North and a high-priced South.**
- **High curtailment rates of 33 % for offshore wind and in total 19.2 % confirm the importance of overcoming these constraints in the German power system.**

The first research question introduced in Chapter 1 reads:

> *How can optimal storage units be characterised in terms of their size, location and utilisation?*

Since this can be considered the basic and guiding question of this work, the respective modelling setup is defined accordingly. The definition of the relevant modelling parameters can be found in detail in Section 4.3. In general, the eGo 100 scenario provides the basic scenario which depicts a completely renewable power system in Germany with some minor natural gas capacities in selected neighbouring countries. The NEP 2035 scenario allows an intermediate analysis between the status quo and the fully renewable scenario. The results of this scenario are presented at the end of this section. The complete data model is reduced to a spatial grid of 500 nodes with each of the electrical neighbours depicted by one node. The power grid structure is based on the 2015 status quo of the German power grid without considering any grid extension. In temporal terms, the analysed full year is reduced to calculating every third hour of the year. The impact of these approaches to reduce the overall complexity is assessed with some variations in Section 5.8. With regards to extendable storage units as the central factor for the results of this thesis, the parameter assumptions are presented in Section 4.3. In short, highly efficient battery storage units with low energy over power ratio of 6 may be installed at each grid bus while less efficient underground hydrogen storage units with an E/P rate of 168 are restricted to grid buses above suitable underground salt formations. The main technical storage parameters, such as their E/P ratio, efficiency, and costs are analysed with regards to their impact on the overall modelling results in the following. Battery and hydrogen storage units are only extendable at German grid buses while for the electrical neighbours the respective capacities are pre-defined.

The results of this base case model reveal a total additional storage capacity of 7.98 GW in Germany. This capacity is subdivided into 2.7 GW of battery storage which equals a share of 33.3 % and 5.3 GW or 66.7 % hydrogen storage. The biggest storage unit reaches a capacity of 1.89 GW while the smallest has a capacity of 5.17 MW. There is no pre-defined limit to the maximum storage capacity per unit. Although the capacity of the largest storage unit of 1.89 GW seems large compared to today's installed capacities of storage or generation units, the capacity is still in line with the 3 GW limit of the UCTE (UCTE, 2004). This limitation defined by the European TSOs is supposed to provide a limit to the provision of primary reserve capacity as this has to be designed according to the short-term loss of the largest possible generation unit within the interconnected system. There is a total of 9 battery storage units with an average capacity of 295 MW and a median of 127 MW. The number of hydrogen storage units is in the same range (10). The average hydrogen storage unit has a capacity of 533 MW and a median of 223 MW. Table 5.1 summarises these results. The existing storage capacity defined by the scenario must be kept in mind when examining these results. For instance, in Germany, there is an existing PHS capacity of 9.3 GW. In the neighbouring countries, there is not only a total PHS capacity of 42.1 GW, but additionally 39.7 GW of hydrogen and 16.7 GW of battery storage capacity. The resulting total capacity of 7.98 GW of additional German storage capacity seems to be in range with these numbers. A more detailed discussion of the impact of neighbouring countries and especially their storage capacities follows in Section 5.5.

The depicted model setup results in a RES generation share of the complete power system of 100%. Gas-fired power plants are the only remaining non-renewable generation type. However, due to their relatively high marginal cost, gas-fired power plants are scarcely dispatched and produce a total of ca. 11.4 GWh, which can be disregarded in terms of total generation shares. In Germany alone, the RES generation share is naturally at 100 % since there are no gas-fired power plants in operation. Figure 5.1 illustrates the resulting generation shares by technology. Accordingly, Table 5.2 shows the full load hours per technology and curtailment rates if curtailment applies. For fluctuating RES note the difference in full load hours compared to the

TABLE 5.1: Resulting storage quantities and sizes per technology in the basic eGo 100 scenario.

	Battery storage	Hydrogen storage	Total
quantity	9	10	19
total capacity [GW]	2.65	5.33	7.98
capacity share [%]	33.3	66.7	100
min. single unit capacity [MW]	37	5	5
max. single unit capacity [MW]	1224	1888	1888
avg. capacity [MW]	295	533	420
median capacity [MW]	127	223	140

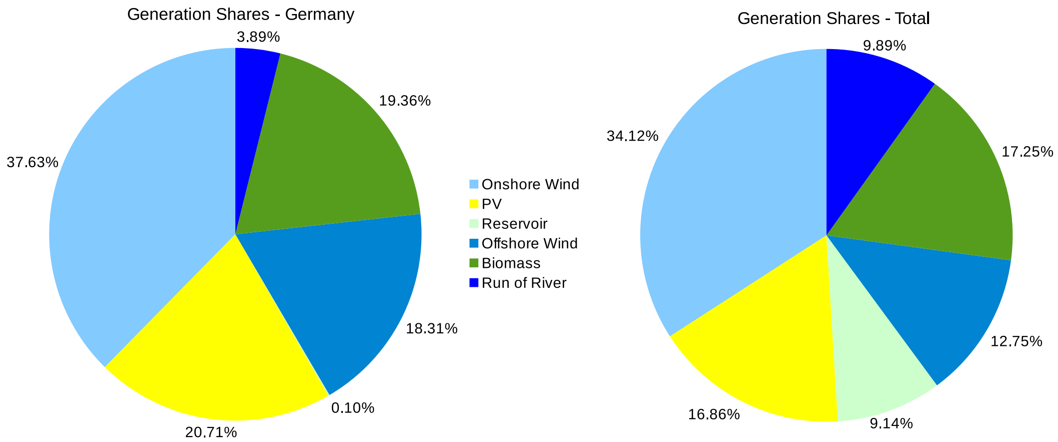


FIGURE 5.1: Generation shares by technology for Germany and the total system including electrical neighbours.

respective potential presented in Table 4.10 in Section 4.2.2. The differences can be explained by curtailment.

The LCOE of the complete system is 56.23 EUR/MWh with 50.25 EUR/MWh or 89.4 % of it induced by exogenous costs of the generation portfolio setup. The remaining 5.98 EUR/MWh are composed of 5.74 EUR/MWh dispatch costs and 0.24 EUR/MWh for the installation of the 7.98 GW of additional storage capacity. When disregarding the neighbouring countries, the German LCOE is 43.66 EUR/MWh with 37.62 EUR/MWh or a 86.2 % share of exogenous costs. Endogenous costs of 6.04 EUR/MWh consist of 5.30 EUR/MWh for dispatch and 0.74 EUR/MWh for storage installations. Since additional storage capacity is installed in Germany only, the absolute number of additional storage costs is the same for Germany and the complete system including neighbouring countries. The difference in total LCOE for the complete system and Germany alone is caused by the significantly higher exogenous costs of the complete system compared to Germany.

The German power demand is covered by German dispatch to the extent of only 86.5 % while imports cover the remainder. At the same time, the total curtailment rate for all generation technologies is at 19.8 % for the complete system and 19.2 % for Germany respectively (see Table 5.2 for details). With 37.5 % (33.0 % for Germany), offshore wind energy is the generation type with the largest share of curtailed

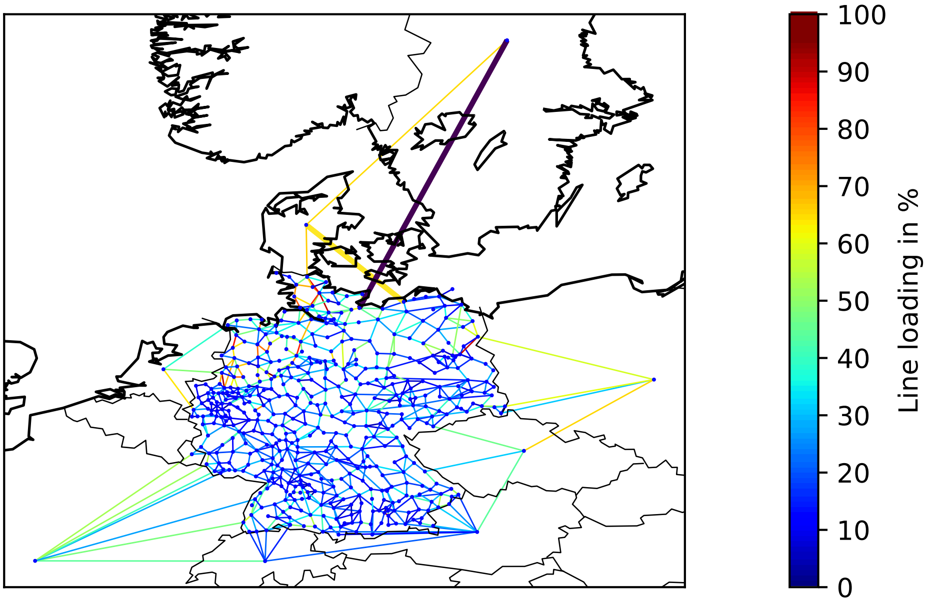


FIGURE 5.2: Average line loading of power lines. Note that the thermal limits of the power lines are rated down to 70 % for EHV and 50 % for HV power lines to be in line with the (n-1) criterion.

TABLE 5.2: Resulting full load hours and curtailment rates per technology, subdivided into Germany alone and including electrical neighbours.

	Full Load Hours [h/a]		Curtailment [%]	
	Germany	Total	Germany	Total
Biomass	3049	3046	0.0	0.0
Onshore Wind	1663	1470	17.8	17.0
Offshore Wind	2963	2936	33.0	37.5
PV	919	925	4.5	6.2
Reservoir	2453	2766	0.0	0.0
Run of River	5645	5409	0.0	0.0
average	–	–	19.2	19.8

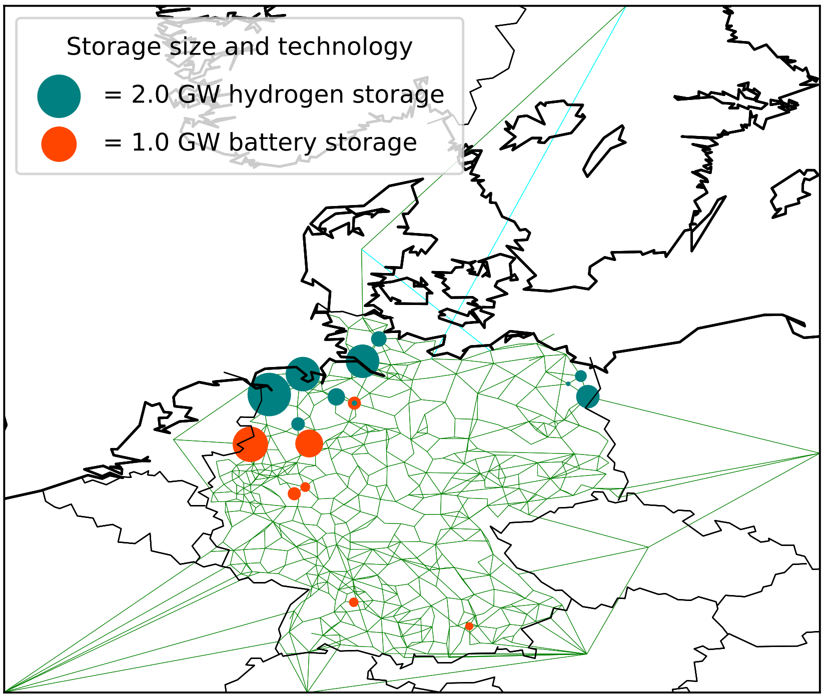


FIGURE 5.3: Spatial distribution of additional storage units. The size of a dot represents the storage capacity. Petrol blue dots show hydrogen storage units, red dots indicate battery storage units. Cross-border DC power lines are depicted in light blue.

power. In this context, it seems likely that grid constraints impede the RES integration. Offshore wind energy is in this manner especially affected as the feed-in is highly concentrated at certain grid connection points. In the case of German offshore wind, the largest shares are concentrated in the North Sea with grid connections in the North and Northwestern part of the country (see Figure 4.4). Historically, the grid has a comparably low degree of meshing and transmission capacities in this region. The model specification of strictly disregarding any grid extension measure and only consider today's grid status then leads to significant grid constraints that cause high curtailment rates for offshore wind production. Figure 5.2 illustrates this correlation with the average line loading over the full modelling horizon of one year. The highest rates can be observed in Northern and Northwestern Germany.

Figure 5.3 depicts the spatial distribution of additional storage units. It can be observed that additional storage units are almost exclusively installed in Northern Germany. In case of hydrogen storage, one reason for this is the limitation to potential sites atop underground salt formations that are predominantly present in Northern Germany. The preparation of underground salt caverns to potential hydrogen storage requires solution mining in a suitable salt formation. Brine is the most important waste product that needs to be taken care of. The large amounts of salty brine are preferably dumped at sea to avoid environmental impacts of salt disposal on land. Thus, a potential site needs to be located either close to shore or at least within reach of a large river going to sea (Kepplinger et al., 2011). In the case of Northern

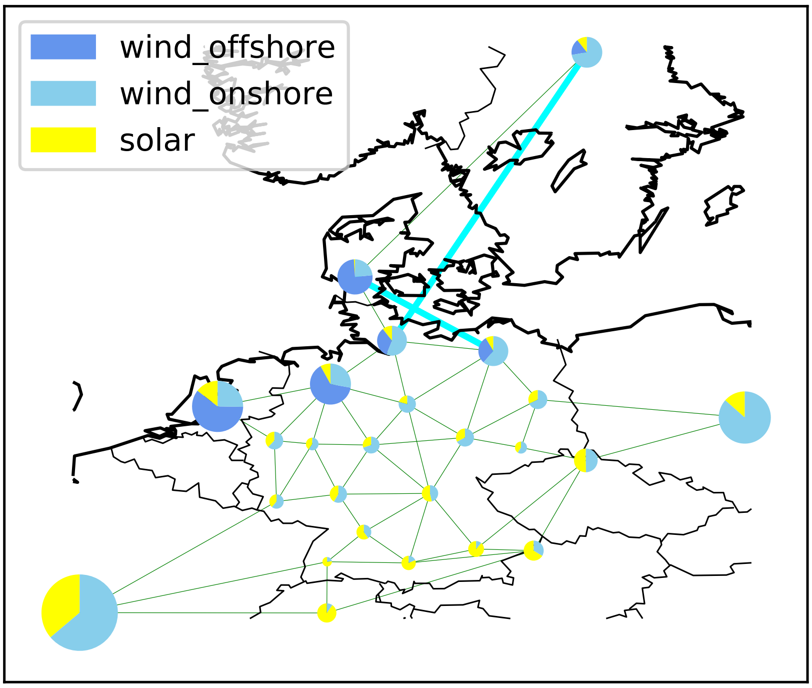


FIGURE 5.4: Spatial distribution of annual production for selected generation types. The size of the dot represents the annual production. Note: The full network has been clustered to 25 buses for better visualisation.

Germany, this could be Ems, Weser, or Elbe. It is expected that the resulting hydrogen storage locations depicted in Figure 5.3 are in sufficient vicinity to shore to allow for brine disposal. Battery storage does not have a limitation to potential sites, but still, the largest batteries are also installed in Northwestern Germany.

The uneven spatial distribution of the annual production of the fluctuating RES wind and solar is presented in Figure 5.4. A clear distinction between the South of Germany which is characterised by solar feed-in and the wind-dominated North is visible. At the same time, the overall production volumes – illustrated by the size of the buses – are significantly higher in the North. In line with this spatial distribution, Figure 5.5 illustrates the average marginal price for certain clustered regions and also indicate a distinction between the North and the South. According to this distribution, an orientation of additional hydrogen storage capacity towards regions with a strong fluctuating generation can be observed. Moreover, solar feed-in seems to induce fewer storage requirements than wind energy due to its typically demand-oriented feed-in characteristic. The distribution of hydrogen storage indicates a favourable correlation of the significant wind power production in the North and hydrogen storage sites in the same area. More specifically, the hydrogen storage sites tend to be located directly at or slightly South of the offshore wind grid connection buses (compare Figure 4.4). This is true for the four largest hydrogen storage visible in Figure 5.3. The same effect applies for the two largest battery storage units which are located South of the most Southern offshore grid connection points.

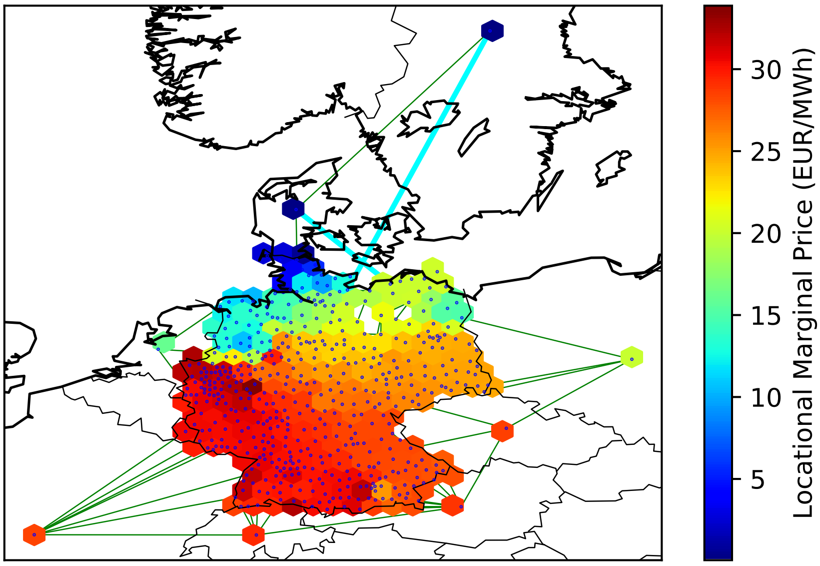


FIGURE 5.5: Average locational marginal price of the modelling period for clustered regions of the power system. The slope from low-priced regions in Northern Germany to higher prices in Western and Southern Germany is clearly visible.

Figure 5.5 shows that these storage units seem to be just North of Western German regions with the highest locational marginal prices. Hence, a substantial grid bottleneck in North-South direction can be assumed in this region. With regards to smaller battery storage units, Figure 5.5 indicates a tendency towards regions with a high locational marginal price due to high power demand and scarce low-priced generation. For instance, the region around Munich and Stuttgart as well as some buses in Western Germany feature battery storage units and are at the same characterised by a comparably high price.

Figure 5.6 shows the annual production balance in a spatial resolution of 25 nodes of the network. Apart from the Czech Republic, all neighbouring countries to Germany are net producers of power. In Germany, on the other hand, only in the northern part of the country which is largely shaped by wind power generation (see Figure 5.4), can the demand be exceeded by production. More southerly and especially Western regions have huge power demand that cannot be covered by local RES production. The fact that in total the German power system can only cover 86.5 % of its demand becomes visible in this Figure. With regards to the spatial distribution of additional storage capacity, the suspicion that storage locations are oriented towards regions with a strong power production rather than being demand-oriented can be proven. When drawing a virtual horizontal line south of the grid constraints visible in Figure 5.2, the additional storage capacity south of this line adds up to 281 MW or just 3.5 % of the total installations. Thus, one can conclude that these bottlenecks impede the transmission of power to the demand centres in the South which leads partly to storage installation before the bottleneck, but mainly causes curtailment of (offshore) wind power.

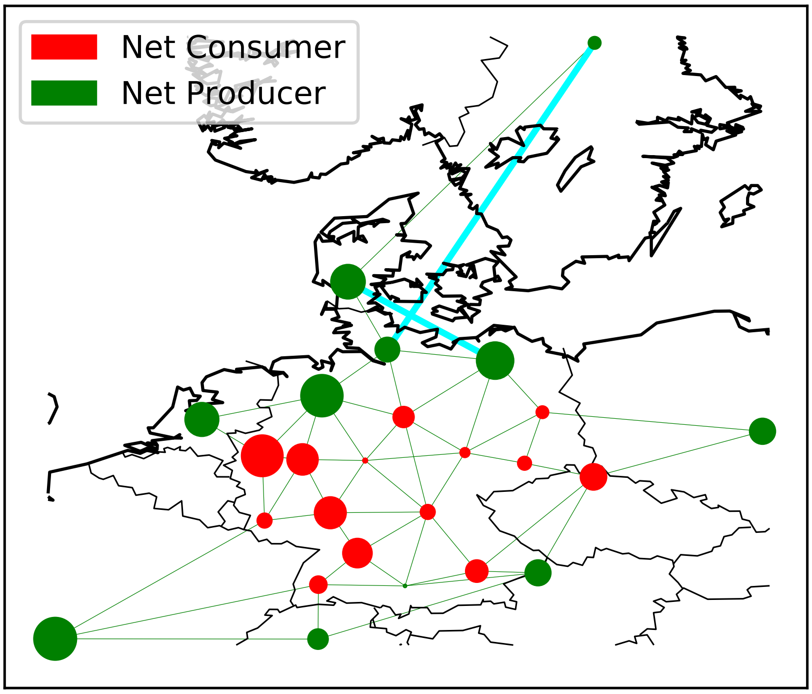


FIGURE 5.6: Annual balance of power generation and load by region. Red dots show regions with a generation deficit. Green dots represent a generation surplus. Note: The full network has been clustered to 25 buses for better visualisation.

With an average storage capacity of 420 MW, the obtained additional storage units can be classified as large and central rather than small and de-central. The total of 19 storage units is installed at 17 different buses with two buses in Northern Germany featuring both hydrogen storage and a battery. Compared to the total of 500 possible nodes for storage installation, the result of 19 individual storage units in this model indicates that central storage units are beneficial compared to smaller de-central ones.

With exactly two-thirds of total additional storage capacity, hydrogen storage has twice the capacity of battery storage. The wind-dominated generation characteristics in Northern Germany are expected to be a driver for the installation of hydrogen rather than battery storage. In contrast to solar feed-in, wind power generation is not shaped by daily variation, but instead by long-term fluctuations. Short-term battery storage that is capable of charging at full power for six hours would thus require ample charging and discharging capacities in order to store larger amounts of wind power. Hydrogen storage, on the other hand, features large-scale underground storage capacities which allow for charging and discharging at full power for 168 hours or one week. Still, the installation of hydrogen storage in Northern Germany may reduce wind power curtailment and allows to reach an optimal result. Despite the installation of 5.3 GW hydrogen storage, curtailment reaches the dimensions mentioned above of around 20 % and even more for offshore wind.

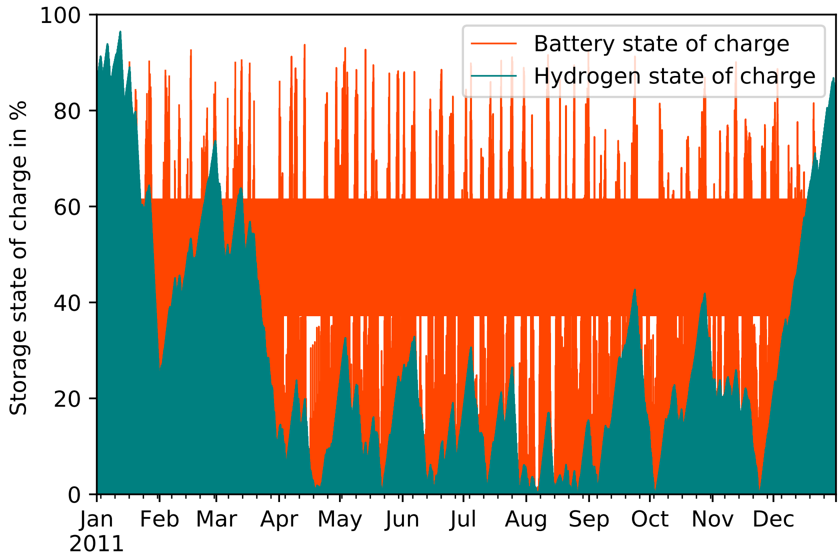


FIGURE 5.7: Annual trend of storage unit state of charge by technology. The petrol blue line shows the state of charge of the hydrogen storage. The red line illustrates battery storage units. For better visualisation, storage units have been accumulated per technology.

The characteristics of storage operation can also be observed through the course of the state of charge of storage throughout the modelled period. Figure 5.7 shows the state of charge by storage technology. The red line illustrates the short-term characteristic of battery storage due to the relatively low energy capacity. In contrast to the hydrogen storage depicted by the petrol blue line, battery storage does not show any seasonal variation in the filling level. The state of charge of hydrogen storage, on the other hand, starts with a relatively high initial value that can only be reached again at the end of the year. The accomplishment of the initial filling level at the end of the modelled period is a precondition in order to maintain a balanced energy level of the model throughout the period. The hydrogen filling level is increased in times of high RES feed-in for instance in February and March, but during summer and autumn from April to December hardly exceeds a level of 40 %.

The storage operation in terms of charging or discharging is depicted in Figure 5.8 by a sorted annual duration curve for both, battery storage (red) and hydrogen storage (petrol blue). The battery storage curve shows an almost equal distribution of charging and discharging times which is due to its relatively high efficiency. Hence, storage losses have a marginal impact and the energy balance of the storage is close to equalised. Hydrogen storage, on the other hand, is marked by comparably high storage losses. This leads to a situation where over the full period the charging mode of a storage unit is by far more common than discharging mode. The plateau at a maximum charging power of the hydrogen storage (right end of the x-axis) is significantly bigger than the one at maximum discharging power (left end of the x-axis).

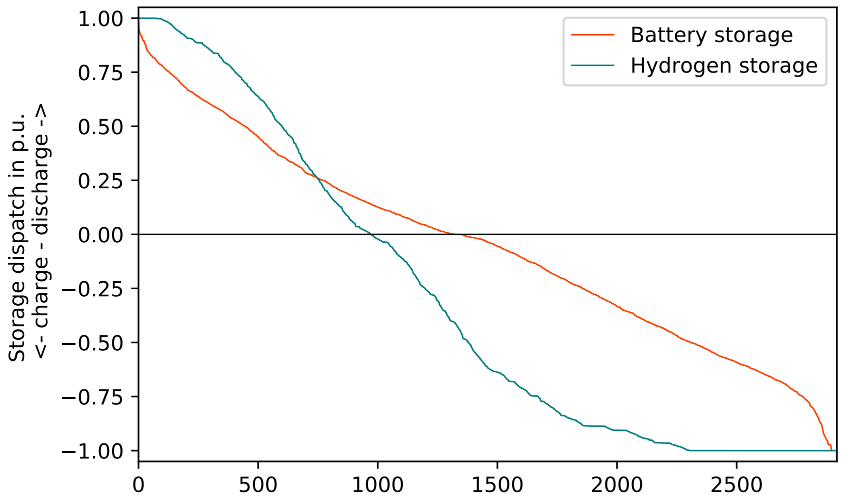


FIGURE 5.8: Sorted annual duration curve of the operation mode by storage technologies. Negative values indicate storage charging, positive values indicate discharging. The petrol blue line shows the hydrogen storage, the red line illustrates battery storage units. Storage units have been accumulated per technology for better visualisation.

5.3 Storage Parameter Variations

In Short:

- **Increasing the capacity to power ratio for battery storage units yields a higher battery storage share and 17.5 % more storage capacity than in the base case.**
- **Hydrogen storage is more sensitive to efficiency variations than batteries. An efficiency gain of 5 % leads to a capacity increase of 12.9 % and supports wind power feed-in by reducing curtailment rates.**
- **Higher storage costs reduce the additional storage capacity by around 70 % for increases starting from 50 %. The LCOE is hardly touched by higher storage costs.**
- **In comparison, storage cost reductions show significant capacity gains up to a factor of 9 and a remarkably lower LCOE. In general, battery storage is more sensitive to costs variations than hydrogen storage.**

In the following, the robustness of the results regarding additional storage capacity is assessed by a variation of the most important storage parameters. Apart from the assumed storage installation costs, these are the storage efficiency and, at least for battery storage, the value of max_hours (t_{max}), i.e. the maximum charging or discharging duration at full power before the energy capacity limit of a storage is reached.

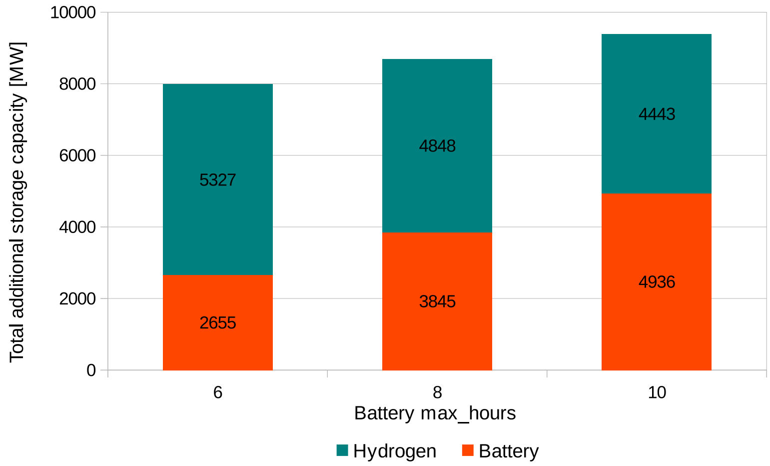


FIGURE 5.9: Total installed capacities of storage units by technology after a variation of the max_hours (t_{max}) value for battery storage. The petrol blue area shows hydrogen storage. The red area illustrates battery storage units.

Storage Capacity to Power Ratio Figure 5.9 shows the installed storage capacity for battery and hydrogen storage after a variation of the max_hours value for batteries from the standard of 6 to 8 and 10. It is expected that an even higher value is unlikely for batteries as short-term storage. By this increase, the energy capacity of storage is increased while charging and discharging power remain unchanged. The figure indicates a significant increase in overall storage capacity of 8.9 % when max_hours (t_{max}) is 8 h and 17.5 % when max_hours (t_{max}) is 10 h. This increase is caused by substantial additional battery capacity, which also yields in a changed ratio of battery to hydrogen capacity. While in the standard case hydrogen capacity is twice as much as battery capacity, there is now more battery than hydrogen storage in the $t_{max} = 10\ h$ case. Hydrogen storage, on the other hand, is slightly decreased, which is caused by a replacement of small hydrogen storage by batteries with a now increased capacity. On the other hand, as the average hydrogen storage capacity increases from 533 MW to 889 MW, large-scale hydrogen storage cannot be replaced by batteries. The total number and location of storage units remain practically unchanged in all three cases. In terms of storage operation, only a slightly decreased frequency of battery storage operation can be observed. Hydrogen storage, on the other hand, shows marginally increased filling levels and operation in peak mode. An explanation for this circumstance may be the fact that the purpose of long-term storage now has to be fulfilled by fewer storage units, i.e. less charging and discharging power. In contrast to the changes to storage installations by the variations, the overall results are hardly touched. The LCOE of the total system is marginally decreased (from 56.23 EUR/MWh to 56.22 EUR/MWh or 56.21 EUR/MWh, respectively) while the LCOE for Germany only is slightly increased accordingly due to higher storage installations. The amount of cross-border exchange and the dispatch of generation technologies remain unchanged. Curtailment rates can be decreased in Germany by about 3 %, expectedly also due to increased storage capacities.

Storage Efficiency The assumptions for storage efficiency in a future scenario such as the eGo 100 scenario applied here are inevitably based on highly uncertain technology projections. At the same time, there are technical or rather physical limits to storage efficiency that cannot be overcome and are considered when assuming efficiency values. Hence, the scenario space regarding storage efficiency is by far more limited than that of the assumed storage costs. In this case, the original assumptions for storage efficiency are varied by 5 % for both hydrogen and battery storage. The results of this variation show a more substantial impact of efficiency variation for hydrogen storage. Here, a 5 % efficiency increase leads to 12.9 % more hydrogen capacity, a 6 % decrease of battery capacity and in total an increase of 6.6 % storage capacity. Reducing the efficiency by the same value results in 11.8 % less hydrogen, 4.5 % more battery and in total 6.4 % less storage capacity. Battery efficiency, on the other hand, shows less impact on the resulting capacity. When battery efficiency increases by 5 %, battery capacity rises by 8.9 % while hydrogen capacity is only slightly reduced by 0.6 %. A decrease, on the other hand, leads to 7.5 % less battery and a plus of 1.9 % in hydrogen capacity. In total, the 5 % variation of battery efficiency leads to an increase of 2.5 % or a decrease of 1.2 % in storage capacity. The naturally lower efficiency of hydrogen storage causes a stronger dependence on its variations compared to the highly efficient batteries. Similar to the max_hours (t_{max}) variation explained above, a 5 % higher battery efficiency or a 5 % lower hydrogen storage efficiency lead to a replacement of small hydrogen storage by batteries. The location of storage units remains the same. The efficiency variations only slightly touch storage operation patterns. Naturally, the charging effort increases with decreasing efficiency. However, this effect is significantly higher for the variation of hydrogen compared to battery storage efficiency. The filling levels are slightly lower in their peaks with increased efficiencies. The total annual energy flowing in and out of additional storage units is raised in the range of 7 % – 9 % when hydrogen storage efficiency is 5 % above the original value and vice versa for the 5 % decrease. For battery storage, the impact is less significant. For all efficiency variations, the overall LCOE, generation dispatch, and cross-border exchanges are equal or in the same range as the original case. A significant impact can again be observed for the amount of curtailed power, especially in Germany. Here, the variation of the hydrogen efficiency leads to a change in overall curtailment rates by about 3 % in both directions, with the strongest impact on offshore wind curtailment rates. In the case of battery efficiency, no such effect is visible. This result supports the hypothesis of the strong interdependence of hydrogen storage and (offshore) wind which was mentioned before in Section 5.2.

Storage Costs The third and most significant parameter to be varied are the storage installation costs. These costs are annualised costs, including not only installation but

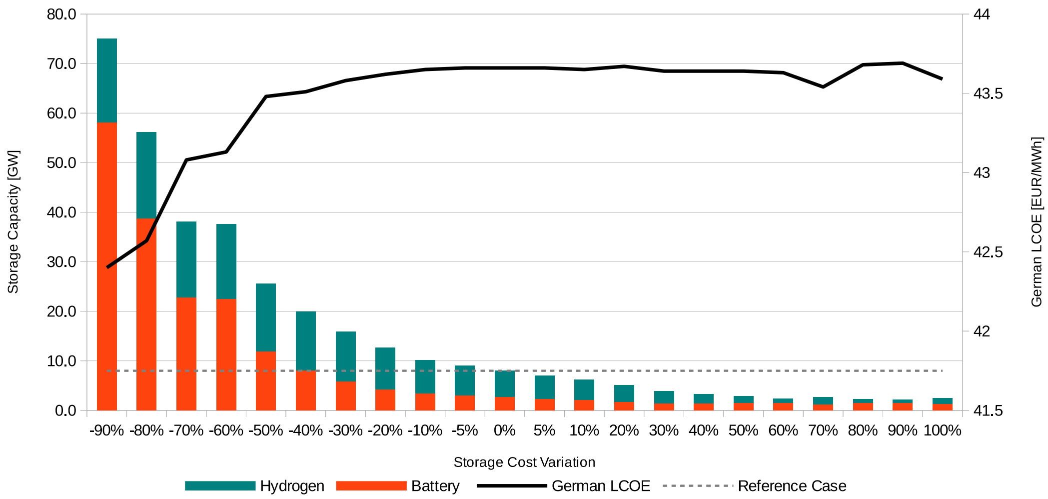


FIGURE 5.10: Impacts of a variation of assumed costs for storage units. The red (battery storage) and petrol blue (hydrogen storage) bars indicate the resulting storage capacity per variation. On the right y-axis, the black line shows the change in total LCOE compared to the reference case.

also a factor for operation and maintenance expenditures (compare Section 4.3). It has been mentioned before that future cost projections are highly uncertain, especially when compared to rather technical parameters like the efficiency of storage. The case of rapidly falling prices for PV modules (Vartiainen et al., 2019; ISE, 2019) is, for instance, considered as a possible reference case once battery storage reaches a high market penetration. Hence, the sensitivity analysis regarding storage costs for both battery and hydrogen covers a relatively large range of cost development. Starting from +/- 5 %, storage costs are from +/- 10 % varied in steps of 10 % to a minimum of - 90 % and a maximum of + 100 % of the original cost assumptions. The variations are carried out for both technologies at the same time, i.e. there is no distinguished assessment of varying cost developments for the two representative technologies. A comprehensive overview of the resulting storage capacities and changes to the LCOE is presented in Figure 5.10.

The overall additional storage capacity ranges from 2.44 GW when costs are doubled to 75 GW when the costs fall by 90 %. In general battery storage shows a stronger sensitivity towards cost variations as its shares are higher in both directions compared to hydrogen storage capacity. Moreover, a cost decrease shows a far more significant impact than an increase. Especially cost reductions below 50 % lead to massive additional storage capacity. Here again, battery storage is the central driver, while the total additional capacity of hydrogen storage remains almost constant from -50 % to -90 %. A cost increase, on the other hand, shows less potent effects. From the reference case to a storage cost increase of 50 %, a moderate shrinking of capacity can be observed. Going further up with storage costs, the capacity is relatively constant, which indicates a robust minimum storage capacity between 2 GW and 3 GW, with a tendency towards larger battery storage shares. The location of additional storage units is relatively constant, even with different storage cost assumptions. In general, with lower storage costs, the battery capacity is more significantly increased, which leads to a broader distribution across Germany. An orientation of battery storage units towards big cities with a higher demand can be observed. Hydrogen storage locations, on the other hand, remain almost unchanged, which is also caused by its local restrictions. Higher storage costs, in contrast, reduce the storage capacity compared to the original setup. Similar to the capacity, the location of storage units is unaffected by cost increases beyond 50 %. For all cases in this range, two large battery storage units at the known grid bottleneck in the Northwest of the country can be found. A third large battery storage occurs in the Southwest close to the French border. Hydrogen storage units are reduced compared to the base case, and it is remarkable that now the largest hydrogen storage is one in the Northeast close to the Polish border.

The distinguished capacity development for rising and falling storage costs also affects the curtailment rates. In the most extreme cost reduction of 90 %, the German curtailment rate can be lowered by 55.7 % to only 8.5 %. With doubled storage costs, on the other hand, the curtailment rate grows by 24.2 % to 23.8 %. For both cases, wind onshore and offshore are the main drivers for changed curtailment rates. It should be noted that even with 75 GW storage capacity resulting from a 90 % cost decrease, the German offshore generation is curtailed by 16.2 %. The generation share of PV, onshore and offshore wind can be brought from the base case's 76.7 % to 82 % in the lowest cost extreme, while it is reduced to 75 % at doubled storage costs. In general, wind generation indicates a stronger dependency compared to PV. Biomass production is adjusted accordingly. As another consequence, the share of imports of the total German yearly load is changed. The import rate can be reduced to 8.6 % with 75 GW storage and increases from 13.6 % in the base case to 16.6 % when storage capacity is at only 2.44 GW. Although this difference is significant, it is eye-catching that 75 GW storage are not capable of reaching an equal exchange balance. Figure 5.10 also depicts the changes to the German LCOE (without neighbouring countries) by storage cost variations. In case of falling costs, the LCOE shows a first noticeable decrease at 50 % and more remarkable falls from 60 % to 90 % lower storage costs. At the maximum of 90 % the LCOE is with 42.40 EUR/MWh 2.9 % below the reference value of 43.66 EUR/MWh. Strikingly, higher storage costs hardly affect the German LCOE, especially when compared to the other extreme.

5.4 Intermediate 70 % RES Scenario

In Short:

- **A 70 % RES generation share in Germany can be reached with an additional storage capacity of 4.0 GW and an import rate of 15.4 % of the yearly German power demand.**
- **Hydrogen storage provides 4/5 of this capacity. The storage locations are in line with the ones for the 100 % RES scenario.**
- **The existence of flexible thermal power plants shows a substantial impact on the resulting storage capacity.**
- **Limiting the flexibility of these power plants leads to substantially higher storage capacities of 37.9 GW, which allow to almost entirely reduce imports. The German LCOE, on the other hand, increases by 13.9 % when applying such a simplified depiction of thermal ramping constraints.**

For a better understanding of the pathway towards a 100 % RES based power system, the general model setup is applied to the intermediate scenario NEP 2035 which represents the German power system at approximately 70 % RES generation share. The scenario is described in detail in Section 4.2.2. The resulting additional storage capacity for this optimisation is 4.0 GW, approximately 50 % of the value reached in the basic eGo 100 scenario. The 4.0 GW consist on the one hand of 871 MW battery storage spread over seven units which results in a relatively low average capacity of 124 MW. On the other hand, hydrogen storage provides the major capacity (78.4 %) with 3.2 GW in five separate units resulting in a 634 MW average. The biggest unit is a 1.8 GW hydrogen storage which is situated at the same node as the biggest storage in the eGo 100 scenario. With a maximum of 308 MW, the biggest battery storage unit is comparably small. The overall storage results need to be assessed under consideration of existing storage capacity. While in the NEP 2035 there are about 30 GW of total storage capacity given before the optimisation (including neighbouring countries), the eGo 100 has existing storage in the range of 100 GW. Nonetheless, the NEP 2035 still features substantial conventional generation capacity.
The LCOE of the complete system is with 55.45 EUR/MWh slightly (-1.4 %) lower than that of the eGo 100 scenario. For Germany without its neighbours, the LCOE is at 48.73 EUR/MWh which equals an increase of 11.6 % compared to the basic setting. More expensive exogenous costs cause higher system costs in Germany. Substantial thermal generation capacities are expected to be the central driver for this effect. The power dispatch costs are in the same range as in the eGo 100 scenario, while storage investment costs are lower. In the complete system, a RES generation share of 70.8 % is reached. Similar to the eGo 100 scenario, the German demand is not completely covered by German dispatch, but heavily relies on imports. The coverage

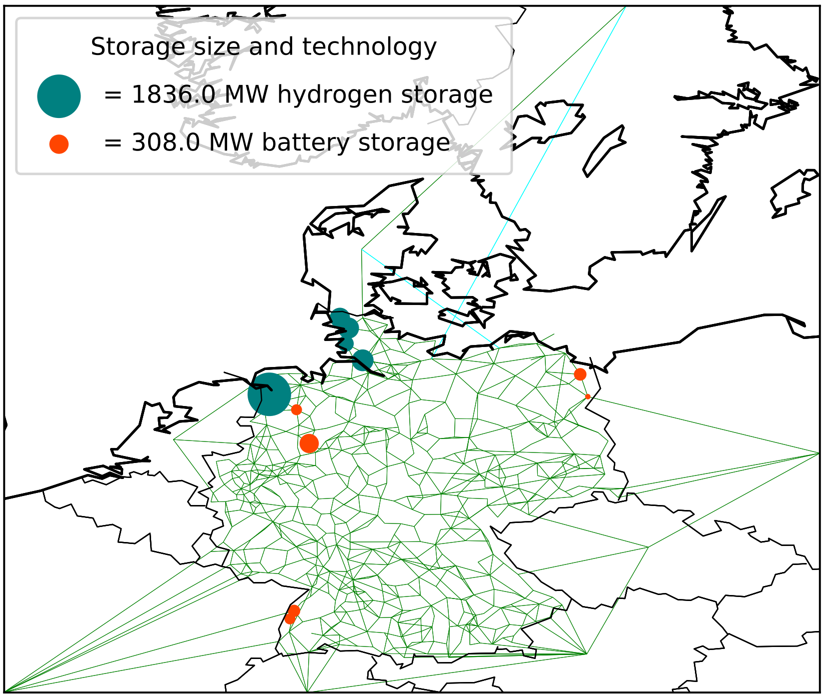


FIGURE 5.11: Spatial distribution of additional storage units in the NEP 2035 scenario. The size of a dot represents the storage capacity. Petrol blue dots show hydrogen storage units. Red dots indicate battery storage units. Cross-border DC power lines are depicted in light blue.

rate is 84.6 % compared to 86.5 % in the basic setting. With 5 %, the curtailment rate of the complete system is within a realistic range. In Germany alone, curtailment reaches 8 % with offshore wind being the most curtailed technology (13.7 %). Figure 5.11 illustrates the spatial distribution of additional storage installations. First, it can be noted that the large hydrogen storage unit in Northwestern Germany can be found in the same location and range of capacity in the NEP 2035 and the eGo 100 scenario (compare Figure 5.3). The remaining hydrogen storage units can be mainly found along the Western coastline of Schleswig-Holstein in Northern Germany, which is a slight shift from more westerly locations in the basic setting. In Eastern Germany, smaller batteries replace hydrogen storage. The biggest battery storage with 308 MW is located north of the Western German demand centres and can be found in a similar location only with higher capacity in the eGo 100 scenario. Although there are minor shifts, especially of small batteries, the overall spatial distribution is very similar in both scenarios.

With regards to the storage filling level, battery and hydrogen storage show a significantly different mode of operation in contrast to the eGo 100 scenario. Battery storage levels regularly reach full capacity, which is substantiated by a relatively high utilisation rate in peak charging and discharging hours. On the contrary, hydrogen storage which represents the major share of additional storage capacity has relatively low storage filling levels. Generally, the filling level profile is in line with the one of the 100 % scenario, but the dimension is far lower and for instance does not feature the characteristic increase in February and March (compare Figure 5.7). Possibly this can be explained by the presence of conventional generation capacity, which reduces the requirement for a seasonal shift of power. In conclusion, battery storage seems to be utilised more extensively, although its capacity share is comparably low.

Limiting Flexibility of Conventional Power Plants In Sections 4.2.2 and 4.5 it is pointed out that potential constraints of the flexibility of conventional generators are disregarded. While this simplification does not affect the results for the eGo 100 scenario due to the absence of such power plants, the impact for the intermediate NEP 2035 scenario is examined in the following. Due to limitations of the computational effort, a simple approach is chosen for this examination. Potential constraints of intertemporal ramping, as well as start-up or shut-down limitations, are disregarded. In contrast, it is assumed that nuclear, lignite, and coal power plants can only be dispatched with full flexibility in a range of 50 % to 100 % of their nominal capacity. Hence, differences in the flexibility of these conventional generation types are disregarded by this uniform approach. By this depiction, it is expected that at least the constraints of start-up and shut-down can be reasonably considered.
When introducing this limitation, the overall results change significantly. The LCOE of the complete system increases by 7.9 % to 59.84 EUR/MWh. For Germany alone, the LCOE increase is even stronger, with plus 13.9 % to 55.49 EUR/MWh compared to the standard NEP 2035 setup. Since the composition of the power system, in general, is not touched, exogenous costs remain constant, which means that any cost increase is due to higher dispatch and storage installation costs. The RES generation share is also increased to 76.1 % (80.3 % for Germany). Regarding the technology-specific dispatch, some significant adjustments can be observed for the flexible power plants while fluctuating RES feed-in remains rather constant. Biomass production is significantly increased; the same applies to coal and lignite. The output of nuclear power plants, that are only situated outside Germany in this scenario, is reduced.
The additional storage capacity grows substantially when considering restrictions to power plant flexibility. In total, the capacity increases from only 4 GW to 37.9 GW, which equals a factor of 8.4. Battery storage makes up for less than 10 % of this capacity while hydrogen provides the large majority. The spatial distribution, however, remains relatively constant with the vast majority of additional storage in Northern Germany. Storage utilisation is in general diverging from the original NEP 2035 case as longer periods in partial load operation occur in contrast to longer operation in peak mode in the reference case. Overall, relatively low storage utilisation can be observed at the total inflow and outflow of storage. Figure 5.12 shows the accumulated hydrogen storage level throughout the year. In contrast not only to the reference NEP 2035 case but also to the storage level dynamics of the eGo 100 scenario depicted in Figure 5.7, a relatively high state of charge can be observed. This result indicates that in this case the large energy capacity and seasonal utilisation pattern of hydrogen

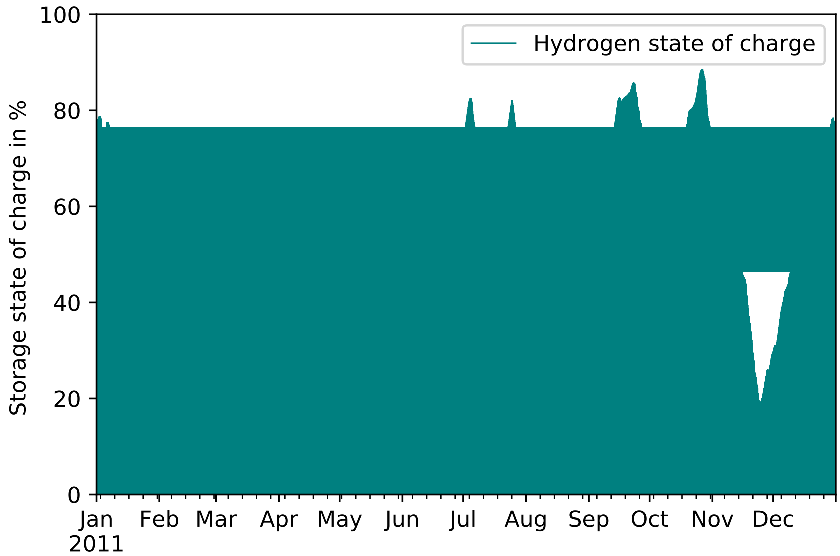


FIGURE 5.12: Annual trend of storage unit state of charge for hydrogen storage. For better visualisation, storage units have been accumulated.

storage is of importance. While the installed capacity increases by a factor of 8.4, the overall charging energy increases by only 3.6 and the discharging even by only 1.5. These values also indicate a rather poor ratio of discharging to charging energy of only 37 % compared to typical values above 60 % for reference cases. A consequence of this low value are high overall storage losses throughout the modelling period. In this case, storage losses make up more than 8 % of the total yearly load. The reference NEP 2035 scenario sees this value at about 1 % while for the eGo 100 results, this parameter moves between 4 % to 5 %.

All in all, it seems that the significantly higher storage capacities first help to integrate larger shares of fluctuating RES to the system. However, the utilisation of the storage capacity comes with massively increased storage losses which need to be covered by more power generation. Therefore, it could be concluded that the increased RES share mainly occurs due to a higher effort to compensate storage losses. The simplified consideration of flexibility limitations indicates a significant impact on the model results. Possibly, these impacts could be even more substantial when considering flexibility constraints in more detail.

5.5 Impact of Neighbouring Countries

In Short:

- **Without pre-defined future storage units in neighbouring countries, additional storage capacity is moved to Germany, and only 10 % of the pre-defined storage capacity in neighbouring countries is required.**
- **The depiction of a connection to Norwegian hydropower capacities through artificial units at potential landing points leads to decreased storage requirements in these regions. Other storage units are hardly affected, which highlights the importance of storage siting. A proper connection of the full-scale Norwegian power system yields similar results.**
- **In general, an early connection to Norway in the intermediate scenario yields benefits, while a connection capacity of 10 GW is rarely utilised to full scale.**
- **The dependency of imports in the base case can be highlighted when disregarding neighbouring countries. In this case, the required original storage capacity of 7.98 GW is brought to 75.79 GW.**

According to the research questions addressed in this thesis and introduced in Chapter 1, central driving factors of siting and sizing of optimal storage units shall be assessed. In the following, the results with regards to the second research question which reads

> *What is the impact of flexibility in neighbouring countries to German storage requirements?*

are presented. In order to answer this question, several modelling setups are put in place that differ from the base case presented in Section 5.2.

Optimisation of Storage Units in Neighbouring Countries First, the general assumption regarding future storage units in neighbouring countries is discussed. It was pointed out in Chapter 4 that it is, in general, assumed that all neighbouring countries would have substantial additional storage capacity installed in a 100 % RES scenario. Therefore, apart from classic PHS, battery and hydrogen storage capacities are pre-defined for each neighbouring country according to Wingenbach, 2018. In short, hydrogen storage capacities are concentrated in Northwestern Europe with the majority in France. Other neighbouring countries to Germany have only minor hydrogen storage capacities which may be due to limited underground potentials. Battery storage, on the other hand, is relatively evenly distributed across Germany's

neighbours. However, countries like Poland or the Czech Republic with more conventional power systems show higher battery capacities compared to countries with significant hydropower potentials. Due to this pre-definition, these capacities are not variable within the basic optimisation process. However, since the assumed capacities are based on a future scenario that is subject to uncertainty, one could argue that such a pre-definition might affect the overall results significantly and may lead to sub-optimal results. For instance, storage units could be installed in countries that feature sufficient flexibility, for example through PHS. The impact of this assumption can be assessed by taking the neighbouring countries' additional storage capacities into account for the optimisation. Within the capacity limits defined by Wingenbach, 2018, the installation of battery and hydrogen storage units in neighbouring countries is then subject to the overall optimisation process.
The results of this adjustment indicate a significant impact to the siting and sizing of storage in Germany. Instead of the 7.98 GW additional German storage capacity in the base case, the capacity is now increased to 12.17 GW. The battery / hydrogen distribution is slightly shifted towards more short-term storage while long-term hydrogen capacity still accounts to 60 %.

The distribution of hydrogen storage units remains similar, with a tendency towards larger storage capacities in Northwestern Germany. Here, the largest storage of the original setup (1.89 GW) now has a capacity of 2.68 GW. Battery storage distribution, on the other hand, shows a more substantial growth, especially in the Southern and Western regions. In the original setup, all neighbouring countries feature battery storage units and most also have some hydrogen storage capacity (compare Appendix A). In total, there are 16.7 GW of battery and 39.7 GW hydrogen storage in all neighbouring countries. Regarding hydrogen, France features the largest capacity with 26 GW followed by the Netherlands with 7.6 GW.
Allowing the optimisation to freely set storage capacity within these country-specific limits yields a total of 5.74 GW distributed over only two units. Apart from a 2.94 GW hydrogen storage in the Netherlands, there is a 2.80 GW battery storage in Poland. Thus, compared to the pre-defined capacity of in total 56.4 GW only around 10 % are installed when storage in neighbouring countries is subject to the optimisation. As indicated above, additional storage capacity in German increases on the other hand.

Overall, the LCOE of the power system is reduced by 1.6 % to 55.35 EUR/MWh when optimising storage in neighbouring countries. This decrease is due to lower exogenous costs as the installation costs for the mentioned 56.4 GW do not occur. As expected, the endogenous costs, on the other hand, increase from 5.98 EUR/MWh to 6.78 EUR/MWh, driven by higher storage optimisation costs and increased dispatch expenditure. In Germany alone, the LCOE is slightly increased by 1.6 % to 44.35 EUR/MWh mainly because of increased storage capacity. Increased dispatch costs can be assigned to a higher feed-in from biomass. In Germany, the offshore wind feed-in rises due to more close-to-shore storage capacity. This effect can reduce the curtailment rates for Germany while in the overall system, curtailment increases by 15.6 % to 22.9 %. Higher RES utilisation in Germany additionally yields lower import rates. Compared to 13.6 % in the base case, the import rate of the total demand can be reduced to 11.3 %. The described results indicate the distinction of different approaches for modelling storage in neighbouring countries. With regards to the required additional storage capacity in Germany, the overall results are in line with the basic modelling case, especially in the case of storage siting.

Consideration of Storage in Norway The power systems of Germany and Norway are not directly connected until the interconnector project NordLink comes to operation. Hence, in the basic modelling setup, Norway's power system is not depicted. At the same time, several studies indicate the vast flexibility potential of Norwegian hydropower to the continental power system (SRU, 2011; Ess et al., 2012; Bökenkamp, 2014). The NordLink interconnector has a transmission capacity of 1.4 GW and came to operation in 2020 (TenneT, 2020). It is expected that through the connection of the German and the Norwegian power systems, another source of flexibility for the increasingly fluctuating generation patterns in Germany can be developed. Therefore, the impact of such a connection to the requirement of additional storage in Germany needs to be assessed.

In a first rather simple modelling approach, the NordLink interconnector is depicted as a PHS at the German landing point in Wilster (Schleswig-Holstein). The technical parameters of this storage unit are the same as the ones already installed. With this simplified approach the Norwegian power system is depicted as a single PHS which is certainly incomplete and does not correspond to the vast (reservoir) hydro power potential in the Scandinavian country. Especially the limitation to $t_{max} = 6\ h$ of maximal charging or discharging can be considered a significant shortfall compared to reality since the maximum storage energy capacity equals 8.4 GWh only. However, the simplified approach is expected to give some first hints towards the effects of substantial connection capacities to Norway.

With this virtual storage unit in place, the overall additional storage capacity can be reduced by 20 % compared to the base case without Norwegian storage to only 6.36 GW. The share of hydrogen and battery storage remains in the same range. In general terms, storage operation gains efficiency due to the comparably efficient PHS. Considering such a storage in Wilster significantly reduces storage requirements in Northern Germany, which results in a shift of the remaining storage capacity further south. The overall generation patters remain in the same range while the curtailment is increased mainly due to onshore wind in Germany. In this case, the curtailment rates increase from 17.8 % in the base case by 11 % to 19.8 % when considering PHS in Wilster. The LCOE for the complete system are hardly touched by this addition while the LCOE in Germany can be decreased by 0.4 %. The decrease in storage installation expenditures overcompensates higher exogenous costs for the additional installation.

With regards to possible future extensions of the transmission capacity to Norway, the original capacity of 1.4 GW at the bus in Wilster is further increased to 10 GW in a second step. The general depiction with as a simple PHS with $t_{max} = 6\ h$ remains unchanged leading to a maximum storage energy capacity of 60 GWh. In this context also the difference between a connection to a single landing point is compared to a separation of the total capacity to two landing points with the same capacity. Hence, the total capacity of 10 GW is separated to 5 GW in Wilster and 5 GW in Wilhelmshaven, another potential interconnector landing point.

Despite the significant storage capacity increase, the results of these cases reveal rather limited impacts compared to the 1.4 GW addition. If 10 GW are installed in Wilster only, the additional storage capacity in Germany is reduced by 11 % to 7.1 GW. Thus, the smaller storage unit of 1.4 GW shows a higher impact to the required additional storage capacity than the larger 10 GW. In both cases the original storage units close to the landing point in Wilster are not required and in general storage units are moved further South and West. Increased storage capacities allow for a higher feed-in from fluctuating RES, especially wind power. Hence, in Germany, curtailment (-10 % in total, -16.3 % for onshore wind) and biomass generation (-9.1 %) can be reduced significantly. This parameter may explain the higher additional storage capacity compared to the 1.4 GW storage case where curtailment is higher than in the original case. On the downside of reducing curtailment rates, the LCOE slightly increases to 56.42 EUR/MWh (+0.3 %) and even more significantly to 44.08 EUR/MWh (+1.0 %) for Germany alone. Again, the costs for the pre-defined storage are the main driver for the increase while decreased dispatch costs are overcompensated. Once the capacity of 10 GW is separated into two buses, another significant impact can be observed. Now the total additional storage capacity adds up to 5.49 GW which is a decrease by 31.2 % compared to the base case and a further decrease by 1.6 GW compared to the case with the non-separated connection of 10 GW in Wilster. This result highlights the importance of storage siting. The overall LCOE in the separated case is at 56.46 EUR/MWh, which is higher than that of the base case and the non-separated case. The same applies for the German LCOE which is with 44.15 EUR/MWh above both references.

In a third modelling approach, the Norwegian power system is depicted in the same way as the other electrical neighbours of Germany. For this case, the assumptions regarding generation, demand, and storage installations are taken from the same source as described in Chapter 4 for the neighbouring countries (e-Highway2050, 2015). Hence, the depiction of the Norwegian hydropower system with its large reservoirs is significantly better depicted than in the former simplified modelling approaches. Apart from the connection to Norway through the NordLink interconnector, the ALEGrO interconnector similarly allows the depiction of Belgium as another new electrical neighbour (Amprion, 2020). For both new electrical neighbours existing connections to other neighbouring countries (e.g. Norway - Sweden, France - Belgium) are depicted.

When Norway and Belgium are added to the modelling scope, the overall additional storage installations in Germany increase by 20.6 % compared to the base case to 9.63 GW. The technology share of hydrogen and battery remains in the same range with hydrogen storage providing around two-thirds of the total capacity. The connection of the NordLink interconnector in Wilster, just North of the river Elbe, leads to a shift of hydrogen capacity from Schleswig-Holstein across the Elbe to the South. However, the general location of hydrogen storage in Northwestern Germany remains constant. In Southern Germany, some more, but small battery storage units can be observed. In Germany, the increased interconnection capacity and the higher storage capacity lead to a decrease in offshore wind curtailment by 9.0 %. Rising onshore wind curtailment compensates this positive effect and leads to an almost unchanged overall curtailment rate. The import rate can still be reduced to 11.8 % compared to 13.6 % in the original setup. In terms of the overall power system, including neighbouring countries a significant increase of 11.1 % of the curtailment rate can be observed. However, in comparison with the base case, the different power system setup due to two new electrical neighbours has to be considered. Still, the generation shares indicate an apparent increase in hydropower generation which can be assigned to the connection to Norway. At the same time, the share of biomass generation decreases significantly by 9.3 %. The connection of the two countries Norway and Belgium also induces higher LCOE, not only for the complete system but also for Germany alone. However, the LCOE increase of 3.2 % to 58.05 EUR/MWh for the overall system can be assigned to higher exogenous costs which can be expected when scaling up the modelled power system. The dispatch costs, on the other hand, are decreased, mainly due to the mentioned increase in hydropower generation. In the case of Germany alone, the LCOE rise is less significant with 1.6 % and is caused by both, an increase in dispatch expenditure and additional storage installations.

Lastly, the previous setup connecting Belgium and Norway is adjusted by increasing the transmission capacity to Norway from 1.4 GW to 10 GW. The resulting additional storage capacity in Germany is in a similar range as in the base case, but with a slight shift to battery storage now providing the majority of capacity. Consequently, the overall storage losses can be decreased and the rate of discharging to charging energy can be increased from 63.6 % in reference to 67.8 % with a 10 GW connection to Norway. The storage locations are similar to those depicted above for the 1.4 GW connection to Norway. A significant battery storage capacity in central Northern Germany is noticeable. It is expected that while the 10 GW connection to Norway may reduce storage requirements in Northern Germany, the existing transmission bottlenecks to the South of the country cannot be overcome and hence lead to a shift of storage capacity further south compared to the original distribution pictured in Figure 5.3.

Similar to the 1.4 GW connection case, the overall curtailment is increased significantly, in this case by 9.9 %. At the same time curtailment in Germany can be reduced by 3.6 % mainly due to lower curtailment rates for offshore wind. As a consequence

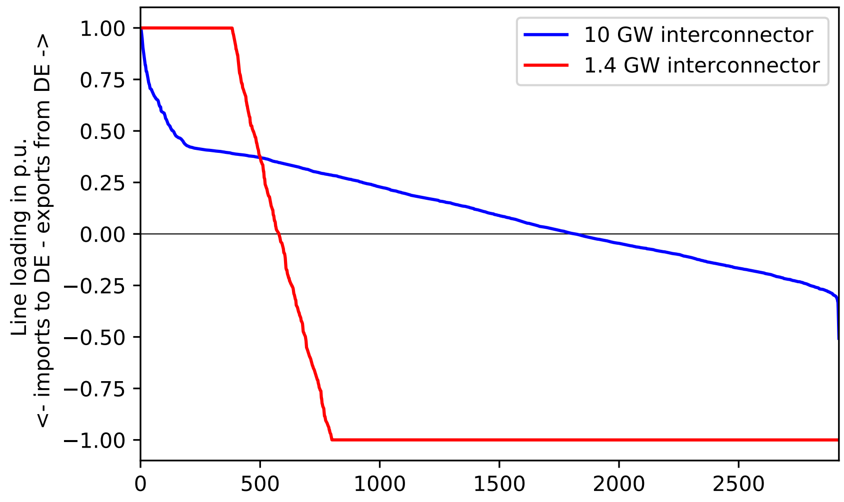


FIGURE 5.13: Normalised sorted annual duration curve of the loading of the two alternative interconnectors from Germany to Norway in the 10 GW (blue) and 1.4 GW (red) alternative. Positive values indicate exports from Germany to Norway, negative values show imports to Germany.

of the extended transmission capacity to Norway, the exports of wind energy production in Northern Germany are increased, leading to a more beneficial exchange balance. Still, 11.1 % of the yearly demand in Germany is covered by imports. Again, the overall costs of the modelled system are hard to compare due to the different scope. However, it can be found that the German LCOE is increased by 1.5 %, which is driven by higher dispatch expenditures caused by more biomass generation and slightly higher storage costs.
Figure 5.13 illustrates the utilisation of the two connections discussed in the two latter cases. The red curve shows the case of a 1.4 GW link to Norway as planned with the NordLink project. The sorted annual duration curve illustrates a high utilisation rate of this interconnector as it operates in peak mode for most of the time. A clear majority of times of imports to Germany is visible through the horizontal red line at the bottom. The blue curve depicts an increase in the same connection to 10 GW. Here, it is evident that the mode of operation is changed and mostly happens in part-load. Exports to Norway only rarely reach the peak capacity of 10 GW while the imports from Norway never exceed a peak of 5.07 GW. It can be concluded that a limited transmission capacity serves imports from Norway and shows a high utilisation rate. Increasing the capacity shifts these patterns and leads to a focus on exports from Germany and relatively limited use of the full capacity.

The commissioning of the NordLink interconnector in 2020 is not only relevant for the long-term eGo 100 scenario but might also impact the results of the NEP 2035 scenario. Although this is generally true for all grid measures that come to operation in the meantime, in this single case, the impacts can be assessed in isolated modelling setups. Thus, similar variations to the ones carried out for the eGo 100 scenario and outlined above are also modelled for the NEP 2035.

When modelling a simplified PHS at the potential interconnector bus Wilster, the overall storage capacity compared to the standard NEP 2035 setup is hardly affected in case of a 1.4 GW storage. The same applies when the capacity is increased to 10 GW, only a split of the 10 GW to Wilster and Wilhelmshaven leads to a substantial decrease of additional storage capacity by 46.8 % to 2.51 GW. In general, the share of hydrogen storage is increased in all variations which is assumed to be caused by a replacement of short-term storage by the new PHS while seasonal storage cannot be replaced accordingly. This effect may be explained by the simplified modelling approach which does not properly depict the seasonal storage potential of the Norwegian power system. As expected, the storage locations are directly affected as the PHS replaces former hydrogen capacity in Schleswig-Holstein. However, since the total capacity remains constant, this is only a locational shift further south. In case of splitting the 10 GW to two buses, the storage location is in its structure almost the same as in the standard NEP 2035 setup, only reduced in its dimension. The generation patterns show a slight decrease in generation from coal, lignite and biomass in Germany. This reduction is compensated by a higher feed-in, especially from offshore wind which is enabled by significantly reduced curtailment rates (-50 % in the 10 GW cases for offshore wind). Hence, the RES generation share can be slightly increased to roughly 75 %. The overall LCOE for Germany is in all variations higher compared to the reference case, driven by the higher exogenous costs of the large pre-defined PHS.

In line with the modelling for the eGo 100 scenario, also the electrical connection to Norway and Belgium implicating a consideration of the respective complete power systems is carried out for the NEP 2035 scenario. In contrast to the results for setting hypothetical storage at the Wilster bus, this extended model setup reveals more significant impacts. The overall additional storage capacity in Germany can be reduced from 4 GW in the base NEP 2035 case by 62.0 % to only 1.54 GW. This capacity is composed of four relatively small battery storage units adding to a capacity of 108 MW. The remaining battery capacity of 293 MW (in total 400 MW) is situated in Saxony in a region characterised by lignite production. This location is unusual in comparison with any other scenario and therefore noticeable. Hydrogen storage constitutes the remaining 1.14 GW in four relatively large units. Two of these are found in Northwestern Schleswig-Holstein, while the other two are in the well-known regions in the Northeast close to the Polish border and in the Northwest. However, the latter one is in comparison situated further West than in the other variations or the standard setup. The significant reduction of seasonal hydrogen storage in this modelling setup indicates that here the seasonal storage character of the Norwegian power system is considered and impacts the results while this is not the case when modelling only a simplified PHS at the interconnector landing point.

Lower storage capacity consequently leads to higher curtailment rates. For Germany, the total curtailment rate is increased by 22.4 % to 9.9 %. This increase is induced by wind onshore and offshore which reach curtailment rates of 9.8 % and 16.4 %

respectively. Regarding flexible generation, biomass is obviously to a relevant extent replaced by low-cost hydropower generation from Norway while lignite generation is also increased. The relatively high marginal costs of biomass production may explain this effect. The mentioned battery storage could incite the increased lignite generation share in Eastern Germany. As a result, the RES generation share in Germany is decreased to only 68.8 % compared to 73.5 % in the base NEP 2035 scenario. Certainly, rising imports leading to a total import rate of the yearly demand of 19.2 % (compared to 15.4 %) are another cause for this reduction. The overall system costs in terms of LCOE can be reduced significantly. For the complete power system, the LCOE can be brought down by 2.9 % to 53.85 EUR/MWh despite the inclusion of two new electrical neighbours. This effect points out the relatively low generation costs in these countries. In contrast to the eGo 100 scenario where no expensive thermal generation capacity exist, here the inclusion of low-cost generation reduces overall costs. In Germany alone, the LCOE is also reduced by 2.6 % to 47.45 EUR/MWh. While naturally the exogenous costs remain the same, dispatch expenditures and costs for additional storage units can be reduced and hence result in lower LCOE. Compared to the simple modelling approach of setting representative PHS to potential interconnector landing points, the more sophisticated method of properly connecting the two power systems of Belgium and Norway shows more significant, but also more plausible results.

Disregard of Germany's Electrical Neighbours All results presented so far indicate a strong dependency of a feasible German power system to imports from neighbouring countries. In the basic setup, on average 13.6 % of the total yearly load have to be covered by foreign generators. Although European interconnection of power systems is of vital importance and brings numerous benefits, it is expected that countries set up policies in order to become as self-sufficient as possible. Moreover, exporting energy to neighbouring countries may yield substantial economic profits. It is, therefore, crucial to keep the relatively high import rate in mind and also analyse a power system structure that allows for a completely self-sufficient German power system. In order to do so any cross-border connections are skipped. Hence, the existing German generation portfolio must cover the demand at any hour throughout the modelled year. In a first approach, such a setup did not yield a feasible power system. Thus, the existing installed capacities of PV and onshore wind are scaled up by 25 % each, which leads to higher generation capacities at the same sites. The spatial distribution of PV and onshore wind then allows for a feasible power system. In contrast, a 25 % increase of wind offshore capacity while keeping PV and wind onshore constant does not lead to a feasible result. It is expected that the very limited North-South transmission capacities impede this solution that would highly depend on generation in the North.

The outlined setup with skipped cross-border connections and 25 % higher wind onshore and PV capacities results in a completely different power system structure. The

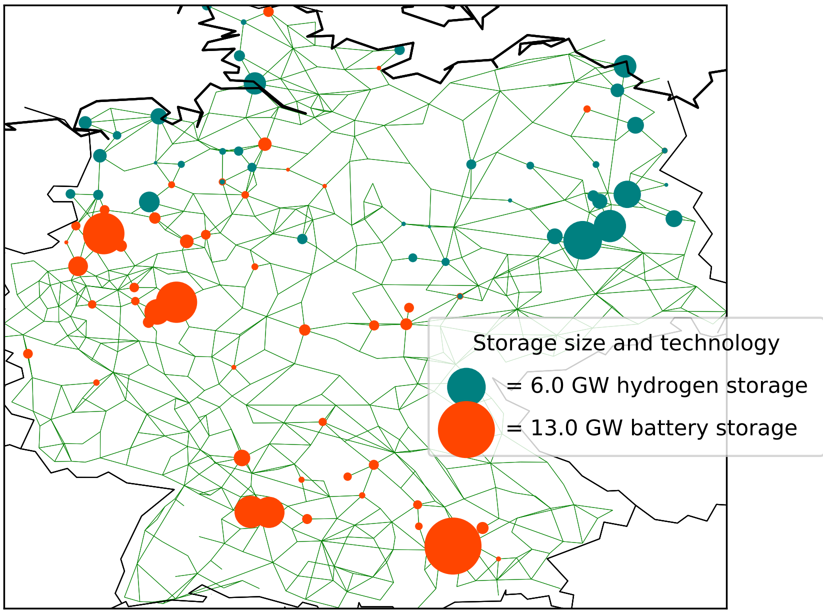


FIGURE 5.14: Spatial distribution of additional storage units in the scenario disregarding Germany's electrical neighbours. The size of a dot represents the storage capacity. Petrol blue dots show hydrogen storage units, red dots indicate battery storage units. Note the different scaling compared to Figure 5.3.

required additional storage capacity is 75.79 GW which consists of 48.58 GW battery and 27.20 GW hydrogen storage. Coming from 7.89 GW in the base case, this equals an increase of almost a factor ten. The division of battery to hydrogen storage is also different with now battery storage providing the majority of additional capacity. These large numbers lead to significant storage losses which add up to 11.7 % of the total yearly load. In this context, the ratio of discharging to charging energy (total outflow to total inflow of storage) is at 51.2 % compared to 63.6 % in the standard setup. Expectedly, the spatial distribution of storage units is clearly distinguished from the base case. While in this one a focus of additional storage in Northern Germany can be observed, storage units are now more evenly distributed across the country as indicated by Figure 5.14. Moreover, in comparison, the Northern regions seem to feature relatively low storage capacities while the focus regions are now obviously oriented towards demand centres in the South and West as well as for hydrogen in Berlin. Figure 5.6 confirms the dependency towards demand centres, which indicates visible negative power production balances in regions with large additional storage capacities.

Consequently to the vast storage capacity, the curtailment rates are significantly lower. In total, curtailment is reduced by 22.3 % to 15.4 %. Offshore wind curtailment is reduced by 28.6 % but still adds up to 26.7 %. In terms of onshore wind, the rate is reduced by 11.7 % to 15.7 %. In general, the generation portfolio is characterised by four main technologies: Onshore wind provides the majority with 36.8 %, followed by 24.9 % for biomass. PV adds up to 20 % while offshore wind provides

15.3 %. The relatively high share of biomass production indeed asks for critical reflection. While the capacity for providing a quarter of yearly generation is less critical, the required biomass seems hardly realisable in the context of limited potentials and possibly competing use in other sectors such as mobility. The system costs in terms of the LCOE sum up to 58.60 EUR/MWh. This value on the one hand equals a 34.2 % increase compared to the German LCOE in the standard setup. On the other hand, the overall LCOE including neighbouring countries is with 56.23 EUR/MWh closer to the LCOE of Germany "as an island". The sum of 58.60 EUR/MWh is composed of (1) 42.82 EUR/MWh for exogenous costs which are higher due to the 25 % increase of wind onshore and PV capacities, (2) 8.93 EUR/MWh for dispatch costs, and (3) 6.85 EUR/MWh for storage installations.

5.6 Effects of Increased Offshore Wind Energy Capacity

In Short:

- **Scaling up offshore wind capacities in the intermediate 70 % RES scenario increases storage requirements and yields very high curtailment rates.**
- **Increasing offshore wind capacity by around 50 % yields a growth of storage capacity by almost the same growth rate. As additional installations overcompensate the savings by reduced dispatch expenditures, the overall LCOE is increased.**
- **In case of additionally reducing the onshore wind capacities, storage requirements are even below the basic setup. Driving up spatially centralised feed-in of offshore wind in Northern Germany leads to higher overall curtailment rates.**
- **A further upscaling beyond the realisable potential in German waters hardly affects storage capacities and leads to massive shut-down rates.**

Offshore wind energy generation in Germany is assumed to be a significant driver for storage requirements. The third research question formulated in Chapter 1 addresses this and reads:

How does an extension of offshore wind energy capacities affect the results?

The motivation for analysing these effects is mainly driven by current discussions on the composition of Germany's future RES portfolio. Due to constraints with licensing, nature conservation, and aero-nautical guidelines, the onshore wind extension in Germany has come to a halt recently (DWG, 2019). From a more abstract viewpoint, it can be assumed that issues with the local acceptance of onshore wind turbines are the main driver for these barriers to further extension. It should be noted that not only the installations of already planned projects are significantly reduced, but also recent auctioning results yield a shortfall in valid bids (BNetzA, 2020a). It is therefore very likely that the ambitious political targets of onshore wind extension cannot be fulfilled. At the same time, the goal of a 65 % RES generation share by 2030 in Germany is still in place (Bundesregierung, 2019). Hence, the other RES sources need to come up for the shortfall of onshore wind. Apart from low-cost PV, offshore wind is now often considered as a fitting backup solution with decreasing generation costs due to forthcoming industrialisation of the sector. Another proclaimed advantage is the large distance of offshore wind installations to shore, which prevents issues with local acceptance. Furthermore, offshore wind has by nature and due to comparably low wake effects from its surroundings the potential of relatively high yield in terms of full load hours (compare Section 4.2.2) (IEA, 2019). High capacity factors not only lead to reduced costs per MWh produced, but also have the potential to reduce flexibility requirements as the feed-in is more harmonised compared to onshore wind and PV. Accordingly, the political target for the extension of this RES source has been steeply increased from 15 GW to 20 GW in 2030 (Bundesregierung, 2019; WindSeeG, 2020).

Capacity Increase in the Intermediate 70 % RES Scenario The NEP 2035 scenario in this thesis, on the other hand, foresees an offshore wind capacity of 16.4 GW by 2030. In two variations, this capacity is increased in the following. The first step is a 20 GW capacity according to the new 2030 target. The second variation of the NEP 2035 numbers is an adoption of the 27 GW foreseen in the eGo 100 scenario to the NEP 2035 scenario. This value is in the range of current sectoral plannings of the responsible authorities BSH and BNetzA. According to the confirmation of the recent NEP and the Site Development Plan (German: Flächenentwicklungsplan (FEP)), offshore sites and grid connections for reaching this capacity are generally possible (Bundesnetzagentur, 2019a; BSH, 2019). Although this variation depicts an ambitious pathway of reaching a long-term target much earlier, 27 GW seem rather likely in 2035 compared to the base value of 16.4 GW in light of the current discussions. Compared to the scenarios defined in the most recent NEP scenario framework, 27 GW for 2035 is the lowest value for the three 2035 scenarios that go up to a capacity of 35 GW (Drees et al., 2020). The grid connection of these capacities is depicted according to the current status of the respective sectoral planning (Bundesnetzagentur, 2019a; BSH, 2019).

The first variation of the NEP 2035 scenario increasing offshore numbers to 20 GW leads to a rise in additional storage capacity by 51.4 % to 6.12 GW. The share of hydrogen storage is with 85.6 % slightly higher than in the base NEP 2035 case (78.4 %). The new storage locations reveal some interesting insights. First, it must be noted that the additional offshore wind capacity of 3.6 GW is allocated at two buses, namely Unterweser and Wilhelmshaven, which are large existing substations close to the North Sea. This allocation is in line with current sectoral planning (Bundesnetzagentur, 2019a). In comparison with the base scenario, two new storage units are situated just south of these new offshore connection points. The hydrogen storage unit south of Unterweser has a capacity of 329 MW while the one South of Wilhelmshaven reaches 461 MW. Southerly locations indicate grid bottlenecks that impede the transmission of offshore wind power to the South of the country. Other noticeable changes to storage locations are on the one hand a stronger concentration of hydrogen storage in Northern Schleswig-Holstein which can only be indirectly assigned to offshore wind since the landing points are in the South of the state and not changed in their capacity either. On the other hand, the large hydrogen storage unit situated close to the offshore grid connection point in the Northwest close to the Dutch border is increased in capacity to now 2.68 GW compared to 1.8 GW in the standard setup. Higher offshore generation capacity yields a higher offshore wind generation share. In total, the share of 15.2 % in the standard NEP 2035 case can be brought to 17.1 % assuming an installed capacity of 20 GW. All other generation technologies are decreased. On the downside, curtailment is in total growing by 21.6 % to 9.8 % and even more for offshore wind. Here, the shut-down rate increases by 27.4 % to 17.5 %. The total RES generation share can still be brought to 74.9 % from originally 73.5 %. Moreover, imports can be reduced from 15.4 % of the total yearly load to 14.3 %. The additional offshore capacity induces higher exogenous costs which drive up the German LCOE by 2.9 % to 50.13 EUR/MWh. Slightly higher costs for additional storage units overcompensate lower dispatch costs. The LCOE of the complete system including neighbouring countries is less affected and grows by 0.8 % to 55.87 EUR/MWh.

A further increase of German offshore wind generation capacity to 27 GW results in an additional storage capacity of 6.03 GW which is almost the same as in the 20 GW variation and 49 % above the result with the basic setup. The relatively high share of hydrogen storage of 91.1 % is noticeable. In contrast to the 20 GW variation, the spatial distribution of the grid connection of the additional offshore wind capacity is now more wide-spread. The most significant capacity increase comes to shore in Schleswig-Holstein at the connection point in Heide/West as well as in two separate buses further South close to Osnabrück. Additionally and in contrast to the 20 GW case, there is an increase of 900 MW for the Baltic Sea as well. However, the resulting storage locations are very similar to the 20 GW variation. The most significant change is the replacement of the two mentioned storage units South of Unterweser and Wilhelmshaven by additional capacity at the already largest storage to now 3.7 GW. At the same time, the mentioned grid connections in the Osnabrück area now lead to some smaller units in this area. In Eastern Germany, the well-known storage unit at the Polish border is further increased to now 600 MW, most probably driven by the increased offshore feed-in in the area.

The offshore wind generation share of the total load can be further raised to 20.6 %

with a capacity of 27 GW. Consequently, all other generation technologies have reduced shares. Again, the RES generation share can be increased to now 76.9 % while the import rate can be further reduced to now 13.4 %. The sizeable offshore capacity otherwise leads to substantial curtailment that now reaches an overall rate of 12.6 % (+56.5 %). For offshore wind alone, the growth is even more significant and results in a curtailment rate of 24.3 % (+76.7 %). The German LCOE is again higher due to increased exogenous costs. It is now at 51.80 EUR/MWh, which is a 6.3 % raise compared to the standard case with 16.4 GW offshore in Germany. Although the dispatch costs are significantly reduced, the installation expenditure of the additional offshore capacity overcompensates these gains. The total system LCOE reaches 56.24 EUR/MWh (+1.4 %).

Capacity Increase in the eGo 100 Scenario The offshore wind capacities are consequently also varied for the eGo 100 scenario. Here, the standard capacity assumption is 27 GW for Germany, which can be considered rather conservative in the context of the development outlined above. Thus, the capacity is further increased to 40 GW in a first step. This number reflects recent discussions on the long-term spatial potential within the German EEZ and coastal waters in the North and Baltic Sea (BSH, 2020) and furthermore equals the long-term target of the German government until 2040 (WindSeeG, 2020). Moreover, 40 GW are also defined by the most recent NEP scenario framework in the lead scenario B up to 2040 (Drees et al., 2020). However, 40 GW may only be an indication, since there is no valid study on the realisable potential considering all relevant constraints such as shipping routes, nature conservation, or large-scale wake effects.

The second and third variations for the eGo 100 scenario also foresee 40 GW offshore, but on the other hand, onshore wind capacities are linearly decreased by 13 GW and 26 GW in order to depict the possibility of rather low onshore wind extension rates. For instance, reducing the onshore wind capacity by 26 GW leads to an installed capacity of 72.4 GW. As indicated in Section 4.5, this number is close to the 67 GW – 71 GW proclaimed by the government as target for 2030.

In a fourth and fifth variation of the eGo 100 scenario offshore numbers, these are increased to an extreme value of 73.2 GW. While in the fourth variation, onshore wind capacity is kept constant, it is decreased again by 26 GW in the fifth variation. The number of 73.2 GW was introduced by the 100 % RES study of the German Advisory Council on the Environment in 2011 (SRU, 2011). Although 73.2 GW is certainly an extreme number that is from today's perspective very unlikely to be realistically installed in German waters, the variation shall indicate the effects of a large-scale shift of the German generation portfolio towards offshore wind.

40 GW Offshore Wind Capacity For the 40 GW variations, the connection of the additional 13 GW takes place mainly in Northwestern Germany. Compared to the close-to-shore grid connection points Wilhelmshaven and Unterweser mentioned above,

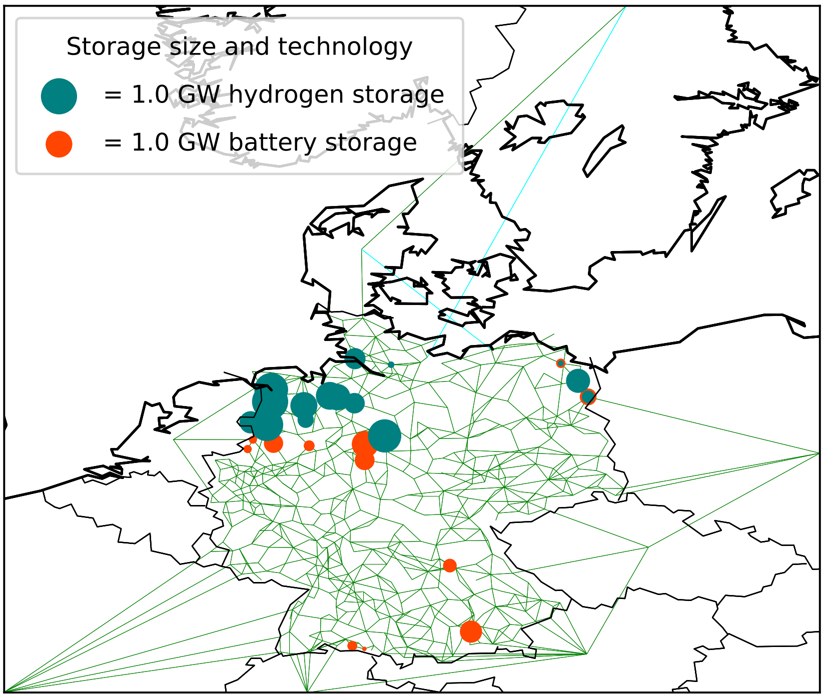


FIGURE 5.15: Spatial distribution of additional storage units in the case with an increased offshore wind capacity of 40 GW. The size of a dot represents the storage capacity in. Petrol blue dots show hydrogen storage units. Red dots indicate battery storage units. Cross-border DC power lines are depicted in light blue.

the additional offshore capacities are now mainly connected further South. Schleswig-Holstein, on the other hand, sees only a minor increase while capacity in the Baltic Sea potentially landing in Eastern Germany is kept constant compared to the base case. The first variation with 40 GW offshore and constant onshore wind capacity reveals a growth of 38.2 % in total additional storage capacity to 11.03 GW. A relatively high hydrogen share of 78.2 % which equals 8.62 GW is noticeable. Figure 5.15 shows that storage locations seem to be oriented towards the mentioned grid connection points now lying further South. While most of the storage units are required close to the shore in the reference case (compare Figure 5.3), large hydrogen storage units are now situated further South. Especially in the Northwest, the well-known largest storage is now complemented with additional units in close vicinity. In contrast, the capacity in Schleswig-Holstein is reduced compared to the base case. Another prominent location is in the central North, close to the city of Hannover. Here, two large battery storage units accompanied by a third large hydrogen storage occur.
In line with the increased offshore wind capacities, curtailment is significantly growing. For offshore wind, the curtailment rate increases by 18 % to 39 %. Strikingly, the onshore wind curtailment rate shows an even higher growth rate of 26.5 % to 22.5 %. At the same time, the onshore wind generation share sinks from 37.6 % to 34.7 %. This is a clear indicator of a replacement by offshore wind, which reaches a generation share of 24.1 % (before: 18.3 %). In total, curtailment reaches 25.4 %.

Despite these high shut-down rates, expensive dispatch from biomass can be reduced significantly. Furthermore, the required imports can be reduced to 11.5 % (-14.8 %) of the yearly load. With regards to the system costs, the offshore wind capacity increase consequently brings up exogenous costs. Additionally, the growth in storage capacity comes at more costs, while the saved dispatch expenditures are overcompensated. In total, the German LCOE increases by 8.5 % to 47.36 EUR/MWh. The overall LCOE is less affected and reaches 57.47 EUR/MWh (+2.2 %).

As these results indicate a replacement of onshore wind generation by increased offshore wind feed-in, the following variations analyse the effects of consequently reducing the installed onshore wind capacity. In the first step, the installed onshore wind capacity is reduced by 13 GW, which is equal to the assumed capacity growth of offshore wind from 27 GW to 40 GW. The capacity is linearly decreased, meaning that a general reduction to all onshore wind sites is applied. The resulting storage capacity of this variation is with 7.55 GW far below the 11.03 GW without onshore wind adjustments and even by 5.4 % below the storage requirement in the base case. The location of this capacity is in general closer to the base case than to the case without onshore wind reduction. For instance, the mentioned storage units in the central North are not required in this case. In Schleswig-Holstein, on the other hand, the required locations are almost equal to those visible in the reference case. However, a tendency towards the more southerly offshore grid connection points can be observed. Again, curtailment rates are heavily increased, in total for Germany by 40.3 % to 26.9 %, which is even higher than the curtailment rate without onshore reduction. This increase is driven by offshore wind, where curtailment reaches 46.2 % (+39.1 %). Due to the lower capacity, the onshore wind curtailment is lower than in the previous case, but still by 4.2 % above the reference case. The generation patterns indicate again a shift compared to the case without onshore reduction. While in the latter biomass generation could be reduced, now even an increase compared to the reference case can be observed. It is expected, that the loss of spatially distributed onshore wind capacities cannot be compensated by offshore wind in times of grid constraints and must, therefore, be covered by expensive biomass dispatch. In contrast to the sole 40 GW case where imports can be reduced, they are now even higher than in the base case and reach 15.5 % (+14.6 %). The analysis of the costs reveals some noticeable insights. First, the exogenous costs for this case are with 39.47 EUR/MWh in the middle between the lower costs of the base case (37.62 EUR/MWh) and the higher costs for the 40 GW without onshore reduction variation (41.44 EUR/MWh). This difference despite the same overall capacity can be explained by the difference in specific investment costs, where onshore wind is assumed to have about half of the costs of offshore wind (Schröder et al., 2013). Hence, the overall German LCOE is with 45.43 EUR/MWh by 4.1 % higher compared to the base case, although storage installation and dispatch costs are slightly lower. Again the overall LCOE is less affected with 56.97 EUR/MWh (+1.3 %).

The described development is continued when onshore wind capacity is further reduced. As explained above, the third variation with 40 GW offshore capacity foresees an onshore wind reduction by 26 GW which equals roughly one-quarter of the total capacity. Similar to the first reduction, the overall storage capacity reaches 7.53 GW. Moreover, the storage locations show hardly any difference compared to the 13 GW onshore wind reduction. The curtailment rates are in this case in the same range, but a little less extreme compared to the latter one. Due to reduced onshore generation, the curtailment rate for this technology is reduced by 7.5 % to 16.5 %. Furthermore, the overall onshore wind generation share sinks from 37.6 % in the base case to only 29.6 % (-21.3 %). On the other hand, not only offshore wind but any other generation type can increase its generation share. Again, the biomass dispatch is increased and reaches now a share of 21.1 %, which significantly increases dispatch costs. As a consequence, the savings on exogenous costs due to less installed capacity are overcompensated by this effect. Moreover, imports are again increased to now 17.8 % (+31.5 %). The German LCOE is with 43.69 EUR/MWh almost equal to the 43.66 EUR/MWh in the base case. The overall LCOE reaches 56.57 EUR/MWh (+0.6 %).

73.2 GW Offshore Wind Capacity The fourth variation regarding offshore wind capacity can be considered an extreme variation assuming 73.2 GW instead of 27 GW in the standard setup. In contrast to the previous variations, there is no basis for allocating grid connections for such a capacity. Hence, the additional capacity is reached by increasing connection capacity at all existing offshore buses. Besides, two new buses, one in central Schleswig-Holstein and one Northwest of Hamburg are introduced. It should be noted that the total capacity could only be reached in the model by connecting up to 6 GW at one bus. Even though the current sectoral planning provides the basis for connecting 4 GW at one bus (Bundesnetzagentur, 2019a), it seems critical to further increase this rating, especially for reasons of grid stability and resilience.
Surprisingly, the significant capacity increase yields a reduction of required storage capacity. In total only 7.35 GW, a reduction by 8 % compared to the standard case, not to be installed. The share of hydrogen and battery storage remains constant with two thirds for hydrogen storage. Similar to the aforementioned offshore variations, the location of additional storage units is oriented towards offshore grid connections and hence has a slight tendency towards more southerly sites. The fact that in contrast to any other variation now the largest storage is a 931 MW battery just South of the southernmost offshore connection point supports this interpretation. Another difference, in this case, is a shift East which is driven by the mentioned introduction of two new grid connection points closer to Hamburg. As expected, curtailment rates are rapidly growing, in total by 110.7 % to 40.3 %. The offshore wind curtailment rate now reaches 56.9 %, which is an increase of 72.3 % compared to the

base case. Without manually reducing the onshore generation capacity, the generation share of this technology goes down from initially 37.6 % to now only 30.7 %. A reduction also applies to any other generation type but offshore wind. The biomass dispatch share of only 16.6 % (-14.1 %) is noticeable. On the other side, the offshore wind generation share goes to 30.3 % from 18.3 % in the standard case (+65.5 %). However, in light of more than doubling the installed capacity, this increase seems rather moderate. Still, with increased offshore generation shares, the import rate can be rapidly reduced by 44.1 % to only 7.6 %. The described effects to storage installations and dispatch patterns consequently significantly reduce the costs for these. However, these savings are by far exceeded by the increase in exogenous costs driven by the additional offshore installations. Hence, the German LCOE is raised by 30.0 % to 56.74 EUR/MWh. Including electrical neighbours the LCOE adds up to 60.35 EUR/MWh which is an increase by 7.3 %.

In line with the 40 GW variations, the installed onshore wind capacity is reduced by 26 GW for the fifth variation. The results on additional storage are in size and location almost equal to the 73 GW variation without onshore reduction (total storage capacity: 7.31 GW (-8.4 %)). The curtailment rates are slightly lower compared to the case mentioned above, but still reach enormous dimensions of 39.3 % (+105.4 %) in total and 53.0 % (+67.5 %) for offshore wind alone. The share of onshore generation is decreased to 24.8 % due to the reduced capacity. The biomass share is with 18.8 % lower than in the standard setup, but higher than in the 73 GW case without onshore reduction. Offshore wind generation reaches 32.8 %, which is a maximum across all offshore variations. Similar to the onshore reduction cases for 40 GW, the import rate is increasing again which is assumed to be caused by the missing spatially distributed onshore wind generation that cannot be compensated by offshore wind in times of grid bottlenecks. In terms of costs, the picture is very similar to the 73 GW case: while dispatch and storage costs can be reduced, the savings are surpassed by higher exogenous costs. In total the German LCOE adds up to 53.19 EUR/MWh which is an increase of 21.8 % compared to the base case and significantly below the 73 GW case without onshore reduction. The same applies for the overall LCOE which is 59.48 EUR/MWh (+5.8 %).

Offshore Wind in Neighbouring Countries The e-Highway 2050 scenario study provides the baseline for the generation portfolio of the eGo 100 scenario in this thesis. However, this study only considers offshore wind installations in the North Sea. Therefore, France and Poland do not have any offshore wind installations, although there are political targets in place (Durakovic, 2019; Jacobsen, 2019). In a sensitivity run, the offshore wind capacity for these two countries set in the NEP 2035 scenario (12 GW in France and 2.7 GW in Poland) is defined instead of no capacity at all. The results indicate some significance. Storage sizing and siting in Germany is hardly affected as the total additional capacity of 7.83 GW is in line with the base case result of

7.89 GW. The additional offshore wind capacity in France and Poland leads to a significantly lower biomass dispatch which reduces the overall and the German LCOE, while storage costs remain constant. Consequently, the additional offshore generation capacity leads to higher exogenous costs which overcompensate the savings by lower biomass dispatch. In Germany alone, exogenous costs are not affected which allows for a 1 % reduction of the LCOE to 43.21 EUR/MWh. On the other hand, the import rate is increased from 13.6 % in the base case to now 14.9 %. Hence, the assumptions regarding the offshore wind generation in neighbouring countries affect the German and the overall dispatch characteristics, but shows insignificant impacts on storage siting and sizing in Germany.

5.7 Generation and Demand Variations

In Short:

- **Cutting the German biomass generation capacity by half yields doubled storage installations and drives up imports.**
- **When restricting the biomass full load hours, in contrast, storage installations remain almost constant. Imports compensate the generation loss.**
- **A 25 % switch of generation capacity from onshore wind to PV hardly affects storage results while curtailment can be significantly reduced. Lower PV installation costs results in a decreased German LCOE.**
- **The robustness of the resulting storage units is assessed by a variation of the total load. Even with a 10 % decrease of total demand almost the same capacities are required while in the other direction storage capacity is increased by 75 %.**

As generation and demand characterise a power system, the projections on the future development for these are a crucial factor for the results obtained from the modelling approach in this thesis. At the same time, the uncertainty regarding future power demand and generation dimensions and characteristics is high and dependent on numerous factors. Especially RES policies – or in more general the regulatory framework – set the path for the evolution in these sectors. In the following, some of the assumptions made within this thesis are critically reflected by analysing the results of certain adjustments or limitations in contrast to the standard modelling setup. A large-scale model that is defined by a large number of assumptions and vast amounts of data demands sensitivity analyses on numerous parameters. However, it is expected that the following selection allows a sufficient estimation regarding the robustness of the results towards different future developments.

Restrictions to Power Generation from Biomass In Section 4.5 it is pointed out that the assumed installed biomass generation capacity of 27.8 GW is considered to be relatively high in Germany. Hence, in a first reduction, the German biomass generation capacity is reduced by 50 % to 13.9 GW. Similar to the onshore wind reduction in Section 5.6, the adjustment is carried out by a general reduction of all biomass generation units. As biomass is the only flexible generation technology, it is expected that a restriction to its capacity yields higher storage installations. In total, the storage capacity is exactly doubled from 7.89 GW to 15.97 GW. Compared to the base case, the share of battery capacity is increased and results in an almost equal distribution of hydrogen and battery capacity. These increased storage capacities result in reduced curtailment rates. In Germany, curtailment is reduced by 8.4 % to 17.5 %, for offshore wind the reduction is most significant with an 11.2 % reduction to 29.4 %. Although this effect allows for a higher production share from PV and wind, the share of imports of the total German load grows from 13.6 % to 19.3 %. In total, biomass production in Germany goes down from 19.4 % to 12.0 %. The biomass full load hours add up to 3532 h (3046 h in the base case) which equals a total biomass power generation of 49.1 TWh. Compared to 84.7 TWh in the basic setup, this is a remarkable decrease. Due to the biomass capacity reduction the exogenous cost components of the German LCOE are decreased, from originally 37.62 EUR/MWh to 34.13 EUR/MWh. The endogenous costs that are made up of dispatch and storage installation costs are also reduced from 6.04 EUR/MWh to 4.53 EUR/MWh. In this case, dispatch costs are significantly decreased as with biomass the only generation technology with marginal production costs is restricted. At the same time, the storage costs are doubled compared to the standard setup. In total the German LCOE can be reduced from 43.66 EUR/MWh by 11.4 % to 38.67 EUR/MWh. Note that the significantly increased import share that partly compensates biomass generation is not considered in these values.

In the case of biomass, however, the installed capacity is a less critical parameter compared to the energy supplied by biomass since this is directly dependent on the available biomass fuels. Thus, in a second variation, the original biomass capacity is kept constant, but the full load hours are restricted. The restriction is implemented by a constraint of keeping biomass full load hours below 2514 h. This value equals a generation potential of 70.4 TWh per year and is taken from Wingenbach, 2018 who uses the same installed capacity and restricts production accordingly due to competing use and limited biomass potentials (compare Section 4.5). Without such a constraint, the full load hours in the base case add up to 3046 h which corresponds to 84.7 TWh.

Introducing this constraint to the model results in almost unchanged storage installations of in total 8.07 GW (+1.1 %). Similarly, curtailment rates remain relatively constant or are increased only very slightly. Hence, the reduced biomass generation (13.4 % instead of 19.4 %) is compensated by increased imports from neighbouring countries. The rate of these grows to 19.5 % of the total yearly load. The full load hours of biomass plants add up to 1971 h. Hence, the constraint of complying to below 2514 h is even exceeded. The German power production from biomass is at 55.2 TWh which is far below the 84.7 TWh of the standard setup and slightly higher than the 49.1 TWh in the variation with the biomass capacity reduction. The German LCOE is at 41.79 EUR/MWh for this variation which is a decrease by 4.3 % compared to the standard setup. As exogenous costs and storage installations remain almost unchanged, this reduction is only due to reduced dispatch costs.

Switching Capacity from Onshore Wind to PV The generation portfolio in the basic setup is characterised by strong wind feed-in. In Germany, onshore wind reaches a generation share of 37.6 % (compare Figure 5.1). In Section 4.5, the recent development of reduced installation rates for onshore wind in Germany is described as an effect that demands consideration in the context of the assumed generation portfolio in this thesis. In this light, a variation depicting a possible switch of generation capacity from onshore wind to PV is analysed and presented in the following. Similar to the previously presented variations, changes to the capacity are made in a general reduction or an increase across all units of a technology. Here, the total German wind onshore capacity is reduced from originally 98.4 GW by 25 % to 73.8 GW. This sum can be considered close to the range of 67 GW – 71 GW onshore wind capacity that is required to reach political target of 65 % RES share by 2030 (Bundesregierung, 2019). To compensate for this reduction, the installed PV capacity is increased from originally 97.8 GW also by 25 % to 122.3 GW.

Surprisingly, such a significant shift in generation patterns does not seem to affect the required additional storage installations. First, the overall capacity remains almost unchanged at 7.9 GW, which is a negligible decrease by 1 %. Only the share of battery storage is increased from originally one third to 38.9 %, which could be expected with a higher PV generation share. Second, the locations of storage are precisely the same as in the standard modelling case depicted in Figure 5.3. The capacity differences occur due to some minor shifts from one location to another. In general, some replacement of hydrogen storage units by batteries can be observed. In the context of this rather constant storage portfolio, the significant reduction of curtailment rates by 13.7 % to 16.5 % in Germany is remarkable. As expected, the most significant reduction can be found for onshore wind, by 13.9 % to 15.3 %. Still, also for offshore wind, the shut-down rate can be reduced by 9.7 % to 29.8 %. Accordingly, the generation shares are affected. For PV, the generation share increases from 20.7 % to 26.4 %. On the other hand, the one for onshore wind is decreased from 37.6 % to 29.7 %. In comparison to the basic setup, the remaining technologies biomass, wind offshore and hydropower all have higher generation shares. This effect illustrates that the missing wind onshore capacity is not only compensated by PV. Still, the import rate is with 15.3 % also higher than the 13.6 % in the basic setting, which means that also more imports are required to come up for onshore wind. The depicted changes to central parameters can also be observed in the German LCOE.

Lower costs for PV installation in comparison to onshore wind yield lower exogenous costs. On the other hand, the increased biomass dispatch brings up the endogenous costs while storage expenditures remain constant. Hence, the reduction of the German LCOE by 4.9 % to 41.53 EUR/MWh is driven only by the reduced installation costs. In general terms, it can be concluded that a remarkable shift of the generation portfolio towards PV hardly affects the required additional storage units, their characteristics, and their location.

Variation of Total Load In all scenarios and variations presented so far, the total yearly load and the hourly demand patterns are kept constant at the standard values of the base case. However, as outlined in Section 4.5, the demand is the central parameter of a power system optimisation as the objective is to meet given loads at any time. On the other hand and similar to the generation technologies, future projections of not only the sum of the yearly demand but also its hourly shape are subject to uncertainty. For instance, a large-scale break-through of electric mobility or electric heat pumps would undoubtedly shift the demand characteristics known today. However, as storage optimisation is the focus of this thesis, the demand depiction is relatively straightforward and is based on historic time-series (compare Section 4.2.3). In the following, variations of the demand are analysed in order to assess the robustness of the obtained results, not for a different demand shape, but at least for the total load. The total yearly demand for Germany is increased and decreased by 5 % and by 10 % respectively, which leads to four variations.

For additional storage installations, a clear distinction between a lower and a higher demand can be made. A load reduction of 5 % or 10 % hardly affects the total additional storage and results in 7.79 GW and 7.77 GW respectively compared to 7.98 GW in the base case. The same applies to the location of these storage units. Increasing the total demand by the same values, on the other hand, indicates more significant effects. Here, additional storage adds up to 9.81 GW for the 5 % increase and 14 GW for the 10 % increase. At the same time, the distribution of hydrogen and battery storage is shifted towards battery storage. While in the standard setup battery capacity is only half the capacity of hydrogen, an almost equal distribution is reached with a 10 % load increase. Again, in contrast to the load reduction, some locational effects can be observed. In the case of a 10 % increase, at first, larger capacities at the existing locations can be noted. Moreover, there are several battery storage units distributed across Germany, which shifts the storage focus region from Northern Germany a bit more to the South. In general, a slight tendency of battery storage units towards demand centres can be observed. The first conclusion of these observations regarding storage units could be that the resulting storage capacities and locations of the standard model setup are quite robust. Even with a 10 % load decrease, which naturally also decreases the stress on the system, almost the same storage units are required. An increase, on the other hand, does not lead to a completely different storage distribution, but rather amplifies the one from the standard setup.

Changing the total load of a system indeed leads to different curtailment rates. The already high shut-down rates of the standard case are further increased by 4.3 % to 20.0 % for the 5 % decrease and by 7.7 % for the 10 % decrease. The generation technologies are affected in the same range without significant distinctions. The same applies to the load increase. In this case, the total rates for Germany can be decreased by 7.5 % for the 5 % increase and by 16.3 % in the case of 10 % load increase. Although the curtailment rates increase for the load reduction, there is still a remarkable reduction of biomass dispatch due to stronger feed-in from fluctuating RES. In Germany, the biomass generation share is reduced from 19.4 % to only 14.6 % in the case of a 10 % load reduction. As expected, this parameter is brought to 24.7 % in the case of a 10 % load increase. The shares of imports of the total load can be reduced to 12.4 % for the 5 % decrease and to 10.9 % for the 10 % decrease compared to 13.6 % in the standard setup. In case of a load increase, the import rates are hardly affected or even slightly sinking, which means that the additional load is mainly covered by German power production. When discussing the resulting system costs with the LCOE parameter, the now changed overall load has to be kept in mind. Hence, the denominator that the total system costs are divided by is different from all other cases with the same total demand. This effect becomes visible when comparing the German LCOE for the load reduction cases to the basic setup. In these cases the German LCOE adds up to 45.09 EUR/MWh for the 5 % reduction and to even 46.72 EUR/MWh for the 10 % reduction compared to 43.66 EUR/MWh in the default. As the storage requirements remain almost unchanged and the exogenous costs of setting up the generation portfolio are not affected either, one could expect lower LCOE due to lower dispatch costs. The decreased dispatch expenditures are overcompensated by the load reduction, which then yields higher LCOE. The same effect occurs when increasing the total load. In these cases the German LCOE is 42.69 EUR/MWh for the 5 % increase and 42.16 EUR/MWh for the 10 % increase. Thus, the changes to the load overcompensate even significantly higher dispatch and storage expenditures.

5.8 Sensitivity of Modelling Parameters

In Short:

- **An increased spatial resolution leads to a more constrained grid and hence drives up storage installations. Battery storage seems to be more sensitive compared to hydrogen and shows increasing capacity with higher spatial resolution.**
- **A validation of the temporal reduction is only possible for a particular period or for the full year with a very limited spatial resolution. In these comparisons, skipping snapshots shows significant impact to storage capacities while locations remain constant.**

Apart from assumptions regarding the different parameters of the depicted power system, there are some parameters regarding the model itself that demand a check regarding their respective impact. The approaches to complexity reduction introduced in Section 4.4 and discussed in Section 4.5 are of specific interest in this regard and are analysed in this Section. Another possibly relevant modelling parameter is the noise on generators' marginal costs. As introduced in Section 4.4, this factor is applied to all marginal costs as a random factor with a standard deviation of 0.01. Although this factor is reproduced in all variations in order to allow the reproduction of results, its impact on the results demands a check. In variations with five different noise seeds and a separate variation with no marginal noise at all, it is found that the impact of this factor is negligible. The LCOE for the total system is affected by 0.09 % at the most. The additional required storage capacity is in the same range and shows a deviation of 6 % at the maximum. Other storage characteristics such as the location are not affected.

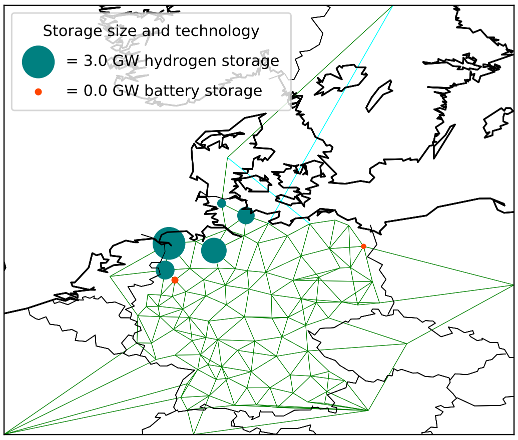
Spatial Clustering The originally very detailed spatial resolution of the data model of the German power system is reduced in order to keep the computational effort manageable. Coming from 3591 substations, the power grid is reduced to only 500 buses using a k-means clustering approach that is described in Section 4.4. The choice of the number of k buses is in general terms a consideration between computational effort and a sufficient level of detail. For instance, a too coarse resolution can yield insufficient results due to the missing of relevant constraints such as grid bottlenecks. On the other hand, the required time to solve the optimisation can be significantly reduced by a simplification. Hence, the impact of the choice of k is analysed with five different setups in comparison to the base case with $k = 500$. Four of the variations depict lower resolutions ranging from $k = 100$ to $k = 400$ in steps of one hundred. The fifth variation is more detailed and considers $k = 600$ buses. Consequently, the optimisation time is very diverse in these variations. It ranges from only 3 % of the original time needed in the $k = 100$ case to more than doubling the standard time in case of $k = 600$. The obtained results for additional storage capacity indicate that the choice of a lower k leads to lower capacities. Compared to the $k = 500$ standard case the total capacity is reduced by 20.3 % for $k = 100$. The remaining variations below $k = 500$ yield similar results, with $k = 300$ showing the closest result to the original value. The distribution of battery and hydrogen shows a share of around 20 % for battery storage which is below the one-third of the base case. Increasing the resolution to $k = 600$ leads to a remarkable increase of storage capacity by 49.5 % and a battery storage share of 52.7 %. This steep increase of battery capacity can be observed in the spatial distribution of the storage installations for the variations in Figure 5.16. The plots show similar distributions. For instance, storage capacity in the Northeast close to the Polish border is present in all cases. Similarly, the focus region in the North and Northwest of Germany remains constant throughout the variations only with different dimensions. A battery storage unit in Southwestern Germany first occurs in the $k = 300$ case but is then constant for any k larger than that. In the $k = 600$ case, the most significant difference is the large battery storage unit installed in the Munich area in Southern Germany. Apart from this unit, the distribution is very similar to the basic $k = 500$ case. This leads to the finding that a higher resolution leads to a more constrained system that requires this large storage unit. Furthermore, the total hydrogen capacity is in the same range for all variations, while the battery storage capacity is varying with a tendency to a larger share with a higher spatial resolution. Another remarkable parameter is the change to the German curtailment rates. This rate is generally below the standard case for all variations with k below 500, but the $k = 400$ case. Lower curtailment rates while at the same time the storage capacity remains constant or is even decreased means that certain grid constraints cannot be depicted entirely with a lower spatial resolution. The same effect is visible with a higher resolution compared to the $k = 500$ case. In the $k = 600$ variation, the storage capacity is by 49.5 % higher while at the same time, the curtailment rates also increase by 11.6 %. The significantly reduced storage capacity explains the exception at $k = 400$ with a slightly higher curtailment rate (+3.6 %) compared to the standard setup.

When analysing the different generation shares, the fluctuating RES technologies show the largest benefit of a lower spatial resolution. This development confirms the hypothesis of missing out certain grid constraints and thereby allowing a better grid integration. The import rate of the total demand is another parameter supporting this assumption. While this rate is at 13.6 % in the standard case, it sinks to 8.1 % for $k = 100$ and increases to 17.1 % for $k = 600$. In the latter case, it is expected that the large battery storage close to the Austrian border allows for more imports from the Alpine countries as the German biomass dispatch can be reduced in this case compared to the basic setup. The German LCOE is for all cases below the basic resolution lower by up to 1 %. The mentioned battery in Southern Germany can replace biomass dispatch in the $k = 600$ case and also yields a slightly lower LCOE (43.47 EUR/MWh compared to 43.66 EUR/MWh). On the other hand, the increased imports that are not considered in this value lead to a higher LCOE when the neighbouring countries are included (56.56 EUR/MWh instead of 56.23 EUR/MWh)

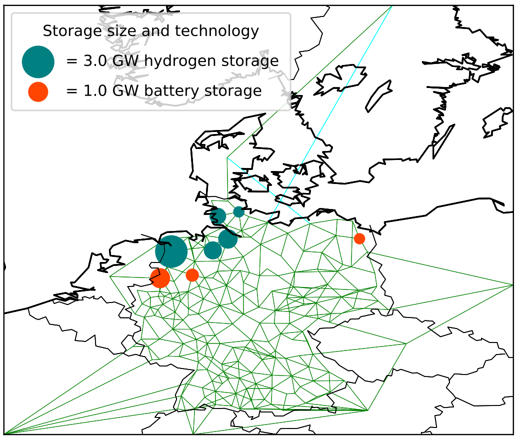
The k-means clustering approach requires initial coordinates of the k number of buses. In general, these buses can be a result of a randomised siting. On the other hand, the depicted German power grid is historically grown and indicates a tendency of the strongest interconnection in regions with sizeable conventional generation capacity and demand. Hence, the initial coordinates for the future scenarios are generated based on the portfolio of the status quo scenario (compare Section 4.4). In a sensitivity of this approach, no initial cluster coordinates are given, which means that the network is clustered based on the portfolio of the eGo 100 scenario. A second sensitivity is carried out by generating the cluster coordinates with the status quo scenario again, which helps to validate the reproducibility of the results. Both cases yield very similar results to the original case. The storage locations are the same while the overall capacity is at a maximum reduced by 6 % in the case with no status quo oriented initial cluster coordinates. Similarly, the LCOE is affected by 0.2 % at the maximum. Hence, it can be concluded that there are slight changes when applying different cluster coordinates of the same total k value, but the overall structure of the results is the same.

Temporal Reduction The original hourly temporal resolution of one year is in this thesis reduced by skipping snapshots (compare Section 4.4). The effects of this simplification to the generation time-series, especially those of the weather-dependent RES is analysed in Section 4.5. It is found that the impact can be considered acceptable. Still, it is expected that skipping to only every third snapshot affects the results of the optimisation. The large model size, unfortunately, does not allow for a yearly optimisation with the full hourly temporal and a $k = 500$ spatial resolution. Hence, two comparisons are carried out. The first by running the model for a limited three-month period from March to June with either no skipping or the skipping to every third hour as implemented in the basic setup for the full year and with $k = 500$. As the absolute numbers of these results cannot be compared to those of the full year, the comparison is carried out only between the two intra-year runs. The second comparison considers a reduced spatial resolution of $k = 100$ and depicts the full year with either with skipping every third snapshot or without any skipping. With regards to storage installations, the two comparisons yield different results. In case of the intra-year comparison the additional storage capacity when skipping snapshots is by 51.7 % above the one without skipping. The second comparison, on the other hand, shows the opposite with a total additional storage capacity that is in the unskipped case by 44.8 % below the case with skipping snapshots. Instead, storage locations remain rather constant in all comparisons and show the usual focus in the North and Northwest. Thus, the reduction of the temporal resolution may lead to different overall storage capacities at similar sites. Other results such as curtailment rates, generation shares, or overall system costs are hard to compare due to the different

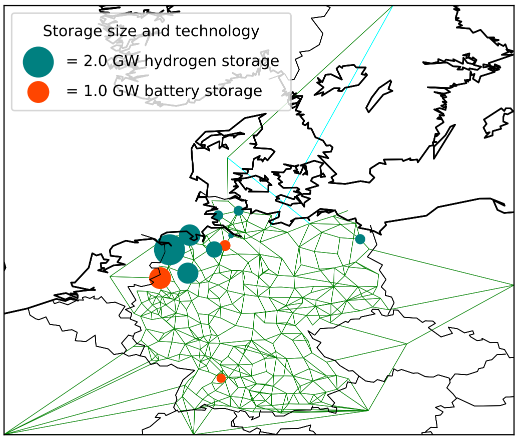
FIGURE 5.16: Spatial distribution of additional storage units for variations of the applied k-means clustering. The size of a dot represents the storage capacity. Petrol blue dots show hydrogen storage units, red dots indicate battery storage units.



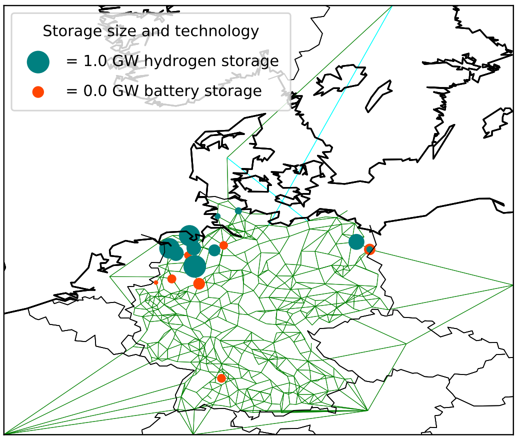
$k = 100$
$\sum = 6.36$ GW



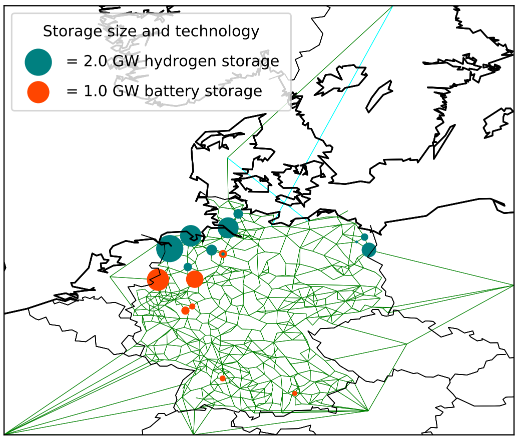
$k = 200$
$\sum = 7.06$ GW



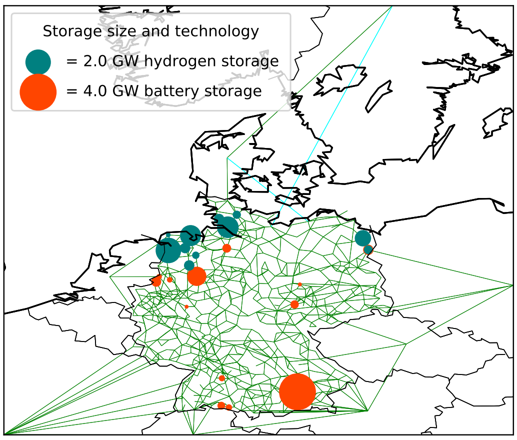
$k = 300$
$\sum = 7.84$ GW



$k = 400$
$\sum = 6.89$ GW



$k = 500$
$\sum = 7.98$ GW



$k = 600$
$\sum = 11.94$ GW

setups. However, the general results are plausible according to the results on storage installations and their impacts for instance to increased or decreased curtailment rates.

TABLE 5.3: Summary of key results of all variations. Refer to the Section indicated in the first column for details of the respective variation.

Sec.	Variation	LCOE [EUR/MWh]		Storage Capacity [GW]			Avg. Cap. [MW]	
		Germany	**Total**	**Batt.**	**Hydr.**	**Total**	**Batt.**	**Hydr.**
5.2	base	43.66	56.23	2.65	5.33	7.98	295	533
5.3	$t_{max} = 8\ h$	43.67	56.22	3.85	4.85	8.69	320	693
5.3	$t_{max} = 10\ h$	43.68	56.21	4.94	4.44	9.38	380	889
5.3	$\eta_{H2} + 5\ \%$	43.65	56.23	2.50	6.01	8.51	277	501
5.3	$\eta_{H2} - 5\ \%$	43.66	56.24	2.77	4.70	7.48	308	588
5.3	$\eta_{Batt} + 5\ \%$	43.67	56.23	2.89	5.29	8.18	289	588
5.3	$\eta_{Batt} - 5\ \%$	43.65	56.23	2.46	5.43	7.89	273	543
5.3	$C_{stor} + 10\ \%$	43.65	56.25	2.08	4.12	6.20	260	589
5.3	$C_{stor} + 20\ \%$	43.67	56.27	1.72	3.34	5.06	215	477
5.3	$C_{stor} + 30\ \%$	43.64	56.28	1.44	2.46	3.91	180	410
5.3	$C_{stor} + 40\ \%$	43.64	56.29	1.40	2.46	3.29	200	315
5.3	$C_{stor} + 50\ \%$	43.64	56.30	1.49	1.37	2.87	299	229
5.3	$C_{stor} + 60\ \%$	43.63	56.31	1.47	0.87	2.33	293	173
5.3	$C_{stor} + 70\ \%$	43.54	56.37	1.23	1.48	2.71	137	246
5.3	$C_{stor} + 80\ \%$	43.68	56.32	1.47	0.76	2.22	244	151
5.3	$C_{stor} + 90\ \%$	43.69	56.33	1.47	0.67	2.14	210	167
5.3	$C_{stor} + 100\ \%$	43.59	56.39	1.32	1.12	2.44	165	186
5.3	$C_{stor} - 10\ \%$	43.65	56.21	3.39	6.75	10.14	339	563
5.3	$C_{stor} - 20\ \%$	43.62	56.17	4.27	8.39	12.66	305	699
5.3	$C_{stor} - 30\ \%$	43.58	56.13	5.84	10.06	15.90	292	838
5.3	$C_{stor} - 40\ \%$	43.51	56.08	8.03	11.88	19.91	268	742
5.3	$C_{stor} - 50\ \%$	43.48	56.01	11.85	13.72	25.57	312	762
5.3	$C_{stor} - 60\ \%$	43.13	56.07	22.48	15.12	37.60	416	840
5.3	$C_{stor} - 70\ \%$	43.08	55.91	22.80	15.38	38.15	362	808
5.3	$C_{stor} - 80\ \%$	42.57	55.81	38.79	17.37	56.16	485	827
5.3	$C_{stor} - 90\ \%$	42.40	55.60	58.09	16.94	75.03	683	941
5.4	NEP base	48.73	55.45	0.87	3.17	4.04	124	634
5.4	NEP lim. PP	55.49	59.84	3.58	34.28	37.86	211	836
5.5	stor. opt. neighb.	44.35	55.35	7.09	10.83	17.92	545	773
5.5	NO PHS 1.4	43.49	56.26	1.94	4.42	6.36	162	442
5.5	NO PHS 10	44.08	56.42	2.82	4.29	7.10	313	612
5.5	NO PHS 10_sep	44.15	56.46	1.94	3.55	5.49	176	507
5.5	NO full sys. 1.4	44.35	58.05	3.19	6.43	9.63	200	536
5.5	NO full sys. 10	44.31	58.21	3.65	4.84	8.49	332	538

Continued on next page

Table 5.3 – *continued from previous page*

Sec.	Variation	LCOE [EUR/MWh]		Storage Capacity [GW]			Avg. Cap. [MW]	
		Germany	Total	Batt.	Hydr.	Total	Batt.	Hydr.
5.5	NEP NO PHS 1.4	48.95	55.56	0.79	3.81	4.60	88	636
5.5	NEP NO PHS 10	49.49	55.62	0.33	3.60	3.93	48	719
5.5	NEP NO PHS 10_sep	49.04	55.45	0.34	1.82	2.15	56	363
5.5	NEP NO full sys. 1.4	47.45	53.85	0.40	1.14	1.54	80	284
5.5	skip neighb.	58.60	58.60	48.58	27.20	75.79	868	680
5.6	NEP 20 GW Offshore	50.13	55.87	0.89	5.24	6.12	89	655
5.6	NEP 27 GW Offshore	51.80	56.24	0.54	5.49	6.03	107	785
5.6	40 GW Off.	47.36	57.47	2.41	8.62	11.03	201	575
5.6	40 GW Off., -13 GW On.	45.43	56.97	2.05	5.51	7.55	186	500
5.6	40 GW Off., -26 GW On.	43.69	56.57	1.98	5.55	7.53	198	505
5.6	73 GW Off.	56.74	60.35	2.20	5.15	7.35	220	468
5.6	73 GW Off., -26 GW On.	53.19	59.48	2.07	5.24	7.31	230	655
5.7	$P_{bio} - 50\%$	38.67	55.33	7.86	8.10	15.97	212	579
5.7	$FLH_{bio} \leq 2514h/a$	41.79	56.24	2.87	5.20	8.07	319	650
5.7	$P_{wind} - 25\ \%$ $P_{PV} + 25\ \%$	41.53	55.63	3.08	4.83	7.91	342	690
5.7	$\sum_{load} +5\ \%$	42.69	54.73	3.68	6.12	9.81	307	510
5.7	$\sum_{load} -5\ \%$	45.09	57.98	2.53	5.26	7.79	281	526
5.7	$\sum_{load} +10\ \%$	42.16	53.49	6.78	7.24	14.02	261	603
5.7	$\sum_{load} -10\ \%$	46.72	59.99	2.53	5.24	7.77	253	524
5.8	$k = 100$	43.25	55.69	0.13	6.24	6.36	64	1247
5.8	$k = 200$	43.41	55.98	1.65	5.41	7.06	548	1083
5.8	$k = 300$	43.24	55.96	1.78	6.06	7.84	444	758
5.8	$k = 400$	43.23	56.21	1.28	5.61	6.89	159	561
5.8	$k = 600$	43.47	56.56	6.29	5.64	11.94	393	513

6 Discussion

The results presented in the previous chapter require a more extensive discussion and a comparison with other relevant publications and findings. In this chapter, the main findings are briefly described and put into perspective. A distinction is made for the sizing and the siting of optimal storage units. For both aspects, characteristics and the central driving factors for the obtained results are discussed. In a critical appraisal, the implications of the overall modelling approach of this thesis are reviewed.

6.1 Sizing of Optimal Storage Units

Optimal Storage Capacity In the basic modelling setup, an additional storage capacity of 7.98 GW in Germany is found. In light of a completely renewable power system, a power generation capacity of 255 GW and a peak load of 77.9 GW in Germany, this number is considered relatively small. Even when adding the existing capacity of PHS of 9.3 GW, the total storage capacity adds up to 17.3 GW, which is 22.2 % of the German peak load. The installed capacity of biomass generators is 27.8 GW which leads to a total flexible generation share of 58 % of the peak load. For the complete system, including neighbouring countries, the storage capacity of 115.8 GW equals 45.8 % of the peak load. Adding 93.3 GW of biomass, the flexible capacity in the complete power system sums up to 83 % of the peak load. The hydro power capacity of 84.5 GW including reservoir power plants may in this regard be considered as a semi-flexible generation type that supports covering peak loads even in times of low wind power or PV feed-in. However, this brief analysis indicates the strong dependence of the German power system of its neighbouring countries in this optimisation setup.

The comparison of the obtained results to other models and publications is complicated by the fact that there is no one-to-one model that could provide a valid reference for the model applied here. Hence, any comparison to other works is limited in its validity. For instance, most of the publications mentioned in the following consider a complete European power system, while in this thesis only Germany and its neighbours are depicted. Apart from the spatial scope of a study, the degree of detail, also in spatial terms, provides a significant deviation. While in this study the degree of detail is relatively high with at least 500 buses, most of the referenced works apply a one-bus-per-country resolution.

Cebulla et al. conducted a study on the European power system subdivided into 29 regions that are connected based on their respective net transfer capacity and expected expansions (Cebulla et al., 2017). They introduce a constraint of reaching an 80 % generation share of fluctuating renewable generation, which is in line with the results in this thesis (81 % for Germany alone, 74 % including neighbours). The total storage capacity in the full European model adds up to 206 GW and in Germany alone to 30 GW (Cebulla et al., 2017). Compared to 108 GW total storage capacity in this thesis, which only considers Germany and its neighbours, the 206 GW corresponds to almost a factor two. This might be explained by the different spatial dimension of the models with a full European model compared to only Germany and its neighbours. A doubled capacity can also be found for Germany alone with 30 GW by Cebulla et al. and 17.3 GW in this setup. An explanation for this deviation could lie in the different generation portfolio that is assumed. For instance, in this thesis, the installed capacity of PV and onshore wind are in the same range, while Cebulla et al., 2017 assume significantly higher PV and offshore wind capacities, which potentially drives up storage installations (Cebulla et al., 2017). While the comparison of absolute storage capacity has the advantage of being clear and easy to compare, it comes with the significant downside of considering different modelling approaches, dimensions, and resolutions. Hence, the comparison to other models and publications is carried out according to relative parameters in the following. The parameters itself are taken from the original sources and compared to the respective values of this thesis' results. A straightforward parameter to assess storage capacity in a power system is applied by Heide et al., 2011 who compare the total storage energy capacity to the total yearly demand. In the case of Europe, they find this parameter at 1 %. This parameter is undoubtedly simplified as it requires further investigations with additional comparisons but it may give a first idea. In the case of this thesis, the total storage energy capacity reaches 1.5 % of the yearly demand, which is slightly higher than the value found by Heide et al., 2011. A similar parameter also referring to the demand is the power output provided by storage units and its share of the total yearly load. The value for the basic setup in this thesis adds up to 8 %. In a similar analysis for a completely renewable European power system, Child et al. find this value at 16 % (Child et al., 2019). However, in their work, PV prosumers with decentral battery and storage systems play an essential role and allow PV to reach a generation share of 41 % compared to only 17 % in this thesis. Hence, in comparison, not only to Cebulla et al., 2017 but also to Child et al., 2019, the power system modelled in this thesis may be regarded as rather wind-oriented.

In an earlier publication of the same model, Child et al. determine the share of storage costs of the total LCOE to be at 28 % (Child et al., 2018). Again, such a high value should be recognised with the knowledge of a PV-dominated power system which drives up (battery) storage installations. In this thesis, the total storage costs, including exogenous costs of existing storage units, are 6.3 % of the total LCOE. If only the costs of additional storage as a result of the optimisation are considered, the share amounts to only 0.4 %. As expected due to lower relative storage capacity, the storage costs in Germany alone amount to 2.4 % with around three quarters made up of costs for additional storage units.

Another parameter that allows discussing the role of storage in a renewable power system is the storage capacity as a factor of the average hourly power demand. This parameter is used by Victoria et al. who also apply PyPSA to set up a European power system with one bus per country and assume HVDC lines linking these (Victoria et al., 2019). Contradicting to the model in this thesis, the authors follow a more greenfield approach which allows the expansion of not only storage but also any considered generation technology and transmission lines up to twice the existing capacity. The central optimisation constraint is the CO_2 budget. As one of the first high definition power system models, Victoria et al., 2019 analyse the effect of different sector coupling strategies. The mentioned correlation of PV generation to short-term battery storage and wind to long-term hydrogen storage is confirmed by Victoria et al., 2019. The parameter of storage energy capacity compared to the average hourly power demand is found to be 1.4 for battery storage and 19.4 for hydrogen storage (Victoria et al., 2019). These values can be interpreted as the capability of storage units to cover the total power system load for an average of 1.4 hours with battery storage and 19.4 hours with hydrogen storage if these are fully charged. The significantly higher value for hydrogen storage highlights the importance of large storage energy capacities while battery storage may only provide short-term balancing.

In comparison, the values in this thesis are 0.7 for batteries and 42.1 for hydrogen storage. Hence, the difference of the storage energy capacity of batteries to those of hydrogen storage is significantly higher. One reason for this result could be the different approach of modelling the energy to power ratio of storage units. In this work, the parameter is fixed per technology with an E/P ratio of $t_{max} = 6\ h$ for short-term battery and $t_{max} = 168\ h$ for long-term hydrogen storage. Such a fixed coupling approach is also applied by Schlachtberger et al., 2018 with the same values. It is undoubtedly a simplification as not all new storage units are built with such strict constraints. Victoria et al., on the other hand, carry out an independent optimisation of power and energy capacity which leads to a similar result for batteries ($t_{max} = 5.6\ h$) but a smaller value of $t_{max} = 40\ h$ for hydrogen storage (Victoria et al., 2019). Thus, the long-term storage in Victoria et al., 2019 is not capable and required to charge or discharge for one week (168 hours) at full power but only for 40 hours.

The fact that the resulting E/P ratio of $t_{max} = 5.6\ h$ is similar to the assumed $t_{max} = 6\ h$ within this thesis leads to the conclusion that for Victoria et al., 2019 the higher battery storage share of the average hourly demand is induced by higher battery storage capacity in the system. Contrarily, for hydrogen storage the comparison of the energy capacity or E/P ratio shows that the value assumed here may be considered to be too high.

The storage utilisation depicted in Figure 5.7 of Section 5.2 seems to confirm this finding as the filling level of hydrogen storage units never reaches its maximum and

is in general throughout the year oriented rather to the lower than to the upper end of its limits. In Bussar et al., 2017, the authors conduct a long-term investment optimisation that covers several years until 2050 and find the hydrogen E/P ratio at $t_{max} = 72\ h$ in the long term. However, the ratio seems to change significantly over the years as the peak value is found in 2035 at almost $t_{max} = 200\ h$ (Bussar et al., 2017). In consequence, the obtained results on storage capacities in this thesis may be not optimal compared to a case where the E/P ratio is subject to the optimisation. In sensitivity analyses, the E/P ratio for short-term storage is adjusted to $t_{max} = 8\ h$ and $t_{max} = 10\ h$. It is found that such an increase leads to a replacement of hydrogen capacity by battery storage. Moreover, the overall capacity increases. Thus, the ability of short-term storage to store energy for longer periods allows their utilisation before the less efficient long-term storage is required. The distinct storage types are also visible in their respective utilisation. Existing PHS and battery storage are both relatively efficient and have the same E/P ratio. Hence, their utilisation is focused on the short-term with variations on an hourly – or at the maximum daily – level. Weekly or monthly variations cannot be observed for these technologies. In opposition, hydrogen storage is characterised by substantial seasonal shifts and hardly any visible variations on an hourly scale. The central reason for this behaviour is the storage efficiency. Due to comparably low efficiencies, the required energy for charging the storage units is higher. With regards to storage utilisation, this results in significantly more extended periods of full charging than those of full discharging. The lower efficiency of hydrogen storage also leads to a higher sensitivity to an adjustment of this parameter. Hence, the distinction between the two representative storage types made in this thesis seems plausible and applicable. The different utilisation patterns are also confirmed by Victoria et al., who analyse the same three storage technologies (Victoria et al., 2019). The authors find that the utilisation patterns of PHS and battery storage are congruent while hydrogen storage shows more long-term shifts that can exceed monthly variations.
The robustness of the resulting storage capacity can be assessed when adjusting the assumed technology costs. In this case, the storage costs are generally adjusted, disregarding potential distinctions between energy or power costs or the two potential additional storage technologies. The results highlight that battery storage is more sensitive to storage costs variations, while hydrogen storage is relatively robust. In general, a base of 2-3 GW of additional storage is required even when storage costs are doubled. Higher storage costs lead to a higher battery storage share which is assigned to the better efficiency. Hence, hydrogen storage may be partly replaced by battery storage in such a scenario. Schlachtberger et al., 2018 find a similar outcome, although here the authors also optimise the generation portfolio, which complicates the comparison. Still, Schlachtberger et al., 2018 support the conclusion of hydrogen storage being more robust to cost variations than batteries.

Apart from the fully renewable scenario, the model is also applied to an intermediate scenario that is defined to reach a RES generation share of around 70 %. The

additional storage installations in this scenario add up to 4 GW, which is almost exactly half the capacity of the fully renewable case. Hydrogen storage contributes the most substantial part of this capacity and reaches a share of 80 % compared to only two thirds in the fully renewable scenario. Compared to the fully renewable scenario, the onshore wind compared to the PV capacity is significantly higher, which could be a driver for this effect. Substantial thermal power generation capacity characterises the intermediate scenario. This affects the results of additional storage. In the basic setup, full shifts of thermal generation from one hour to the next are possible. Limiting this flexibility only to operating points from 50 % to 100 % of the power plants shows significant impacts as the storage capacity is increased to 38 GW. At the same time, the imports are reduced almost entirely from originally 15 % without flexibility limitations. These results highlight the importance of a detailed depiction of the considered power system, especially when thermal generation is included. In opposition, for fully renewable power systems far more flexible operation is assumed. In Wienholt et al., 2018 results to a very similar setting of the intermediate scenario are published and discussed. However, when comparing these results to the ones presented here, one has to consider that different model versions are applied, which lead to significantly different results. For instance, the reactances of HV power lines are falsely represented and constraints to thermal generation are not considered, which showed a significant impact on the results.
A potential study to compare the results of the intermediate scenario to is Babrowski et al., 2016. The authors set up a DC grid model for Germany considering the transmission grid level with today's infrastructure and planned extensions within the NEP up to the year 2020 (the considered NEP is dated 2012). Neighbouring countries are disregarded, which requires consideration when comparing to this thesis. Another limitation is the restriction to typical days for each season which means that no full year with extreme events is analysed and long-term storage cannot be adequately considered. The scenario that comes closest to the one of this thesis is the 2040 scenario with a RES generation share of 60 %. In this scenario, the authors find a total additional battery storage capacity of 3.2 GW (Babrowski et al., 2016). Despite the mentioned distinctions in the respective modelling approach, this number is congruent to the 4 GW found in this thesis. It is expected that the assumed grid expansions until 2020 by Babrowski et al., 2016 are moderate in terms of their additional transmission capacity which would result in a similar grid consideration. Coming from today's perspective with a RES generation share of 37 % in the year 2018 (Bundesnetzagentur and Bundeskartellamt, 2019), the result of additional 4 GW storage capacity to reach a RES generation share of 70 % is considered moderate and realistic.

Central Drivers for Storage Sizing In comparison to the mentioned publications that have a similar approach and regional scope, the resulting additional storage capacity in this thesis is considered relatively small. Several explanations can be found for this circumstance. One explanation is certainly the generation portfolio that is dominated by wind power generation in Northern Germany and hence significantly impacts the required storage installations. The hydrogen storage capacity is twice the capacity of battery storage which illustrates an orientation towards wind generation and here especially offshore wind. The high capacity factors of offshore wind allow for a reduced storage capacity compared to PV feed-in. Child et al., 2019 apply a contrasting power generation portfolio with a high PV share and find significantly higher battery storage shares. The sensitivity analyses of shifting generation capacity from onshore wind to PV by 25 % of the respective German capacity is a too light variation to observe such significant changes to the overall results. Still, the shift leads to a replacement of onshore wind by not only PV but also by biomass and offshore wind generation. Both types show higher generation shares which are interpreted as an increased requirement for flexibility. Moreover, a slight shift of hydrogen storage capacity to battery storage is observed while the overall capacity remains constant.

Potential impacts of a higher feed-in from offshore wind are analysed in more detail and presented in Section 5.6. The general approach is to increase the offshore wind generation capacity from the original 27 GW in Germany to 40 GW and in an extreme case to even 73 GW. Furthermore, the onshore wind capacity is reduced in some sensitivities. It is found that a sole increase of offshore wind generation capacity would trigger storage installations, while a reduction of onshore wind capacity at the same time could reduce these, even compared to the original setup. Still, the spatially centralised offshore wind feed-in increases curtailment rates for offshore wind with any additional capacity. Especially in case of extremely high offshore wind capacities, the additional positive effect to the power system is small while curtailment rates reach ranges above 50 %. These findings show that expanding offshore wind capacity requires adjustments also for other generation types, storage in general, and the power grid.

When putting the focus to the intermediate perspective, the findings are more differentiated as conventional generation still plays a significant role. Here, additional offshore wind generation may replace expensive dispatch from thermal generators, although it requires slightly higher storage capacities and also brings up the curtailment rates. In total, the financial savings of replacing thermal dispatch are higher than the costs for additional storage. In their European study, Schachtberger et al. carry out a similar investigation as they reduce the onshore wind generation stepwise down to zero and check how other technologies compensate this loss. They find that a general effect regarding storage installations can only be observed for very significant onshore wind reductions. The result that PV and offshore wind are the essential replacements for reduced onshore wind capacity is not surprising. In general, the authors conclude that the effects even of significant changes to the generation patterns are limited regarding overall storage expenditures but can be significant regarding the storage technology required (Schlachtberger et al., 2018).

In light of the discussion of a potential partial replacement of onshore wind by offshore wind generation in Germany, some constraints require a critical review. First, the current discussion is mainly driven by the assumption that offshore wind is largely available and that the distance to shore is an advantage regarding public acceptance compared to onshore wind. At the same time, the high capacity factors of offshore wind are considered to be another prominent advantage of this technology. However, recent investigations of the wind resource in the German Bight indicate that long-distance wake effects may have been underestimated so far (Agora Energiewende, 2020). Platis et al., 2018 find that the recovery of wake effects requires more space at sea than on land and they measured wake effects from existing offshore wind turbines in distances of up to 45 km. A similar but more recent analysis finds wake effects up to a distance of even 55 km (Schneemann et al., 2020). Although these publications do not quantify the wake losses, the significance of an impact is confirmed by the largest offshore wind operator Ørsted. In a recent notification Ørsted announced a reduction of the expected average wind farm return rates for projects in different countries (Ørsted, 2019). Hence, installing wind turbines in a too tight layout may prevent the wind and its kinetic energy from recovering properly. In contrast, a lower density in turbine spacing reduces the available area, which limits the overall generation potential of offshore wind energy. In light of this discussion, high offshore wind full load hours of up to 4500 that are found in this thesis, seem to become more unlikely with increased capacity installed. The academic discussion in this field is ongoing in different research projects but as of today, there is no valid study on the economic potential of offshore wind generation in German waters considering these recent findings. Furthermore, the results obtained indicate that the centralised feed-in of offshore wind in Germany could be disadvantageous. This will be further discussed in the following Section.

Another reason for low storage capacity is found in the comparably high capacity and utilisation of flexible biomass. Natural gas generation is not possible in Germany and hardly dispatched in the neighbouring countries, which leaves biomass as the only fully flexible generation technology. The installed biomass capacity of 27.8 GW providing a generation share of 19.4 % in Germany is considered high, especially when compared to publications disregarding biomass for power generation (Jacobson et al., 2015; Schlachtberger et al., 2017; Brown et al., 2018c). The results of the sensitivity analyses regarding biomass generation are described in Section 5.7. First, the available biomass generation capacity is reduced by 50 %, which leads to a doubling of the required storage installations. Second, the full load hours of biomass generation are limited while the capacity remains constant. In this sensitivity, storage installations are hardly affected. Therefore, it is concluded that a reduction of the biomass generation capacity yields a far more significant impact on storage requirements than a limitation to the full load hours of biomass generation. At the same time it is expected that generation capacity is not the limiting factor of future biomass power generation as it is only a matter of costs to provide additional generators. The power produced, in contrast, is directly dependent on the available resource, which in case of biomass is mainly waste and energy crops. Especially the latter requires extensive areas to harvest and is, therefore, competing with other uses.

Substantial import rates from neighbouring countries are another very significant explanation for the relatively low storage capacity. The value of 13.6 % of the total German load being covered by imports from neighbouring countries highlights this effect. The modelling approach does not consider the additional costs of imports that could be relevant in reality. Hence, a generator or a storage unit in a neighbouring country competes with the assets in Germany. The cross-border capacity is the only relevant constraint that could potentially bring a disadvantage for foreign assets. In this light, it seems consistent that the capability of the neighbouring power systems is used to provide flexible generation in Germany before additional expensive storage units are installed. The sensitivity analysis in Section 5.5 is therefore conducted to assess the German power system without the possibility to exchange power with its electrical neighbours. The result with regards to the required storage capacity is enormous. Compared to the basic setup with 7.98 GW, the additional storage capacity now adds up to 75.79 GW. Apart from such extensive storage installations, the generation from flexible biomass is with 5138 full load hours and a 25 % generation share very high in this setup. Even though this is an extreme case that will not occur in reality, these results show that the connection to neighbouring power systems is central and can help to reduce the requirements for storage and flexible generation. This finding is supported by Cebulla et al., who reviewed several studies on flexibility requirements. They find that within any study, the consideration of additional transmission capacity helps to reduce storage requirements (Cebulla et al., 2018). The same applies to Schlachtberger et al., who analyse the European power system with PyPSA in three different scenarios. In the first scenario, no connections are considered leaving every country self-sufficient. The second scenario considers an extension of cross-border capacity up to four times of the existing capacities, while the third scenario allows unlimited cross-border capacities. The average system costs per MWh are more than halved for battery and hydrogen storage when power transmission with up to four times of today's cross-border capacities is allowed compared to no interconnection at all (Schlachtberger et al., 2018). Additionally, Child et al. find that the requirement for long-term seasonal storage is reduced in the scenario allowing interconnection between regions (Child et al., 2018). This thesis confirms this finding in general terms as the share of hydrogen and battery storage is shifted from 67 % hydrogen to 64 % battery capacity. Although these publications are all focused on the full European power system and not Germany and its neighbouring countries alone, the general importance of interconnection is confirmed across the different approaches. Moreover, it should be noted that the scenario of no interconnection certainly provides an extreme and unrealistic case but it highlights the central role of cross-border capacity. One could, therefore, derive that any restriction to cross-border capacity affects the flexibility requirements of the respective individual power systems. For instance, the installation of phase-shifters regulating cross-border power flows could be such a restriction that is not considered in this thesis but possible in reality.

In another sensitivity presented in Section 5.5, the impact of a connection to the Norwegian power system is assessed in more detail. The benefits of such a connection are often assigned to the vast hydropower reservoirs in Norway that could provide a natural storage of fluctuating power generation (SRU, 2011; Bökenkamp, 2014; Ess et al., 2012). In order to analyse the dimension of a potential connection to Norway, in a first simple approach, a virtual PHS unit is set to potential grid connection points in Germany. The results indicate that there is a benefit for a 1.4 GW storage which has the capacity of the NordLink interconnector from Germany to Norway. In contrast, a further increase of this capacity up to 10 GW does not yield such clear benefits as it cannot reduce the additional storage units found by the optimisation as significantly. Moreover, the respective storage utilisation shows that such a large capacity would not be taken advantage of. A central factor for this effect is the disregard of the seasonal storage character of the Norwegian power system which cannot be depicted properly when being modelled only through virtual PHS. The proper connection of the Norwegian power system in full scale reveals higher impacts to import rates and LCOE but may not reduce storage requirements in a fully renewable German power system. For the intermediate scenario in contrast the benefits of such an interconnection are significant for LCOE and overall German storage requirements. The results may lead to the conclusion that for the power system analysed here the limit of the optimal connection capacity to Norway is between 1.4 GW and 10 GW. The results contradict SRU, 2011 where transmission capacity between Germany and Norway in a range of 42 GW to 69 GW is found. However, it must be noted that the approach of SRU, 2011 is significantly different from the one in this work, which results, for instance, in different import rates. In general, a short-term benefit of the connection is observed as the advantages regarding required storage and overall system costs are visible for the intermediate scenario as well.

The curtailment or shut-down rate of fluctuating RES is a central parameter in the context of assessing storage. The basic setup of this thesis yields an overall curtailment rate of 19 % in Germany. The majority of these shut-downs is assigned to offshore wind which reaches a curtailment rate of 33 %. In general, the reasons for curtailment of fluctuating RES that do not have marginal costs can be twofold. First, it is possible that in a power system generation exceeds demand leading to a negative residual load in the respective timestep. In these cases, the excess power can be either used to charge storage units, or it is curtailed. The second – and in this thesis more relevant – reason are grid congestions. Here, bottlenecks in the power grid impede the transmission of generated power to the locations of demand. The fact that no power grid expansion is considered in this model leads to a stressed power grid. Figure 5.2 in Section 5.2 shows that on average, the North and Northwest of the country are the regions with the highest power grid utilisation which is mainly induced by offshore wind power feed-in. This weak spot in the German power grid is already visible today with a RES generation share of only 37 % in the year 2018 (Bundesnetzagentur and Bundeskartellamt, 2019). In 2018, an installed offshore wind capacity of 6.4 GW lead to a curtailment rate for this technology of 7 % (Bundesnetzagentur and Bundeskartellamt, 2019). Hence, when considering the same power grid infrastructure but an increased offshore wind generation capacity of 27 GW, a steep increase of this rate is evident. The intermediate scenario with a 70 % RES generation share yields an offshore curtailment rate of 14 %, which is in line with the current status and the result modelled for the fully renewable power system. When discussing the curtailment rate of this model, the fact that there is no additional malus for curtailment needs to be recognised. Due to the absence of any costs for curtailment, the optimisation process may freely shut-down RES generation until an alternative measure, such as the installation of a storage unit, becomes feasible. In the German power market, on the other hand, curtailment by the grid operator requires financial compensation of the lost feed-in to the operator of the generation unit. Such a mechanism is not implemented in this model which may be one explanation for the comparably high curtailment rates. A strict limitation of the curtailment rate within the optimisation process is found to yield no optimal solution, possibly due to the limited transmission capacities and the enormous problem size. The case study on the isolated Texas, U.S. power system carried out by Denholm and Hand, 2011 finds that a significant reduction of curtailment rates in a power system shaped by weather-dependent RES comes at high efforts. For instance, they assume significant load shifting or large scale seasonal storage as possible reduction measures (Denholm and Hand, 2011). In this light, the results of this thesis indicate that even large scale storage installations, for instance in the Germany "as an island" scenario, are not capable of bringing curtailment below 15 %. For their 2040 power system achieving a RES share of 60 %, Babrowski et al. find an overall curtailment rate of 16 % (Babrowski et al., 2016). When considering that the authors do not depict power exchange to other countries, this value might be explained by an extension of thermal power generation that is allowed in their model. The 70 % RES scenario comes closest to the setup of the 60 % setup by Babrowski et al., 2016 and yields a curtailment rate of 8 %.

6.2 Siting of Optimal Storage Units

Apart from the sizing of additional storage units, their siting is the second central characteristic. In general, the results presented in Chapter 5 not only for the base case but also for any other sensitivity yield a clear tendency of storage siting in Northwestern Germany. Here, mainly large scale hydrogen storage units are installed. It should be noted in this context that hydrogen storage can only be installed in the North due to the restriction of a suitable underground salt formation that can only be found here (compare Figure 4.5). In contrast, battery storage units are generally smaller in their size and more distributed throughout Germany. The hypothesis that hydrogen storage is oriented to wind power wind feed-in, while battery storage shows an orientation to PV and demand centres is generally confirmed with regards to the location. These overall results are not only valid for the 100 % RES scenario but can also be confirmed for the 70 % RES scenario. In this case, the hydrogen storage share is even slightly higher, which is also visible in the storage siting. A comparison to other relevant studies is complicated by the fact that most publications have a lower spatial resolution allowing conclusions on a regional scale at the maximum. Still, such conclusions are drawn in the following. Two recent publications confirm the focus region of Northwestern Germany regarding additional storage installations. Cebulla et al., 2017 apply in general a European approach but with a more detailed scope within Germany as it is subdivided into 18 regions. In a power system with 89 % RES share, they find a relatively even distribution of additional battery storage throughout the 18 regions. Furthermore, additional hydrogen storage mainly occurs in Northwest Germany and a reduced dimension also in the Northeast. The authors assign this distribution to the strong wind power feed-in in these regions. Moreover, the same effect is observed in countries like the United Kingdom, Denmark, the Netherlands or France, which all feature high (offshore) wind generation and consequently substantial hydrogen storage capacity (Cebulla et al., 2017). The second relevant study on storage siting in a future German power system is by Babrowski et al., 2016. The latter is the only recent publication featuring an analysis on storage siting on a grid bus level. However, the siting process itself is limited due to a restriction to short-term storage and a temporal depiction of typical days. Although the highest RES generation share considered is 60 %, the siting of additional storage units still allows a comparison. The 3.2 GW of additional battery storage capacity in this scenario is almost completely concentrated in the North and Northwestern part of Germany (Babrowski et al., 2016). Similar to the results in this thesis, there are minor battery storage units distributed across the country. Apart from the wind-dominated generation pattern in the Northwest, Babrowski et al. explain their results also with congested power lines in Northern Germany that lead to diverging marginal prices between the North and the South of the country (Babrowski et al., 2016).

Apart from the storage siting, the results of Babrowski et al. can also be considered as a reference for finding a tendency towards central storage units. The second hypothesis guiding this thesis states that large central storage meets the criterion of optimality. Consequently, it is expected that in contrast, small decentral storage units are not. In general, it is expected that a more decentral power system structure is driven by an orientation towards demand centres, whereas a more centralised structure is oriented rather to regions with strong power generation. Another indicator for central or decentral storage is the connectivity to either the distribution or the transmission grid (Bauknecht et al., 2020). The results in the base case of this thesis reveal an average capacity per storage unit of 420 MW distributed across 19 units at 17 buses. Two nodes feature both a battery and a hydrogen storage. Compared to the potential 500 nodes that allow storage installations, these results support the hypothesis of large central storage connected to the transmission grid being optimal in a fully renewable power system. Even the scenario disregarding the electrical neighbours, which results in almost a tenfold storage capacity, yields 96 storage units at 91 buses. The average storage unit capacity is even higher with 789 MW. Hence, even in such a scenario with extensive additional storage capacity, less than one-fifth of all potential nodes feature a storage unit. The results of Babrowski et al. show a similar structure and distribution (Babrowski et al., 2016) and support the hypothesis of large central storage units being optimal.

Central Drivers for Storage Siting The Northwestern focus region is characterised not only by significant onshore wind capacity (compare Figure 5.1) but also the grid connection points of offshore wind capacity from the North Sea are situated in this region (compare Figure 4.4). However, an orientation of storage sites to (former) sites of conventional power generation cannot be observed. Such an orientation could be expected due to the absence of these flexible generators at potentially critical buses. Hence, it is concluded that the location of additional storage sites indicates a tendency to regions with a substantial wind feed-in, while other types of generation seem less triggering. A similar result is found by Fernández-Blanco et al., who conducted a study on storage siting and sizing in the U.S. Western Electricity Coordinating Council (WECC) area with 240 buses. Although they consider only short-term battery storage, the siting is found to be dependent on wind power feed-in (Fernández-Blanco et al., 2017).
The hypothesis of offshore wind feed-in triggering storage siting is supported by the sensitivities carried out with regards to higher offshore wind capacity. For these sensitivities, additional grid connection points for offshore wind are introduced. The spatial distribution of the storage units in these scenarios show a clear orientation to these newly introduced buses. For instance, it is expected that in the long-term grid connection points in the Northwest are moving further south leading to relatively long distances over land before the connection feed into the power grid. This tendency is also observed in the storage unit siting, which is – in case of the largest storage units – often at the same bus as the offshore grid connection point. An indirect confirmation of this finding can be derived from the latest scenario framework of the German NEP. Here, the TSOs assume 3 GW of grid-oriented power-to-gas storage in Northwestern Germany (Drees et al., 2020). The motivation for this assumption is the concentrated offshore wind feed-in in this region. In spite the 3 GW being within the greater range of the storage size in the Northwest found in this thesis, a comparison is impeded by the fact that the NEP considers substantial grid extension which the model of this thesis does not.
The fact that short-term battery storage expansion is oriented on PV generation while hydrogen follows wind generation can be observed with regards to storage siting as well. The storage units at offshore wind grid connection points are almost exclusively hydrogen storage units. A similar result is found by Hörsch and Brown, 2017 who conducted a European study also applying PyPSA. The authors find hydrogen storage

mainly along the northern coasts while the most significant battery storage shares are found at sites with a strong PV generation (Hörsch and Brown, 2017).

However, generation patterns are not the only factor affecting storage siting. Grid constraints possibly have an even higher impact on storage locations. In the most recent confirmation of the NEP, the German Federal Network Agency highlights the bottlenecks in the Northwest (Bundesnetzagentur, 2019a, p.44). The grid extension measures confirmed by the Agency in this document are expected to reduce these constraints until the year 2030. However, in this thesis, the status quo grid with these limitations in place is applied, and no extension measures are considered. One result of such significant transmission constraints is an apparent distinction of nodal prices between North and South (compare Figure 5.5). While the nodal prices are very low in the North due to high wind power feed-in, those in the South are relatively high because of higher power demand and hence a negative power balance. Nodal prices are a measure to illustrate the potential power price at each grid node with consideration of the transmission constraints. In the German power market design, nodal pricing is not applied and instead, one power price is set for the complete market area. By this design, the German power system is assumed as a copperplate with unlimited transmission capacity within its borders. In Sweden and Norway, on the contrary, a compromise between nodal pricing and the copperplate is applied, and the two countries are subdivided into nine regions or market areas with different prices (Nord Pool AS, 2020).

The resulting differences in nodal prices in this thesis are also dependent on the distribution of power generation. As this is a future scenario, assumptions regarding the siting have to made and a simplified approach of scaling up today's sites is applied. Indeed, a more sophisticated approach could lead to a more detailed result. For instance, Wingenbach, 2018 developed a method to consider socio-economic factors in RES siting in her thesis. Nodal prices as an indicator for grid bottlenecks are also applied by Svendsen and Spro, 2016 in the case of the Western European power system connected to North Africa in the scenario year 2030. The authors support the importance of grid bottlenecks to storage siting. For instance, it is found that large scale solar generation in Southern Morocco cannot be transported to the load centres in the North of the country, which triggers nodal price differences and flexibility requirements (Svendsen and Spro, 2016). In a more abstract approach applied to the 96-node IEEE reference network, Dvijotham et al., 2011 come to a similar conclusion regarding the importance of grid constraints to storage siting. Noticeably, Pandžić et al., 2015 use the same network model with a different power system model and conclude that generation patterns drive storage siting. Having these contradicting statements in mind, it can be concluded that the results of this thesis show that both effects have a tremendous impact on storage siting.

The sensitivity analyses addressing the impact of a potential connection to the Norwegian power system also reveal some interesting findings regarding the siting of storage units in Germany. In general, the expectation that an artificial Norwegian storage unit or the landing point of a connection to Norway reduce storage requirements in this particular region is confirmed. These measures replace the large hydrogen storage unit that is found in the original setup in Southern Schleswig-Holstein. Still, one could argue that a more significant effect on storage siting is somewhat limited since other storage units in the North and Northwest of Germany are still required and hardly reduced in their capacity. This limited effect may be explained by the simplified modelling of Norwegian storage without a seasonal storage potential. Another interesting finding is the subject of siting a larger connection capacity or a more extensive artificial storage. In these cases, the distinction of siting 10 GW at one or two nodes already reveals a very significant impact on the results. Thus, it is concluded that the decision on where an interconnector is brought to the mainland power grid plays an essential role regarding the overall storage requirements in a region.

In comparison to generation patterns and grid constraints, the orientation of storage siting seems to be less oriented towards demand centres. Only for a few sensitivity analyses, a stronger orientation is observed. The first is the case disregarding Germany's electrical neighbours which leads to a steep increase in storage installation and especially battery storage. In this case, the siting of storage units is triggered by the power demand as the largest units are found in the areas of Munich, Stuttgart, and Western Germany (compare Figure 5.14). A less extreme but similar distribution is observed in the sensitivity with a 10 % increase of the total annual power demand in Germany. These results lead to the realisation that increased stress on the system, which is here induced by preventing exchange and increasing demand, requires storage capacity at demand centres.

In total, a clear orientation of the storage siting towards wind power generation and grid bottlenecks is identified. Other types of power generation, as well as the power demand, seem to be less significant to the siting and show relevant impacts only in extreme cases.

6.3 Critical Appraisal of the Model

The setup and application of a large scale power system with a high resolution requires a critical discussion. In Section 4.5, which closes the Method Chapter, the central parameters, assumptions, and uncertainties are discussed. The impacts of most of these parameters are addressed in respective sensitivity analyses (compare Section 5.8), while in single cases this is not possible.

Power Grid Representation The spatial scope of this thesis' model is Germany and its electrical neighbours. In additional investigations, the foreseeable connection of Belgium and Norway as new electrical neighbours is considered. Such a scope allows, on the one hand, a more detailed representation compared to an approach restricted to Germany alone as effects of the cross-border power exchange are depicted. On the other hand, this scope is less detailed compared to an entirely European scope that is applied in many similar publications. A European scope is undoubtedly helpful since the interactions of an interconnected power system become visible. These large scale interactions cannot be depicted by the scope in this thesis which is limited to direct neighbours. Moreover, the discussion above illustrates that the different spatial scope complicates comparison to other publications. The restriction to Germany, however, allows a more detailed depiction of the German power system with a resolution that does not allow an application to the entire European scale. Especially with regards to storage siting, which is highly dependent on local characteristics, such a detailed approach is necessary. For instance, the finding that storage units are often located at the same buses where offshore wind energy is connected to the power grid cannot be drawn when the resolution is limited to nations or regions. In addition, an increased spatial resolution allows to properly consider grid constraints which trigger storage installations. The sensitivity analyses on the different spatial resolutions presented in Section 5.8 show how sensitive storage siting and sizing react to different choices. The comparison to literature shows that even when applying a reduction to 500 buses, the spatial resolution is significantly higher than other approaches. Another central assumption regarding the power grid in this thesis is the limitation to the status quo and hence the disregard of any grid extension measures. This approach aims to analyse the role of grid capacity for a future fully renewable power system and the implications for storage requirements. However, this assumption is undoubtedly unrealistic as grid extension measures that increase the capacity are already in place today and will be further extended within the NEP process at least until 2030. Based on the same model and data as in this thesis, a combined optimisation of storage units and grid extension measures is carried out by Müller, 2020.

Generation The general uncertainties that apply when using future scenarios are discussed in Section 4.5. The scenario pathway depicted in this thesis has a tendency to a stronger wind generation portfolio which shows direct implications to the resulting storage sizing and siting. Hence, these results have to be assessed with the knowledge of scenario uncertainties that could potentially lead to very different results. Concerning current discussions in Germany, the extension of onshore wind and biomass generation capacity is highly uncertain due to decreasing public acceptance and could, for instance, drive up PV and offshore wind installations. Not only the overall capacity but also the power produced is subject to modelling uncertainties. The consideration of modern wind turbine power curves could induce a different generation pattern that affects storage installations. However, the discussion regarding offshore wind reveals the so far underestimated subject of large scale wake effects at sea. These developments have a direct impact on the full load hours but could not be further investigated within this thesis. One of the main findings is the fact that storage siting is highly dependent on generation locations. In the case of offshore wind generation as a central driver, the future locations in terms of their grid connection points are relatively straightforward. The locations for future onshore wind and

PV capacities, in contrast, are subject to substantial uncertainty but not considered as sensitivity in this thesis.

Demand In contrast to the generation portfolio, the demand side has a relatively coarse depiction in this thesis. For instance, flexible demand options that could be considered as an alternative means to provide power system flexibility are not considered at all. Furthermore, sector coupling options are disregarded, which is a simplification when assessing a fully renewable power system. Victoria et al., 2019 find in this regard that electric mobility has the potential to replace short-term battery storage units if it is integrated accordingly. The impact of such active consumers or prosumers to a power system's storage requirement are investigated by Child et al., 2019. A comparison of the results of this thesis shows significantly different results. However, similar to the generation portfolio, a more detailed demand depiction requires extensive assumptions on the penetration of certain technologies and on people's behaviour in general.

The relatively simple demand depiction makes the demand time-series and the sum of the annual demand the central parameters. The impact of the overall annual demand on the storage results is discussed in Section 5.8. The fact that even with a decreased demand storage requirements are in the same range confirms the robustness of the results. However, the significant growth of storage requirements with a 10 % total demand increase indicates the importance of this parameter. In light of an increased electrification and sector coupling, this direction of demand development seems more realistic. At the same time, more distributed and decentral developments could fundamentally change storage requirements, possibly towards short-term battery storage.

7 Conclusion and Outlook

The central findings of this thesis are summarised and assessed in the following. First, the most import aspects are concluded along with the hypotheses introduced in Chapter 3. Second, recommendations to outlines of the future power system are drawn from these conclusions. A brief outlook to possible tracks of further research in the field closes the chapter and the thesis.

7.1 Assessment of Hypotheses

The two guiding hypotheses of this thesis can be distinguished to one addressing the method to optimise sizing and siting of storage units and the other one to the characteristics and drivers of these optimal storage units. The first hypothesis reads:

A. *It is possible to develop an integrated method to realistically model the utilisation of different storage technologies in power systems with a high spatial and temporal resolution. At the same time, the optimality of installation and utilisation of storage units can be assessed.*

The model that is set up to address the research questions of this thesis depicts the German power system, including its electrical neighbours in the form of two future scenarios. In both scenarios, the overall power demand and the power grid infrastructure are kept constant. The lead scenario is a 100 % RES scenario with a tendency to wind power generation and assuming minor natural gas generation capacities in neighbouring countries as the only non-renewable source. An intermediate scenario reaching a RES generation share of around 70 % is applied to gain first insights on the pathway to such a fully renewable power system. The matter of storage optimisation in Germany has not been analysed with an hourly and full-year model that features a spatial resolution going down to the HV level, yet. At the same time, such a high resolution for both, the temporal and the spatial scale is necessary, especially with regards to storage siting. A high temporal resolution is the only way to depict extreme events and seasonal effects of a generation portfolio that is shaped by weather-dependent units. On the spatial scale analyses on the grid level, rather than a national or regional approach, allow assessing storage siting and its drivers with a higher degree of certainty. However, the high resolution of the data model used in this thesis has to be reduced cautiously in order to keep the computational burden in an acceptable range. The impacts of these reductions on both temporal and spatial scale are assessed with extensive sensitivity analyses. Hence, the reduction measures are found to be reasonable and still leave a comparably high level of detail. It is expected that the restrictions on the computational effort can be reduced in the future due to technological progress. Such a development could potentially mitigate the requirements to reduce resolutions. The applied LOPF method allows for an optimisation of storage utilisation and installation at the same time. Therefore, an iterative process that appropriately depicts these different scopes and that has been applied in several other works can be avoided. The obtained results on storage utilisation and installations are plausible. Thus, hypothesis A can be confirmed.

The second hypothesis reads:

B. *The characteristics and optimality of the utilisation of storage units are dependent on local or regional situations regarding generation, demand, and power grid. The approach developed within this thesis helps to prove that in a renewable energy system, even under detailed consideration of the electricity grid, central large storage units are necessary and meet the criterion of optimality.*

The results of the basic optimisation setup yield a relatively low additional storage capacity in combination with significant imports from neighbouring countries. Moreover, the generation portfolio can be summarised to be mainly characterised by weather-dependent RES and flexible biomass generation. Generation from natural gas, which in this model is only possible outside of Germany, is hardly utilised. This result confirms that a large scale and 100 % RES power system is feasible without natural gas or any other so-called firm low-carbon resources. A specific case for Germany without any connection to neighbouring countries highlights the effect of cross-border power exchange to storage requirements. The additional storage capacity is then tenfold its original value. Consequently, the LCOE depicting the total system costs are significantly higher. Hence, it is found that an interconnected system is beneficial and would allow reduced storage installations. Still, such a strong interconnection and strategic dependency of the German power system to imports from its neighbours bears several risks. For instance, the assumed development of the neighbouring power systems is subject to uncertainty and may not be fully utilised in an interconnected system but rather according to national interests. Moreover, it is questionable if the German power system should be set up in a way that assumes a specific import rate and hence puts this critical asset to an avoidable risk.
The power grid in this model is kept at today's status, which can be considered as a very conservative depiction of grid extension measures. At the same time, the reduction of grid bottlenecks through grid extension may reduce storage requirements. In this thesis, this effect has been investigated only with the specific case of future connections to the Belgian and Norwegian power systems while grid extension measures within Germany are not depicted. Indeed, intelligent grid capacity increases could

reduce the need for additional storage.
Apart from imports and power grid capacity, the obtained results are also found to be dependent on the assumed generation portfolio. Most significantly, wind generation drives storage installations. Offshore wind energy is characterised by a centralised feed-in at individual grid buses which results in storage installations at most offshore grid connection points. However, the dependency of storage extension to offshore wind is also limited as the increase of its generation capacity beyond a certain point drives up curtailment rather than storage capacity. This effect again highlights the importance of overcoming critical grid constraints. The curtailment rates, in general, are found to be relatively high, which is expected in a power system shaped by weather-dependent generation. Storage units certainly help to reduce curtailment rates but are not dimensioned to bring curtailment rates to ranges below 10 %. Even the mentioned case of no connection to neighbouring countries with a tenfold storage capacity yields curtailment rates of at least 15 %. The discussed drivers imports, grid capacity, and generation portfolio are not only triggering the resulting storage capacity but are even more significant to their siting. A comparison of all setups analysed in this thesis shows very robust results of storage sites, while their capacity is changed according to the respective parametrisation. Hence, the importance of an intelligent storage siting is not to be underestimated. Furthermore, the results yield a visible tendency to large and central storage units in contrast to distributed smaller storage units.

The described and discussed results lead to the overall conclusion that there are many ways to reach a 100 % RES based power system. The characteristics of optimal storage units are mainly dependent on assumed imports, grid constraints, and the generation portfolio. Hence, hypothesis B can be confirmed.

7.2 Recommendations

Based on the conclusions and assessment of hypotheses, recommendations to potential decision-makers are derived in the following. The finding that storage siting is a central aspect of future power systems leads to the requirement of intelligent and long-term planning. A widespread upscaling of storage capacity without any intelligent planning mechanism should be avoided. In Germany, the well established NEP process takes a perspective of 10 to 15 years in advance and identifies individual grid extension measures based on scenario assumptions. The integration of storage unit planning from a systems perspective into this process should be aspired. With the help of such an integration, at least potential regions for storage installations can be identified. Ideally, storage installations would then be incited mainly in these regions. Moreover, the long-term nature of power system infrastructure requires an according planning perspective. Hence, the NEP process should be extended to depicting a fully renewable power system. The results of this thesis highlight the fact that storage installations are dependent on several factors. The challenge of developing an efficient and intelligent RES based power system should, therefore, be tackled by an integrated and long-term planning approach.

The specific dependency on grid constraints highlights the necessity to increase North-South transmission capacity in Germany. Although the mentioned NEP identified several measures in this context, a structural imbalance between North and South remains due to their different demand and generation patterns. The existing uniform price zone in Germany amplifies the need for higher transmission capacity. In this light, a splitting not necessarily to nodal but potentially to regional prices should be critically examined (Fraunholz et al., 2020). It is expected that such a measure is economically beneficial but politically challenging. Another recommendation that can be derived from the dependency to grid constraints is the intelligent utilisation of curtailed power. In a power system shaped by weather-dependent generation, substantial curtailment rates are inevitable. Hence, storage siting should consider this fact and strive for the most efficient use of curtailed power in front of a grid bottleneck. Still, it is expected that storage units will never fully utilise the curtailed power, which calls for sector coupling approaches to utilise these volumes efficiently.

In general, the results and recommendations show that many implications touch several aspects of the future energy system. Moreover, not only technical and economical but also political aspects play a vital role in this context. To facilitate these discussions and support the respective decision-making, the underlying energy system models need to be transparent and easy to reproduce.

7.3 Outlook

The initiation of a strategic and long-term planning process requires some improvements for current models. One example is the relatively coarse spatial distribution of decentral RES generators. In this thesis, this distribution is strictly linked to today's distribution which impedes the proper depiction of certain developments. For instance, socio-economic aspects of the further RES extension could lead to a completely different distribution (Wingenbach, 2018). Hence, a more detailed consideration would be beneficial, especially due to the significant impact on storage siting. Apart from the spatial distribution, the technological depiction could be more detailed. It is, for example, expected that the power curves of future wind turbines will be further improved to higher utilisation rates and consequently smoother feed-in characteristics (Hirth and Müller, 2016). A sensitivity analysis with a focus on this aspect is not conducted in this thesis but is desirable. Furthermore, long-term experiences with wake effects, especially for offshore wind turbines, should be considered. A potential finding of such an assessment could be that the expected full load hours cannot be achieved with current layouts and that a more widespread layout is required. As a consequence, the available space for wind power installations would have to be utilised with lower installed capacities. A comparative check with

real wind feed-in time-series over a long period could help to understand these risks better.
The applied spatial dimension of Germany and its electrical neighbours may lead to a disregard of dependencies from other, not directly connected power systems. Hence, an entirely European power system with the same resolution is desirable. However, it is expected that the computational effort, as well as the availability of the corresponding open data sets currently hinder such an approach. Moreover, the already complex assumptions regarding the future power system of Germany would have to be extended to a much broader scope with more diverse impact factors. Apart from the spatial resolution, an increased temporal resolution would allow a more sophisticated depiction of the power system. For instance, uncertainties that come along with reducing the temporal resolution (compare Section 5.8) could be reduced. Moreover, not only techno-economic effects on an hourly scale could be investigated but also the power system stability that is assessed on a sub-hourly scale. Especially the role of storage units, which could provide reserve power, is affected by these effects that are insufficiently covered in current publications. One out of the few ones doing so is Brijs et al., 2017 who conducted a study on the Belgian power system but had to make significant simplifications to allow for such a higher temporal resolution.
With regards to the process of long-term planning recommended in the prior section, a shift to using open-source models with open data is necessary to comply with the challenge of adequately discussing the findings. It is in this regard not acceptable that the very meaningful German NEP process is still based on a closed proprietary power system model and that the corresponding power grid data is not made available to the public. A central challenge of using open data, however, is the proper validation. For instance, the power grid in this thesis is based on crowd-sourced OpenStreetMap data which is hard to validate. Hence, the validation of open data sets is another argument for publishing relevant energy system data with an open license.

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A Appendix: Installed Capacities

TABLE A.1: Installed generation and storage capacities in GW for Germany and its electrical neighbours in the status quo scenario. Source: Bunke et al., 2017

Technology	AT	CH	CZ	DK	FR	LU	NL	PL	SE	Total without DE	DE	**Total**
Nuclear energy	0.0	3.2	3.7	0.0	63.1	0.0	0.5	0.0	9.9	80.4	12.1	**92.5**
Lignite	0.0	0.0	7.6	0.0	0.0	0.0	0.0	8.6	8.6	24.8	21.2	**46.0**
Hard coal	0.0	0.0	1.3	2.4	5.2	0.0	5.7	19.8	0.2	34.6	27.8	**62.3**
Natural gas	0.0	0.1	1.4	2.2	5.8	0.5	20.1	0.9	0.9	31.9	27.5	**59.4**
Oil	0.0	0.0	0.0	0.1	6.7	0.0	0.0	0.0	4.6	11.4	4.4	**15.8**
Waste	0.0	0.0	0.0	0.0	5.3	0.0	1.0	0.0	0.1	6.4	1.7	**8.0**
Other conventional generation (mixed fuels)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	**2.5**
Total conventional generation	**0.0**	**3.3**	**14.0**	**4.7**	**86.1**	**0.5**	**27.3**	**29.3**	**24.4**	**189.4**	**97.1**	**286.5**
Wind onshore	1.9	0.1	0.3	3.5	9.0	0.0	2.5	3.6	3.8	24.8	41.3	**66.1**
Wind offshore	0.0	0.0	0.0	1.3	0.0	0.0	0.2	0.0	0.2	1.7	3.4	**5.0**
Photovoltaic	0.4	0.7	2.2	0.6	5.1	0.0	0.8	0.0	0.0	9.8	38.5	**48.3**
Biomass	0.4	0.0	0.4	1.4	1.5	0.0	0.4	0.7	3.3	8.0	7.2	**15.2**
Hydro power	13.8	12.1	0.3	0.0	21.1	0.0	0.0	0.9	16.2	64.4	5.3	**69.7**
Total renewable generation	**16.5**	**12.9**	**3.1**	**6.8**	**36.7**	**0.1**	**3.9**	**5.3**	**23.4**	**108.7**	**95.6**	**204.3**
Pump storage	0.0	1.9	1.9	0.0	4.1	1.1	0.0	1.4	0.0	10.5	9.3	**19.7**
Total capacity	**16.5**	**18.1**	**19.0**	**11.4**	**126.9**	**1.7**	**31.2**	**36.0**	**47.8**	**308.6**	**201.9**	**510.5**

TABLE A.2: Installed generation and storage capacities in GW for Germany and its electrical neighbours in the NEP 2035 scenario. Source: Bunke et al., 2017

Technology	AT	CH	CZ	DK	FR	LU	NL	PL	SE	Total without DE	DE	**Total**	BE	NO	Total incl. extension
Nuclear energy	0.0	1.2	1.8	0.0	40.0	0.0	0.0	4.5	9.9	57.5	0.0	**57.5**	0.0	0.0	0.0
Lignite	0.0	0.0	5.2	0.0	0.0	0.0	0.0	11.4	0.0	16.6	9.1	**25.7**	0.0	0.0	0.0
Hard coal	1.2	0.0	0.3	0.0	1.7	0.0	3.3	9.7	0.0	16.3	11.0	**27.3**	0.0	0.0	0.0
Natural gas	8.0	1.2	2.0	2.0	12.5	0.6	22.2	7.1	0.0	55.5	40.7	**96.2**	15.6	1.3	0.0
Oil	0.3	0.0	0.0	0.0	3.8	0.0	0.0	0.0	0.7	4.8	0.8	**5.6**	0.0	0.0	0.0
Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	**1.6**	0.0	0.0	0.0
Other conventional generation (mixed fuels)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	**1.0**	0.0	0.0	0.0
Total conventional generation	**9.5**	**2.3**	**9.4**	**2.0**	**58.0**	**0.6**	**25.6**	**32.7**	**10.6**	**150.6**	**64.3**	**214.9**	15.6	1.3	231.8
Wind onshore	5.5	0.9	0.9	5.9	28.0	0.2	6.0	7.3	10.0	64.7	88.9	**153.6**	4.5	5.0	0.0
Wind offshore	0.0	0.0	0.0	4.5	12.0	0.0	6.0	2.7	1.1	26.3	16.4	**42.8**	4.0	0.0	0.0
Photovoltaic	3.5	3.0	3.6	3.4	30.0	0.1	8.0	1.0	1.0	53.7	60.1	**113.8**	5.7	0.0	0.0
Biomass	1.8	1.3	0.6	4.1	9.3	0.1	2.9	2.4	5.3	27.7	8.3	**36.0**	2.3	0.0	0.0
Hydro power	13.8	12.1	0.3	0.0	21.1	0.0	0.2	1.3	16.2	64.9	5.8	**70.7**	0.1	37.2	0.0
Total renewable generation	**24.5**	**17.3**	**5.3**	**18.0**	**100.4**	**0.4**	**23.1**	**14.7**	**33.6**	**237.3**	**179.6**	**416.8**	16.6	42.2	475.6
Pump storage	6.3	6.6	2.0	0.0	7.1	1.3	0.0	1.4	0.0	24.7	9.3	**33.9**	1.9	0.8	36.6
Total capacity	**40.4**	**26.2**	**16.6**	**20.1**	**165.5**	**2.3**	**48.6**	**48.8**	**44.2**	**412.5**	**253.1**	**665.7**	34.1	44.3	744

TABLE A.3: Installed generation and storage capacities in GW for Germany and its electrical neighbours in the eGo 100 scenario. Source: Bunke et al., 2017

Technology	AT	CH	CZ	DK	FR	LU	NL	PL	SE	Total without DE	DE	**Total**	BE	NO	Total incl. extension
Nuclear energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
Hard coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
Natural gas	1.5	2.0	1.8	1.0	16.0	0.3	3.0	3.0	0.0	28.5	0.0	**28.5**	2.5	0.0	31.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
Other conventional generation (mixed fuels)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
Total conventional generation	**1.5**	**2.0**	**1.8**	**1.0**	**16.0**	**0.3**	**3.0**	**3.0**	**0.0**	**28.5**	**0.0**	**28.5**	2.5	0.0	31.0
Wind onshore	6.9	1.4	10.2	18.7	124.2	0.7	15.0	81.9	24.2	283.3	98.9	**382.1**	10.9	12.2	405.2
Wind offshore	0.0	0.0	0.0	25.6	0.0	0.0	15.9	0.0	3.0	44.5	27.0	**71.5**	3.0	3.0	77.5
Photovoltaic	12.1	15.0	13.1	2.0	103.1	1.0	22.3	24.2	8.9	201.7	98.5	**300.1**	24.1	5.4	329.6
Biomass	3.5	1.3	5.0	3.8	28.3	0.0	4.0	14.3	5.5	65.5	27.8	**93.3**	4.8	0.0	98.1
Hydro power	13.1	12.3	1.3	0.0	28.5	0.2	0.1	2.1	23.8	81.3	3.2	**84.5**	0.3	70.9	155.7
Total renewable generation	**35.6**	**29.9**	**29.6**	**50.1**	**284.0**	**1.9**	**57.3**	**122.5**	**65.5**	**676.2**	**255.3**	**931.5**	43.1	91.5	1066,1
Pump storage	10.8	5.5	2.8	0.2	13.7	1.9	1.8	5.5	0.0	42.1	9.3	**51.4**	2.3	17.3	71.0
Battery storage	0.3	0.3	2.5	0.9	3.5	0.1	1.4	4.6	3.2	16.7	–	**16.7**	0.3	0.0	17.0
Hydrogen storage	0.0	0.0	0.2	5.0	26.0	0.6	7.6	0.3	0.0	39.7	–	**39.7**	1.8	0.0	41.5
Total capacity	**48.1**	**37.7**	**36.7**	**57.2**	**343.2**	**4.8**	**71.1**	**135.9**	**68.7**	**803.2**	**264.5**	**1067.7**	50.0	108.8	1226.5

B Appendix: Extended Grid Map

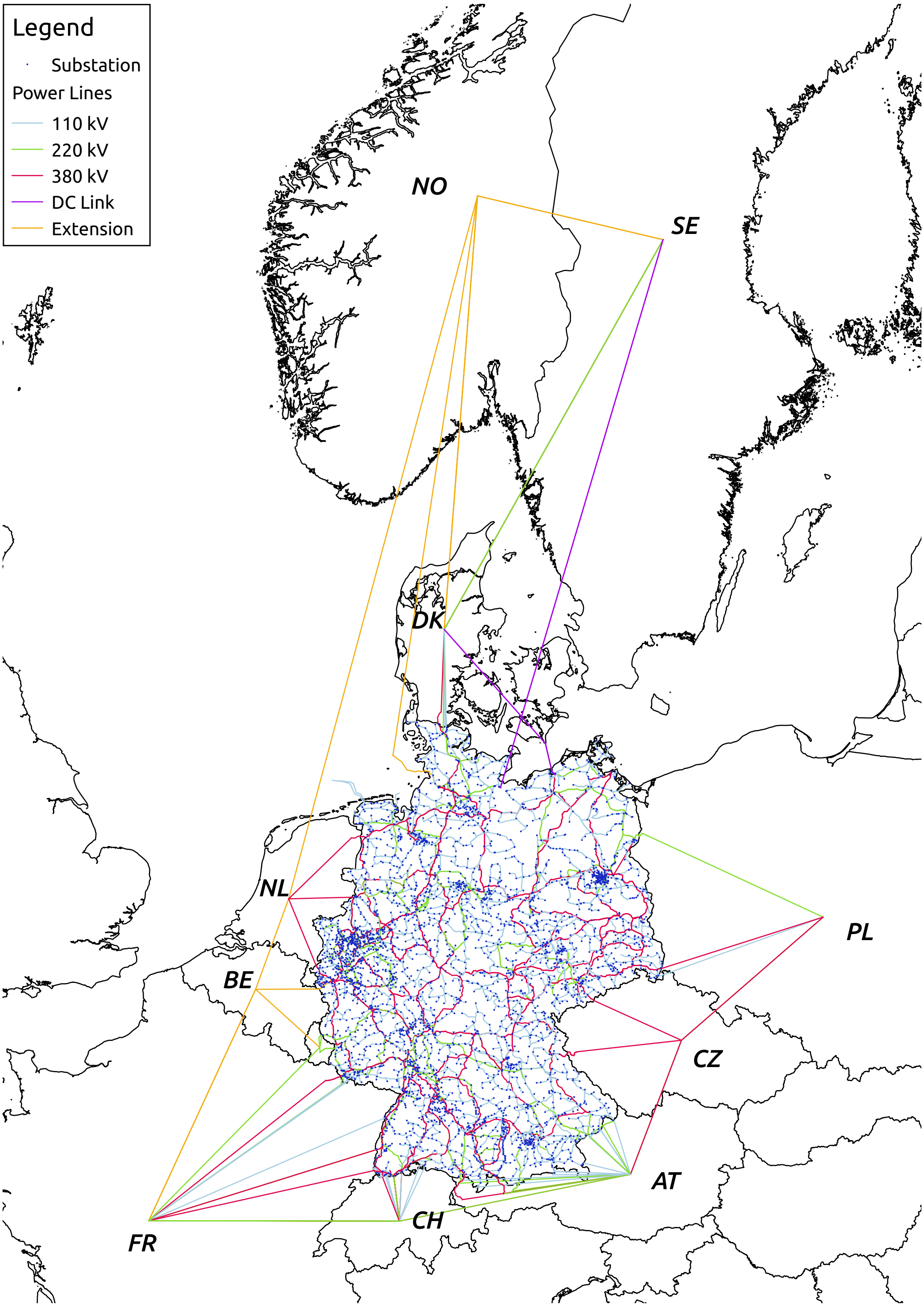

FIGURE B.1: Spatial illustration of the final power grid model. Note: (1) Offshore grid connections are not depicted here. (2) lines in orange indicate the extension scenario connection Norway and Belgium. These lines are not included in the basic setup and only added for certain variations (compare Section 5.5).

C Appendix: Storage Expansion Plots

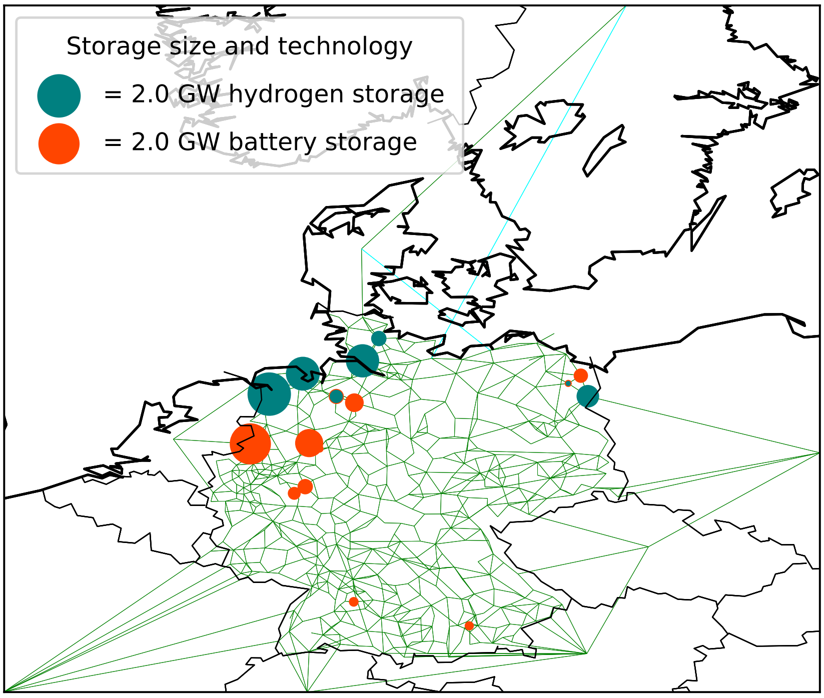

FIGURE C.1: Scenario: eGo 100; Battery Storage E/P ratio is 8
$\sum = 8.69$ GW

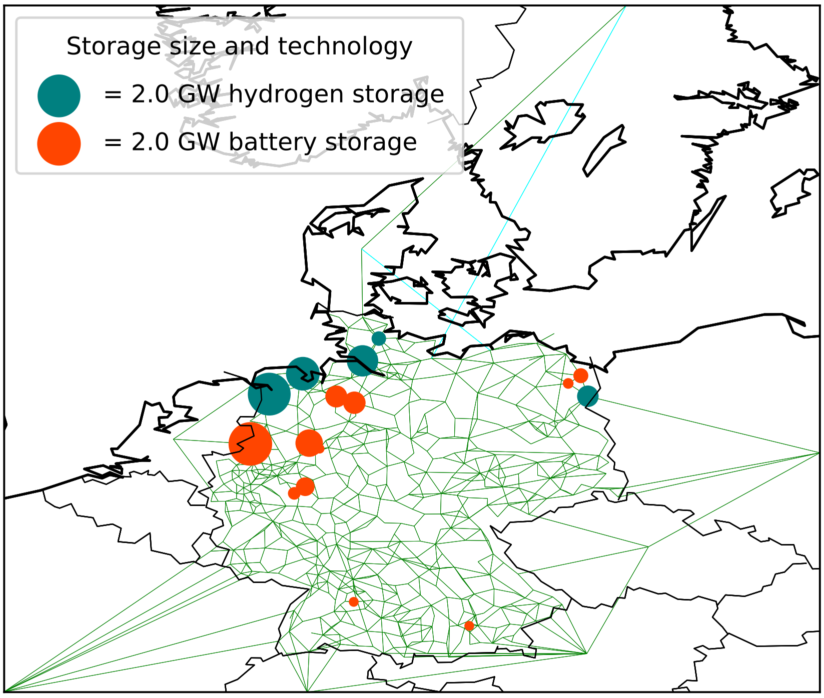

FIGURE C.2: Scenario: eGo 100; Battery Storage E/P ratio is 10
$\sum = 9.38$ GW

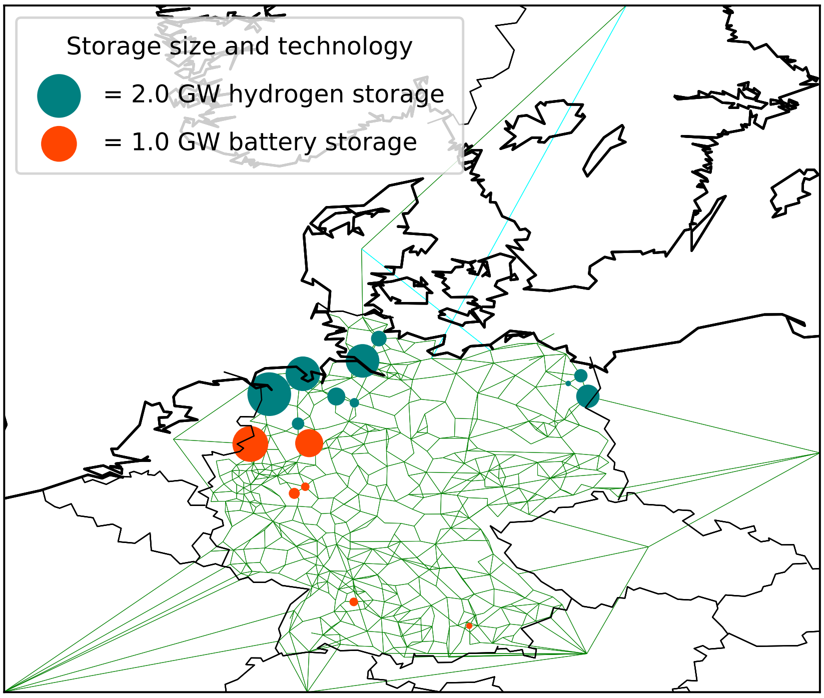

FIGURE C.3: Scenario: eGo 100; Battery Storage efficiency is decreased by 5 %

$\sum = 7.89$ GW

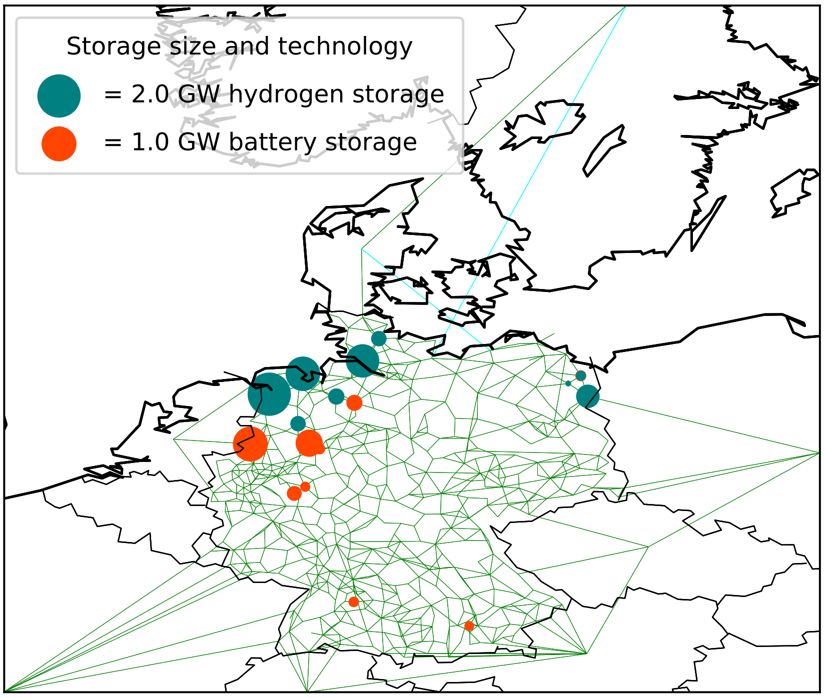

FIGURE C.4: Scenario: eGo 100; Battery Storage efficiency is increased by 5 %

$\sum = 8.18$ GW

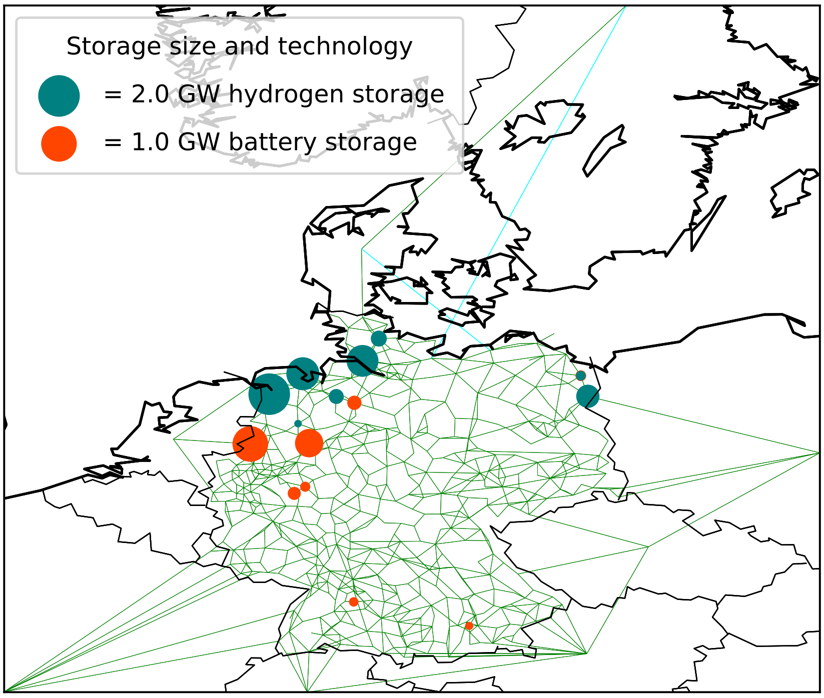

FIGURE C.5: Scenario: eGo 100; Hydrogen Storage efficiency is decreased by 5 %

$\sum = 7.48$ GW

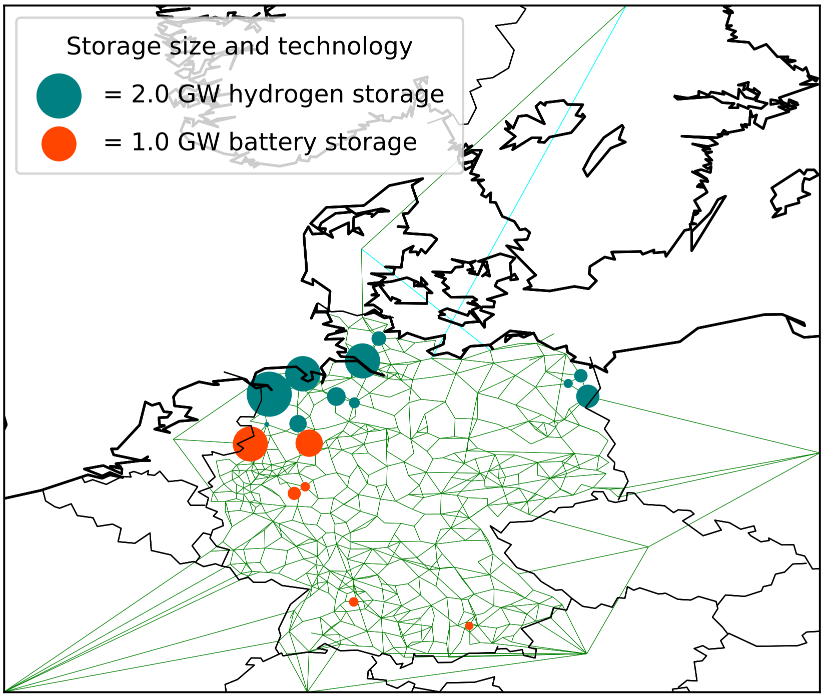

FIGURE C.6: Scenario: eGo 100; Hydrogen Storage efficiency is increased by 5 %

$\sum = 8.51$ GW

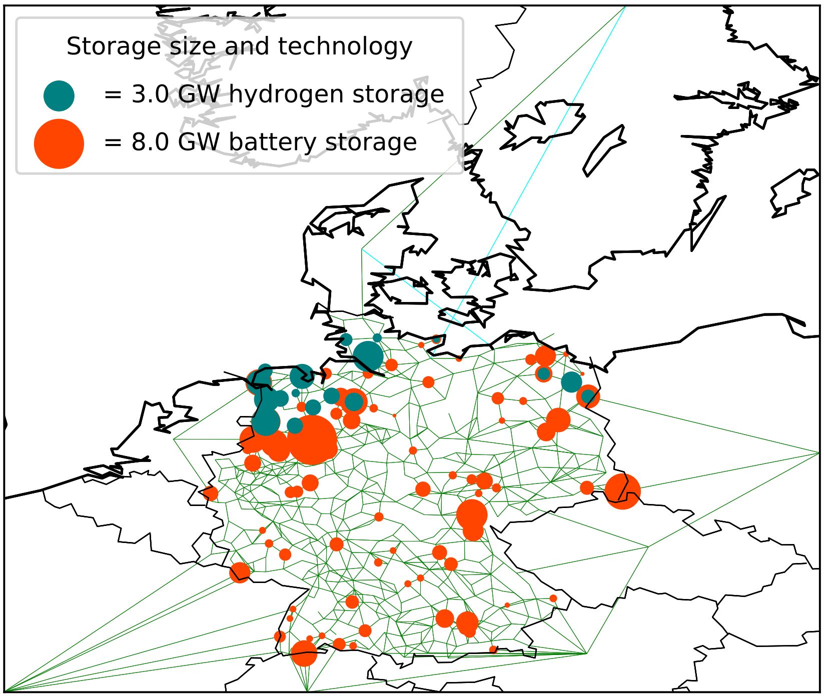

FIGURE C.7: Scenario: eGo 100; Storage costs are decreased by 90 %. Note the different scaling.

$\sum = 75.03$ GW

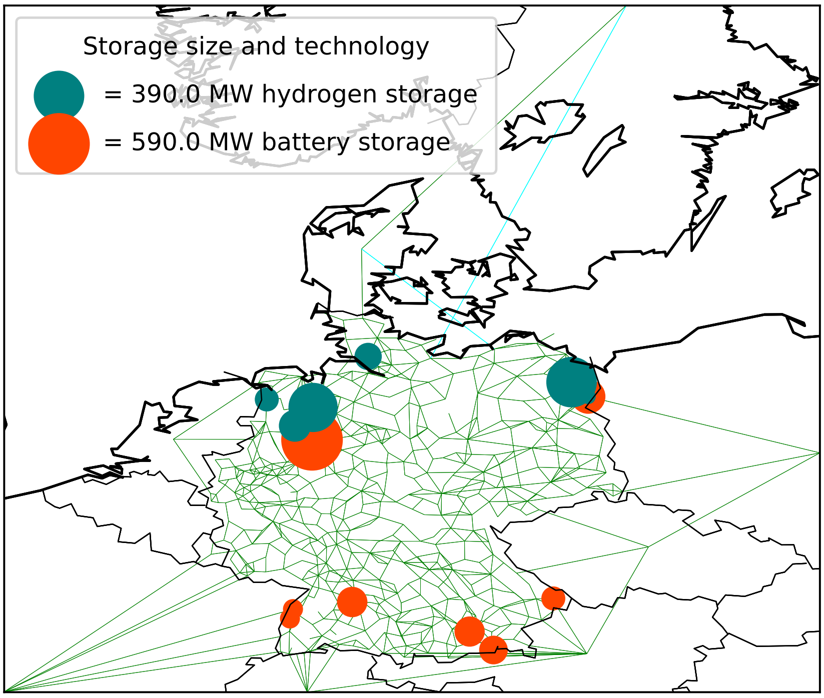

FIGURE C.8: Scenario: eGo 100; Storage costs are increased by 100 %. Note the different scaling.

$\sum = 2.44$ GW

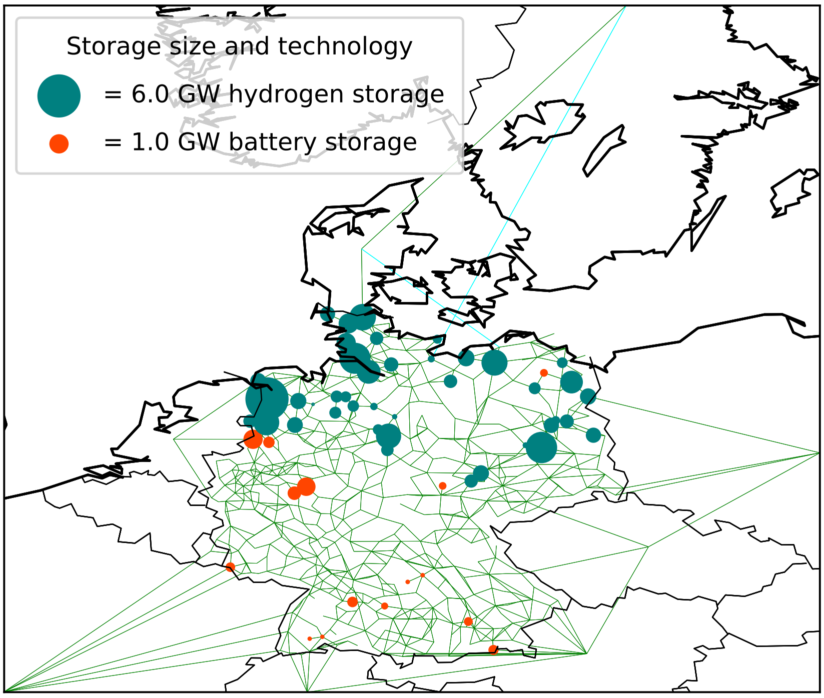

FIGURE C.9: Scenario: NEP 2035; Thermal power plants are only flexible from 50 % to 100 %. Note the different scaling.
$\sum = 37.86$ GW

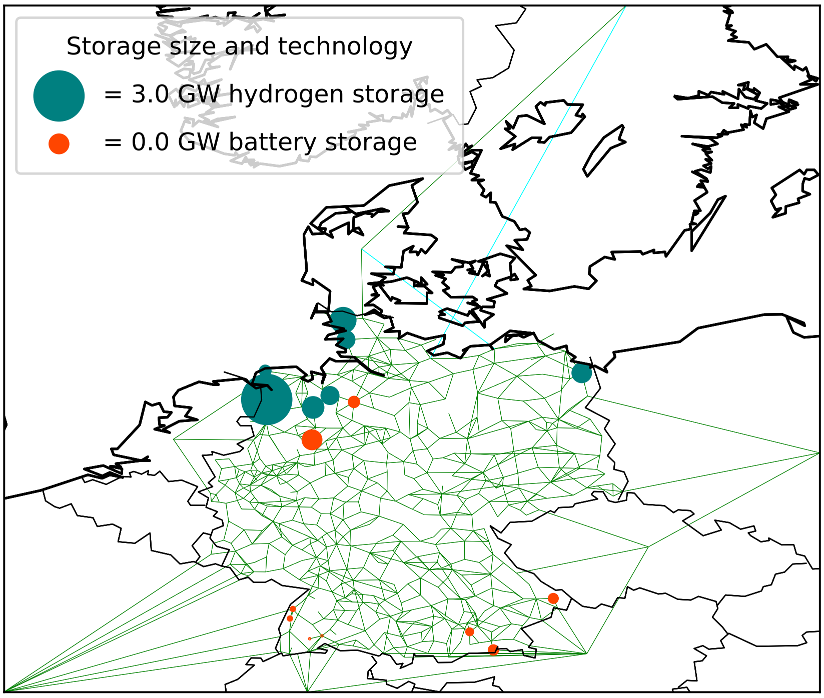

FIGURE C.10: Scenario: NEP 2035 %; 20 GW offshore wind; constant onshore wind capacity
$\sum = 6.12$ GW

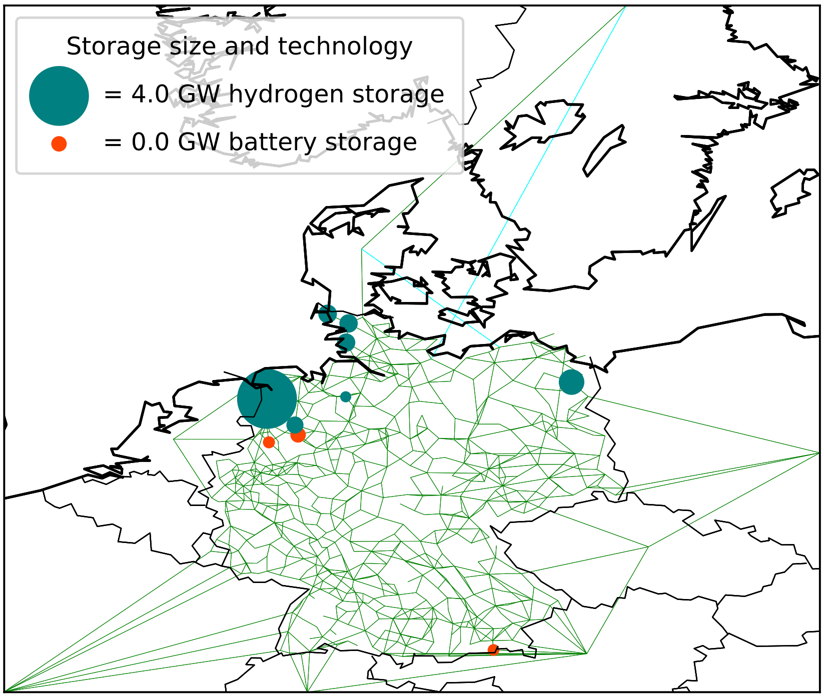

FIGURE C.11: Scenario: NEP 2035 %; 27 GW offshore wind; constant onshore wind capacity
$\sum = 6.03$ GW

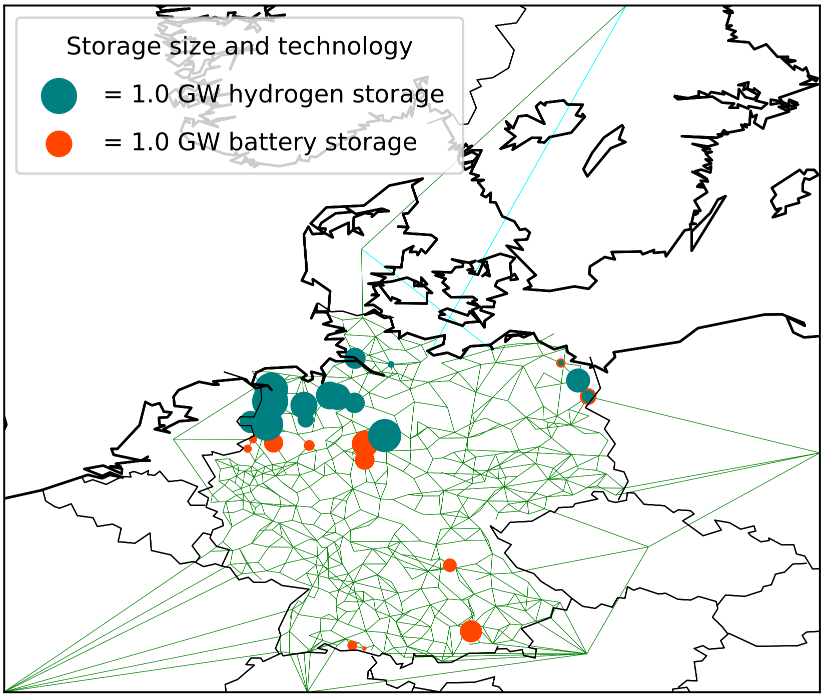

FIGURE C.12: Scenario: eGo 100 %; 40 GW offshore wind; constant onshore wind capacity
$\sum = 11.03$ GW

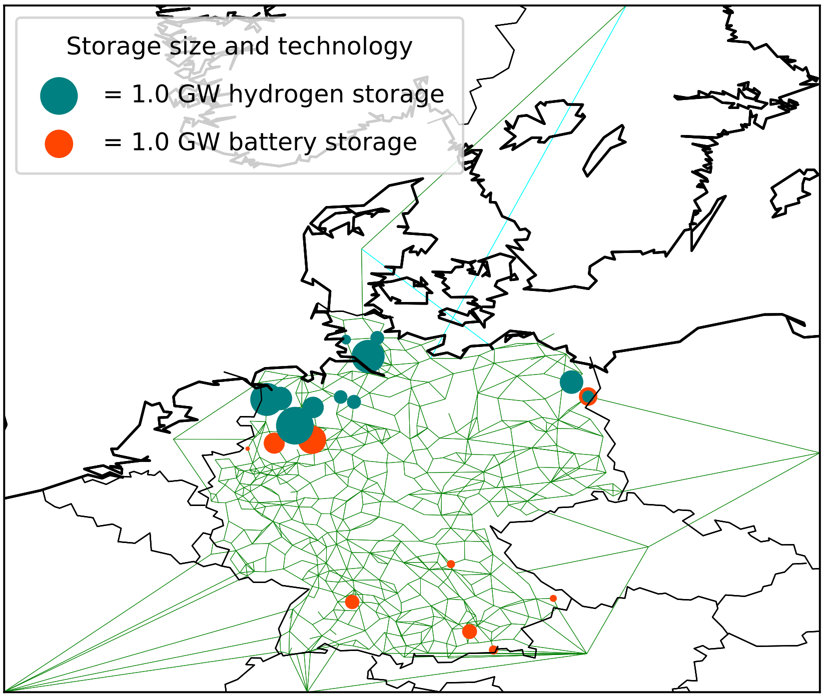

FIGURE C.13: Scenario: eGo 100 %; 40 GW offshore wind; onshore wind capacity reduced by 13 GW
$\sum = 7.55$ GW

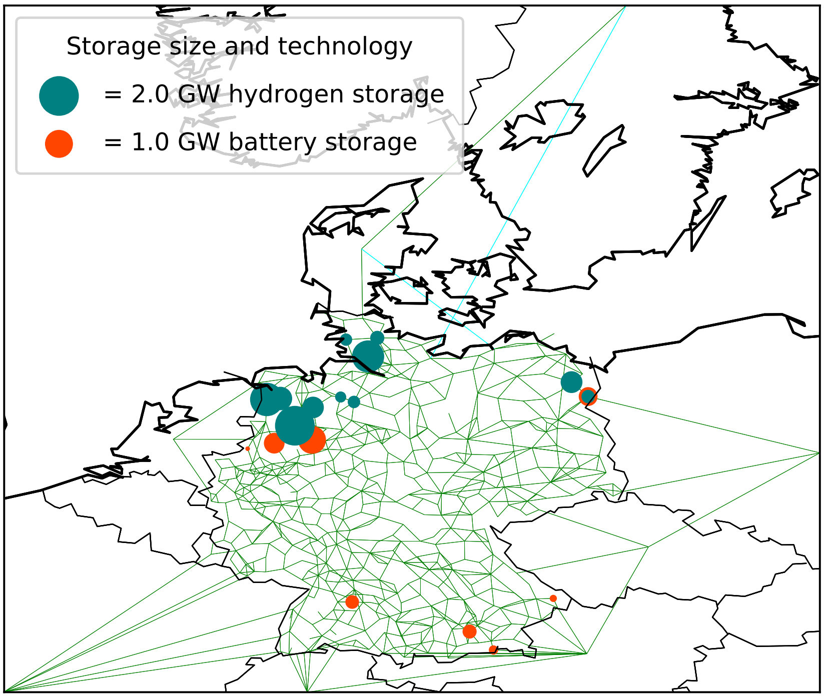

FIGURE C.14: Scenario: eGo 100 %; 40 GW offshore wind; onshore wind capacity reduced by 26 GW
$\sum = 7.53$ GW

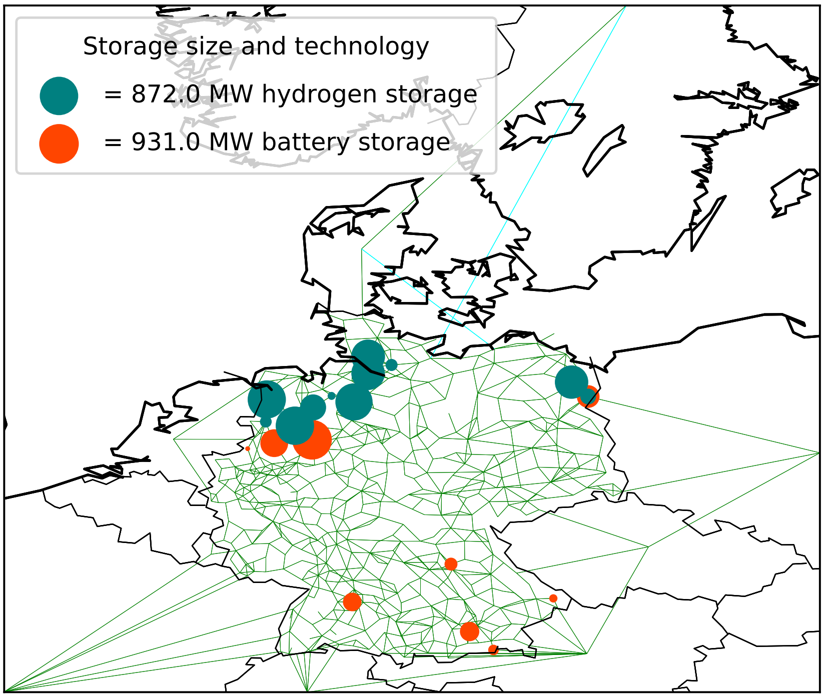

FIGURE C.15: Scenario: eGo 100 %; 73 GW offshore wind; constant onshore wind capacity
$\sum = 7.35$ GW

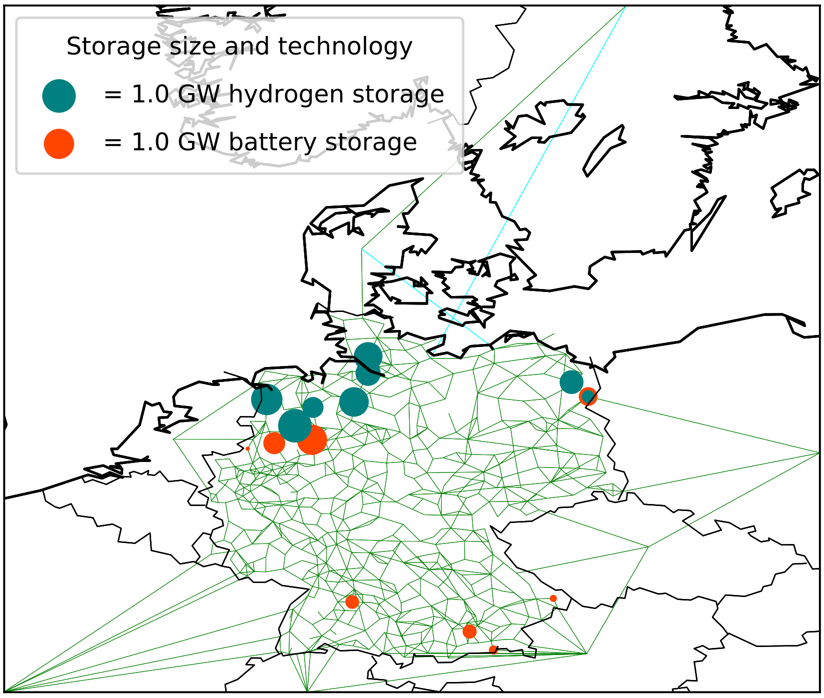

FIGURE C.16: Scenario: eGo 100 %; 73 GW offshore wind; onshore wind capacity reduced by 26 GW
$\sum = 7.31$ GW

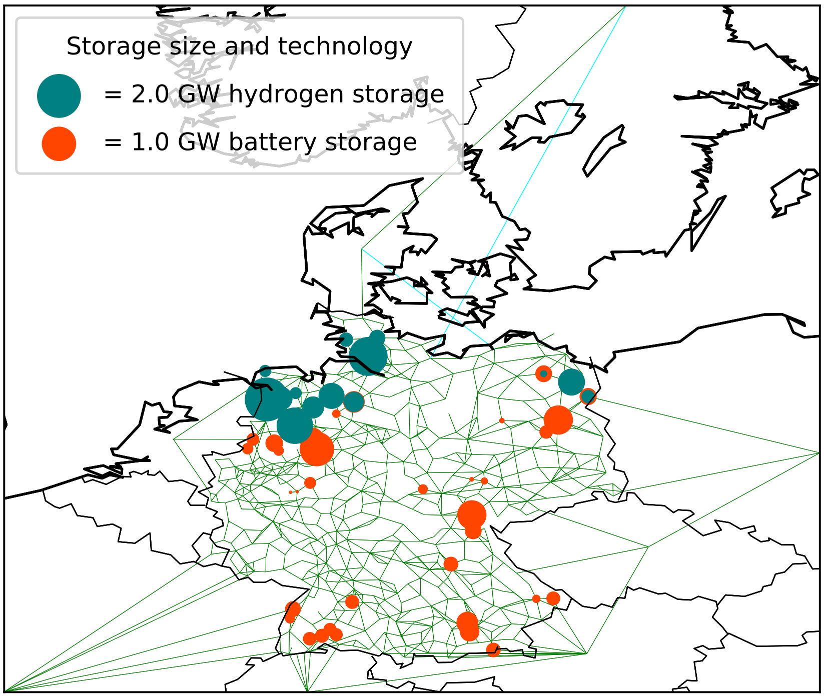

FIGURE C.17: Scenario: eGo 100; Biomass generation capacity is decreased to 50 %

$\sum = 15.97$ GW

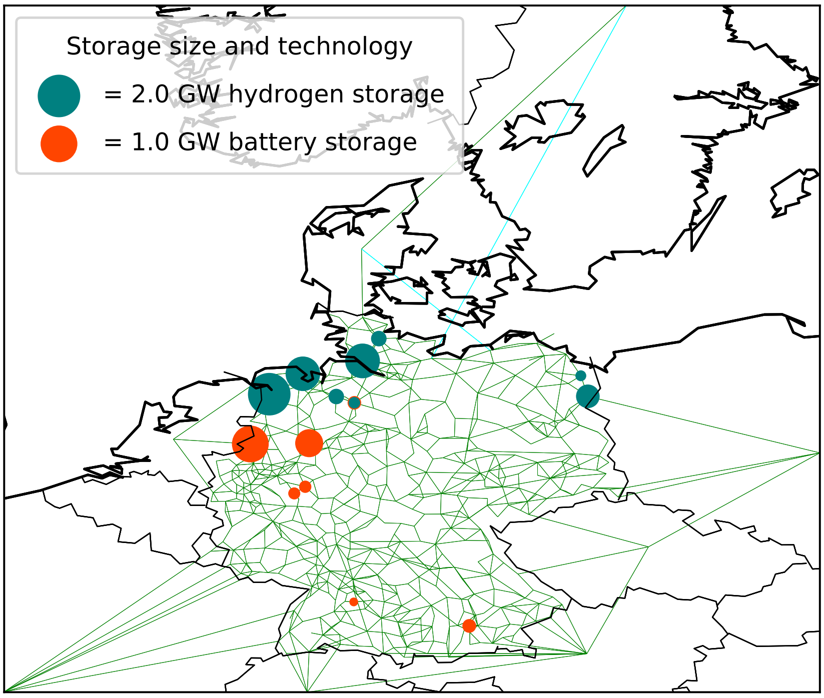

FIGURE C.18: Scenario: eGo 100; Biomass full load hours are limited to below 2514 h.

$\sum = 8.07$ GW

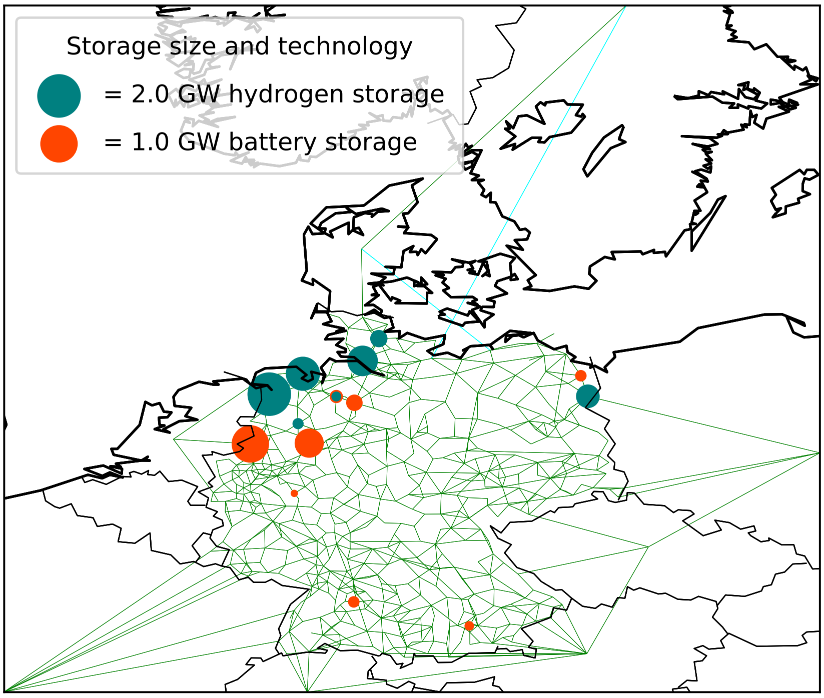

FIGURE C.19: Scenario: eGo 100; German PV generation capacity is increased by 25 %, while onshore wind is decreased by 25 %.
$\sum = 7.91$ GW

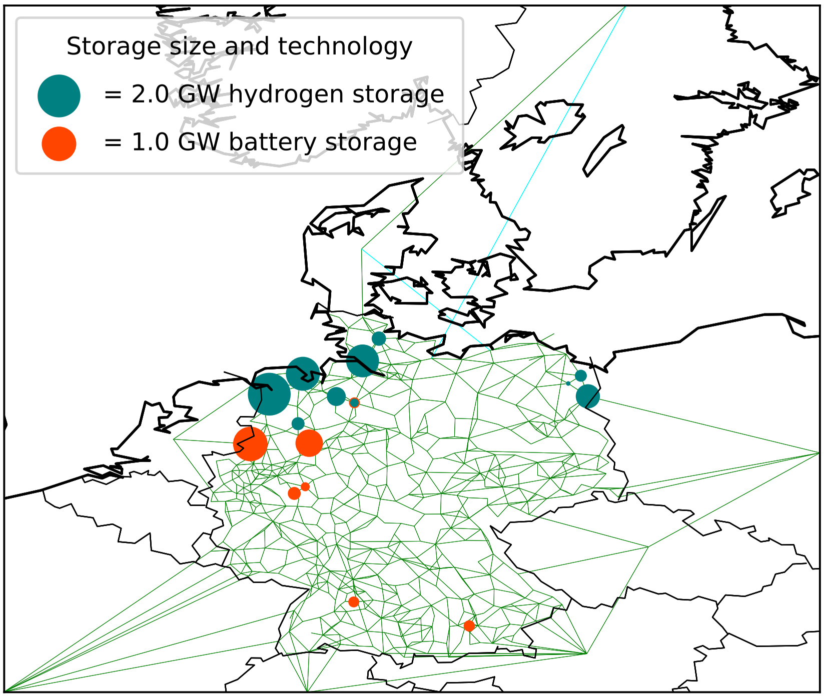

FIGURE C.20: Scenario: eGo 100; Total power demand is decreased by 5 %.

$\sum = 7.79$ GW

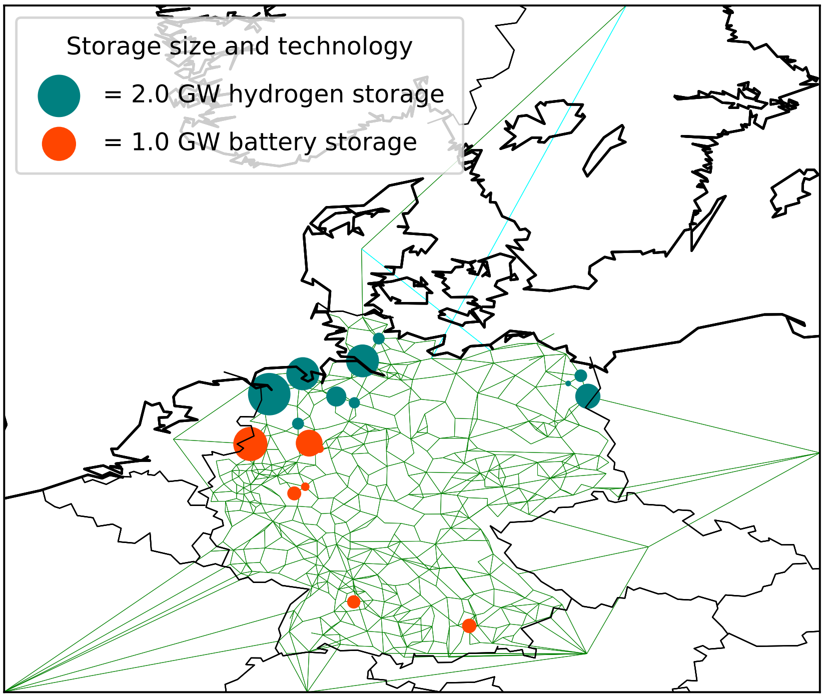

FIGURE C.21: Scenario: eGo 100; Total power demand is decreased by 10 %.

$\sum = 7.77$ GW

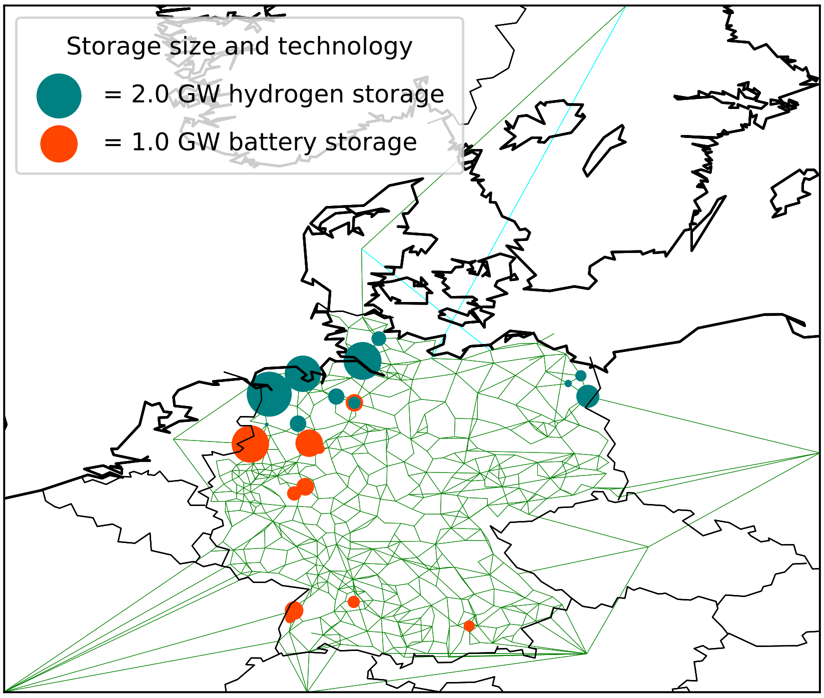

FIGURE C.22: Scenario: eGo 100; Total power demand is increased by 5 %.

$\sum = 9.81$ GW

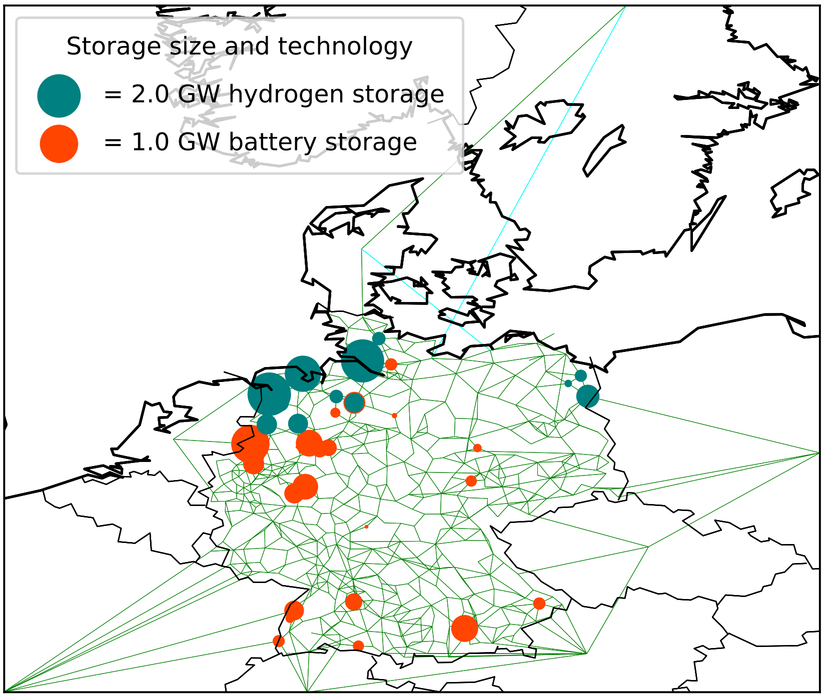

FIGURE C.23: Scenario: eGo 100; Total power demand is increased by 10 %.
$\sum = 14.02$ GW