Carl von Ossietzky Universität Oldenburg
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Modeling decarbonization pathways of Europe's electricity supply system until 2050

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Guido Pleßmann

geboren am 8.9.1986 in Göttingen

Gutachter
Prof. Dr.-Ing. Axel Hahn
Prof. Dr. Carsten Agert

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Erklärung

Ich erkläre hiermit, dass ich die vorliegende Arbeit selbständig verfasst und keine anderen als die angegebenen Quellen und Hilfsmittel verwendet habe.

Girona den 27.9.2018,

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Zusammenfassung

Der voranschreitende Klimawandel stellt eine der größten Herausforderungen für das Wohlergehen der Menschheit dar. Auf Basis wissenschaftlicher Erkenntnisse, insbesondere durch die des Intergovernmental Panel on Climate Change (IPCC), wurden globale und multinationale Abkommen zur langfristigen Stabilisierung des weltweiten Klimas vereinbart. Das globale Klimaschutzabkommen von Paris im Jahr 2015 zielt auf eine Begrenzung der globalen Erderwärmung von maximal 2°C – bevorzugt höchsten 1,5°C – bis 2100 ab. Um dies zu erreichen hat die EU umfassende Emissionsminderungsziele von -80 % bis -95 % bis zum Jahr 2050 in Energie- und nicht-Energiesektoren vereinbart. Von diesem Ziel leiten sich unterschiedliche Minderungsziele für einzelne Sektoren ab. Für die Erreichung der langfristigen Emissionsminderung werden schrittweise kurzfristigere Ziele für einzelne Mitgliedsstaaten vereinbart. Ein Masterplan für die konkrete Realisierung der sektoralen Emissionsminderungsziele bis zum Jahr 2050 liegt allerdings bisher nicht vor. Dabei wird insbesondere die zweite Hälfte der Umsetzungsphase des Klimaschutzabkommens verschärfte Herausforderungen mit sich bringen. Im Bereich der Energieversorgungssektoren betrifft dies insbesondere den Stromsektor, da dieser mit besonders strengen Minderungszielen belegt ist und zusätzlich eine Verlagerung von Lasten aus anderen Energiesektoren zu erwarten sind.

Eine kostengünstige Umsetzung der Klimaschutzziele im Stromsektor benötigt eine optimierte Planung und Strategie. Langfristige Planungs- und Abschreibungszeiträume für Kraftwerke und ein tiefgreifender technologischer Wandel erzeugen ein komplexes und dynamisches Umfeld. Kurzfristige Entscheidungen haben Auswirkungen auf die mittel- und langfristige Energieversorgungsstruktur. Daher unterstützen modellbasierte Studien zum Umbau der Energieversorgungsinfrastruktur politische Planungsprozesse und geben Einblicke in entscheidungsrelevante technisch-ökonomischer Zusammenhänge. Trotz einer Vielzahl an Studien zur zukünftigen Europäischen Energie- und insbesondere Stromversorgung, besteht zu wenig Kenntnis über den schrittweisen Wandel im Stromversorgungssystem. Dies betrifft insbesondere die Übergangspfade hin zu einem klimafreundlichen System und die technologischen Veränderungen in der Phase ab 2030.

Um diese Lücke zu füllen, skizziert diese Arbeit kostengünstige Dekarbonisierungspfade für

den europäischen Stromsektor zur Erreichung der EU-Treibhausgasminderungsziele. Diese Pfade beschreiben die Umstrukturierung der Energieversorgungsinfrastruktur hinsichtlich Investitionen in Kraftwerks-, Energiespeicher-, und Übertragungsnetzkapazitäten in 5-Jahres-Schritten bis zum Jahr 2050. Zur Ermittlung dieser Pfade wurde das mehr-perioden, mehr-regionen Energiesystemmodell elesplan-m für den europäischen Stromsektor entwickelt und angewendet. Basierend auf linearer Programmierung ermöglicht es kostenoptimale Investitionsentscheidungen unter Berücksichtigung der technischen und wirtschaftlichen Rahmenbedingungen zu treffen. Dafür wurden Referenzjahre in stündlicher Auflösung berechnet.

Die analysierten Übergangspfade, die zu einer Minderung der Treibhausgasemissionen bis 2050 um -98 % bezogen auf 1990 führen, zeigen, dass erhebliche Investitionen mit der Umstrukturierung der europäischen Stromversorgung verbunden sind. Stromerzeugung aus Photovoltaik (PV) und Windenergieanlagen wird den Großteil der Gesamtstromerzeugung ausmachen. Dazu werden 1.430 GW Windenergieanlagen und 1.260 GW PV-Anlagen im Jahr 2050 benötigt. Um dies zu erreichen, muss ein durchschnittlicher jährlicher Ausbau von ca. 40 GW/a beider Technologien erfolgen. Eine verstärkte internationale Kooperation in der Stromversorgung durch den Ausbau der Grenzüberschreitenden Übertragungsnetzkapazitäten begünstigt die kosteneffiziente Umsetzung der Klimaschutzmaßnahmen im Stromsektor. Energiespeicher in einer Größenordnung von 43 GW Pumpspeicherkraftwerken, 230 GW Batteriespeichern und 260 GW Power-to-gas werden im Jahr 2050 benötigt, um Schwankungen in der Energieversorgung auszugleichen. Die Analyse verschiedener Sensitivitäten verdeutlicht, dass langfrist-Energiespeicher, z.B. Power-to-gas, zur Erreichung von einer Treibhausgasemissionsminderung von -88 % und weniger erforderlich sind. Emissionsintensive Kohleverstromung muss spätestens Mitte der 2030er Jahre beendet werden, um den Dekarbonisierungspfad zu realisieren. Insgesamt ist ein Anstieg der Stromgestehungskosten von rund 60 % zu erwarten. Analysierte Szenarien weisen diesbezüglich einen Schwankungsbereich von +/- 10 % auf, womit die Kostensteigerung als erwartbar angesehen werden kann. Unter Berücksichtigung externer Kosten zeigt sich ein anderes Bild. Werden steigende Brennstoffkosten, Folgekosten des Klimawandels und weitere externe Kosten berücksichtigt, entsprechen diese nahezu der Steigerung der Stromgestehungskosten des dekarbonisierten Stromsystems.

Aus den Ergebnissen dieser Arbeit lässt sich schlussfolgern, dass ein verlässlicher politischer Rahmen für die erfolgreiche Umsetzung der Klimaschutzvorhaben notwendig ist. Ein europaweiter Umsetzungsplan zur Realisierung der Klimaschutzziele im Stromsektor ermöglicht koordinierte Maßnahmen in einzelnen Ländern und kann zu einem insgesamt kostengünstigen Übergang führen. Die Schaffung eines verlässlichen Investitionsumfeldes ist notwendig für Investoren, um einen Anreiz für Investitionen in Kraftwerks- und Speicherprojekte zu bieten. Ferner muss sichergestellt werden, dass notwendige Technologien, wie z.B. Power-to-gas, und ausreichend Produktionskapazitäten für bspw. Windenergie- und PV-Anlagen verfügbar sind. Sofortiges Handeln ist erforderlich, um Klimaschutz im Rahmen der 2°C Ziele zu realisieren. Investitionen in fossile Kraftwerkstechnologien, die bald nicht mehr wirtschaftlich nutzbar sind, müssen vermieden und auf der anderen Seite Investitionen in erneuerbare Technologien gestärkt werden.

Abstract

Climate change is one of the most challenging issues faced by humankind today. Scientific evidence regarding the existence of anthropogenic climate change was proven by the Intergovernmental Panel on Climate Change (IPCC). Based on the evidence, negotiations led to international agreements on the long-term stabilization of the climate system. In 2015, a limit on the global average temperature increase was set to 2°C, preferably 1.5°C, until 2100. To achieve this goal on a European scale, the EU agreed to reduce total greenhouse-gas (GHG) emissions by 80 to 95 % by 2050. Thereof, emission targets for individual sectors were derived. The effort is shared among member countries. Individual intermediate targets are being continually negotiated. However, a holistic plan that sets the pathway for implementing effective measures to achieve the GHG emission reduction targets in all sectors by 2050 is missing. It is expected that challenges to achieve the reduction will increase in the last twenty years due to the growing integration of variable renewable energy sources. In addition, anticipated demand shift from other sectors to the electricity sector and relatively strict reduction targets in the latter corroborate the priority to decarbonize the electricity sector.

The cost-effective implementation of measures to achieve the GHG emission reduction targets requires a strategy based on optimal planning. Long-term economic depreciation of power plants and a radical technological change create a dynamic and a complex environment. Decisions taken on short-term scale affect the design of the electricity system on a long term. Therefore, model-based studies help to unveil insights about the transition towards a decarbonized electricity supply and provide important information for planning of the future electricity system. Despite the large number of studies on the future of the electricity sector, cost-effective decarbonization pathways to achieve the GHG emission reduction goals are insufficiently explored. Successive transformation planning of the European electricity system is needed in order to achieve the GHG emission reduction targets by 2050.

This thesis assesses cost-optimal decarbonization pathways for the European electricity sector to meet emission reduction targets by 2050. These pathways outline the transformation of the electricity supply infrastructure in successive 5-years increments until 2050. It includes

investments in power plants, energy storage facilities, and the transmission system. For assessing these pathways, the multi-period, multi-region energy system model elesplan-m for European electricity sector was developed and used. This computer model is based on linear programming allowing the assessment of investment decisions constrained by technical and economic circumstances. These decisions are evaluated based on analyzing the electricity supply on an hourly scale for each reference year.

The analyzed decarbonization pathways show that enormous effort is required to cut GHG emissions in the European electricity sector by 98 % by 2050 relative to 1990 levels. According to the investigated pathways, electricity generation by wind and photovoltaic (PV) power will meet the majority of the electricity demand by 2050. This requires 1,430 GW of wind power and 1,260 GW of PV power to be installed by 2050. Therefore, capacity of both technologies needs to be extended by approximately 40 GW on average per year. Enhanced international cooperation through the extension of cross-border transmission capacities allows a cost-effective implementation of climate protection measures in the electricity sector. The proposed electricity system design for 2050 includes 43 GW of pumped-hydro storage, 230 GW of battery energy storage systems, and 260 GW of power-to-gas (PtG) to balance supply and demand mismatches. Several sensitivity scenarios show that PtG is required to achieve climate change mitigation beyond the GHG reduction of 88 %. Carbon-intense electricity generation technologies, such as coal power, must be abandoned around 2035 to realize effective decarbonization. Cost of electricity supply is very likely to increase by approximately 60 % until 2050. The sensitivity scenarios show the cost increase only deviates by +/- 10 % relative to the reference case. If rising fuel prices, costs due to the impact of climate change, and other external costs would be incorporated in the cost of electricity supply, costs would be comparable to the expected cost increase of deploying renewables.

Based on the results of this thesis, it can be concluded that a reliable political framework is required for a successful implementation of GHG reduction measures in the European electricity supply sector. A European-wide agenda to decarbonize the electricity sector allows cost-effective coordinated actions. A guaranteed reliable environment attracts investors to finance power plants, energy storage systems, and transmission system projects. Furthermore, it must be guaranteed that required technologies, i.e. power-to-gas, and manufacturing capacities for PV and wind power, are available. Immediate action is needed to realize climate change mitigation within the 2°C limits. Among other requirements, investments in coal power must be avoided and replaced by investments in renewable energy.

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Acronyms

GHG	greenhouse gas
RES	renewable energy sources
CCS	carbon dioxide capture and storage
PV	photovoltaics
CSP	concentrating solar power
PHS	pumped hydro storage
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
CHP	combined heat and power
$\mathbf{CO_2}$	carbon dioxide
$\mathbf{CO_2eq}$	carbon dioxide equivalent
UK	United Kingdom
LULUCF	land use, land-use change and forestry
EU-ETS	European Union Emission Trading System
NTC	net transfer capacity
TIMES	The Integrated MARKAL-EFOM System
PRIMES	a computable Price-driven equilibrium Model of the Energy System and markets for Europe
POLES	Prospective Outlook on Long-Term Energy Systems
MARKAL	Market Allocation
EFOM	Energy Flow Optimization Model
LP	linear programming
elesplan-m	European long-term energy system planning model

CRF	capital recovery factor
CAPEX	capital expenditures
PtG	power-to-gas
SNG	synthetic natural gas
SoC	state of charge
OCGT	open cycle gas turbine
CCGT	combined cycle gas turbine
IPCC	Intergovernmental Panel on Climate Change
WACC	weighted average cost of capital
IRENA	International Renewable Energy Agency
US	United states of America
UNFCCC	United Nations Framework Conventions on Climate Change
PEM	polymer electrolyte membrane
AEL	alkaline electrolysis
$\mathbf{OPEX_{fix}}$	fixed operational expenditures
$\mathbf{OPEX_{var}}$	variable operational expenditures
LCOE	levelized cost of electricity
IGCC	integrated gasification combined-cycle
DoD	depth of discharge
AC	alternating current
FLH	full-load hours
NaS	sodium-sulfur battery
Li-ion	lithium-ion battery
ESS	energy storage system
EIA	*Energy Information Administration*
CAES	compressed-air energy storage
pahesmf	*power and heat energy system modeling framework*
oemof	open energy modeling framework

DC	direct current
SMES	superconducting magnetic energy storage
HVDC	high-voltage direct current
GDP	gross domestic product
BAU	business as usual
BESS	battery energy storage system
GHI	global horizontal irradiance
GIS	geographical information systems
DSM	demand side management
ETSAP	Energy Technology Systems Analysis Program
IEA	International Energy Agency
LEAP	the Long-range Energy Alternatives Planning system
NEMS	National Energy Modeling System
IAM	integrated assessment model
MILP	mixed-integer linear programming
PTDF	power transfer distribution factor
TSO	transmission system operator
IAEA	International Atomic Energy Agency

1 Introduction

This thesis presents a model-based analysis of decarbonization pathways to meet the 2°C climate change mitigation target within the European electricity supply sector. Results of this thesis aspire to address policy-makers in particular to support the implementation of a transition towards sustainable energy supply. Therefore, least-cost pathways for power plant, energy storage system, and transmission capacity investments are explored from a system-planners perspective. These pathways detail about the transformation of the electricity supply infrastructure on a five years time scale.

1.1 Motivation and research objective

Fighting anthropogenic climate change is one of the world's largest challenge in the 21st century (UNFCCC, 1997). Current greenhouse gas (GHG) emission mitigation efforts are still not sufficient to achieve scenarios with temperature increase below 2 °C until 2100 (IPCC, 2014). Since the industrialization period in the 19th century the annual GHG emissions have constantly increased and a turnaround is not foreseeable (Boden et al., 2010). Human behavior not only intensifies climate change, furthermore it augments natural resources scarcity (Bardi, 2014).

Current heat and electricity supply account for approximately 25 % of global GHG emissions and are consequently major emitting sectors (IPCC, 2007; IEA, 2013). In 2009, the European Commission agreed on ambitious GHG emissions reduction targets until the year 2050 in accordance with the Kyoto protocol (European Council, 2009). The efforts to achieve these goals were strengthened at the COP 21 by the United Nations Framework Conventions on Climate Change (UNFCCC) participating member states in Paris (UNFCCC, 2015b). The European Union (EU) has to take a leading role within these group of countries to cope with the burden of GHG emissions. As a result of its critical role the EU quantified the following ambitious reduction targets (European Commission, 2016):

> *By 2050, the EU aims to cut its emissions substantially by 80 to 95 % compared to 1990 levels as part of the efforts required by developed countries as a group.*

The strongest emission reduction targets are planned within the power sector ranging from 93 % to 99 % based on 1990 emission levels (European Commission, 2011a). This provides a clear outline on long-term decarbonization of Europe's power supply system. Due to diverse demand shifts from other sectors (such as heat and mobility) the decarbonization of the electricity supply sector gains special importance (Williams et al., 2012).

Although most of European countries came to an agreement about strong GHG emission reduction targets until 2050, details of the transition – in particular with focus on the electricity supply sector – are still undefined (European Commission, 2011a; UNFCCC, 2015b). Besides the long-term objective of an almost complete decarbonization of the European power sector, intermediate binding targets for the years 2020 (20 % GHG emission reduction compared to 1990 levels) and 2030 (40 % GHG reduction) are in place (European Union, 2009a; European Council, 2014; Kanellakis et al., 2013). Policy makers have to observe the practical effects of current directives and adjust those to achieve the designated goals as well as develop new directives to support the achievement of GHG mitigation goals in 2050. Therefore, pathway analyses towards the mitigation targets in 2050 as well as in-depth sectoral analysis as basis for decision-making are required. This is necessary to meet all social, ecological and economic expectations (Vandenbergh et al., 2008). Therefore, model-based analysis must be conducted transparently and results must be communicated to enable evidence-based decision-making. Meeting economic expectations is achieved by providing least-cost strategies through appropriate model design.

In order to identify feasible and cost-effective decarbonization by the use of renewable energy sources (RES), available opportunities have to be studied. Among others this includes allocation of new RES and conventional balancing capacities, power generation mix, energy storages, transmission capacity expansion and curtailment of power plants. Different power generation technologies combined with balancing capacities and flexibility options (e.g. energy storage system, transmission system, curtailment) span a wide range of feasible electricity system structures to meet assumed demand while adhering to GHG emission constraints. Due to complexity of this issue, model based analyses of future electricity supply are necessary to identify optimal power system designs. Another dimension of complexity is added by choice of temporal deployment of capacities upon the next decades. Discovering optimal – in most cases this is equal to least-cost – transition pathways towards a decarbonized European power system requires a strong modeling methodology. Both, long-term climate mitigation targets and short-term power supply issues, have to be addressed simultaneously because both may potentially result in high economic and social costs (Turton and Barreto, 2006).

Many model based studies were conducted to analyze options for future electricity supply in Europe. This stems from a motivation either to show the feasibility of RES based power supply in general or to illustrate practical implementation of climate change mitigation options in the power sector. Both goals incorporate studying the effects of large-scale integration of RES. Studies that analyze options for climate mitigation mostly refer to targets set for the years 2030 and 2050. In particular, these studies focus on showing the effects of the transformation of the European electricity system towards sustainable electricity supply. This includes analyzing the supply mix, its spatial allocation, the need for transmission capacity extension, the role of energy storage systems, as well as resulting cost of electricity supply and investment needs.

According to Knopf et al. (2015) a share of 43 % to 56 % RES at electricity supply is cost-effective to achieve EU goals for 2030 that are consistent with long-term GHG reduction goal for 2050. Both, -40 % GHG emission reduction compared to 1990 and a share of 27 % renewable energy at total energy supply can be realized through this scenario. In this case RES based electricity generation comprise mostly of hydro, wind and biomass while photovoltaics (PV) electricity generation plays a minor role. The electricity system design does not include energy storage systems but transmission system extensions are identified as being beneficial for realizing a low-cost deployment of RES installations. Knopf et al. (2015) pointed out that regional differences in RES based electricity generation increase by least-cost scenario for 2030 and that policy mechanism to support implementation of RES deployment are needed. Brown et al. (2016) analyzed scenarios for grid integration of RES in Europe for the year 2030 in context of the Greenpeace energy [R]evolution study. They found electricity supply by 77 % based on RES can be realized by 2030 with modest changes to already planned transmission system upgrades by ENTSO-E (2012). Therefore, this scenario requires large-scale extension of wind and PV power capacity. Similarly to findings by Knopf et al. (2015) results suggest that the realization of 2030 climate mitigation targets is possible with relatively low effort when analyzed from a techno-economic perspective. According to Buck et al. (2016), a smart design of the European power market is required to achieve investments by private stakeholders. As claimed by the study, a smart electricity market design comprises of: energy-only market, emissions trading system , smart retirement measures, stable revenues for RES, and measures to safeguard system adequacy.

Electricity supply in Europe by the year 2050 is the focus of numerous studies. These studies, mainly motivated by the need for climate change mitigation, analyze the feasibility of 100 %

RES based electricity supply and seek options to achieve GHG emission reduction goals set for 2050. The core focus was to identify electricity system designs that are suitable to realize climate change mitigation at low cost. Therefore, Jacobson and Delucchi (2011) investigated the principle feasibility of providing energy globally with wind, hydro, and PV power. In the first part of the two paper series, Jacobson and Delucchi (2011) identified a global energy system design to serve all energy sectors (electricity, transportation, heating/cooling, etc.) by RES. The analysis assessed energy demand and supply on an annual scale. According to this study, global energy demand by 2050 is to be supplied by 50 % wind power, 40 % solar power, supported by 4 % geothermal and 4 % hydro power. Tidal and wave power serve almost neglectable shares. This requires large generation capacities of the former technologies. For example, the capacity of wind power plants needs to increase to 19 TW globally. The second part covers aspects of variability of RES electricity supply, resulting balancing needs and cost of electricity supply. Delucchi and Jacobson (2011) found that RES based energy supply is possible by 2050 at similar cost to that of today. Barriers for the successful implementation that are identified are rather social or political than technical or economical. Pleßmann et al. (2014) analyzed the global need for energy storage systems at 100 % RES based electricity generation. The analysis that was conducted with a cellular, regional approach revealed that the optimal energy storage technology mix depends on regional generation resource potential of wind and PV power. Aboumahboub et al. (2010, 2012) investigated potential power flows in a fictional global electricity. The second focus of these studies was on RES based electricity generation in Europe. According to Aboumahboub et al. (2012), electricity supply in Europe could be realized by annual generation primarily based on wind power that is supplemented by 20 % solar power generation and 5 % of balancing power supplied by gas power plants. An early and comprehensive study on future RES based electricity supply in the EU-MENA region was conducted by Czisch (2005). By combined extension and dispatch planning of power plants and the transmission system, a cost-optimal electricity system design was found that entirely relies on RES based generation. The cost-optimal identified electricity system considers only small amounts of solar power electricity generation (4 %) which is generated in countries in the south of Europe and North Africa. Wind power serves most of the electricity demand in this study. Variability of RES based electricity generation is balanced by flexible generation based on biomass and hydro power. Therefore, this study considered large-scale hydro power plants located in Africa. Scholz (2012) built upon the work by Czisch (2005) and created the model REMix. They analyzed electricity supply in Europe and North Africa and found an almost entirely RES based system design that allows for electricity supply at cost of 7 ct€ in case of large-scale transmission capacity extension. Further, they report that higher levelized cost of electricity (LCOE) of up to 8.3 ct€ will be likely if no transmission extension takes place. Despite the prevailing opinion that RES technologies will pave the way towards sustainable GHG mitigation, among the studies that explore feasible electricity systems designs to meet GHG reduction goals, certain reports studies suggest considering significant shares of coal or nuclear power in the electricity mix.

Research results by Odenberger and Johnsson (2010) consider up to 50 % of power generation being based on fossil-fueled technologies equipped with carbon dioxide capture and storage (CCS) facility in order to achieve GHG emission reduction targets by 2050. Nuclear power is also discussed as a suitable technological option to achieve 2050 GHG mitigation targets (Bauer et al., 2012; van der Zwaan, 2013). van der Zwaan (2013) pointed out that advances in the nuclear power fuel cycle decreased significantly and that further technological improvement is to be expected for the future. Bauer et al. (2012) reported that small economic benefits are provided by the extended use of nuclear power. Encouraged by the Fukushima disaster, Srinivasan and Rethinaraj (2013) analyzed risks of nuclear power plant operation. According to this paper, incorporating social costs would withdraw this technology from the options for achieving GHG emission reduction targets. The potential for large-scale use of CCS technology for supporting climate change mitigation is questioned in the literature. For example, Marshall (2016) pointed out that this technology is mainly used to extend the use of coal.

Providing flexibility options for the operation of electricity supply systems with high shares of RES based generation is often the subject of research on the integration of volatile power generation technologies. The review by Alizadeh et al. (2016) suggests, that flexibility is required on different time scales and can be provided by several options such as short-term and long-term storage technologies, demand side management and grid capacity expansion. Huber et al. (2014) studied flexibility requirements for electricity supply systems with significant shares of RES. As claimed by the authors of this study, up to 30 % of annual demand can be supplied by volatile RES generation without requiring additional flexibility measures. Furthermore they state that the future flexibility requirements mainly depend on three factors: the RES share, the generation mix and the balancing area size. A series of studies was conducted based on weather-driven modeling. This series initiated by Heide et al. (2010) analyzed the optimal generation mix for a 100 % RES based electricity supply in Europe. The generation mix was identified to include 55 % generation by wind power and 45 % generation by PV power. In a second study Heide et al. (2011) derived balancing needs for the electricity system from the demand and supply mismatches. These balancing needs time series were translated into storage demand in terms of energy capacity and conversion power. Weitemeyer et al. (2015, 2016) extended the model and took a more detailed look at energy storage needs. They claim, as opposed to Huber et al. (2014), that up to 50 % of demand can be supplied without requiring additional energy storage capacity when wind and PV is optimally deployed. For large-scale integration of RES with very high wind shares (≥80 %) the use of seasonal energy storage systems is beneficial. Bussar et al. (2015) found a 100 % RES based electricity system design to serve the electricity demand in the EU-MENA region by 2050. Electricity generation splits almost equally among PV (3,900 TWh/a) and wind power (3,700 TWh/a). The fluctuations of RES supply are balanced by three energy storage system technologies: pumped hydro storage (PHS), hydrogen storage and battery energy storage system (BESS). The RESTORE 2050 project investigated the potential of flexibility options (energy storage system (ESS), demand side management (DSM), etc.) and transmission system extensions for the successful integration of RES (Vogt et al., 2016). It was found that transmission system extensions support the integration of RES and in particular these are suitable to balance wind power generation on a spatial scale. The study also found energy storage system technologies are optimal for use in alignment with RES technologies deployment. Furthermore, the study reports that benefits for the European electricity system operation of using concentrating solar power (CSP) in North Africa equipped with a thermal energy storage are insignificant. The role of power-to-gas (PtG) technology in future electricity system designs was investigated by further research. In a study regarding future electricity in Germany, Jentsch et al. (2014) found 6 GW up to 12 GW of PtG based energy storage systems are being economically optimal for electricity supply based on 85 % RES. Belderbos et al. (2015) reported that PtG based long-term energy storage systems are useful for the integration of very high shares of variable RES.

Transmission system extension and in particular the extension of cross-border capacities is studied widely. In the context of integrating increasing shares of RES in the electricity supply system, transmission capacity extension is understood as the option to balance out variations of RES supply on a spatial scale. Fürsch et al. (2013); Fürsch et al. (2012) showed the benefits of large-scale transmission system extension for accessing high potential RES sites across Europe. According to research by Rodríguez et al. (2014), the European overall balancing demand that is required to cope with fluctuations of RES supply can be reduced through transmission capacity extension. Therefore, this work suggests to extend transmission capacities to multiples of the current capacities. Similarly, Schaber et al. (2012a) found out that transmission system extensions reduce ramping rates for balancing units and lead to more equal distribution of balancing needs across regions in Europe. The study by Becker et al. (2013) drew attention to the increased generation shares of wind power due to extended transmission capacity. The economic benefits of integrating electricity supply of Europe and North Africa is highlighted by Boie et al. (2016). The findings suggest that transmission capacity extensions are a key leverage to enable such scenarios. A second study by Bussar et al. (2016) analyzed variations of the electricity system designs with focus on the trade-off between energy storage systems and the transmission system. For very high shares of RES electricity supply they found an interdependency between transmission system extension and investments into long-term energy storage systems. Based on the series of weather-driven modeling initiated by Heide et al. (2010), Steinke et al. (2013) systematically studied the need for balancing power as function of transmission system extension and energy storage deployment. The study suggests, that ESS and transmission system are partially interchangeable. Dispatchable balancing capacity is still required even if transmission system extensions take place and ESS are considered for balancing tasks. Furthermore Steinke et al. (2013) pointed out that additional research on the transition towards RES based electricity supply would yield interesting insights.

Gils et al. (2017) used the electricity system model REMix to assess cost-optimal electricity system designs for different RES shares and different combinations of wind and PV power generation. They found that for a 100 % RES based electricity system, the cost will be in the range of 10.5 ct€ to 12 ct€. Findings by Bussar et al. (2016) underlines the identified range of cost and suggest similar cost for RES based electricity supply by 2050. According to the authors, LCOE will range between 9.7 ct€ and 12 ct€. In contrast, other studies found significant lower LCOE for RES based supply by 2050. Delucchi and Jacobson (2011) report analyzed a scenario that results in similar LCOE compared to todays cost. Similarly, Czisch (2005) suggested that cost of 100 % RES based electricity supply won't exceed present cost too much. REMix was used by Scholz (2012) to analyze electricity supply in Europe and North Africa. In this study, cost of electricity supply were reported that range from 7 ct€ to 8.3 ct€. To conclude, LCOE reported by different studies that use distinct models, analyze different scenarios, and apply contrasting parameters vary.

While most of the studies analyzing electricity system endeavors towards a snapshot in the future (i.e. the year 2050), some studies focus on the transition towards these aspirations. The idea originates from linking long-term investment planning models with short-term power system operation models and was conducted for example by Haller et al. (2012a,b); Ludig et al. (2011); Poncelet et al. (2016a); Nahmmacher et al. (2016). These studies aim to provide pathways towards long-term climate mitigation targets under consideration of short-term fluctuations of intermittent RES electricity supply. Due to the high model complexity that is induced by this type of modeling, a reduction regarding the representation on short-term time scale was introduced. These complexity reductions either resulted in using time slices (Haller et al., 2012a; Ludig et al., 2011) or representative days (Nahmmacher et al., 2016; Poncelet et al., 2016a) to account for short-term variability. Haller et al. (2012b) found that transmission grid extension and energy storage system deployment facilitate in achieving -70 % up to -90 % of GHG emission reduction at moderate cost increase. Such a scenario would significantly change the regimes of electricity supply. According to Haller et al. (2012b), for example, central European countries would import 30 % to 60 % of their annual electricity demand through the extended European transmission system. Depending on the details of the methodology to represent short-term variability, characteristics of intermittent RES based power supply are not covered entirely (Haller et al., 2012a). In particular, appropriate representation of ESS is difficult by such a methodology. Variability of RES based power generation can statistically be reflected by an approach of representative time steps, but the information about its chronology is lost (Poncelet et al., 2016a). This is a crucial information for planning of long-term ESS operation such as PtG based energy storage systems. Kotzur et al. (2018) evaluated time series aggregation methods for the application in energy system models. According to this study, well-chosen aggregated time series are suited to represent variability of fluctuating power generation in terms of energy system planning. Planning of energy systems that incorporate energy storage systems at large-scale and in particular long-term (seasonal energy storages) is not possible based on aggregated time series.

To sum up the findings of the presented studies it is evident that EU GHG reduction targets for 2050 can be met. Most of the studies agree that electricity generation based on RES technologies is the most sustainable option for future electricity supply compliant with climate change mitigation goals. The resource potential of wind and solar energy is sufficient to cover the electricity demand by currently available power generation technologies. Among electricity from RES technologies, wind power will have largest shares on total generation. According to the surveyed studies, its generation will cover 55 % up to 80 % of the entire electricity demand. The minority of studies consider nuclear and coal based power generation by 2050. In general, it can be said, that transmission extensions are beneficial for accessing high potential RES sites and realize electricity supply based on RES at moderate cost. Energy storage systems (ESSs) are needed for the large-scale integration of RES generation technologies to balance fluctuations of supply. Most studies report a share of RES of 50 % to 80 % when ESS technologies are required for the operation of the electricity system with moderate curtailment of RES. The studies further agree on a moderate cost increase for electricity supply compliant with GHG reduction targets for 2050.

Despite the presented research, there is currently a lack of research on decarbonization pathways for the power system towards demand and GHG emission targets in 2050. Further analysis have to be carried out to provide knowledge on a cost-efficient transition towards decarbonization of the power system. According to Pfenninger et al. (2014) and Després et al. (2015), a suitable modeling approach is required that, on the one hand, covers long-term power system planning up to 2050 and, on the other hand, is suitable to represent short-term operation of power supply. The latter is particularly gaining importance with increasing shares of RES and the application of energy storage system. Currently, studies that analyze decarbonization pathways for electricity supply systems inadequately showcase the last steps towards 100 % RES based electricity supply in detail. At this point, long-term energy storage system come into play that require more detailed representation on temporal scale than it is currently incorporated in available studies.

Thus, this thesis aims to provide new insights on cost-optimal decarbonization pathways until 2050 and therefore contribute necessary methodical improvements to energy system modeling. The definition of decarbonization pathways includes capacity planning, temporal and spatial allocation of considered power system technologies as well as identifying needed power system flexibility technologies. The focus of this thesis is to assess feasible electricity supply system designs and transition pathways towards deep decarbonized European electricity supply. In particular, this includes assessing designs of electricity systems incorporating long-term energy storage system technologies to cope with seasonal variations of highly RES based electricity supply. Therefore, this thesis looks at electricity supply at high temporal resolution aside from the long-term perspective until 2050 and responds to the following research questions.

RQ 1 How can decarbonization pathways of Europe's electricity supply system effectively be modeled?

- RQ 1.a What are the requirements for modeling short- and long-term effects of such a pathway?
- RQ 1.b What technical components and economic characteristics have to be considered to meet these requirements?

RQ 2 What is the techno-economically optimal decarbonization pathway for meeting EU GHG emission targets within the electricity supply sector by 2050?

- RQ 2.a What does a decarbonization pathway for Europe look like regarding generation capacity and supply mix, energy storage systems, transmission system, and cost of electricity supply?
- RQ 2.b What is the impact of decarbonizing Europe's electricity supply on regional level?
- RQ 2.c How do changed input parameters and boundary conditions affect results?

The second research question (RQ 2) seeks for pathways of electricity system transformation leading to effective GHG reduction which fulfill goals set for 2050. In answering RQ2 an electricity system optimization model is used that is capable of revealing least-cost electricity system designs by determining investments into electricity system infrastructure based on the operation power plants, energy storage systems, and the transmission system. Results obtained from the model calculations must fulfill certain requirements. The model results need to describe a consistent pathway from the present status of electricity supply until the year 2050. This pathway shall comprise of successive steps of decommissioning and investments into electricity system infrastructure in periods of five years. The model-based results for these steps have to detail the power system operation at an adequate spatio-temporal scale such that relevant features of electricity supply are sufficiently covered. The spatial resolution needs to be sufficiently detailed to represent the spatial features of demand and supply patterns. In particular, variations in generation potential of RES must be represented. On temporal scale the resolution must be thoroughly detailed to consider for the operational characteristics of the electricity supply. This specifically applies to the representation of RES power generation technologies and the operation of energy storage systems. Therefore, a temporal resolution of results data of at least one hour is required. Furthermore, results must include all feasible technological options for carbon-constrained electricity supply in order to find the cost-optimal electricity system design. In order to consider for uncertainty of input parameters, the electricity system design resulting from the model calculations needs to be tested regarding parametric uncertainty.

Research question one (RQ 1) asks for details of the modeling approach. This research question is answered with a mathematical formulation of the applied energy system model. The requirements for the modeling approach can be derived from the requirements that are defined for the the model results. In a nutshell, the applied energy system model needs to have a decent spatio-temporal resolution, a sufficiently detailed coverage of electricity system infrastructure, the ability to reveal least-cost electricity system designs based on optimal operation, and an approach to represent a pathway of successive electricity system restructuring. Furthermore, the implementation of the electricity system model into software needs to available for the author and needs to be computable in a decent timeframe.

1.2 Approach and scope

To answer these research questions, an analysis of Europe's power supply system transformation is conducted. In 5-years increments the techno-economically optimized power system design is determined that meets the entire electricity demand and adheres to GHG reduction targets. Determining the optimal power system design refers to plan power system technologies' capacity and its operation for future circumstances in a least-cost manner. Hence, along a pathway of GHG emission reduction targets for the power sector as discussed by European Commission (2011a), successively, the adaptation of the power system is studied. A series of 5-years increments is used to evaluate investments and decommissioning in the electricity system. Thereby, the electricity system encompasses of power plants, energy storage systems, and the transmission system. While EU emission reduction targets relative to emissions of 1990 levels are applied, the spatial scope of this study includes member countries of the EU and European Network of Transmission System Operators for Electricity (ENTSO-E)[1]. Thereby, the analysis follows the goals of energy policy: security of supply, affordability, and sustainability (cf. Figure 1.1).

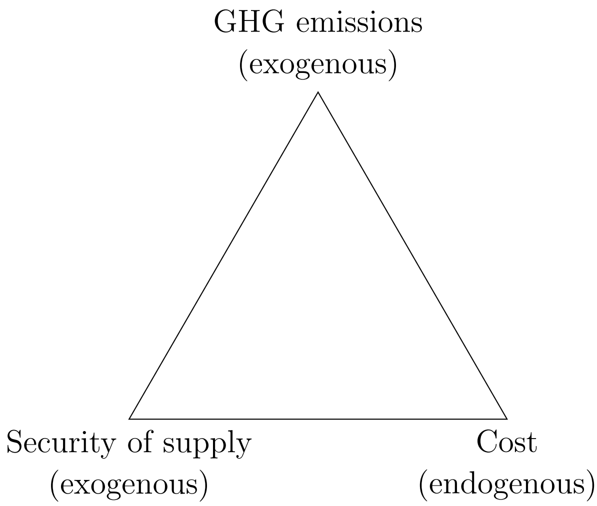


Figure 1.1: Triangle of energy policy goals

Security of supply is translated to serving electricity demand at 100 %. Affordability of electricity supply is reflected by cost which is the objective to be minimized while assessing feasible electricity designs. The latter aspect of sustainability refers to GHG emissions within this study. Greenhouse gas emissions are provided as boundary condition to the model.

A broad range of aspects is related to the transformation of the power supply system in Europe. Among others these include a diverse set of power generation technologies, a large number of individual power plant sites and power system equipment, different national regulatory frameworks, and different societal perception and expectations of the transformation

[1] These include Albania, Andorra, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Kosovo, Latvia, Liechtenstein, Lithuania, Luxemburg, Macedonia, Monaco, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, San Marino, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Vatican City State

of power supply. For example, the number of power plants within only four countries of Europe (Denmark, France, Germany and Poland) adds up to almost two million power plants. Representing each single unit would result in high complexity. Other aspects add further complexity that cannot be modeled effectively and, thus, appropriate reductions are needed. In order to reduce the diversity of power system technologies, the analysis considers a certain set of technologies comprising of conventional power generation technologies (nuclear, coal, gas and hydro power), RES power generation technologies (wind and PV), ESS technologies (PHS, battery storage and PtG), as well as the cross-border transmission capacity. Among these technologies all are considered for capacity extension except for nuclear power, hydro power and PHS. Nuclear power phases-out according to remaining technical lifetime. Hydro power and PHS are only considered for refurbishment and consequently remain at constant capacity levels. The transmission and distribution grid infrastructure of an individual country is not part of this study. The reliability of power system operation (also referred as short-term) is tested by analyzing supply and demand balances on an one-hour basis. Power system service operating on sub-hourly time-scale (such as control or spinning reserve for frequency control) are not included in this study nor are its current market schemes reflected by the analysis.

As the analysis looks for the most economically optimal future electricity supply system designs, results underlie the influence of uncertainty related to several assumptions on technical and economic parameters of electricity system technologies. In order to cope with this uncertainty the thesis founds on a *base scenario* that is defined as the most reliable set of parameter assumptions. Therefore, inspired by the scenario development method of *intuitive logics* (Wright et al., 2013), the *base scenario* is accompanied by 12 other scenarios. The scenarios are used to test sensitivity of crucial or uncertainty parameters and study the impact of additional exogenous model constraints. Parameters that are varied in these scenarios are related to cost of RES technologies and ESS. Additional constraints, for example, are induced by studying a limit on transmission grid capacity extension.

In order to obtain unbiased results, purely reflecting the technical-economically optimal power system configurations for the upcoming three decades, implications from electricity market regimes, individual behavior of market participants and a detailed policy framework are not considered planning the future power system. The goal is to explore the space of technical feasible solutions aiming for a least-cost future power supply. Therefore, the analysis takes place from a system-planners point of view. Thus, the only energy policy that is included in this study are GHG emission reduction targets applied on the 5-years increments. Further policy regulation (i.e. RES support schemes or feedin tariff systems) are not considered but the study allows for a discussion of those concepts based on the obtained findings. Current electricity market regime structured into over-the-counter long-term supply contracts, day-ahead and intra-day trading, plus an additional market for control reserve and a cost compensation scheme for redispatch is not reflected in detail by this study. Adhering to the systems-planner view a perfect market is assumed that enables a technical-economically optimum untouched from implications of additional constraints induced by considering the electricity market in detail. Consequently, cost reported in this thesis do not include additional cost induced by a electricity market regime. As a consequence of neglecting the electricity market structure in the analysis, individual behavior of market participants (power plant operators, retailers, grid operators, customers) remains undiscussed. This exceeds the scope of this thesis by far, but is crucial for (re-)design of the power market system and regulatory frameworks.

To enable for such an analysis, the power system model European long-term energy system planning model (*elesplan-m*) is developed. It is based on state-of-the-art energy system modeling techniques and builds on a series of model development at the Reiner Lemoine Institut (RLI) (Pleßmann et al., 2014; Möller et al., 2014; Breyer and Müller, 2013). *elesplan-m* is implemented based on linear programming and combines investment and dispatch planning. In distinction to long-term energy system planning models such as LIMES-EU+ (Haller et al., 2012a), that uses inter-temporal modeling across the planning intervals, *elesplan-m* is myopic beyond each planning period. In other words, the decarbonization pathway is assessed successively by analyzing one planning period after another. For each planning period a so-called snapshot planning model is applied to determine a new electricity system design. This snapshot model, that is highly inspired by Czisch (2005) and Aboumahboub et al. (2010), analyzes one year of electricity system operation and determines required investments based on this. The choice of the modeling approach is described in larger detail in Ch. 3.

1.3 Structure

The thesis is structured into eight chapters. Chapter 2 – *Background on electricity supply* provides an overview on European electricity supply, related GHG emissions and ambitions to reduce these. The methodological approach to model the transition of Europe's power system towards decarbonized supply by 2050 is presented in Chapter 3. Based on a literature review of available energy system models, the approach of newly developed power system model *elesplan-m* is described. Subsequently, scenarios are defined and its model parameters are described in Chapter 4. The following two chapters present results of conducted analysis.

Chapter 5 outlines results of the *base scenario* in detail. It presents capacity of electricity system technologies, its annual generation, capacity extension of transmission system and ESS, cost of power supply and spatial aspects of future power supply. This is followed by a look at sensitivities and alternative pathways in Chapter 6. In Chapter 7, limitations of the conducted study are highlighted and findings are discussed and put into the greater context. The last chapter provides a summary, gives answers to research questions and finally compiles a set of recommendations regarding the implementation of decarbonization in the European electricity sector as well as further research needs.

2 Background on electricity supply

This chapter provides an overview on electricity system technologies and current European electricity supply. The first section describes available power generation, energy storage systems and transmission system technologies. The second part presents the status quo of power supply of Europe including related GHG emissions and climate change mitigation policy.

2.1 Electricity system technologies

The first chapter of Exposito et al. (2016) describes principles of electric energy systems. Principles of electricity generation, energy storage systems, and the electricity grid are recapped here. It mainly focuses on presenting various technological options for electricity generation and energy storage, as well as how the electricity grid integrates power plants, electricity consumers and energy storage systems.

2.1.1 Power generation

Power generation describes the process of converting primary energy to electricity (Breeze, 2014). Sources of primary energy are fossil fuels (coal, natural gas, oil), mineral fuel (uranium), solar energy, wind energy, water, biomass and geothermal energy (renewable energy sources) (Quaschning, 2016b). Thereof, wind energy, flowing or falling water, and biomass are actually converted forms solar energy. In terms of electricity generation it makes sense to treat these as sources of primary energy. Several power generation technologies exists to convert these types of primary energy to electricity (Breeze, 2014; Quaschning, 2016b).

Fossil fuels are converted to electricity via combustion and subsequently a steam-electric process (coal, natural gas) or an internal combustion process (natural gas and oil). Energy from the uranium is converted by a steam-electric process as well. Coal has two types of fuels;

lignite which is, in general, cheaper but has a low heat value and consequently is not typically transported over long distances and hard coal, which is due to its higher heat rate, in the global trade market (Ekawan and Duchêne, 2006). Coal power generation technologies can be distinguished best by the combustion process that is used along with a turbine's process parameters (mostly pressure and temperature) (Schröder et al., 2013). Pulverized coal can be combusted under subcritical conditions which refers to a pressure below 221 bar. This achieves the lowest efficiency among coal power generation processes. Supercritical and ultra-supercritical steam processes exceed this pressure and reach steam temperatures of 700 °C. Consequently, a higher conversion efficiency is achieved. Using the integrated gasification combined-cycle (IGCC) process provides potential for further efficiency increase (Minchener, 2005). High emissions of coal power based electricity generation can be reduced with the oxy-fuel process (Buhre et al., 2005). In this process, the combustion process is fed by pure oxygen instead of ambient air. Chemical energy of natural gas and oil can be converted to electricity by two types of processes: stand-alone combustion and combustion plus a subsequent steam turbine process. The first type of process is typically used in open cycle gas turbines (OCGTs), operates at lower efficiency, but requires less investment. The process extended by a steam process is implemented in combined cycle gas turbine (CCGT) power plants achieves higher efficiency, but requires almost double the investment cost compared to OCGT (Kosmadakis et al., 2013). Nuclear power generation nowadays mostly refers to a system that uses nuclear fission for heat generation and a subsequent steam process to generate electricity which is similar to the steam process of coal power plants. Nuclear fission is this terms means to convert uranium U^{235} to less radioactive uranium U^{238} while releasing three electrons that account for the heating process (Breeze, 2014). Breeze (2014) provides further details on conventional power generation technologies.

Solar energy can be harvested by two general types of technologies: photovoltaics (PV) and concentrating solar power (CSP). Photovoltaics power converts energy from sunlight to electricity by using the photovoltaic effect: a photon absorbed by the semi-conductor material of a solar cell excites an electron (Green, 1982). Through preparation of the semi-conductor material charge carriers are separated and can be used in an external electrical circuit. Typically, a grid connected inverter converts direct current (DC) to alternating current (AC) and supplies power to the grid (Teodorescu et al., 2011). Chaar et al. (2011) describe four major PV technologies: crystalline, thin film, compound and nanotechnology. Concentrated solar power (CSP) uses thermal energy of sunlight to drive a steam process or support gas combustion process. Main large-scale technologies are tower (point focusing) and parabolic trough (linear focusing) concepts (Reddy et al., 2013). Typically, CSP is equipped with a thermal energy storage in order to smoothen the generation profile and allow for operation during night and cloudy days (Kuravi et al., 2013).

Wind energy converters, often also called wind turbines, make use of kinetic energy of flowing air masses. A rotor extracts energy from the wind and converts it to mechanical energy which used to generate electricity by a generator connected to the rotor. A variety of rotor concepts for wind energy turbines exist. The preferred technology is a horizontal axis three-blade rotor design with different generator concepts (Gasch and Twele, 2011).

Energy contained in falling or flowing water and tidal or wave energy can be harvested as well. Hydro power generation refers to a set of technologies that use potential or kinetic energy contained in water. Conventional hydro power mostly refers to dammed hydro power that uses potential energy of water. Run-of-river technology access energy in the water through extracting its kinetic energy. Furthermore, small-hydro often is categorized separately (Ardizzon et al., 2014). Turbine technologies are distinguished by two principle types: impulse turbines (i.e. pelton turbine) and reaction turbines (francis and axial turbines) where the latter uses the fluids pressure additionally to the kinetic energy (Ardizzon et al., 2014). Pumped-hydro storage is a technology closely related to hydro power but will be explained later (see Section 2.1.2). Related to hydro power generation are tidal power that converts energy obtained from tides (Sleiti, 2017) and wave power that use wave's motions to generate electricity (Rodrigues, 2008).

Power generation from biomass has three primary conversion processes: direct combustion, gasification and pyrolysis (Evans et al., 2010). In regards to decentralized electricity supply, biomass gasification is the most promising option for biomass power generation (Asadullah, 2014). At locations with appropriate potential high-temperature geothermal energy can be used to generate electricity for example via a organic ranking process (Vélez et al., 2012).

The conventional power generation technologies coal, natural gas and nuclear (often hydro power is included as well) provided most of the electricity that was consumed in the last decades (Quaschning, 2016b). All these technologies are characterized by a high availability and dispatchability to a certain degree. In other words, power generation can be controlled in order to follow the patterns of electricity consumption (Kehlhofer et al., 2009). Operation of these technologies is determined by its cost and technical characteristics. (Exposito et al., 2016). Coal-fueled power generation and nuclear power, both with high investment cost and relatively low fuel cost, supply base load (minimum demand occurring) in order to achieve high full-load hours. Hard coal and natural gas power plants (in particular CCGT) provide mid-load power. Thus, this allows for the supply of electricity demand on regularly occurring events, i.e. day-night variations. In particular gas turbines (OCGT) supply electricity only at peak demand times as this type of technology allows for sharp power generation ramps (Joskoaw, 2011). In addition, this technology relies on low investment cost and high fuel cost (due to low efficiency) which requires higher prices compared to coal or nuclear power

(Exposito et al., 2016). Hydro power with a water reservoir is also a dispatchable source of electricity. It has zero fuel cost but relies on the availability of water in the reservoir. Typically, this type of hydro power is used to supply electricity in mid and peak load times. Run-of-river power generation is not equipped with a reservoir or a water storage and thus depends on the available water flow (Paish, 2002). Hence, this technology is not dispatchable. Power generation from geothermal and biomass can follow demand as well (Tester et al., 2007). For power generation from biomass a biogas storage enables for dispatchable power supply (Hahn et al., 2014). Remaining RES technologies' power generation potential, similarly to run-of-river hydro power, highly depends on weather conditions at the site of the power plant. While run-of-river hydro power faces seasonal variations of water availability, PV and wind power include variations up to sub-hourly scale (Quaschning, 2016b). Photovoltaics power relies on available direct and diffuse irradiation and, thus, in principle supplies power superimposed by a diurnal pattern with an additional seasonal variation (Widen, 2011). Wind power generation analogously directly depends on the wind speed. The variability of wind speed follows a stochastic pattern overlayed by an annual variation (Widen, 2011). PV and wind power supply are negatively correlated to a certain extend – in particular on monthly scale (Widen, 2011). In comparison to PV technology, CSP can be more flexible when it is equipped with a thermal energy storage (Denholm and Mehos, 2011).

Power generation technologies have different associated GHG emissions and, hence, various impact on climate change. Figure 2.1 illustrates the range of GHG emissions and average GHG emissions for major power generation technologies (Weisser, 2007). Fossil-fueled technologies contribute highest emissions by far. Lignite based power generation on average is related to GHG emissions of 1,100 g CO_2eq/kWh. Associated GHG of gas-fueled power generation add up to approximately 600 g CO_2eq/kWh. Renewable energy technologies and nuclear power have significantly lower emissions. Those are on average below 20 g CO_2eq/kWh for hydro, nuclear and wind power. Emissions related to power generation by biomass and PV range between around 60 g CO_2eq/kWh to 70 g CO_2eq/kWh.

Electricity generation is associated with external costs which include all cost related to the fuel cycle that are not part of the electric utility cost structure (Roth and Ambs, 2004; Larsson et al., 2014). The fuel cycle describes all processes required to generate electricity from a specific resource including extraction, preparation, transport, storage, processing, conversion, and disposal. Despite any uncertainties external cost can be determined as 10 ctEUR/kWh for coal power generation technology, 8 ctEUR/kWh for gas technologies (Roth and Ambs, 2004) and 0.5 ctEUR/kWh for nuclear power generation (Larsson et al., 2014). Renewable energy sources technologies have external cost associated as well. In a

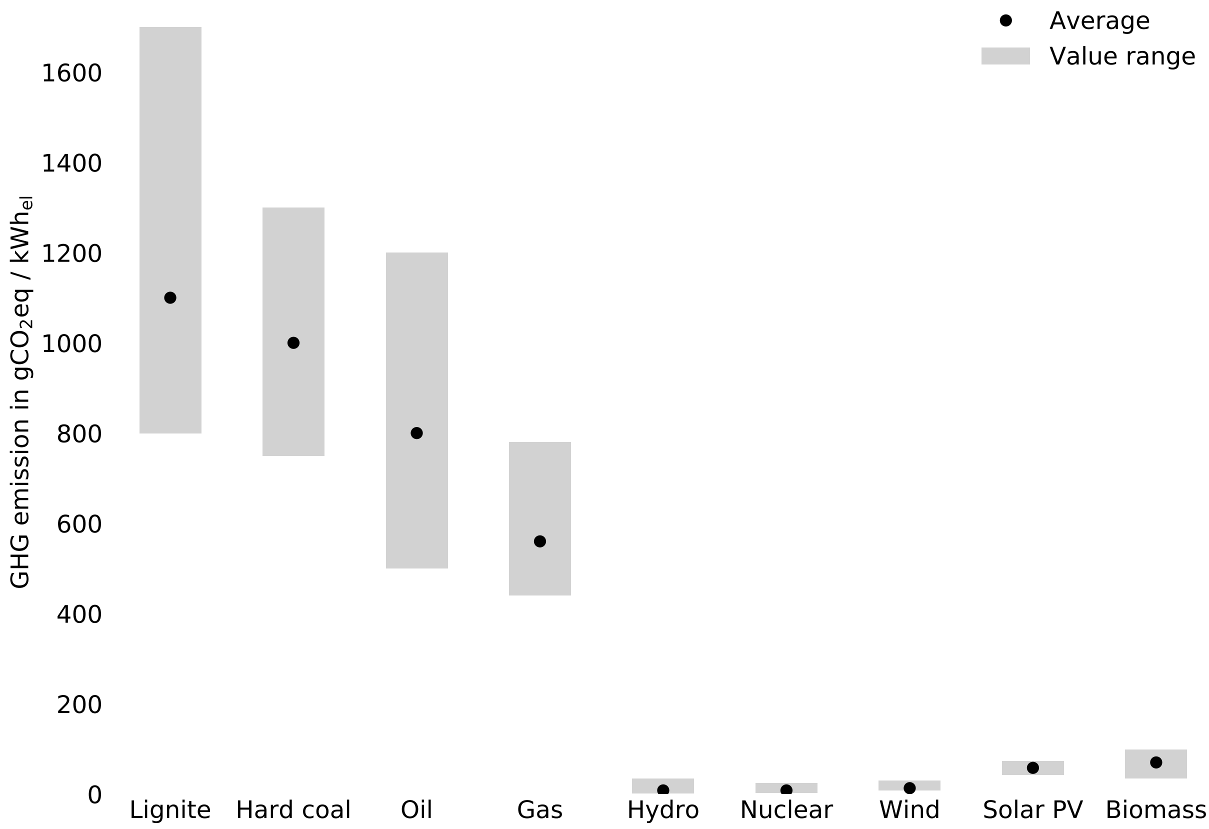


Figure 2.1: Life-cycle GHG emissions of power generation technologies in g of CO_2-equivalent (gCO_2eq). Gray areas indicate range of emissions of each power generation technology. Based on data by Weisser (2007).

descending order these add up to 2 ctEUR for wind power, 1.2 EUR for biomass, 1 ctEUR for PV power and 0.5 ctEUR hydro power (Roth and Ambs, 2004).

2.1.2 Energy storage systems

Energy storage systems are used to shift power on the axis of time. Various reviews on technologies and their application are available in literature (Díaz-González et al., 2012; Luo et al., 2015; Beaudin et al., 2010; Hadjipaschalis et al., 2009). Seven principles of storing electrical energy in energy storage systems are used: as gravitational potential energy with water reservoirs, as mechanical energy in compressed-air, as electrochemical energy in batteries and flow batteries, as chemical energy in fuel cells, as kinetic energy in flywheels, as magnetic field in inductors, as electric field in capacitors (Díaz-González et al., 2012). These principles of storing electrical energy are applied by a set of ESS technologies: pumped-hydro storage, compressed-air CAES, battery (thereof various types), flow battery energy storage system, hydrogen-based (additionally extended by PtG (Schiebahn et al., 2015)), flywheel, superconducting magnetic and supercapacitor energy storage systems (Díaz-González et al., 2012; Luo et al., 2015).

Pumped-hydro storage (PHS) uses gravitational potential energy to store energy. This energy storage system is charged by pumping water from a lower water reservoir to an upper water reservoir consuming electricity from the grid. Discharging or releasing energy is realized by using water from the upper reservoir to drive turbines and generate electricity (Deane et al., 2010). Pumped-hydro storage systems use reversible pump/turbine technology that provides pumping and turbine operation in one unit (Rehman et al., 2015). The compressed-air energy storage system CAES converts electricity to compressed-air that is stored in an underground cavern or tank. In times of electricity demand, this compressed air supplies a gas turbine process typically fueled with natural gas (Raju and Khaitan, 2012). This replaces the compressor for air in the gas turbine process and thus increases efficiency of the gas turbine process. The technology is further developed in order to save the dissipating heat during air compression. The advanced-adiabatic compressed-air energy storage (AA-CAES) saves heat from the compressor in a thermal energy storage and later supplies it to the gas turbine process. This requires no longer to supply additionally natural gas when releasing energy from the compressed-air energy storage (CAES) system but at the same time limits the storage cycle duration (Bullough et al., 2004).

Various technologies of battery energy storage systems (BESSs) exist. Though, they principle of energy storage remains similar. Electricity is converted to electrochemical energy contained in multiple cells of a battery that are connected in series and/or in parallel. Each cell comprises of two conductor electrodes (cathode and anode) wrapped by an electrolyte and builds a electrical circuit with an external generator or load. The electrolyte is isolated from the environment through its containment in a special sealed container. The electrolyte allows for ion transport from the cathode to the anode (during charge and vice-versa during discharge) whereas electrons are transported through the external circuit where its electrical potential is used. A battery energy storage system is equipped with a battery management system that takes control of the storage system operation. In other words, it, manages charging and discharging (Díaz-González et al., 2012). Four major technologies are relevant in terms of power system operation with RES generation: lead-acid (Pb), nickel-cadmium (Ni-Cd), Sodium-Sulphur (NaS), Lithium-ion (Li-ion), with each having several subtypes (Díaz-González et al., 2012; Luo et al., 2015; Beaudin et al., 2010). Those are distinguish by materials used for anode/cathode and electrolyte, operation temperature, self-discharge, energy density, charging time, toxicity, and other aspects (for details see Díaz-González et al. (2012); Luo et al. (2015); Beaudin et al. (2010)).

A similar approach to BESS are flow battery energy storage systems – often also called redox flow batteries. Their setup comprises of two tanks with different aqueous electrolytic solutions, a stack of cells (connected in series and/or in parallel), and a pump system to transport the electrolytes. During charge and discharge the two electrolytes are pumped into the cell stack and change their oxidation level by consuming or releasing electrical energy. The oxidation/reduction reaction is realized by a ion selective membrane that is contained in the cell. Three technologies of flow batteries are available that are most distinct by electrolytic solutions. Vanadium redox flow batteries have two types vanadium at different oxidation level. Zinc-bromide batteries have zinc as one electrolyte and bromide as the second electrolyte. The third flow battery technology called polysulphide–bromide flow battery uses a sodium-bromide and a sodium-polysulphide electrolyte. Among these different types of flow-based battery concepts, material of membrane, efficiency, energy density, and lifetime vary. Nevertheless, a common factor of all these technologies is that the energy capacity is easily scalable by increasing the size of electrolyte tanks. Even changing the rated power is relatively easy by installing a large stack of cells (Díaz-González et al., 2012).

Hydrogen-based energy storage systems can be another option to store electricity. These system comprise of an electrolysis unit, a hydrogen storage, and typically a fuel cell to re-electrify produced hydrogen. Alkaline electrolyzers (AEL) and polymer electrolyte membrane (PEM) electrolyzers are most common technologies for the electrolysis process (Rashid et al., 2015). Hydrogen storages can be realized as high pressure gas storage, solid material storage such as metal hydrides, or by liquefaction. Available fuel cell technologies comprise PEM, alkaline, molten carbonate, and solid oxide fuel cells. Schiebahn et al. (2015) propose to extend the concept of hydrogen based energy storage systems by further converting hydrogen from electrolysis to synthetic methane (also called synthetic natural gas (SNG)). This is realized by using the sabatier process that converts hydrogen and additional CO_2 into methane. This additional process step has a large impact on the efficiency, but produces gas that can be stored easier compared to hydrogen (Schiebahn et al., 2015; Götz et al., 2015). Taking large-scale use of PtG into account, CO_2 supply is an important secondary aspect. The sabatier reaction requires $0.1975\,\mathrm{kg_{CO_2}/kWh_{CH_4}}$ (Reiter and Lindorfer, 2015). Ideally, CO_2 supply has a sustainable origin, is available at a low cost, with low energy demand, and is available in a high purity quality (Reiter and Lindorfer, 2015). Potential sources according to Schiebahn et al. (2015) are

- CO_2 from fossil power plants
- CO_2 from biomass
- CO_2 from industrial processes

- CO_2 from ambient air

Sustainability of the CO_2 source has to be considered. A non-biogenic CO_2 source causes net CO_2 emissions that contradict the goals of climate change mitigation. CO_2 of fossil-fueled power plants and industrial process have high potential (Brownsort, 2013), but induce net emissions too. Available sustainable sources of CO_2 for PtG are biogas plants and capturing from ambient air (Belderbos et al., 2015). Synthetic natural gas can be stored in abundant underground gas storage capacity and later used by existing gas power plant infrastructure to generate electricity.

Flywheel energy storage systems consist of rotating mass accelerated by an electric motor. The reverse process of discharging is realized when the motor acts as generator and decelerates the rotating mass. Supercapacitor energy storage systems, also called double-layer capacitors, combine features of classical capacitors and battery energy storage systems. These comprise of two conductor electrodes, an electrolyte and a porous membrane separator. Two electrostatic fields are generated at the interface between the electrolyte and each of the conductor electrodes that store the energy (Díaz-González et al., 2012).

Superconducting magnetic energy storage systems makes it possible to store energy in a magnetic field by inducing a DC in a large superconducting coil at cryogenic temperature. Typical operational temperatures are between 5 K (low temperature) and 70 K (high temperature). Thus, the cryogenic cooling system is a central component of this storage technology (Díaz-González et al., 2012).

The above presented ESS technologies in general provide the same functionality: shift power on the axis of time. Regarding their potential application, energy capacity, nominal power, time of discharge at rated power, and efficiency are the most characterizing parameters. Figure 2.2 presents ESS technologies by the nominal power and energy capacity. The illustration builds on the data collected in a review by Luo et al. (2015). Based on investigated realized ESS projects, areas of operation and application are determined that are highlight by outlined and semi-transparent colored areas in Fig. 2.2. Diagonal dotted gray lines in the figure indicate discharge time when the storage is discharged at rated power from state of charge (SoC) of 100 %.

Energy storage system technologies can be categorized according to their charge/discharge time at rated power (Luo et al., 2015) and, thus, certain suitable applications result. Supercapacitors, flywheels and superconducting magnetic energy storage (SMES) typically operate below one-hourly time scale. Lead-acid, CAES, Li-ion, NiCd, ZnBr and PSB energy storage system have a dicharge time a rated power of 1 h up to 10 hours. Remaining ESS

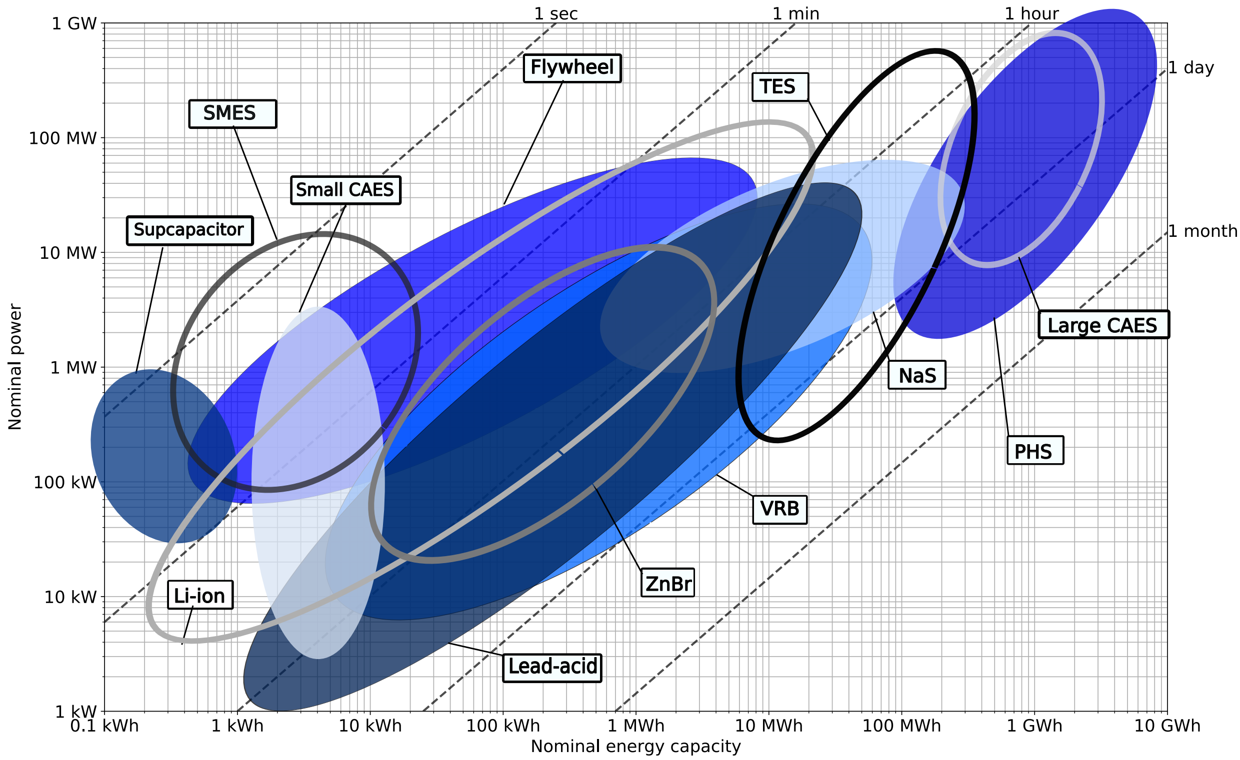


Figure 2.2: Energy storage system technologies distinguished by energy capacity and nominal power. Abbrevations used in the figure: compressed-air energy storage (CAES), flywheel energy storage system (FES), lithium-ion (Li-ion), sodium-sulphur (NaS), nickel-cadmium (NiCd), pumped hydro storage (PHS), superconducting magnetic energy storage (SMES), thermal energy storage (TES), vanadium redox flow battery (VRB), Zinc-bromide (ZnBr). The figure is inspired by and data is taken from Luo et al. (2015).

technologies have a nominal discharge time of over more than 10 hours up to 1 day. These are PHS, vanadium redox flow batteries, hydrogen, and PtG energy storage systems. CAES depending on size could also have minimum discharge time of above ten hours. The same applies for PHS and vanadium redox flow batteries and vice-versa. There are operating PHS projects with nominal discharge time around 8 hours (Beyer, 2009).

Applications of energy storage systems in power systems with intermittent supply are fluctuation suppression, low voltage ride through, voltage control support, oscillation damping, spinning reserve, load following, peak shaving, transmission curtailment, time shifting, unit commitment, and seasonal storage (Díaz-González et al., 2012). The last six applications are the most relevant in the context of this thesis. Suitable for these applications are energy storage system technologies of nominal discharge time equal to or greater than one hour. These are battery energy storage systems (lead-acid, Li-ion, NiCd, NaS), redox flow batteries (vanadium, zinc-bromide and polysulphide-bromide), PHS, CAES, hydrogen energy storage, and in particular PtG energy storage systems.

2.1.3 Transmission and distribution system

Power plants, electricity consumers and energy storage system are connected through the electricity grid. The electricity grid is hierarchically structured into several voltage levels as illustrated by Figure 2.3. Different voltage levels are connected via transformers that are located in substations. Typically, grid levels of nominal voltage greater than 220 kV are ascribed to the transmission system. Electricity grid levels of lower nominal voltage are summarized as the distribution system. The transmission system in principle is designed to deliver electricity over large distances from generation sites (i.e. large-scale power plants) to centers of electricity demand (i.e. larger cities). The high operating voltage enables for efficient transmission of electricity at low losses.

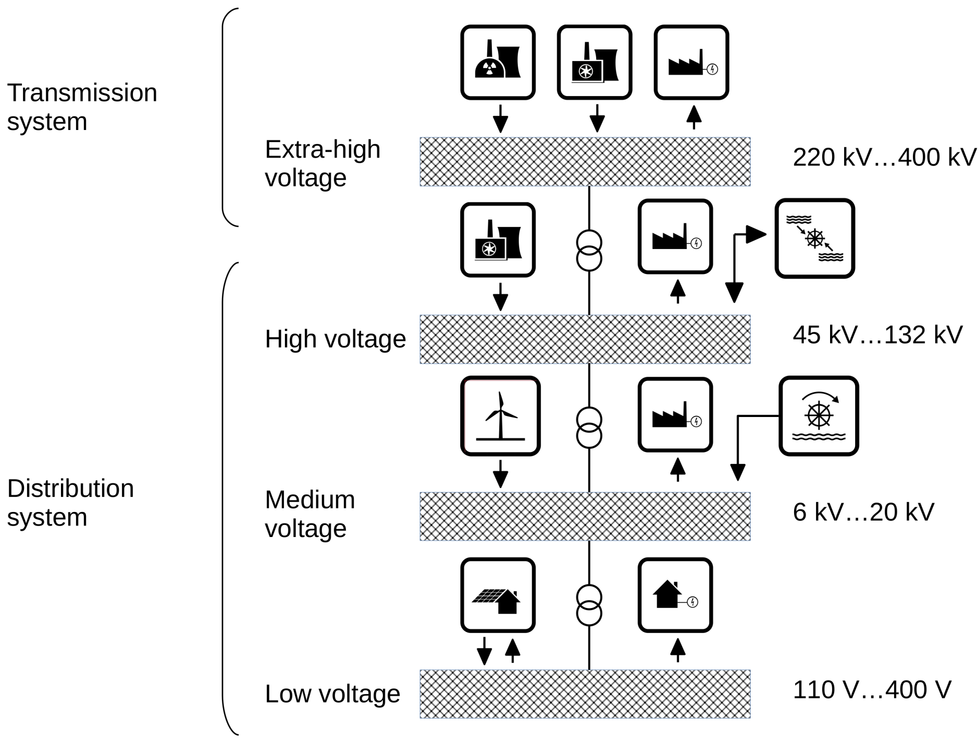


Figure 2.3: Structure of the electricity supply system. Various voltage levels that typically exist including power plants and consumers that are connected to different voltage levels. The illustration and in particular the distinction between the transmission and distribution system along voltage levels is inspired by (Exposito et al., 2016).

Large-scale power plants of several hundred megawatts nominal power such as nuclear or coal power plants are directly connected to the voltage levels of the transmission system, as well as large industrial consumers. The distribution system comprises of high, medium and low voltage levels. Coal power plants, large-scale gas power plants as well as large-scale hydro power plants and pumped-hydro storage system are connected to the high voltage level. Various consumers of industry and production are connected to this level as well. The medium voltage level connects medium-scale consumers and medium-scale power plants such as gas power plants, wind power plants, hydro power plants and utility scale solar PV power plants. Last, the low voltage grid, is mainly designed to supply residential and retail consumers. In addition, small scale power generation units such as residential PV or small combined heat and power plants are connected to this grid level (Gonen, 2011; Buchholz and Styczynski, 2014).

As this thesis analyzes the European electricity supply in the future, it focuses on the role of the transmission grid. This grid layer also interconnects electricity grids of several countries via cross-border capacities. The transmission grid comprises mainly of AC transmission lines operating at different voltage levels that range from 220 kV to 400 kV (Lewin et al., 2009). Transmission lines can be realized as overhead lines or underground cables, whereas the first technology is the most common and more cost-efficient solution (Gonen, 2011). A technology increasingly discussed in the past decade are high-voltage direct current (HVDC) transmission lines. Those, operating at higher voltage compared to normal AC transmission lines enable for bulk electricity transport of long distances at smaller losses (Kim et al., 2009).

2.2 Electricity supply in Europe

In the following, the status quo of electricity supply in Europe is described. Beginning with the demand for electrical energy, the generation mix and structure of power plants is presented. Related GHG emissions and the responding climate protection policy of the EU are described in the remaining sections.

2.2.1 Electricity demand and supply

By 2012, the cumulative net electricity consumption (calculated as generation plus imports minus exports and transmission and distribution losses) in Europe[1] adds up to 3,294 TWh/a (ENTSO-E, 2012b). On a temporal scale, the electricity demand follows daily, weekly and seasonal patterns as shown in Fig. 2.4. Consumption during winter is higher compared to summer months. In general, demand is higher during the day with two peaks. One peak of electricity consumption is close to noon. The second occurs in the evening and is more pronounced in the winter months. Furthermore, light vertical stripes highlight weekends in Fig. 2.4 where electricity demand is lower compared to workdays.

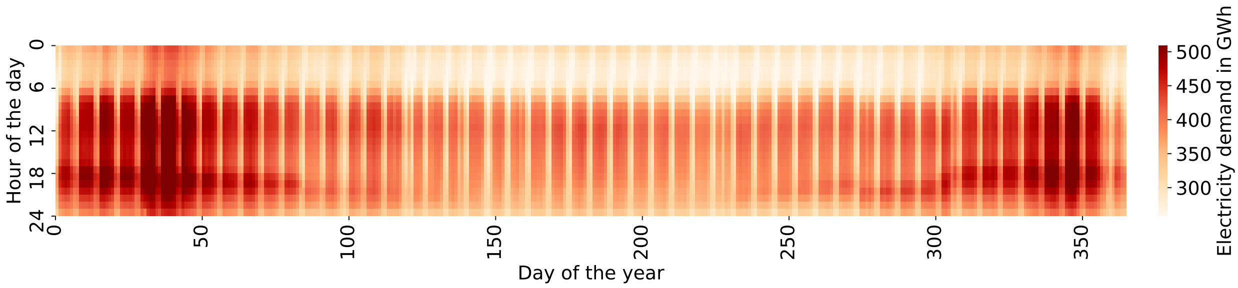


Figure 2.4: Daily and seasonal variations of cumulative European electricity demand in 2012 shown in GWh/h.

On a spatial scale, the electricity demand distributes unequally among European countries (see Figure 2.5). The annual electricity consumption of a country ranges from 3.1 TWh/a up to 540 TWh/a. The five most populated countries, Germany (540 TWh/a), France (490 TWh/a), United Kingdom (333 TWh/a), Italy (328 TWh/a) and Spain (267 TWh/a) have the highest annual electricity consumption and represent around 60 % of cumulative European electricity demand. Lowest electricity consumers are Kosovo (4.8 TWh/a), Albania (4.1 TWh/a) and Montenegro (3.9 TWh/a).

The electricity demand can be expected to grow in the next decades. According to Fürsch et al. (2013), by 2050, the European cumulative electricity demand adds up to 4,474 TWh/a (a detailed projection for each country in Europe is provided by Table A.1). On average, this equals an annual increase about 1 % per year. But, future development of electricity demand is uncertain. Attempts for efficiency increases in energy use are faced with growing economic

[1] which is defined as the union of member state of the EU and the ENTSO-E, see Section 3.3 for further details)

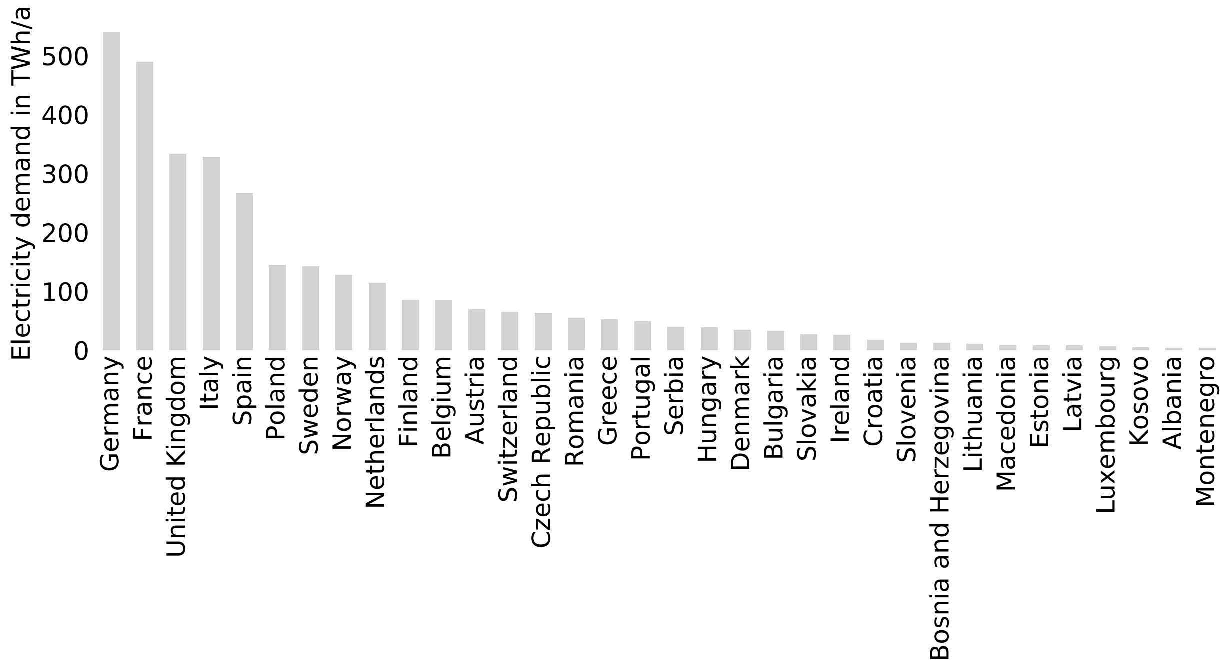


Figure 2.5: Spatially resolved electricity consumption of EU and ENTSO-E member countries in 2012. The figures bases on hourly and monthly demand data provided by ENTSO-E (2012a,b), except data for Kosovo and Albania that bases on EIA (2015).

development which typically leads to increase demands. Furthermore, the sectoral coupling of energy sectors and electrification of heat and mobility sector may triple the electricity demand by 2050 (Quaschning, 2016a).

The demand is covered by cumulative annual generation of 3,449 TWh/a [2] (EIA, 2015; EEA, 2012). With 1,622 TWh/a, almost 50 % of the generated electricity by 2012 in Europe is based on fossil fuels. This includes generation by coal power plants of 891 TWh/a, power plants fueled with natural gas of 616 TWh/a, oil-based electricity generation of 67 TWh/a, and 47 TWh/a supplied by other fuels (EEA, 2012). A quarter of annual electricity in Europe (862 TWh/a) is supplied by nuclear power. The remaining quarter of electricity generation is provided by renewable energy sources (RES) technologies. Electricity generation by RES comprises of 531 TWh/a by hydro power, 207 TWh/a by wind power 148 TWh/a by biomass [3], 72 TWh/a by solar power and 5.7 TWh/a by geothermal power plants (EIA, 2015).

Corresponding to the electricity demand, electricity generation is spatially unequally dis-

[2]Electricity generation deviates from demand due losses and differences in data acquisition. Gross electricity production incorporates self-consumption of power plants and distribution and transmission losses.

[3]Electricity generation by biomass incorporates unknown amount of waste.

tributed among European countries (see Figure 2.6). The electricity generation mix is different among countries as well. Countries with high hydro power capabilities largely base their electricity supply on this technology. In the remaining countries, electricity generation by conventional technologies dominates. The largest electricity suppliers in those countries are coal, nuclear, and natural gas power plants. Non-hydro power RES technologies played a minor role in Europe's electricity supply in 2012.

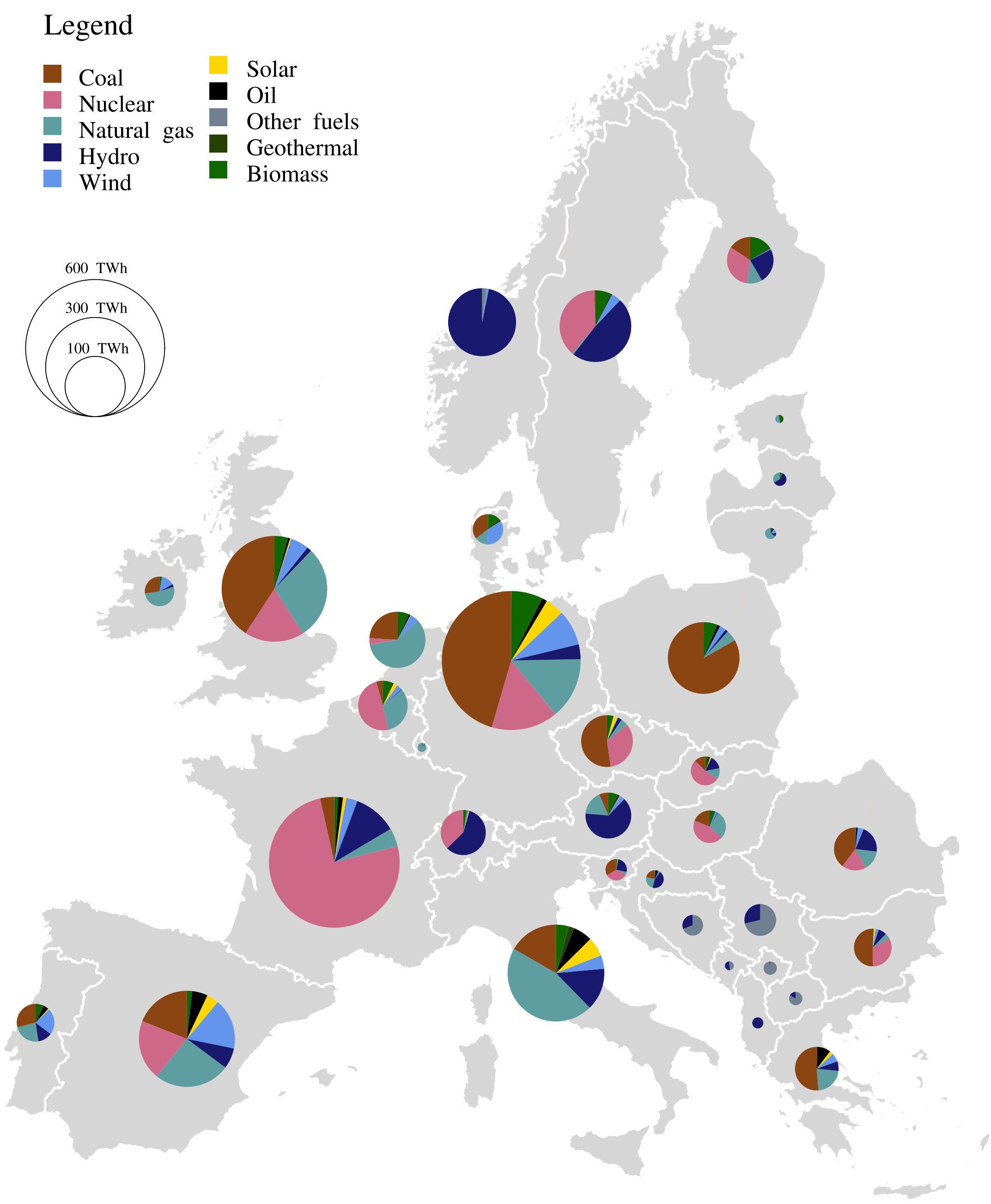


Figure 2.6: European spatially disaggregated annual electricity generation by 2012. Sizes of pie chart indicate cumulative annual electricity generation. Generation data for conventional technologies is taken from EEA (2012). Data on RES based generation is provided by EIA (2015).

2.2.2 Power generation and transmission capacity

The cumulative generation capacity in Europe by 2012 added up to 762 GW (Platts, 2012). Renewable energy sources based electricity generation capacity adds up to 386 GW (British Petroleum (BP), 2014; Pierrot, 2015; EurObservÉR, 2015). Cumulative capacity of nuclear power plants in Europe amounts to 128.5 GW. The majority of 407 GW of the cumulative generation capacity is provided by fossil power plants. Among fossil-fueled generation technologies, coal power is the largest technology with 191 GW. Natural gas and other gas fueled power generation technologies add up to a cumulative capacity of 154 GW. The capacity of oil-fueled power plants totals to 59 GW. Other power generation technologies that are

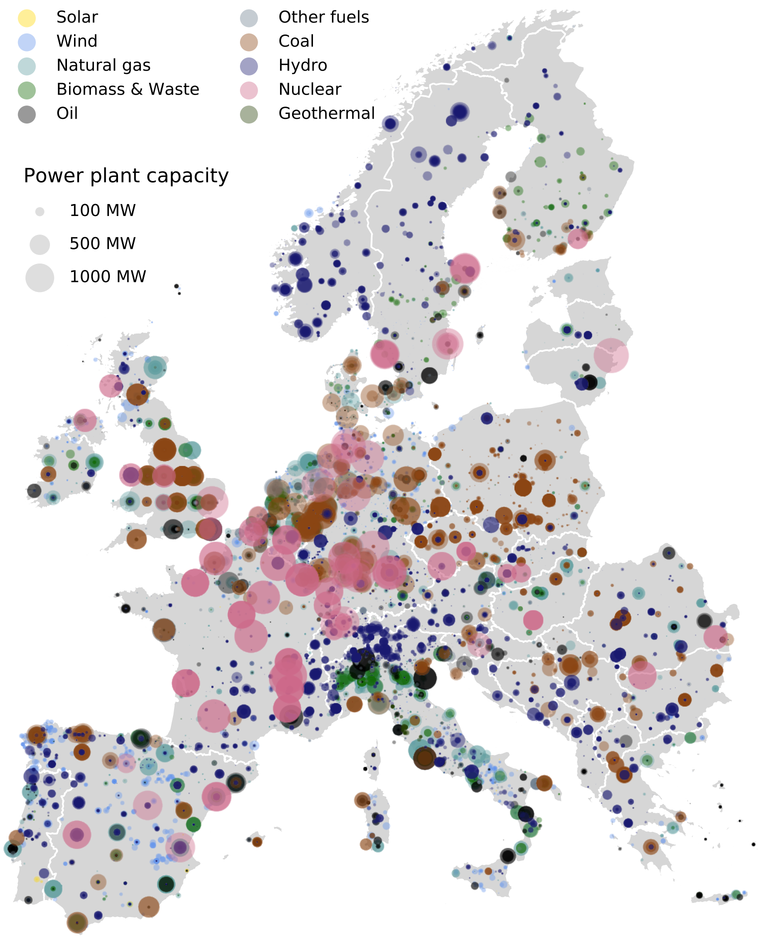


Figure 2.7: Spatially disaggregated European power plant capacity per technology by Platts (2012). Note, the data source lacks on representing smaller scale RES power plants. In particular, small scale PV power plants are underrepresented.

subsumed by other fuels have a cumulative capacity of around 3 GW. Among RES technologies hydro power is the generation technology of largest capacity (148.5 GW). Wind power as second largest RES technology provides a capacity of 118 GW, followed by 79.6 GW of solar power. The remaining capacity distributes among biomass and waste (39 GW) and approximately 1 GW of geothermal power generation capacity. In addition, 43.2 GW of pumped-hydro storage operate in the European electricity system by 2012.

Spatially, the generation capacity and its technological mix is different among European countries (see Figure 2.7). Countries with considerable consumption are furnished with large generation capacity and large-scale generation units. Each country has an individual mix of power plant infrastructure. For example, Switzerland, Austria and Norway have large hydro power capacity. France, is an outstanding example regarding the use of nuclear power, whereas Germany owns extensive coal power capacity.

The European transmission system comprises of 74.4 GW cumulative cross-border capacity (Entso-E, 2011). Most of the neighboring European countries are connected directly via transmission lines as shown in Figure 2.8. Cross-border capacities range from 150 MW up to 4,165 MW. The smallest capacity links the Montenegran with the Greek electricity system. The largest cross-border capacity connects Switzerland and Italy. In particular, centrally located countries with relatively high electricity demand possess large-scale transmission capacity with its neighbors. Likewise, Norway and Sweden are well connected. Countries in south-east Europe consuming less electricity annually are less interconnected.

2.2.3 Greenhouse gas emissions

Europe's electricity supply causes sectoral GHG emissions[4] of 1,227 Mt carbon dioxide equivalent (CO_2eq)[5] in 2012. Greenhouse gas emissions related electricity supply constitute 28.4 % of total GHG emissions including land use, land-use change and forestry (LULUCF) in 2012 that total to 4,323 Mt CO_2eq. Relative to total energy related emissions (3,685 MtCO_2eq), GHG emissions originating from the power sector accounted for 33 % (UNFCCC, 2015a; Phylipsen et al., 1998). Coal-fueled power generation is by far the largest emitter among power generation technologies. Natural gas burning technologies have lower specific emissions due to higher efficiency and lower carbon intensity of fuel (Davis et al., 2010; Peng et al., 2013). Nuclear and RES technologies have infrastructure related emission through en-

[4]IPCC 2006 source/sink category 1.A.1.a contains GHG emissions related to electricity generation, combined heat and power (CHP) and heat generation.

[5]carbon dioxide equivalent (CO_2eq) is a normalized unit to represent equivalent global warming potentials of different gases relatively to units of carbon dioxide (CO_2).

Figure 2.8: European transmission system cross-border capacities. Data bases on Entso-E (2011)

ergy demand for manufacturing (Amponsah et al., 2014). Additionally, emissions are related to fuel production of nuclear power (Sovacool, 2008).

Figure 2.9 reflects historic GHG emissions of the energy sector ranging from the year 1990 to 2012 at country level. The energy sector comprises *Electricity/Heat*, *Manufacturing/Construction*, *Transportation*, *Other Fuel Combustion*, and *Fugitive Emissions* according to the Intergovernmental Panel on Climate Change (IPCC). Total energy related GHG emissions decreased in this period by circa 23.6 %. Greenhouse gas emission from the power generation sector declined by about 15 % in this period. Consequently, the share of emissions related to power generation at total GHG emissions increased from 25.4 % in 1990 to 28.4 % in 2012. The dominating emitter in 2012 is Germany with emissions of 334 Mt CO_2eq, fol-

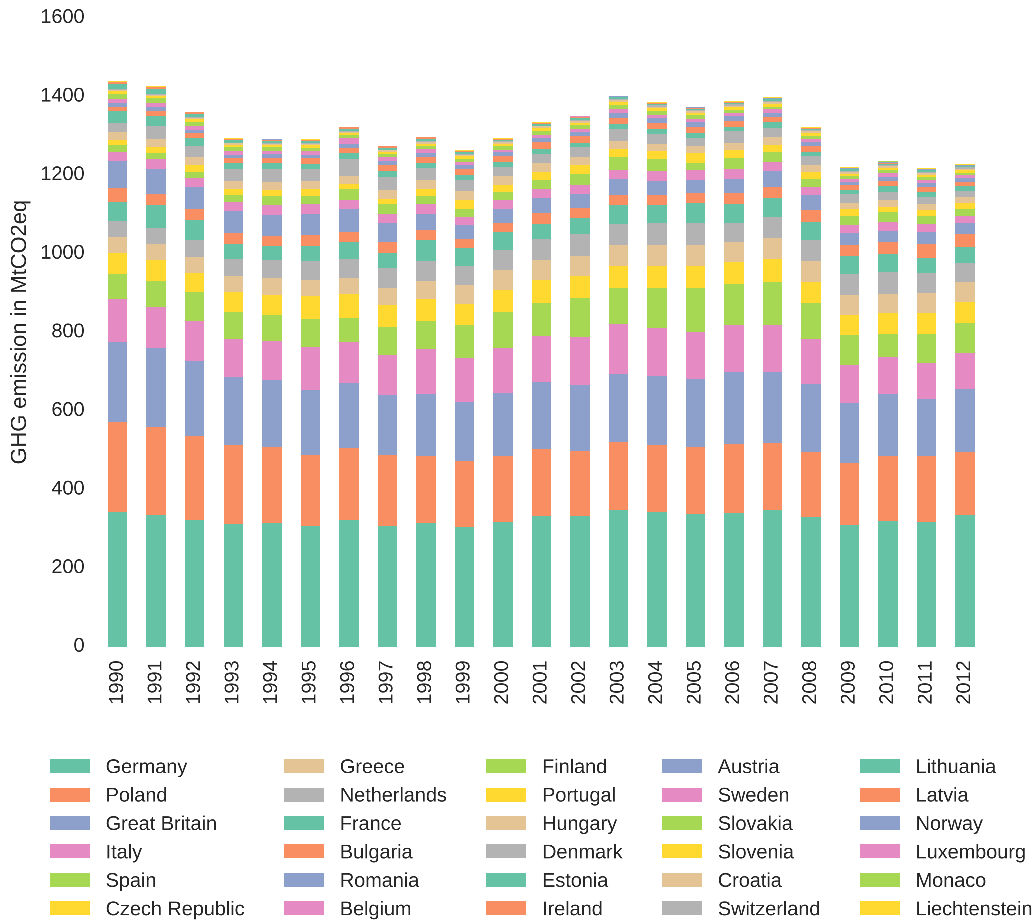


Figure 2.9: Historic GHG emissions of the energy sector from 1990 to 2012 at country level. UNFCCC (2015a) data is provided covering heat and electricity production. A cross-check with Phylipsen et al. (1998) shows small deviations, but still allows to work with the data provided by the UNFCCC.

lowed by the United Kingdom (UK) with 161 Mt CO_2eq and Italy with 91 Mt CO_2eq. These three countries are responsible for approximately half of European GHG emissions.

2.2.4 European climate policy

The so-called *Kyoto Protocol* marks the foundations of global climate protection policy. In 1997, UNFCCC member countries agreed on the frameworks of this treaty that was intended to stipulate GHG emission reduction measures. It was the first binding agreement on climate change mitigation under international law, built on the consensus "that (a) global warming exists and (b) human-made CO2 emissions have caused it". The agreement entered into force as from the year 2005 and ends by 2020 (UNFCCC, 1997). The ultimate goal of the agreement is to keep the climate system in balance by reduction of anthropogenic impact. Therefore, based on burden sharing, participating countries negotiated individual GHG reduction goals. In order to achieve these, countries passed different policy instruments i.e. the European Union Emission Trading System (EU-ETS). The efforts to address climate change issue are reaffirmed and climate change mitigation is continued by the adoption of the *Paris agreement*. By this agreement, UNFCCC participating member countries found a consensus to limit global average temperature increase to a maximum of +2 °C, and preferably below +1.5 °C relative to pre-industrial levels (UNFCCC, 2015b); a goal the United Nations Climate Change Conference member countries missed six years earlier at *COP15* in Copenhagen (UNFCCC, 2009).

In the light of global UNFCCC treaties, the EU confirmed its willingness to further engage in fighting anthropogenic climate change and its impact on humans. This has resulted in a number of long-term goals, binding medium-term goals, and practical implementation of measurements result. A result of the *Kyoto Protocol* is the EU-ETS which the EU passed in 2003 (European Union, 2003). This emission trading system aims to incentivize economically attractive GHG emission reduction measures by the so-called *cap and trade mechanism*. The EU-ETS covers large-scale energy production units and energy intensive industry. In total it covers sectors representing 45 % of EU total GHG emissions (European Commission, 2013). The emission reduction target for sectors covered by EU-ETS is 21 % compared to 2005 emission levels by 2020. Besides the EU-ETS, in the remaining sectors GHG emission reduction targets of -10 % are aspired towards 2020, which is established by the “EU climate and energy package” (the so-called 20-20-20 goals). Furthermore, sector independent targets of 20 % emission reduction (European Commission, 2008a), 20 % of RES based energy supply across all sectors (European Union, 2009a) and 20 % efficiency (European Commission, 2008b) increase are passed by the EU (European Parliament, 2009b). Efforts are continued by the “2030 framework of energy and climate policies”. This directive set targets for 2030: 27 % RES based energy supply, 40 % GHG emission reduction and indicative 27 % efficiency increase, respectively 27 % less energy consumption (European Council, 2014).

The long-term goals of the EU are targeted for the year 2050. By 2009, the EU passed a directive to oblige its member states to adhere to the 2 °C objective (European Union, 2009b). This target refers to a limit of global average surface temperature increase of at maximum 2 °C relative to pre-industrial times. This target shall prevent climate change impacts from worsening (Randalls, 2010). In order to achieve the 2 °C temperature increase target, the EU aims for a reduction of GHG emissions of 80 % up to 95 % relative to 1990’s levels by 2050 (European Union, 2009b). A roadmap published by the European Commission in 2011 breaks these targets down to sectoral targets and defines intermediate targets on the way towards 2050 (European Commission, 2011a). Key figures of the sketched roadmap are illustrated in Table 2.1.

Table 2.1: A roadmap of sectoral GHG emissions reduction targets towards long-term mitigation goals of 2050 (European Commission, 2011a). This roadmap defines effective steps towards and is compliant with the targets intended for 2050 (European Union, 2009b)

GHG reductions compared to 1990	2005	2030	2050
Total	-7 %	-40 to -44 %	-79 to -82 %
Sectors			
Power (CO_2)	-7 %	-54 to -68 %	-93 to -99 %
Industry (CO_2)	-20 %	-34 to -40 %	-83 to -87 %
Transport			
(incl. CO_2 aviation, excl. maritime)	+30 %	+20 to -9 %	-54 to -67 %
Residential and services (CO_2)	-12 %	-37 to -53 %	-88 to -91 %
Agriculture (non-CO_2)	-20 %	-36 to -37 %	-42 to -49 %
Other non-CO_2 emissions	-30 %	-72 to -73 %	-70 to -78 %

The roadmap towards 2050 targets (outlined by numbers in Table 2.1) aims for a lower bound of emission reduction of -80 %. According to modeling results underlying the European Commission's roadmap, this -80 % reduction of total GHG emissions requires reductions in the power sector of 93 % to 99 % by 2050. Even the medium-term target of around -40 % total GHG emission reduction relates to emission reduction of -54 % up to -68 % in the power sector. The EU intends to share the effort of climate change mitigation according to economic potential of member countries. For example, the targets of the "2020 EU climate and energy package" adapts to individual targets for each member country ranging from -20 % to emission increases of at maximum 11 % relative to 2005 levels (European Parliament, 2009a).

The European Council agreed on initiating an European Energy Union in order to have an adequate framework for coordination of measures in the energy system to achieve climate change mitigation targets. The Energy Union supports energy security, solidarity and trust; a fully integrated European energy market; energy efficiency contributing to moderation of demand; decarbonization of the economy; and research, innovation and competitiveness (European Council, 2015; Helm, 2014).

2.3 Electricity supply system planning

Energy system planning describes the process of assessing future energy demand and supply to consult decision processes for infrastructure planning. Electricity supply system planning aims for outlining the electricity supply infrastructure in particular, for example capacity extension planning for power plants and the transmission system. Typically, modeling tools support this planning process by providing a mathematical description of the energy system, analytical methods, and often optimization methods. These tools, often named energy models, energy system models, energy system optimization models, or power/electricity system models, depends on the specific sectoral or methodological focus.

Since the 1950s energy demand and supply balances were used in the USA to assess future needs of the energy system. In the subsequent years and decades, more aspects were included in energy system planning resulting in higher complexity for this process. Accordingly, the modeling tools that were used in the planning process increase in complexity too (Bhattacharyya and Timilsina, 2010). For example, in the early 1970s, analyzing interdependencies of energy supply and economy were the focus of energy system analysis. Many energy system modeling tools emerged during this time. One popular example still utilized in updated versions is the tool WASP developed by the International Atomic Energy Agency (IAEA) at the end of 1970s (Pfenninger et al., 2014). After the end of the second oil crisis in the 1980s, global warming was identified as a major concern among scientist (Wei et al., 2006). By that time, energy system analysis began to incorporate environmental protection as an important aspect of energy planning (Bhattacharyya and Timilsina, 2010). The inclusion of climate change issues into energy planning emerged in 1990s. The next major focal change of energy system analysis took place ten years later and was partially motivated by climate change issues (Pfenninger et al., 2014). The focus shifted towards the integration of RES technologies in energy systems which brought up a large number of new challenges for energy system modeling. These new challenges lead to new model developments with focus on the integration of RES.

2.3.1 Classification of energy system modeling tools

The increasing number of energy system models and the consequent development in their applications augment the effort to keep track of available models. A classification scheme for energy system models can help to describe the landscape of present models and identify suitable approaches. Various approaches to survey and classify energy models or energy system models have been made in the past. Most reviews focus on models for the electricity sector, but models that cover the entire energy sector or consider the effects of the wider economy are included as well. Jebaraj and Iniyan (2006) scanned more than 200 scientific publications dealing with energy models. The application of energy models included in this review range from demand-focused models, energy planning models, forecasting models, model for single RES technologies, emission reduction models, and optimization models. Foley et al. (2010) assessed the capabilities of seven electricity systems models presented by 2010. It was found that the investigated tools, all designed for electricity system modeling, are very distinct in many aspects. The review suggests that the choice of a suitable tool for the specific goals of a study is crucial in order to capture all relevant aspects. A review of computer tools for analysis of integrating RES technologies in the electricity supply system is provided by Connolly et al. (2010). Out of 68 computer tools or energy system models, whose application ranges from the analysis of single buildings to national energy systems, 37 were selected for a deeper survey. By a survey based analysis, these tools were categorized according to type of the model, spatio-temporal structure plus special focus, and energy sectors considered, as well as electricity system technologies represented in the model. Seven types of models were used to classify the investigated tools: simulation, scenario, equilibrium, top-down, bottom-up, operation optimization, and investment optimization. Connolly et al. (2010) emphasized that these seven types are mutually non-exclusive. For example, top-down models typically use an equilibrium approach and investment optimization models determine investments based on optimal operation. Focusing on the integration of short-variations of power system operation into long-term energy system planning, Collins et al. (2017) distinguishes three types of energy modeling approaches. The first group comprises of operational power system models that are used for unit commitment and economic dispatch. Long-term energy system optimization models form the second category of models typically used to assess the evolution of energy sectors for several decades. The last considered category includes integrated assessment models (IAMs). Compared to long-term energy system optimization models, these type of model incorporate more factors than the energy sector, are used for analyzing longer time horizons, and often cover the spatial extend of the entire world. For example, IAMs include socio-economic modeling and typically looked at the year 2100 as this year is an important set point for climate change scenarios. Other reviews focus on specific aspects of energy system modeling. Ventosa et al. (2005), for example, reviewed trends in electricity market modeling. Wierzbowski et al. (2016) and Cebulla and Fichter (2017) focus on the mathematical approach of mixed-integer linear programming (MILP) applied in energy system modeling. For an assessment of 21st century energy system modeling challenges, Pfenninger et al. (2014) conducted a classification of presently available energy system models. According to the authors, requirements on energy system planning tools will further increase due to "stringent climate policy, energy security and economic development concerns, and increasing challenges due to the changing nature of the twenty-first century energy system". In consideration of previously existing model reviews, for example those stated above, a classification scheme was constructed. Pfenninger et al. (2014) underline that grouping of models can follow multiple categorizations and that the boundaries between these groups are usually fluid. Thus, a suitable distinction between modeling approaches depends on the focus of a review. For their review, Pfenninger et al. (2014) categorized currently available energy system models in the groups energy systems optimization models, energy systems simulation models, power systems and electricity market models, and qualitative and mixed-methods scenarios. Despite the limits of the proposed energy system model classification scheme, it is very useful to provide a greater picture of the energy (system) modeling tools landscape in order focus on models pertinent in the context of this thesis. The characteristics of models that fall in each of these groups explain as follows

- ENERGY SYSTEMS OPTIMIZATION MODELS mostly use an bottom-up approach, are technology-rich, and make necessary reductions in technical and/or temporal representation in order to remain computable. Its regional scope span from regional to global while allowing for multi-region representation. The goal of the model class is to identify potential future energy system designs. Bottom-up models can be linked (soft-linked or hard-linked) with economy-wide top-down models to study effects of changing energy system on the broader economy.

  Prominent model implementations of the group of energy system optimization model are the MARKAL/TIMES (G. and Harold, 1981) and the MESSAGE (Schrattenholzer, 1981) model families. The Market Allocation (MARKAL) model is possibly the best known and used energy system modeling tool. TIMES (The Integrated MARKAL-EFOM System) emerged from combining MARKAL with the EFOM (Energy Flow Optimization Model) (Loulou and Labriet, 2008). Since decades, the model family is maintained and further developed at IEA-ETSAP (International Energy Agency Energy Technology Systems Analysis Program), a consortium of researchers from the International Energy Agency (IEA) member countries. Tools of the MARKAL/TIMES model group were used for various studies that deal with the evolution of energy systems including a study used as the basis of the definition of the EU 20-20-20 goals (European Parliament, 2009b). Examples for general purpose energy-system optimization models linked to economic models are MESSAGE-MACRO (soft-linked) (Messner and Schrattenholzer, 2000) and MARKAL-MACRO (hard-linked) (Manne and Wene, 1992). These type of energy-economy models are also called hybrid models as they are composed of both a macro-economic top-down approach and an engineering bottom-up approach.

- Energy system simulation models are the alternative to large-scale optimization based long-term energy system planning tools. Simulation methods are used to forecast or predict likely development of energy systems. Typically, simulation model are designed in a very modular manner which makes its application flexible and eases the integration of external modules.

  Most known models of this category are National Energy Modeling System (NEMS), a computable Price-driven equilibrium Model of the Energy System and markets for Europe (PRIMES) and the Long-range Energy Alternatives Planning system (LEAP) that all emerged in the late 1980's until early 1990's. NEMS (Gabriel et al., 2001) is extensively used to analyze the US energy sector, for example to calculate scenarios for the Annual Energy Outlook. PRIMES (E3MLab, 2014) is the European pendant and has a very similar purpose. Due to the model's modular nature, that involves submodules for each task, a certain amount of effort is required to find an equilibrium between energy supply, demand, cross-border energy trade, and emissions which are determined by independent agents. It was used by the European Commission to support decisions on energy policy. For example, the EU Energy Roadmap 2050 is based on analysis by PRIMES.

- Power systems and electricity market models can be understood as a special class of energy system optimization/simulation models concerned solely on the electricity system. A central, distinctive feature of power system or electricity supply system models is the focus on reflecting temporal variation in electricity supply. Power system and electricity markets models are used to support decisions on operation of power systems and investments into new capacity. In clear distinction to long-term energy system models, power system and electricity market models explicitly incorporate the dispatch of power plants. Numerous techniques from the fields of optimization and simulation methods find application in power systems and electricity market models. Electricity market models are very similar to power systems models considering for the temporal dimension of electricity supply. In contrast to power system models, these typically do not incorporate effects of power grid operation, but model electricity trading schemes like day-ahead or intra-day markets (Ventosa et al., 2005).

  Established examples for power system models are the commercial tools WASP (IAEA, 2006) and PLEXOS (Energy Exemplar, 2011). WASP (Wien Automatic System Planning) is primarily used for generation capacity expansion planning and uses dynamic programming to solve the optimization problem. PLEXOS (PLEXOS for Power Systems-Power Market Simulation and Analysis Software) relies on mixed-integer linear modeling and includes detailed modules for power system equipment and the surrounding environment such as different power plant types, the transmission system, electricity market and capacity expansion. In the context of academics and policy consultancy, in recent years, several power system planning models emerged focusing on the analysis of RES integration and the design of future electricity supply systems. These models are to some extend akin to energy system optimization models except for for their focus on solely a single energy sector. On the other hand, these models share similarities with power system models in that a particular focus is set on the representation of temporal scale in detail. Many of these use the classical approach of linear programming for combined modeling of capacity extension planning and dispatch optimization. An early and prominent example of linked dispatch and capacity extension planning with focus on RES based electricity supply originates from Czisch (2005). More recent research took up on this approach and led to the development of the electricity sector model URBS. This model was used for example to analyze optimal electricity system designs in terms of intended GHG emission reductions (Aboumahboub et al., 2010) or transmission grid extension needs for integrating variable RES (Schaber et al., 2012a). Other models developed for the same purpose apply different methods to determine optimal power system designs. The model GENESYS (Bussar et al., 2015, 2016) evaluates electricity supply system operation based on a heuristic approach. The system design in terms of generation, energy storage and transmission system capacity is evaluated by a evolutionary strategy that seeks for a least-cost mix. Another modeling approach for assessing electricity supply system design involving large shares of RES based supply concentrates on evaluating temporal resolved mismatches of electricity supply by wind and PV power with electricity demand (Heide et al., 2010; Becker et al., 2013; Weitemeyer et al., 2015). An example for the electricity market models is ELMOD (Leuthold et al., 2012). This bottom-up model, combines electrical engineering and economics modeling and covers the spatial extent of the European electricity market including the transmission system. It is designed for different analyses of the electricity market. Among others these are: nodal vs. zonal pricing, network expansion design, and market integration of RES technologies. Richstein et al. (2015) developed and applied the agent-based model model EMLab to analyze effects of policy options for the European electricity market. The agent-based approach allows studying the behavior of individual market participants in detail.

- Qualitative and mixed-methods scenarios

In contrast to large-scale, often optimization based, energy system models Pfenninger et al. (2014) grouped qualitative and mixed-method scenarios into a distinct group. Because of the number of factors included in the large-scale models, these are complex, frequently intransparent and induce high computational cost. Qualitative methods and mixed quantitative-qualitative methods are used to reduce facts and circumstances to the basics. One example is the stakeholder empowerment process for new transmission lines in France and Norway (Späth and Scolobig, 2017).

As many authors of model reviews state (i.e. Hall and Buckley (2016) and Pfenninger et al. (2014)), the scope of a classification scheme usually cannot cover all details of models. Nevertheless, the classification scheme of energy (system) models proposed by Pfenninger et al. (2014) helped to achieve a rough classification of available modeling approaches and model implementations. Derived from this classification and in context of this thesis, it is clear that power system models and certain aspects of energy system optimization models are most relevant. To highlight further aspects of energy system modeling and the current state of art, in Section 2.3.2 well-qualified modeling approaches and model implementations with their important features are discussed with respect to these facts.

2.3.2 Challenges and key aspects of energy system modeling

It is prevalent that authors of model based studies about future energy supply scanned the energy system modeling landscape along the dimensions of important features for their intended modeling approach. Instead of assigning models to distinct groups, they highlight certain aspects that are relevant in the context of the specific study. Haller (2012) distinguished the challenges for the analysis of system integration of fluctuating RES into three dimensions: long-term development, short-term dynamics, and spatial distribution. Along each of these dimensions, models incorporate aspects in different detail. The review regarding 21st century energy system modeling challenges by Pfenninger et al. (2014) declares resolving time and space, balancing uncertainty and transparency, addressing the growing complexity of the energy system, and integrating human behavior and social risks and opportunities as most important aspect to be tackled by modelers. For a survey on energy system models used for energy policy advice in the UK, Hall and Buckley (2016) identified 14 categories to analyze features of existing models. The proposed classification scheme is found on previous reviews and merged their categories to achieve a finer distinction between models. The 14 categories encompass purpose and structure, technological detail, and mathematical detail of energy system models. Purpose and structure is subdivided into purpose of the model (general and specific), structure of the model, geographical coverage, sectoral coverage, the time horizon, and the time step. The technological detail is discussed along RES technologies considered, ESS technologies considered, demand characteristics, and costs included. The mathematical detail of models, the analytical approach, the underlying methodology, the mathematical approach, data requirements are defined as subcategories. A review about the integration of short-term variations of RES based electricity supply into power system models by Collins et al. (2017) discussed possible model simplifications for complexity reduction on different scales. Methods are presented along the model features temporal representation, technical representation, and spatial representation.

It shows that most aspects of energy system model are recurring in different reviews. Based on aspects considered in available reviews, important modeling techniques and energy system model features are presented. Therefore, the categories technological detail, long-term modeling and time horizon, spatial dimension and transmission system representation, short-term temporal scale, mathematical approach, market modeling, planning perspective and policy modeling are used. Unlike the model classification in Section 2.3.1 model features are discussed with a narrower focus on the goal of this thesis.

Technological detail The technological detail of representing the electricity supply infrastructure in energy system models is twofold. First, it is the modeler's choice to decide how many technologies are to be considered and how a distinction between technologies is made. Second, each of the considered technologies can be modeled according to different tiers with regard to details. In general, the representation of the technological detail needs to be chosen in consideration of the goal of a study and is constrained by model complexity and resulting computational cost (Collins et al., 2017). Models with a geographical coverage of multiple national energy systems typically represent electricity supply infrastructure aggregated per type of technology (Hall and Buckley, 2016). As the considered electricity supply and energy storage system technologies highly depend on the aims of a study, three exemplary studies show the range of technological details. Studies using the approach of weather-driven modeling, i.e. Heide et al. (2010) and Becker et al. (2013), have a strong focus on flexibility needs of electricity systems with very high shares. Consequently, only the main future fluctuating RES technologies wind and PV power are considered in the model in detail. Dispatchable generation technologies and energy storage systems are represented by a generic balancing unit and eventually analyzed ex post facto. In contrast, Scholz (2012) considered 13 power generation and three ESS technologies. Again, the focus lies on RES based electricity supply and thus conventional technologies are represented by a generic unit. Jägemann et al. (2013), looking at low RES shares of up to 80 %, distinguished six conventional generation technologies. For example, coal-fired generation is modeled by three different technologies including one equipped with CCS.

The scope of a study sets the requirements for modeling of technological detail of power generation and ESS technologies. While a detailed modeling of operational characteristics (i.e. start-up and ramping costs) and limits (i.e. load-following constraints) is typically considered in unit commitment and economic dispatch models (i.e. in PLEXOS (Energy Exemplar, 2011)), large-scale aggregating long-term investment models do not incorporate such details (Collins et al., 2017). In the latter, where individual power plants units are represented per country/region, the impact of operational characteristics and limits are balanced out by coincidental effects.

Incorporating technological detail in energy system models is linked to other aspects of modeling. Besides the interdependency to spatial scale of modeling, the technological detail sets requirements for the temporal scale of modeling and the mathematical approach. Considering for high technological detail requires for high temporal resolution and perhaps a particular mathematical approach.

Long-term modeling and time horizon According to Hall and Buckley (2016), the long-term time horizon in energy system modeling refers to planning periods larger than 15 years. Energy system models are distinguished by how the long-term planning goal is approached and by the time horizon that is used. For ease of understanding, the differences of between models are exemplified along the case to study of deep GHG emission reductions in the European electricity sector by the year 2050. This long-term planning goal can be analyzed with an energy system model by distinct approaches. Snapshot planning would allow to identify a suitable electricity system design as for example applied in Bussar et al. (2015) and Czisch (2005). It refers to building the electricity system from scratch neglecting the changes in the electricity infrastructure from now to 2050. Thus, decommissioning, refurbishment, and new installations of power plants are not studied. In order to incorporate these aspects, the pathway of the electricity system transformation needs to be included. Therefore, Becker et al. (2013) extrapolated capacities of electricity system infrastructure and subsequently analyzed the prescribed pathway with a simulation to assess the operation of the electricity supply system. In contrast to Becker et al. (2013), the development of electricity system infrastructure can be assessed endogenously by the model. Therefore, Pina et al. (2013) developed a modeling framework for the Portuguese electricity system comprising the long-term energy system model TIMES and the operational model EnergyPLAN. To determine a transition pathway for the electricity system infrastructure including the assessment of feasible operation on short-term scale, these models are iteratively linked. Haller (2012) and Fürsch et al. (2013), for example, used an inter-temporal modeling approach to determine the least-cost transformation in the electricity sector. Inter-temporal in this context means that the time horizon of optimization for investments into electricity system infrastructure covers multiple periods from now until 2050. It is a model-endogenous decision in which of these periods new capacity is built.

Spatial dimension and transmission system representation Spatial aspects such as the representation of grid infrastructure are other important features of energy system models. Whereas the spatial extent of the model is typically defined by the scope of a study, its spatial resolution and the level of detail for grid infrastructure modeling are to be defined during the model development process. The level of detail in which the grid infrastructure is considered in a model ranges from being disregarded (copper plate model), to aggregated approximation in multi-region models (net transfer capacity (NTC) or power transfer distribution factor (PTDF) approaches), to actual power flow calculations (AC or DC) on real grid infrastructure data. Not considering the grid infrastructure might be applicable to national studies when electricity exchanges with neighboring countries can be neglected as for example in Pina et al. (2013). Multi-regional energy system models are one approach for considering constraints in the transmission system. For example, Bussar et al. (2015) modeled the European-MENA electricity with 21 and 49 cross-border capacities and Scholz (2012) modeled the European-North African electricity system by 36 regions. These two models, among others, use NTCs to describe the limits of cross-border power flows. According to ETSO (2001), the capacities describe the maximum exchangeable power between two market regions respectively transmission system operators (TSOs) areas. Typically, NTC are used for market allocation of power plant capacity. A closer approximation of transmission capacity in multi-regional energy system models can be achieved by using the PTDF approach (Duthaler et al., 2008). Power transmission distribution factors describe flows on lines that occur when electricity is exchanged between two nodes. These applied on flow gates in a zonal or regional model provide a description of cross-border transmission capacity. Despite the common usage of the NTC approach, PTDFs attain increasing importance in power system modeling. For example, PTDFs were used in a multi-regional electricity system model for the assessment of RES integration by Brown et al. (2016). Power flow calculations on real grid infrastructure models allow for more detailed analysis of the power system operation. The non-linear power flow (also AC or full power flow) allows to assess nodal voltage magnitude, voltage angles, as well as active and reactive power flow on lines (Tinney and Hart, 1967). For the transmission level, when voltage angles and reactive power supply are not in focus of the analysis, DC power flow might be a suitable method to analyze power system operations (Purchala et al., 2005). As linear and non-linear power flow methods are typically used for the analysis in non-aggregated electricity networks, their computational cost are quite high. In order to add more detail regarding the effects on the electricity grid, energy system models can be soft-linked to power system models for conduction a power flow analysis (linear or non-linear). For example, a European electricity market model was iteratively linked to a power flow calculation by Fürsch et al. (2013). Using the example of Ireland, Deane et al. (2012) showed by linking an energy system model to a power system model, that the former potentially undervalue the potential of flexibility and underestimate wind curtailment.

Short-term temporal scale In recent years, many authors stated the need for more precise modeling on short-term scale in long-term energy system models in order to cope with variability of RES based electricity supply (i.e. Welsch et al. (2015); Pfenninger et al. (2014); Poncelet et al. (2014)). In particular, long-term energy system modeling models should incorporate variability for a profound assessment of flexibility options that can serve the balancing needs (Després et al., 2015). Otherwise, the dispatch of RES power plants cannot be assessed accurately, the RES share in the electricity mix might be overestimated, and the amount of CO_2 emitted by the electric system might be underestimated (Haydt et al., 2011). Brouwer et al. (2014) recommended using a temporal resolution of at least one hour for unit commitment and economic dispatch models for accurately considering the variability of RES based electricity supply. Traditionally, in established long-term energy system models designed to plan energy systems dominated by dispatchable generation capacity, the balance between supply and demand was evaluated by only a few time slices per year. For example, PRIMES (E3MLab, 2014), as used to explore pathways for multiple energy sectors in the EU until 2050, takes 11 blocks per year into account in order to consider for variability (Després et al., 2015). Electricity system models that emerged for studying the integration of RES based generation considered the temporal scale in detail right from the beginning. For example, Czisch (2005) set up a multi-regional long-term electricity planning model (combined investment and operational model) that analyzes electricity supply by sequential time steps with a temporal resolution of three hours. Due to lower computing power back in these days and greater system complexity, the study finally analyzed the performance of electricity supply for only six months. The study by Czisch (2005) inspired other researchers to build similar energy system models for analyzing electricity supply systems with high generation shares of RES technologies. To name a few examples with different modeling techniques: Aboumahboub et al. (2010) investigated high RES supply by linearly combined investment and dispatch modeling, Bussar et al. (2016) examined a study on energy storage system needs in Europe, and Becker et al. (2013) who analyzed transmission grid extension needs based on the weather-driven modeling approach. These examples of recent model developments, all represent the temporal scale in one-hourly resolution and maintaining chronology, underline the recent trend towards high detail on temporal for analyzing the integration of RES supply technologies.

Another aspect of temporal scale is the time horizon of energy system planning. In long-term inter-temporal planning energy system models, the time horizon spans across year to decades and describes the period in which investments and decommissioning is assessed. In energy system models that determine system designs based on one reference year, the time horizon defines the period of time used to determine the dispatch of power plants and the operation of ESSs. The time horizon can range from myopic (1 hour time horizon) to perfect foresight (time horizons equal the entire year) with arbitrary increments. For example, Bussar et al. (2015) used a time horizon of 24 hours to assess the operation of energy storage systems. Aboumahboub et al. (2010) determined future power plant infrastructure by applying perfect foresight in the linear programming based combined investment and dispatch model.

In order to achieve decent computation times of energy system models, complexity reduction at various scales is required. Detailed modeling on temporal scale is necessary to incorporate variability of RES supply, but leads to increased complexity. As a consequence, methods for complexity reduction of temporal scale is a trending research topic in the field of energy system modeling (Merrick, 2016; Poncelet et al., 2016a; Kotzur et al., 2018). Haller et al. (2012a) and Ludig et al. (2011) introduced the long-term planning capacity extension and dispatch model LIMES-EU+ that includes a novel method to select representative time slices for the analysis of electricity system operation. Using the model LIMES-EU+ to assess decarbonization pathways for EU-MENA region, temporal variability is accounted by 49 representative time slices. The selection of time slices from 6 hourly time series of RES feedin and electricity demand in particular considers RES generation and peak demand (Haller et al., 2012b). The selection of representative time slice in LIMES-EU+ was improved by Nahmmacher et al. (2016) by using hierarchical clustering methods. Similarly, Fürsch et al. (2013) used time slices of 4 hourly data of representative days. Palmintier et al. (2017) presented an approach to select representative days based on bootstrapping. According to the Poncelet et al. (2016b), the quality regarding accuracy of the results in selecting representative days can be improved using optimization-based methods. Furthermore, Kristiansen et al. (2017) emphasized that the performance of different time slice selection methods is also dependent of the applied model. Despite the valuable feature of significantly reduced computation time when time slices are used, the methods include some drawbacks. Kotzur et al. (2018) point out that time slice aggregation methods cannot be applied to assess operation of electricity system incorporating a high share of RES based supply. This is due to the need for long-term or seasonal energy storage system that cannot be assessed based on aggregated temporal representation. For assessing the operation of long-term energy storage the chronology of time steps across a longer time frame greater than multiple weeks is required.

Mathematical approach Mathematical and programming approaches used in energy system models are widespread. Well-established methods like linear, mixed-integer and dynamic programming are supplemented by approaches like fuzzy logic and agent-based modeling for example (Hall and Buckley, 2016). In context of exploring future electricity system designs, optimization and heuristic methods are suitable and often used mathematical approaches (Hall and Buckley, 2016). Exploring in this case refers to determine the (often cost) optimal electricity system design based on investment and decommissioning decisions. Typically, the identification of optimal investments is found on assessing the optimal operation of the electricity system. The most commonly used approach for this task is to combine invest and dispatch modeling in one linear programming (LP) model as for example done by Czisch (2005). This is achieved by bounding electricity generation, charge and discharge of ESSs, and electricity exchanges through the transmission system to existing capacity plus prospective newly built capacity. Another approach of combining the invest and dispatch modeling is to decouple operational and investment decisions. This also allows using non-linear and simulation based models for assessing the electricity system operation. The optimal system design, then, is determined using an optimization or a metaheuristic approach that investigates feasible system designs based on the operational model. One example that uses this approach is the model GENESYS (Bussar et al., 2015, 2016). The operational model in this case is built based on a hierarchical system management. This determines dispatch of power plants, ESSs operation, and power flows in the transmission system based on predefined rules with a fixed order. An evolutionary strategy is used to identify the cost-optimal system design based on the system operation.

Market modeling, planning perspective and policy modeling Energy system models are to be distinguished further by aspects of markets that are included the planning perspective that the model takes, and by policy instruments that are considered in the model (Hall and Buckley, 2016). Aspects of electricity markets are considered in energy system models in various ways and in different detail (Ventosa et al., 2005). Typical applications are portfolio management in private sector companies and studies that analyze the effects of RES integration on spot market prices (Sensfuß et al., 2008). Long-term planning models often neglect market schemes and investigate the energy system design from a systems planner perspective. Therefore, optimization goals of minimal total costs or maximum welfare are typically used (Hall and Buckley, 2016). Furthermore, it is common to incorporate exogenous boundary conditions for the assessment of energy system designs. Prominent examples are shares of RES electricity supply as applied in Fürsch et al. (2013) or the GHG reduction goals exemplified in numerous studies (i.e. Haller et al. (2012b)).

3 Modeling of the electricity supply system

This chapter describes methods that are used to assess cost-optimal decarbonization pathways for the electricity supply infrastructure in Europe. The methods mainly comprise of an electricity system model capable of determining least-cost electricity system designs for defined GHG emission limits. First, requirements for the electricity system model are defined. Subsequently, based on the model overview in Section 2.3, available modeling approaches are evaluated according to their suitability. The following two sections illustrate the electricity supply system infrastructure considered in this study and the spatial extent of the analysis. The remaining three sections describe the theoretical framework, the mathematical notation, and the software implementation.

3.1 Evaluation of available models

Based on the review of available energy system models in Sec. 2.3 the suitability of existing modeling approaches is assessed. Therefore, first, the requirements regarding the desired energy system model are defined. Secondly, the most promising models and modeling techniques are discussed in line with the requirements regarding their suitability for the goal of this thesis.

3.1.1 Model requirements

The power system model must fulfill certain requirements so as to fully answer the research questions of this thesis. Important features that need to be included in the desired energy system model are defined along the following modeling aspects:

- Purpose and scope of the model
- Technological detail

- Spatial and transmission system representation
- Short-term temporal representation
- Long-term and pathway modeling
- GHG emission limit.

As the goal of this thesis is to explore potential cost-effective pathways for the transformation in the electricity sector in order to meet defined sectoral GHG reduction goals, the electricity sector must be the focus of the scope of the model. Exploring least-cost decarbonization pathways requires assessing the investments and decommissioning of the electricity infrastructure that leads to effective emission reduction at low cost. Therefore, a modeling approach is required that is capable of determining optimal investments based on the assessment of electricity system operation including related GHG emissions. Thus, a combined invest and dispatch is needed. The planning perspective and the level of electricity market representation are closely related to the purpose and the general approach of the model. As this thesis looks at electricity designs until the year 2050, the present electricity market structures and trading schemes do not need to be included in the model. Rather, these should be excluded explicitly in order to obtain unbiased results from a perspective of total costs. In the following sections, this is referred to as the systems planning perspective that seeks for a European-wide cost-optimal transition pathway neglecting any country specific goals.

Regarding technological detail, the model must include major power generation and energy storage system technologies, as well as consider the transmission system. First, the model must take into account power generation technologies currently operating in Europe and those planned for future power supply with high shares of RES. This allows reflecting both present and future power generation mix. These encompass conventional power generation technologies (coal, gas and nuclear power) and RES technologies (hydro, wind and PV power). Technologies that supply less than 5 % of total generation (IEA, 2013), i.e. geothermal or tidal and wave power, are neglected in this study (for details see Sec. 3.2). In addition to power generation technologies, the electricity system model must include ESS technologies operating on different time horizons. This is necessary in order to address the volatility of electricity supply by RES technologies which causes additional balancing needs in the electricity system. A suitable set of ESS technologies are pumped hydro storages, battery energy storage systems, and the PtG technology (Jentsch et al., 2014). These three types of energy storage systems cover the range of technologies pertinent to the scope of this study: existing PHS, a stationary large-scale battery technology for short-term balancing needs, and PtG systems intended for balancing electricity demand and supply on long-term. The latter is required to analyze electricity system designs incorporating very high shares ($\geq 80\,\%$) of RES based electricity supply (Belderbos et al., 2015). In such electricity systems, large-scale seasonal variations of electricity supply occur that need to be shifted on the axis of time.

The spatial extent of the model used in this thesis shall include the EU member countries as well ENTSO-E member countries. Whereas the former is motivated by the already defined sectoral GHG reduction goals that serve as a reference point, the latter is motivated from a technical perspective. The transmission systems of these member countries are connected and, thus, electricity supply system operation of these countries is inter-dependent. Moreover, a electricity system model covering a large area like Europe must reflect regional differences in electricity supply potential and demand characteristics. Thus, a multi-region approach including the representation of transmission capacities between these regions is required. This enables the representation of inter-regional electricity exchange. The spatial resolution of an energy system model partially sets the requirements for modeling technological detail. Because countries or even multiple countries are to be modeled by one region (for details see Sec. 3.3), modeling of technological details can be kept at low level. In such an approach, power plants are represented in aggregated manner by modeling one reference unit per technology type. Thus, technical aspects, for example ramping constraints, do not need to be modeled due to coincidental effects of power plant operation.

Requirements regarding representation of temporal scale in the electricity system model are manifold. It must cover short-term effects of electricity supply in order to provide an adequate representation of RES technologies operational characteristics (Després et al., 2015; Skea et al., 2008). Intermittent supply characteristics of RES technologies need more detailed modeling on temporal scale compared to modeling of dispatchable technologies such as conventional power generation technologies (Merrick, 2016; Pina et al., 2011). Furthermore, this allows for ensuring security of supply and system adequacy in electricity systems with high shares of variable RES (Welsch et al., 2015). Within this thesis adequate representation of short-term effects refers to one-hourly modeling of electricity supply. This temporal resolution is in the least required to account for variability of RES based electricity supply in capacity planning (Haydt et al., 2011). In addition to the required temporal resolution, information on chronology is required to describe operation of ESS (Wogrin et al., 2016). Based on chronologically analyzed time steps the SoC can be assessed which is required to the energy capacity of ESS. Without detailed information about discharge and charge events, in particular in chronological order, this is not possible, and thus, the capacity cannot be determined. In particular, the assessment of long-term energy storage system demands for detailed modeling on a short-term temporal scale. However, in addition to the importance of the temporal resolution, capacity assessment for long-term ESS requires a long period of time being analyzed chronologically.

Besides the short-term effects of electricity supply, long-term investment cycles need to be considered in the model. This allows for studying a potential change in the electricity supply system structure in the upcoming decades. Pfenninger et al. (2014) pointed out that electricity system planning along a pathway is crucial to determine a suitable transition of the electricity supply structure. In this thesis, long-term investment decisions are drawn on the basis of a consecutive analysis of five years intervals. Hence, power plant, ESS and transmission capacity commissioning and decommissioning is determined in these intervals. Furthermore, Pfenninger et al. (2014) emphasizes the need for amalgamation of detailed modeling on short-term temporal scale and long-term energy system planning. This especially includes consideration of challenges arising from variable supply of RES and the increased demand of flexibility while assessing future electricity supply options. The amalgamation of these modeling aspects links back to the purpose of the model and the mathematical approach. In order to do so, a modeling approach capable of combining investment planning and dispatch modeling is required. The approach of this thesis therefore in particular requires the ability to identify electricity supply mix compliant with GHG emissions reduction targets. Therefore, the modeling approach must offer the option to define GHG limits that are considered model-endogenously while determining investments into electricity system infrastructure and determining the operation.

Considering the above defined requirements, it results in a large and complex model. Thus, the formulation and the level of detail of certain aspects must be chosen concisely. The model must be as adequate as achievable, but at the same time, as simple as possible to be computable in a reasonable time frame.

3.1.2 Discussion of suitability

The reviews of energy system modeling tools in Section 2.3 showed that a large and diversified landscape of modeling tools exists. The presented modeling tools are all suitable to a certain extent analyze future European electricity supply and reveal insights from electricity supply systems with high shares of RES based electricity generation. However, as each tool was designed for a specific purpose, its details regarding the scope of the model, technology representation, temporal modeling, and its general modeling approach are different. Guided by the above defined requirements a detailed discussion of most suitable energy system models is conducted. Therefore, eight tools are selected that are investigated in detail: the model by Czisch (2005), URBS, REMix, GENESYS, the ReStore2050 model, the model by Becker et al. (2013), DIMENSION (ext. version), and LIMES-EU+. Most important features of these models summarized in Table 3.1.

The model developed by Czisch (2005) set a milestone in the field of energy system analysis for the integration of RES technologies. The study for which, the model was designed for, strongly focused on highlighting the feasibility and economic implications of 100 % RES based electricity supply. The outstanding novelty of this model approach was to combine long-term investment planning with detailed modeling on short-term scale. This was achieved by formulating an integrated linear model that assesses electricity infrastructure investments based on the operation of the electricity system. Therefore, the electricity system operation was evaluated across half a year in three-hourly resolution. The long-term evolution of the electricity supply system is not explicitly modeled by Czisch (2005). The model uses snapshot planning to determine the cost-optimal electricity system for 2050.

Despite differences in the modeling approach and other aspects, URBS (Aboumahboub et al., 2012, 2010; Schaber et al., 2012a), REMix (Scholz, 2012), and GENESYS (Bussar et al., 2015, 2016) are very similar approaches to the model created by Czisch (2005). This is in particular true for the model's purpose. All these tools are designed to assess electricity designs with very high shares of RES technologies up to 100 % RES supply scenarios. Therefore, all the models implemented a combined investment and dispatch modeling approach. URBS and REMix apply linear programming as it was used by Czisch (2005). GENESYS implemented combined invest and dispatch planning based on a two-stage heuristic approach. The electricity system operation is evaluated by hierarchical system management that dispatches based on a predefined set of rules. This operational model is iteratively evaluated by an evolutionary algorithm that determines optimal investments into electricity supply infrastructure. These four models are well-suited for the aims of this thesis, due to numerous features: combined investment and dispatch planning, technological detail of generation and energy storage units, short-term temporal resolution. However, these models all use a snapshot planning approach for the assessment of future electricity system designs. The lack the feature of analyzing transition pathways for a step-wise transformation of the electricity system towards a decarbonized supply system. As this feature is crucial for this work, these models are not suitable for the intended analysis.

Table 3.1: Analysis of current existing energy system models regarding requirements presented in Section 3.1.1. Numbers in parentheses indicate quantity of technologies considered.

Model	Purpose	Power generation	Energy storage systems	Spatiality & transmission	Short-term modeling	Long-term modeling	GHG limit
Czisch (2005)	Invest & dispatch	wind, fall wind, solar, hydro power, geothermal, biomass, gas	PHS, H_2	EU-MENA, regions, NTC	3 hours, 1/2 year	snapshot planning	no
URBS	Invest & dispatch	Nuclear, Coal (2), gas (2), oil (2), hydro, biomass, PV, CSP, wind (2)	PHS	EU, (sub-)country, NTC	hourly, 1 year	snapshot planning	no
REMix	Invest & dispatch	PV, CSP, wind, hydro power, biomass, geothermal, generic balancing	PHS, AA-CAES, H_2	EU-MENA, 36 regions, NTC	1 hour (3 hours), 1 year	snapshot planning	no
GENESYS	Invest & dispatch	wind, PV	PHS, Battery, H_2	EU-MENA, 21 regions, NTC	1 hour, 1 year	snapshot planning	no

Table 3.1: *Continued from previous page*

Model	Purpose	Power generation	Energy storage systems	Spatiality & transmission	Short-term modeling	Long-term modeling	GHG limit
ReStore2050	Dispatch	wind (2), PV, CSP, hydro power, geothermal, biomass, generic balancing	PHS, seasonal, AA-CEAS, H_2	EU-NA, 8 regions	1 hour, 1 year	scenario	no
Becker et al. (2013)	Capacity extension scenarios	wind, PV	generic balancing	EU+, countries, NTC	hourly, 8 years	extrapolation	no
DIMENSION (ext. version)	Invest & dispatch	Nuclear, Coal (2), gas, oil, hydro, biomass, PV, CSP, wind (2), geothermal, imports, other	PHS, CAES	EU-27, countries, NTC + power flow	24 time slices per year, 4 h	inter-temporal, 10-years-steps	-80 % in 2050
LIMES-EU+	Invest & dispatch	Nuclear, Coal, Gas, Hydro, Biomass, Wind (2), PV, CSP	Day/night, day to day, CSP	20 regions EU-MENA, NTC	49 time slices per year, 6 h	inter-temporal, 5-years steps	-90 % in 2050

The models by Becker et al. (2013) and the ReStore2050 model (Vogt et al., 2016) present distinct simulation based models. The latter is designed for analyzing flexibility options based on predefined electricity system infrastructure. One important and outstanding aspect is the rolling time horizon for dispatch planning. In contrast to other optimization based models like URBS, no perfect information (perfect foresight) is assumed. This allows for more realistic assessments of electricity system operation. The missing feature of investment planning makes this model unsuitable in the context of this thesis. The model used by Becker et al. (2013) is suitable to obtain insights from varying shares of wind and PV along a exogenously defined pathway. However, the model has shortcomings in certain important aspects. It lacks in representing large variety of power generation and energy storage system technologies. Regarding the analysis of least-cost decarbonization pathways the tool misses the option for model endogenous determination of electricity system designs. This information must be provided as a priori to the model. Hence, this approach does not allow for analyzing economically-optimized electricity supply system designs that are constrained by GHG emission reduction targets and therefore it cannot be applied in this thesis.

The most promising approaches for the aim of this work that were found in the literature review are the models LIMES-EU+ (Haller et al., 2012a,b; Ludig et al., 2011; Nahmmacher et al., 2014) and DIMENSION (ext. version) (Fürsch et al., 2013; Jägemann et al., 2013; Richter, 2011). Both of these models have a strong focus on assessing possible future electricity system design while studying the transition of infrastructural changes. LIMES-EU+ was used to assess the cost-optimal development of the European electricity system under -90 % GHG emission reduction until 2050 (Haller et al., 2012b; Haller, 2012). DIMENSION (ext. version) was applied in a study that analyzed -80 % GHG reduction in the electricity system complemented by the goal of a RES share of 80 %. Furthermore, the models provide a decent technology representation, the ability to plan electricity system designs along a predefined GHG reduction pathway, a sufficient spatial representation, representation of the transmission system, and consideration of short-term electricity system dynamics.

LIMES-EU+ and DIMENSION both explore future electricity system design with combined invest and dispatch planning that is implemented based on linear programming. Both models have the feature of explicitly incorporating the pathway towards the 2050 goals. Therefore, DIMENSION (ext. version) applies 10 years steps whereas LIMES-EU+ represents the steps towards 2050 on a 5-years scale. The assessment of the decarbonization pathway is based on inter-temporal modeling across decades. In other words, the model has perfect foresight across the entire period of time. Hence, investment decisions by 2050 could be drawn on the basis from information decades earlier.

Both models reflect present major and potentially future major power generation technologies in sufficient technological distinction and detail. Whereas DIMENSION includes two specific energy storage system technologies, PHS and CAES, LIMES-EU+ model one specific technology (CSP storage system) and two generic energy storage systems. The generic ESSs are described as day/night and day-to-day storages. Both models are designed to represent multiple regions with NTC approximation for the transmission system. DIMENSION (ext. version) adds a detailed investigation of transmission grid operation on top by iteratively linking the long-term energy system model (called the electricity market model by the authors). This allows to validate the findings regarding transmission system extensions and provides a more detailed perspective for the transmission grid. However, this valuable feature goes beyond the scope of this thesis.

Both, Haller et al. (2012b) and Fürsch et al. (2013), argue towards representing the short-term temporal in fine details. This is true when looking from the perspective of established long-term planning models. In the context of recent model development, the temporal scale of modeling is limited. In DIMENSION (ext. version) short-term effect of electricity system operation is modeled with four hour resolution of time steps. LIMES-EU+ used six hourly time steps to describes these short-term effects. In addition, both models use only a subset of time steps to evaluate the electricity system operation for one reference year which reflects one planning period. DIMESION (ext. version) daily and seasonal variations of demand and supply by four typical days. LIMES-EU+ uses 49 time slices that were selected to reflect variability of supply and demand.

The features of both models, DIMESION (ext. version) and LIMES-EU+, aligned very closely to the above defined criteria for a suitable model in context of this thesis. Nevertheless, modeling time steps by time slices, the temporal resolution, and missing long-term energy storage system technologies make LIMES-EU+ and DIMENSION (ext. version) unsuitable for the purpose of this work. Whereas the temporal resolution could be improved by using better data and long-term energy storage system could be integrated into the model, the issue with time slices remains. Despite the improvements in time step aggregation/clustering methods to reveal representative time slices, long-term energy storage systems cannot be sufficiently described by time slice without any information about the chronology (Kotzur et al., 2018). Therefore, the assessment of GHG reduction pathways close to zero emissions, which is primarily based on electricity generation by volatile RES and extensive use of ESS, is not accurately possible with using time slices. This approach of complexity reduction might work for the assessment of high RES shares (80 %) as for example in the study by Fürsch et al. (2013) because operation of fossil-fueled power plants is not strongly restricted. Electricity systems involving GHG reductions greater than 90 %

through massive extension of RES electricity supply cannot be assessed due to inaccurate representation of long-term energy storage systems.

Despite valuable features included in these eight electricity system models, none of these entirely meets the requirements that are defined in context of this thesis. The approach of combined investment planning and dispatch modeling used by Czisch (2005), URBS-EU, REMix, LIMES-EU+ and DIMENSION which is implemented by using LP is in general applicable in the context of this thesis. Hence, the electricity system model developed for the aims of this thesis builds upon this approach. How the approach is adapted and extended for the specific needs of this thesis is explained in Section 3.4.

3.2 Considered technologies

The overview on electricity system technologies in Section 2.1 shows that a vastly diversified landscape of technologies exists. Representing each of the available generation technologies individually in the electricity system model would lead to unmanageable model complexity in terms of computational cost. Therefore, the focus is laid on most important technologies of present and potential future electricity supply. Generation technologies that have relatively small shares on cumulative generation are neglected. Furthermore, the technological distinction is reduced in order to handle complexity. The degree of technological distinction is defined in accordance with technical detail that can be represented by the modeling approach. One should bear in mind that decarbonization pathways carried out by this thesis only provide a sketch of the future electricity system design.

A large variety of RES based generation technologies is available. The choice of technologies considered in the model depends on the technical potential (i.e. due to available resources or land-use), stage of technological development, and cost. A number of technologies are not considered in this study: biomass, concentrated solar power, tidal and wave power, geothermal, offshore wind energy, and airborne wind energy. The potential for biomass power supply is assessed to be quite low; due to conflict of interest with food sector and high land-use requirements (Ignaciuk et al., 2006). Concentrated thermal solar power (CSP) offers great technological potential when it is equipped with a thermal energy storage. However, due to current high cost compared to PV power (Schröder et al., 2013), it is not considered in the model. Despite its current high investment cost, offshore wind energy may have a larger role in future electricity supply. In terms of limiting the model's complexity, a particular distinction between onshore and offshore wind energy is not undertaken. Tidal and wave as well as airborne wind energy are excluded in this study. These are technologies of relatively small generation capacity and limited importance for future electricity supply. Two RES technologies remain to be represented by the applied electricity system model: wind and photovoltaic power. The vast variety of the types of these technologies is reduced to the representation of solely one technology each in the model.

The selection of conventional power generation technologies represented in the model is motivated by (a) reflecting current major technologies and (b) technologies that are expected to be relevant in future low-carbon electricity supply. Thus, the study considers gas, coal, and nuclear fueled power plant technologies as well as hydro power. Oil-fueled power plants are not considered but are comparable to gas power plants regarding operational characteristics. Conventional power generation technologies included in this study are represented by four distinct technologies. One generic coal power plant represents hard coal and lignite fueled power generation technology. Gas power generation technologies are distinguished to open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT). The quite detailed representation is explained by differences regarding efficiencies and costs of both technologies. Furthermore, gas-fueled electricity generation is expected to serve as bridging technology towards low-carbon electricity and as part of a PtG based long-term energy storage system using gas power plants for re-electrification of SNG. Nuclear power is represented by a single technology reflecting current state of technology. Likewise, a single technology in the model represents different technological concepts of hydro power electricity generation.

Strongly intermittent RES based electricity supply is expected for the future in order to meet mitigation targets (Jacobson and Delucchi, 2011). Such intermittent supply creates balancing needs ranging from hours to weeks or even months. Six applications that are relevant in the context of this thesis were identified (see Section 2.1.2): load following, peak shaving, transmission curtailment, time shifting, unit commitment, and seasonal storage. Thus, storage technologies operating at short-term (hourly) and medium to long-term (weeks to month) are required to meet those needs. A study on balancing needs of intermittent RES based electricity supply found a 6-h storage technology is optimal for balancing needs of intermittent electricity supply by wind and solar power best (Rasmussen et al., 2012). Hydro power is a suitable and available technology to balance demand and supply mismatches of intermittent RES electricity supply system at short to medium term. But, as no further extension of PHS capacity is considered in this study, other energy storage technologies must be taken into account. Plenty of BESS technologies are available operating on hourly to daily basis, and are suitable to cover a part of the range PHS operates (Luo et al., 2015). Considering electricity supply with very high shares of intermittent RES may require a storage technology that operates on long-term scale. Besides compressed-air energy storages and electrolyzer-fuel cell based storage systems, power-to-gas (PtG) offers affordable energy storage of mid to long-term range. Thus, besides PHS technology, a battery energy storage system and power-to-gas are considered in the electricity system model. The latter encompasses of an electrolyzer, methanation unit and a gas storage. Gyuk et al. identified the same technologies as suitable for above mentioned applications (except from seasonal storage). These are lead-acid, sodium-sulfur battery (NaS), lithium-ion battery (Li-ion) and flow batteries (Gyuk et al., 2013). Considering a capacity-power ratio of 6 kWh/kW as suggested by Rasmussen et al. (2012), Li-ion batteries are not ideal. Thus, the technologies lead-acid, NaS or flow batteries are adequate technologies for the modeling approach. The choice among these three potential technologies is primarily motivated by expected future cost and discussed in Section 4.4 in detail. The choice for a particular technology is mainly motivated by expected future cost. Nevertheless, due to the relatively simple model applied for energy storage systems, depending on the deviation of parameters, findings are transferable to similar energy storage system technologies.

Regarding grid infrastructure, the modeling approach only takes into account cross-border transmission capacity. These typically comprise of extra-high and high voltage systems. Technologically, the model refers to current existent technology of AC transmission systems. A high-voltage direct current overlay grid is not explicitly considered in this context, but findings on that can derived by this modeling approach. A further distinction of transmission system technologies is not made.

3.3 Study region

As this thesis analyzes decarbonization in Europe, it needs a definition of the spatial extent of this region. Despite various definitions that are available for the spatial extent of Europe, in this thesis Europe is defined as the union of the member countries of the EU and the ENTSO-E with a few exceptions. This definition, on the one hand, reflects the political region of the EU where important climate protection legislation applies. On the other hand, considering the geographical extent of the ENTSO-E member countries reflects the technical circumstances of the interconnected European transmission grid. Three exceptions from this approach apply: Albania is considered in this work and the Russian exclave is not considered here[1]. The three island countries Iceland, Malta and Cyprus are excluded from investigations

[1]Albania is neither a member of the ENTSO-E nor a member of the EU but it's grid frequency is synchronized to the ENTSO-E grid and a transmission link exists. The Russian exclave Kaliningrad is due to its geographic location connected to the ENTSO-E grid, but is not accounted for in this thesis. Kaliningrad is part of Russia and therefore not member of the EU nor the ENTSO-E.

due to missing links to the land-based grid. This results in 39 countries considered in this thesis.

The 39 investigated countries create large computational cost if they are all individually modeled in a multi-regional energy system model so as to deal with the compiled research questions. To reduce computational effort raised by a large number of modeled regions, countries are clustered to representative regions. Clustering is performed according to following criteria (the order does not reflect importance):

1. Topology of ENTSO-E transmission grid
2. Typical country grouping (i.e. *Benelux*)
3. Impact of an individual country

From analyzing the topological features of the ENTSO-E transmission grid it is advisable to cluster countries like Spain and Portugal that are connected to the remaining ENTSO-E countries via a single transmission link. This applies similarly to Great Britain and Ireland. Typical groups of countries are used to cluster countries to regions like Benelux or Baltic. The impact of a country on the results of the analysis is predominantly defined by its electricity demand. Countries of low consumption marginally affect the cumulative cost for decarbonizing Europe's electricity supply. Hence, super-small countries like Andorra, Liechtenstein or San Marino are included in the region of large neighboring countries. Furthermore, countries with low electricity demand (see Figure 2.5), as for example many of the Balkan countries, are clustered to regions reflecting multiple countries.

The resulting 18 regions model of Europe is depicted in Figure 3.1. Countries that are aggregated to these regions are shown as well. Table 3.2 shows the regions-countries relationships.

3.4 Theoretical framework of *elesplan-m*

Model parameters required to study GHG mitigation options in the European electricity sector, were already been outlined in Section 3.1 and cover the following aspects: purpose and scope, technological detail, spatial representation and transmission system, short-term temporal representation, long-term and pathway modeling, and GHG limit modeling. As the requirements regarding these aspects are not entirely met by any of the available energy system models (refer to Section 3.1), a model is built that meets the described requirements and seizes upon available electricity system model implementations. The developed electricity

Figure 3.1: European countries and derived 18 regions. Bold lines indicated region border; light and dashed lines show country borders.

system model is entitled European long-term energy system planning model (*elesplan-m*).

The design of *elesplan-m* provides insights on least-cost GHG mitigation pathways of the European electricity sector. The decarbonization of Europe's electricity supply is studied along a pathway of predefined GHG reduction targets in five years intervals from 2020 until 2050. The least-cost decarbonization pathway is identified by successively determining the economically optimal electricity system design compliant with defined GHG emission limits for each interval. Each of the planning intervals stands for a representative year of electricity supply in this interval. The assessment of the cost-optimal system design takes places in due consideration of the present electricity supply system infrastructure. Thus, with respect to the technical lifetime of the infrastructure, generation capacity, energy storage systems, and the transmission system is extended in each interval in order to meet the electricity demand.

Table 3.2: Defined regions and the respective countries

Region	Countries
Eastern Balkans	Serbia, Kosovo, Bulgaria
Italy	Italy, San Marino, Vatican City State
Iberia	Spain, Portugal, Andorra
Hungary-Romania	Hungary, Romania
Southern Balkans	Greece, Macedonia, Albania
Great Britain & Ireland	Great Britain, Ireland
Western Balkans	Slovenia, Croatia, Bosnia and Herzegovina, Montenegro
France	France, Monaco
Czech Republic & Slovakia	Czech Republic, Slovakia
Baltic	Lithuania, Latvia, Estonia
Alpine Region	Switzerland, Austria, Liechtenstein
Benelux	Belgium, Netherlands, Luxemburg
Germany	Germany
Norway	Norway
Finland	Finland
Sweden	Sweden
Poland	Poland
Denmark	Denmark

Figure 3.2 illustrates the successive electricity system transformation planning approach that is implemented by *elesplan-m*.

This approach of decarbonization pathway assessment can be understood as successive application of a *snapshot planning* model, such as URBS (Aboumahboub et al., 2012; Schaber et al., 2012a) or GENESYS (Bussar et al., 2015, 2016). This means, as shown in Fig. 3.2, that beginning with the planning period starting in 2020 the inner snapshot planning model is applied to each planning interval to determine the cost-optimal electricity system design under given GHG emission limits. When the snapshot planning model is applied to the next planning period, parameters and data are updated according to the predefined decarbonization pathway scenario (cf. Ch. 4). As indicated in Fig. 3.2, planning periods are linked by capacity data of existing electricity system infrastructure. Previously installed capacity is taken from the preceding planning interval and fed to the model as existing capacity. This includes capacity of power generation, energy storage systems and the transmission system. Necessary and least-cost investments into electricity system infrastructure are determined under consideration of optimal dispatch. Optimal dispatch in this case refers to the power plant, ESS and transmission system operation that meets the given demand, adheres to GHG

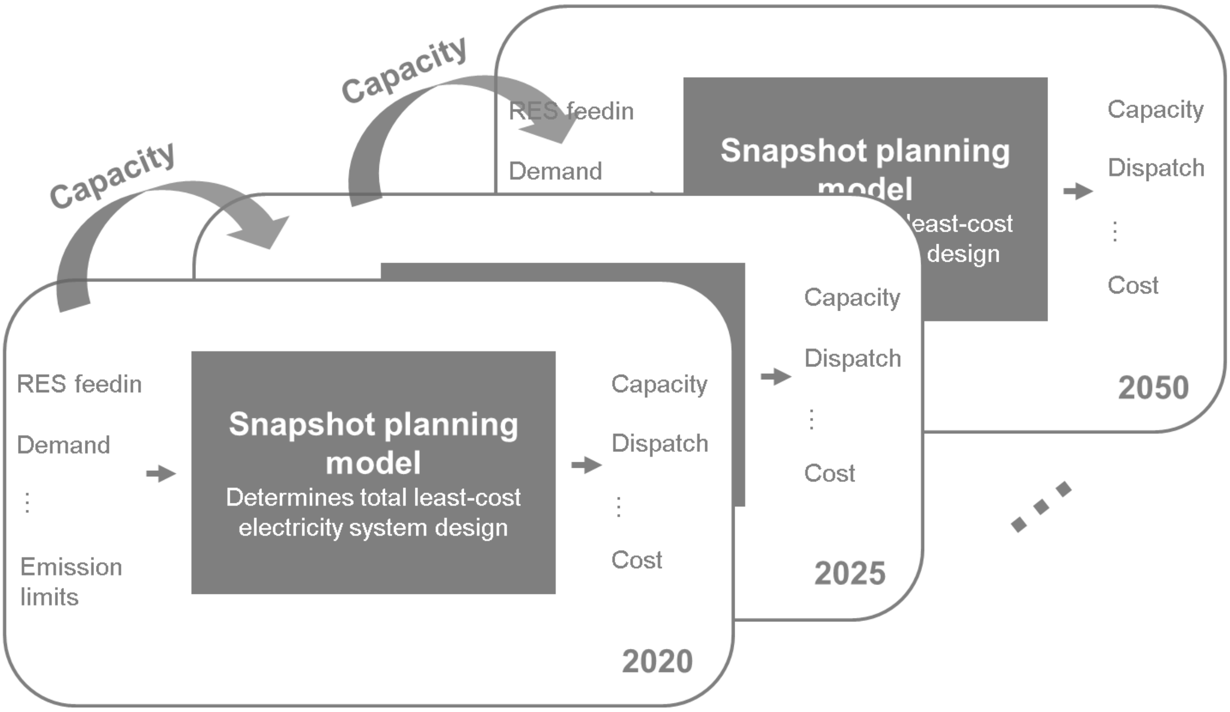


Figure 3.2: Approach of the electricity system modeling tool *elesplan-m* for successively assessing the transformation of the electricity supply system. Capacity passed from one planning interval to the next includes power plants, energy storage system and transmission system capacity.

emission limits, and results in lowest cumulative annual cost. The cumulative annual cost comprise of annuities of electricity system infrastructure – present and newly invested capacity – and its operational cost. The latter includes both, operational and maintenance cost as well as fuel cost. Compared to the inter-temporal modeling that is used in DIMENSION (Fürsch et al., 2013; Richter, 2011) and LIMES-EU+ (Haller et al., 2012a; Nahmmacher et al., 2014) which implies perfect foresight, the pathway assessment by *elesplan-m* has myopic character. LIMES-EU+ is used for example by Haller et al. (2012b) to study -90 % GHG until 2050. Due to perfect foresight that spans multiple decades, the electricity system design is determined along the planning period with full knowledge regarding future circumstances and model decisions. Aside from overestimating the long-term planning capabilities in terms of knowledge about future events, this inter-temporal approach induces large complexity which has to be saved elsewhere in the model. In contrast, *elesplan-m* is myopic beyond the present planning period. Thus, investment decisions in the model are individually determined for each planning period omitting future circumstances. In the following, the inner snapshot planning model is discussed in more detail.

The *snapshot planning* model is greatly inspired by the combined investment and dispatch models by Czisch (2005) and the model URBS Aboumahboub et al. (2010). In particular, the aspect of combining investment and dispatch planning tightly in a linear programming (LP) based model implementation is borrowed. Compared to GENESYS (Bussar et al., 2015) this is advantageous because the power system operation can be determined flexibly instead of being restricted due to a rigid system management. A LP approach facilitates implementing combined dispatch and investment planning efficiently. Linear programming is a suitable modeling technique to achieve computable large-scale models comprising of a large number of variables and constraints (Bixby et al., 1992).

A principle – in this case minimization – LP model is displayed in Eq. (3.1).

$$\begin{aligned} \min \quad & c^T \cdot \vec{x} \\ \text{s.t.} \quad A \cdot \vec{x} & \leq \vec{b} \\ \vec{x} & \geq 0 \end{aligned} \tag{3.1}$$

Models using linear programming, often referred as linear models or linear problems, consist of four components: objective function, decision variables, constraints and parameters (Dantzig and Thapa, 2006). The first line of this minimal LP model represents the objective function. The latter two lines represent constraints that bound the solution space. The goal is to find minimal values for the objective by varying the model variables $\vec{x}$ (also decision variables) in consideration of the solution space being bounded by the constraints. The term c^T describes costs that are associated to each decision variable. Model parameters are reflected by matrix A. Data that sets the bounds of the constraints is given by the term $\vec{b}$.

The amalgamation of capacity extension of electricity system units (power plants, energy storage systems, transmission system) and dispatch planning is achieved by treating both as decision variables. Thus, for example, the actual electricity generation of a power plant is not constrained by existing capacity. Its upper limit comprises of the currently existing capacity plus newly invested capacity. This approach was introduced by Czisch (2005) in order to assess volatility of RES at high temporal resolution. Numerous work embraced this approach in order to assess suitable options to integrate intermittent RES in the current electricity supply system (Aboumahboub et al., 2010; Schaber et al., 2012b,a). The aforementioned perfect foresight over one year implies that solutions obtained from *elesplan-m* are drawn by full-transparent information about the entire year. In terms of market modeling this inherently imposes a representation of the European electricity market with perfect competition. On the one hand this overestimates market competition, but on the other hand it provides easily interpretable results. Results reflect the technical-economically optimized electricity supply system unbiased from any influence of electricity trade schemes (such as the current European electricity trade that is based on marginal cost).

The model is implemented by a multi-regional approach that uses countries or groups of countries as regions. The spatial distinction of these regions is described in Section 3.3. This multi-regional approach allows for analyzing spatial effects. This includes spatially different distributed potential of RES based electricity generation and congestions of cross-border transmission capacity. The latter are analyzed by modeling cross-border transmission capacities by the NTC approach which is a common grid modeling technique in energy system models (Hall and Buckley, 2016). According to the technological distinction defined for this thesis (see Section 3.2) and the 18-regions representation of electricity supply in Europe, aggregation of electricity system infrastructure capacity takes place. Thus, the capacity of each power generation and energy storage system technology is represented by a single decision variable in each region. Figure 3.3 exemplifies a model region by sketching electricity supply infrastructure of this region plus indicating transmission links to neighboring regions (regions B and C).

The electricity supply system in each of the regions comprises of the technologies which are shown in Figure 3.3. Electricity exchange among regions is represented by aggregated cross-border transmission capacities between these regions. The electricity system comprises of three RES technologies (hydro power, wind power and PV power), four thermal power plant technologies (nuclear, coal, open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT)) and three ESS technologies (PHS, battery storage and PtG based storage systems). The latter ESS technology additionally requires a gas power plant for re-electrification of SNG that is produced by the PtG facility. Arrows in Figure 3.3 reflect potential power (respectively energy) flows that are foreseen by the modeling approach. Further details on modeling of each technology is elaborated upon Section 3.5. The model applies a 1-hourly representation on the temporal scale. Thus, one reference year that is representatively assessed for one planning period comprises of 8760 intervals that are consecutively analyzed. This relatively high temporal resolution and the preserved chronology of time steps allow studying low-carbon electricity supply scenarios that are mainly based on RES supply. In particular, the intermittency of RES electricity generation and emerging balancing needs can be studied in sufficient detail (Després et al., 2015; Welsch et al., 2015). The retained chronology of time steps furthermore enable assessing operation and, therefore its required capacity of long-term energy storage systems (Kotzur et al., 2018), such as the PtG systems used in this thesis. This uniquely distinguishes *elesplan-m* from long-term planning models that used time step aggregation methods and representative time slice such as LIMES-

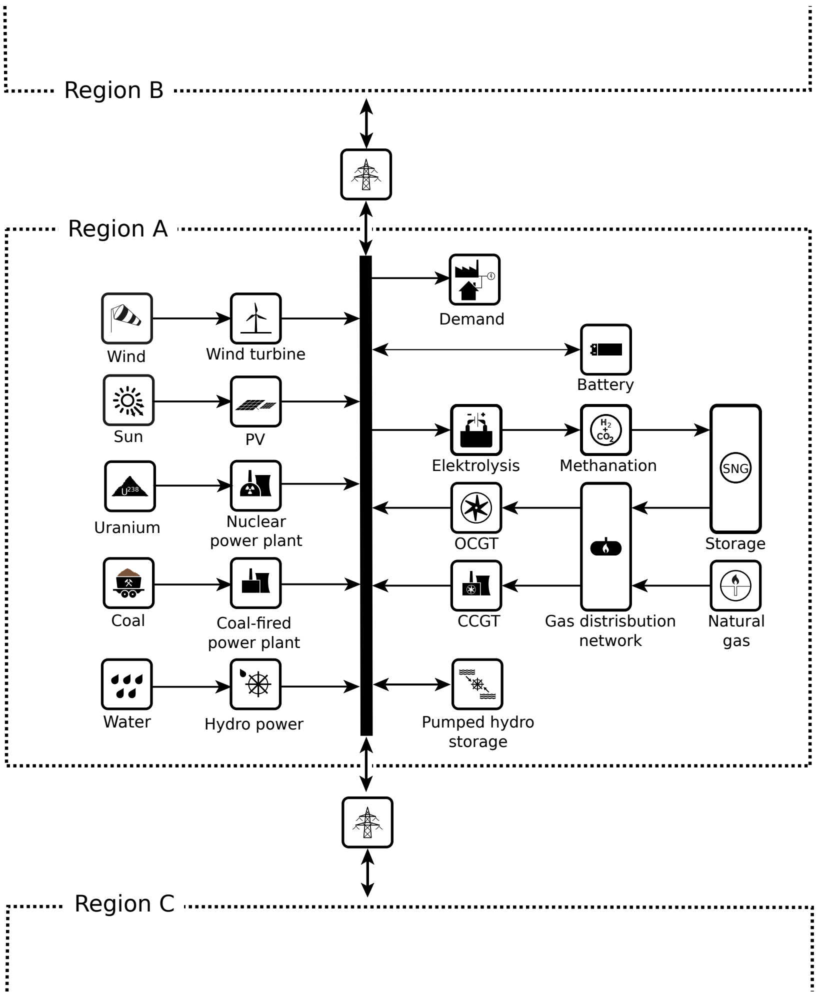


Figure 3.3: Schematic representation of the electricity system model *elesplan-m* exemplary for one region.

EU+ and DIMENSION. Consequently, *elesplan-m* has the advantage of analyzing deep decarbonization pathways which involves modeling of electricity supply system with very high shares of RES supply. These system, supplied by mainly wind and PV power, then require for cost-efficient seasonal storage of electricity.

The output of *elesplan-m*, hence the determined decision variables for each year that is analyzed, include newly installed capacity and operation of power plants, energy storage system and the transmission system, as well as fuel consumption. In case of power plants the operation refers to dispatch. The operation of energy storage systems is described by charging, discharging and the SoC. Regarding the transmission system electricity exchanges between regions are determined. All this operational data is available as one hourly resolved time series for the entire year. From these raw model outputs descriptive figures like GHG emissions and levelized cost of electricity (LCOE) are calculated.

3.5 Model structure and notation

This section presents the model structure and its mathematical notation in detail. The modeling approach of *elesplan-m*, explained in Section 3.4, is translated to a mathematical linear programming model. First, the objective function that drives the electricity system planning towards a least-cost solution is detailed. This is followed by model's constraints regarding electricity system technologies, its operation and guarantee electricity supply compliant with GHG mitigation targets. Finally, a quick overview on the implementation and applied solver is provided.

3.5.1 Objective function

The objective function of a linear problem defines the aim of its optimization and drives the decision variables into a certain direction. Depending on the type of optimization goal – minimization or maximization – the objective function aims for minimal or maximal value. This minimal or maximal value is restricted by constraints that affect decision variables which are part of the objection function as presented in following.

The objective function applied in *elesplan-m* (see Eq. (3.2)) aims to minimizes the total cost of electricity supply. Total cost of electricity supply comprise of cost of power generation, energy storage system operation, transmission system utilization and curtailment. This includes expenditures for existing and newly built electricity supply system infrastructure. Operational expenditures of the electricity system include all costs of operation such as fuel and maintenance cost. Cost of investments into new capacity and cost of existing infrastructure are reflect on the basis of equivalent annual cost. These calculate as capital expenditures $Capex_{i,r}$ multiplied by the capital recovery factor CRF_i which annualizes cost respecting cost of capital and distributes the annuities across the expected lifetime. Operational and maintenance cost are reflected by fixed operational expenditures $Opex_{\mathrm{fix},i,r}$ and variable operational expenditures $Opex_{\mathrm{var},j,r}$, whereas the latter are related to each kilowatthour produced and mainly comprise of fuel cost. Fixed operational cost reflect fixed annual expenditures per unit of capacity. The objective function distinguishes between existing electricity system infrastructure ($P_{\mathrm{cap,exist},i,r}$) and new installations ($P_{\mathrm{cap,new},i,r}$) in order to respect a potential change in costs.

$$\begin{aligned}\min \quad cost_{total} = \sum_r \Bigg(& \sum_i \left(Capex_{i,r} \cdot CRF_i + Opex_{\text{fix},i,r}\right) \cdot (P_{\text{cap,exist},i,r} \\ & + P_{\text{cap,new},i,r}\ ) + \sum_j \sum_t Opex_{\text{var},j,r} \cdot P_{\text{resource},j,r,t} \Bigg)\end{aligned} \tag{3.2}$$

with

r	region index
i	power plant, energy storage, transmission technology index
j	resource index
t	time index
$Capex_{i,r}$	Capital expenditures of technology i in region r
CRF_i	Capital recovery factory of technology i
$Opex_{\text{fix},i,r}$	Fix operational expenditures of technology i in region t
$P_{\text{cap,new},i,r}$	Nominal capacity (new installations) of technology i in region r
$P_{\text{cap,exist},i,r}$	Nominal capacity (existing capacities) of technology i in region r
$Opex_{\text{var},j,r}$	Variable operational expenditures of resource j in region r
$P_{\text{resource},j,r,t}$	Consumption of resource j in region r and time step t

The capital recovery factor (CRF) uses weighted average cost of capital (WACC) and the lifetime of the respective electricity system component to determine an equal distribution of cost over the entire lifetime of an investment (cf. Eq. (3.3)) – the equivalent annual cost. The WACC therefore considers cost of equity and dept.

$$CRF_i = \frac{WACC \cdot (1 + WACC)^n}{(1 + WACC)^n - 1} \tag{3.3}$$

where

$WACC$	weighted average cost of capital

n	lifetime

3.5.2 Electricity generation

Electricity generation technologies are modeled as transformer converting energy from primary energy to electricity while considering the efficiency of said conversion. A distinction is made between existing and newly built power generation capacity in order to reflect a potential change in cost and efficiency. Furthermore, thermal power plant technologies are represented differently from RES power generation technologies. Power output of the latter is dependent on the meteorological conditions, whereas thermal power plant technologies consume resources.

3.5.2.1 Renewable energy sources technologies

Electricity generation by the renewable energy sources technologies wind, PV, and hydro power depends on weather conditions. More precisely the potential electricity generation of wind power is limited by the wind speed, electricity generation by PV power depends on sunlight irradiation, and hydro power is related to precipitation and resulting water flows. These external circumstances that determines power output of RES technologies are described by time series of weather data. Weather data time series are converted to time series of normalized electricity generation for each technology denoted by the parameter $k_{\mathrm{feedin},i,r,t}$. Weather data is converted to feedin time series considering the conversion efficiency of a technologies. Details about the construction of time series including the actual model of the RES technologies are provided in Section 4.9. The actual power output of a RES technology is determined by scaling normalized electricity generation time series with the nominal capacity (cf. Eq.(3.4)). Curtailment of electricity generation is not explicitly modeled here, but described in Section 3.5.5.

$$P^{\mathrm{volatile}}_{\mathrm{gen},i,r,t} = k_{\mathrm{feedin},i,r,t} \cdot (P_{\mathrm{cap,exist},i,r} + P_{\mathrm{cap,new},i,r}) \quad \forall i \in I, r \in R, t \in T \tag{3.4}$$

with

$P^{\mathrm{volatile}}_{\mathrm{gen},i,r,t}$	Power generation of RES technology i in region r and time step t
$k_{\mathrm{feedin},i,r,t}$	normalized power generation of RES technology i

3.5.2.2 Conventional power plants

Modeling of thermal power plants takes two aspects into account. First resource consumption (gas, coal, uranium) that is reflected by the conversion efficiency from primary energy to electricity. Second, the nominal power of a power generation technology. The latter is considered by Eq. (3.5) that defines actual generation by a technology i to be less or equal to the available capacity composed of existing and newly built capacity.

$$P^{\text{elec}}_{\text{gen},i,r,t} \leq (P_{\text{cap,exist},i,r} + P_{\text{cap,new},i,r}) \quad \forall i \in I, r \in R, t \in T \tag{3.5}$$

where

$P^{\text{elec}}_{\text{gen},i,r,t}$ electricity generation of power plant technology i in region r and time step t

Modeling of power plant efficiency η are applied differently for coal and nuclear than for gas-fueled power plants. As *elesplan-m* considers SNG production by PtG units that is potentially used in gas power plants, gas streams of natural gas and synthetic gas are treated separately in the model (cf. Section 3.5.3.2).

Coal and nuclear power plants Coal and nuclear power plants convert primary energy from coal respectively uranium to electricity. The electricity generation by these power plant technologies $P^{\text{elec}}_{\text{gen},i,r,t}$ translates to resource consumption $P_{\text{resource},j,r,t}$ by considering the conversion efficiency η_i as described by Eq. (3.6).

$$P^{\text{elec}}_{\text{gen},i,r,t} = \eta_i \cdot P_{\text{resource},j,r,t} \quad \forall i \times j \in I \times J, r \in R, t \in T \tag{3.6}$$

where

η_i efficiency of power plant type i

$P_{resource,j,r,t}$ Energy contained in resource j in region r and time step t

Gas power plants Modeling of gas power technologies (OCGT and CCGT) take the origin of gas into consideration. This allows for ex-post assessment of natural and synthetic gas consumption. Similarly to coal and nuclear power plants, gas power plant technologies' power output $P^{\text{elec}}_{\text{gen},i,r,t}$ is defined by the efficiency η_i multiplied by the amount of energy from resource consumed (see Eq. (3.7)). The latter term composes of a natural gas stream $P_{\text{fos. gas},i,r,t}$ and synthetic gas stream $P_{\text{syn. gas},i,r,t}$. In what specific manner the separate treatment of the gas streams is implemented is described in Section 3.5.3.2.

$$P^{\text{elec}}_{\text{gen},i,r,t} = \eta_i \cdot \left(P_{\text{syn. gas},i,r,t} + P_{\text{fos. gas},i,r,t}\right) \quad \forall i \in I, r \in R, t \in T \tag{3.7}$$

where

i	gas power plant technology with I = {OCGT, CCGT}
$P_{\text{syn. gas},i,r,t}$	gas flow of SNG gas feeding gas power plant i
$P_{\text{fos. gas},,ir,t}$	gas flow of fossil gas feeding gas power plant i

3.5.3 Energy storage systems

Of the three energy storage technologies considered, PtG stands out because its modeling approach is more complex. Energy storage systems are represented by a basic model that is comparable to a bucket which can be filled and emptied. This *bucket model* includes lower and upper bounds for the SoC as well as the charge and discharge efficiency of energy storage systems. This applies for all storage technologies batteries, PHS and PtG along with a gas storage. First the storage model is explained on the example of battery and pumped-hydro storage systems. Subsequently the PtG unit including its gas storage is described which is based on the modeling approach for battery and pumped hydro storage systems.

3.5.3.1 Battery and pumped-hydro storage systems

The energy storage system model applied in this thesis considers charge and discharge efficiency, nominal charge and discharge power, nominal storage capacity, and the state of charge (SoC) in terms of conservation of power. For ease of understanding the model can be compared to a bucket with a maximum fill level defined by its size. Translated to a energy storage system, size is the capacity of a energy storage system in terms of energy that can be stored. Furthermore, the flow into the bucket is constrained which can be translated to a limit on charge and discharge power. Energy storage system technologies differentiate themselves by the parameters charge and discharge efficiency, CP ratio (that describe to nominal capacity of a storage unit related to the nominal power), and cost of the particular technology.

Conservation of SoC in terms of updating SoC on charge or discharge events is realized by notation of Eq. (3.8). The current state of charge $SoC_{\text{storage},i,r,t}$ within each time step t is determined from state of charge plus charge $P^{\text{charge}}_{\text{storage},i,r,t}$ and discharge $P^{\text{discharge}}_{\text{storage},i,r,t}$. Charge and discharge efficiency of the energy storage system technology are considered respectively.

$$\begin{aligned} SoC_{\text{storage},i,r,t} = SoC_{\text{storage},i,r,t-1} - \frac{P^{\text{discharge}}_{\text{storage},i,r,t} \cdot \Delta t}{\eta^{\text{out}}_{\text{storage},i}} \\ + P^{\text{charge}}_{\text{storage},i,r,t} \cdot \Delta t \cdot \eta^{\text{in}}_{\text{storage},i} \quad \forall i \in I, r \in R, t \in \{2..8760\} \end{aligned} \tag{3.8}$$

where

$SoC_{\text{storage},i,r,t}$	SoC of storage technology i in region r and time step t
$P^{\text{discharge}}_{\text{storage},i,r,t}$	storage discharge power of technology i in region r and time step t
$\eta^{\text{out}}_{\text{storage},i}$	discharge efficiency of storage technology i
$P^{\text{charge}}_{\text{storage},i,r,t}$	storage charge power of technology i in region r and time step t
$\eta^{\text{in}}_{\text{storage},i}$	charge efficiency of storage technology i
Δt	time interval of charging/ discharging

Equation (3.8) only applies beginning with the second time step. The state of charge for the first time step of a model run has to be determined individually. As the availability of electricity from energy storage systems has particular importance in the first time steps of a year when high shares of RES are involved, the SoC needs to be chosen concisely. In this thesis *elesplan-m* balances annual storage power by interlinking the SoC of the last time step with the one of the first time step as denoted by Eq. (3.9). Analogously to Equation (3.8) this applies under consideration of charge and discharge in the first time step.

$$\begin{aligned} SoC_{\text{storage},i,r,t=1} = SoC_{\text{storage},i,r,t=8760} - \frac{P^{\text{discharge}}_{\text{storage},i,r,t=1} \cdot \Delta t}{\eta^{\text{out}}_{\text{storage},i}} \\ + P^{\text{charge}}_{\text{storage},i,r,t=1} \cdot \Delta t \cdot \eta^{\text{in}}_{\text{storage},i} \quad \forall i \in I, r \in R \end{aligned} \tag{3.9}$$

Discharge power of energy storage technologies is bounded by maximum discharge power and available energy in the storage. The maximum discharge power is defined by the quotient of energy storage capacity $E^{\text{cap}}_{\text{storage},i,r}$ to the ratio of storage capacity and storage power $CP^{\text{out}}_{\text{storage},i}$ (see Eq. (3.10)).

$$P^{\text{discharge}}_{\text{storage},i,r,t} \leq \frac{E^{\text{cap}}_{\text{storage},i,r}}{CP^{\text{out}}_{\text{storage},i}} \quad \forall i \in I, r \in R, t \in T \tag{3.10}$$

where

$E^{\text{cap}}_{\text{storage},i,r}$ capacity of storage technology i in region r

$CP^{\text{out}}_{\text{storage},i}$ energy to power ratio of storage technology i (discharge)

The momentarily available energy from an energy storage system is defined by the $SoC_{\text{storage},i,r,t}$. The actual discharge must be less than or equal to $SoC_{\text{storage},i,r,t}$ considering the discharge efficiency $\eta^{\text{out}}_{\text{storage},i}$. Thus, discharge power is limited for each time step by the SoC as notated in Eq. (3.11).

$$P^{\text{discharge}}_{\text{storage},i,r,t} \cdot \Delta t \leq SoC_{\text{storage},i,r,t} \cdot \eta^{\text{out}}_{\text{storage},i} \quad \forall i \in I, r \in R, t \in T \tag{3.11}$$

Limitation of power while charging the energy storage applies analogously as for discharging as described by Equation (3.10). Equation (3.12) determined the upper bound of charge power which is defined by the storage capacity $E^{cap}_{\text{storage},i,r}$ and capacity power ratio $CP^{\text{in}}_{\text{storage}}$.

$$P^{\text{charge}}_{\text{storage},i,r,t} \leq \frac{E^{cap}_{\text{storage},i,r}}{CP^{\text{in}}_{\text{storage}}} \quad \forall i \in I, r \in R, t \in T \tag{3.12}$$

where

$CP^{\text{in}}_{\text{storage}}$ energy to power ratio of storage technology i

Lastly, it must be guaranteed that the energy storage is not overcharged. Equation (3.13) bounds the SoC by nominal storage capacity. In combination with Eq. (3.8) charge power $P^{\text{charge}}_{\text{storage},i,r,t}$ is kept below remaining storage capacity.

$$SoC_{\text{storage},i,r,t} \leq E^{\text{cap}}_{\text{storage},i,r} \quad \forall i \in I, r \in R, t \in T \tag{3.13}$$

3.5.3.2 Power-to-Gas

Power-to-gas (PtG) refers to a system comprising of a conversion unit and a gas storage. The conversion unit converts electricity to SNG based on electrolysis and a subsequent methanation process. The gas storage is modeled analogously to the battery and pumped-hydro storage using the *bucket model*. In order to calculate the balance of SNG flows from the PtG conversion unit, the gas storage and gas power plants, a gas bus is introduced. Subsequently, this gas bus is described followed by a description of the converter unit.

Gas bus The gas bus creates a balance of gas flows from and to sources and sinks of SNG. Figure 3.4 illustrates components connected to the bus and indicates related gas flows. The gas storage on the left hand side can be charged and discharged. At the bottom of the right hand side, the electrolysis unit convert electrical energy into H_2 which is subsequently converted to SNG (CH_4) by the methanation unit and fed to the gas bus. The gas bus connects to gas power plants that convert SNG back to electricity. In addition, gas power plants can use natural gas (indicated by dashed lines in Fig. 3.4).

Equation (3.14) provides the mathematical notation to describe the gas bus in *elesplan-m*. Sources of SNG (PtG converter and discharge of gas storage) on the left hand side must be balanced with gas flows to sinks (SNG consumption of gas power plants and charge of gas storage) on the right hand side.

$$\begin{aligned} P^{\text{syn. gas}}_{\text{gen, PtG},r,t} + P^{\text{discharge}}_{\text{storage,gas},r,t} &= P^{\text{OCGT}}_{\text{syn. gas},r,t} \\ &+ P^{\text{CCGT}}_{\text{syn. gas},r,t} + P^{\text{charge}}_{\text{storage, gas},r,t} \quad \forall r \in R, t \in T \end{aligned} \tag{3.14}$$

where

$P^{\text{syn. gas}}_{\text{gen, PtG},r,t}$ PtG SNG out flow in region r and time step t

$P^{\text{discharge}}_{\text{storage,gas},r,t}$ gas storage discharge power in region r and time step t

$P^{\text{charge}}_{\text{storage,gas},r,t}$ gas storage charge power in region r and time step t

Power-to-gas conversion The power-to-gas unit converts surplus electricity, produced in times of high power generation and low demand, to SNG. First, electricity is used to produced H_2 in a electrolysis process. Second, the produced H_2 is converted via methanation

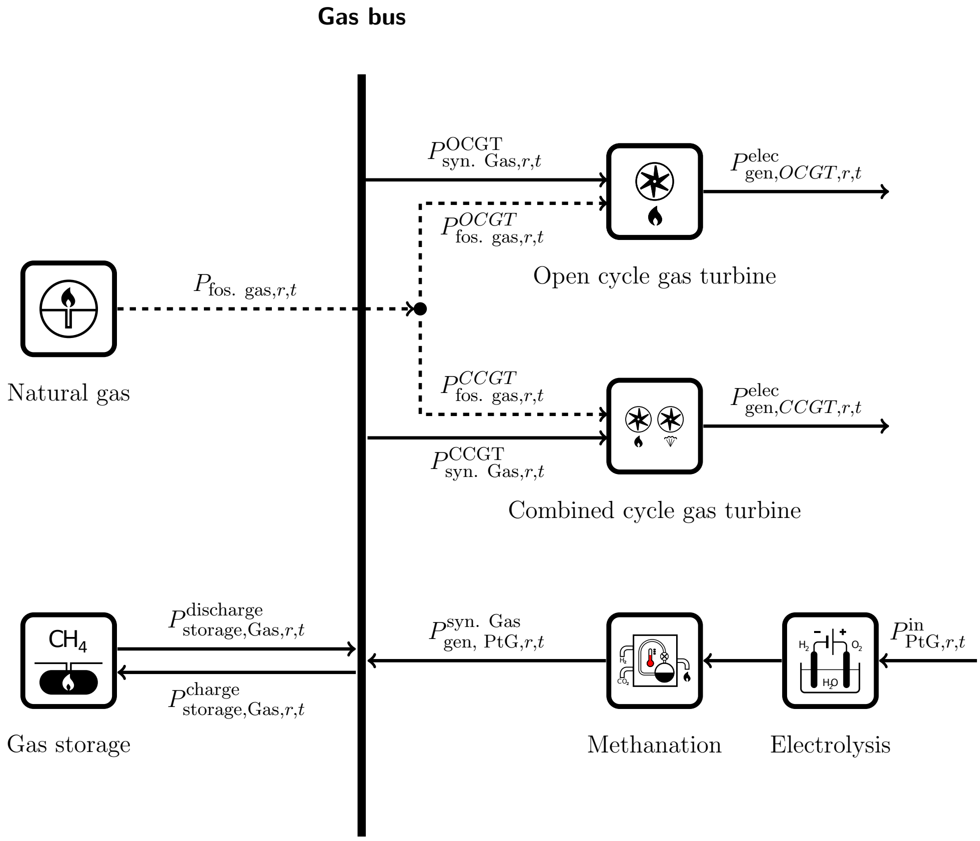


Figure 3.4: Model-internal gas bus that links gas (SNG) producer PtG with the gas storage and gas power plants. Dashed lines reflect flows of natural gas.

to SNG considering for additionally required CO_2. Both process steps are modeled at once and are characterized by a single conversion efficiency, a nominal capacity and related cost. The energy contained in the produced SNG derives from electricity consumption considering the conversion efficiency η_{PtG} (see Equation (3.15)).

$$P^{\text{syn. gas}}_{\text{gen, PtG},r,t} = \eta_{PtG} \cdot P^{\text{in}}_{\text{PtG},r,t} \quad \forall r \in R, t \in T \tag{3.15}$$

where

$P^{in}_{\text{PtG},r,t}$ PtG unit electricity consumption in region r and time step t

The nominal power of the PtG converter $P_{\text{inst, PtG},r}$ defines the upper limit of SNG production (see Eq 3.16). The nominal power refers to both existing and newly built capacity.

$$P^{\text{syn. gas},r,t}_{\text{gen, PtG}} \leq P_{\text{inst, PtG},r} \quad \forall r \in R, t \in T \tag{3.16}$$

where

$P_{\text{inst, PtG},r,t}$ nominal power of PtG converter in region r

3.5.4 Transmission system

The transmission system is represented by aggregation of cross-border capacities to single representative transmission capacities connecting regions pairwise. The analysis with the model *elesplan-m* aims for minimum cost of electricity supply and thus, for optimal power flows in the transmission system. The modeling approach for the transmission system is inspired by a transhipment problem (Bradley et al., 1977), but extended by considering capacity of a route, efficiency of the transmission system and variable amount of goods shipped. The overall optimization goal of minimal total electricity supply cost incentivizes for low losses due to transmission efficiency which can be directly translated to the preference for short routes of power flows. The amount of electricity shipped and received via the transmission system in each region determines of the regional balance $P_{\text{trans},r,t}$ of supply and demand under consideration of available energy storage system capacity.

The mathematical notation of the transmission system model is realized by two equations. The first equation (equation 3.17) ensures flow conservation at the nodes (respectively regions) by calculating the sum of all incoming and outgoing power flows of lines connected to a node under consideration of transmission efficiency. Hence, it is the application of Kirchhoff's current law. The model uses two decision variables $P_{\text{trans,in},l,t}$ and $P_{\text{trans,out},l,t}$ for representing a transmission line. This allows to successfully take transmission system losses into account.

$$P_{\text{trans},r,t} = \sum_{l} \left(\eta_l \cdot P_{\text{trans,out},l,t} - P_{\text{trans,in},l,t}\right) \quad \forall r \in R, t \in T \tag{3.17}$$

where

l indices of transmission lines

$P_{\text{trans},r,t}$ balance of all transmission line connected to region r in time step t

η_l transmission efficiency of line l

$P_{\text{trans,out},l,t}$ outgoing[2] transmission power on line l in time step t

[2]Indices *in* and *out* are seen from transmission system's point of view. Hence, *out* refers to

$P_{\text{trans,in},l,t}$ incoming transmission power on line l in time step t

Secondly, the nominal power $P_{\text{trans,in},l,t}$ of each representative transmission line is considered by limiting the power flow (cf. Eq. 3.18).

$$P_{\text{trans,out},l,t} - P_{\text{trans,in},l,t} \leq P_{\text{inst, trans},l} \quad \forall l \in L, t \in T \tag{3.18}$$

where

$P_{\text{inst, trans},l}$ nominal capacity of transmission line l

3.5.5 Demand coverage and dispatch

Electricity demand in each region and each time step must be met by generation complemented by energy storages and electricity imports via the transmission system. This demand is assumed to be inelastic. The constraint introduced by Equation (3.19) ensures electricity demand coverage in every time step t and every region r. Decision variables of electricity generation, energy storage system operation, and transmission system operation are forced to serve exogenously defined demand. The left hand side of Equation (3.19) reflects terms of electricity supply: power generation by power plants $\sum_i P^{\text{elec}}_{\text{gen},i,r,t}$, of electricity imports via the transmission system $P_{\text{trans},r,t}$, and discharge of energy storage systems $P^{\text{discharge}}_{\text{storage},i,r,t}$. The right hand side reflects terms of electricity consumption. This includes the actual electricity demand $P_{\text{demand},r,t}$, charging of energy storage systems $P^{\text{charge}}_{\text{storage},i,r,t}$ and electricity demand of the PtG conversion unit $P^{\text{in}}_{\text{PtG},r,t}$. Furthermore, the term of transmission power $P_{\text{trans},r,t}$ can be negative which translates to the export of electricity. The term $P_{\text{excess},r,t}$ relaxes Equation (3.19) if surpluses of generation occur that cannot economically used by energy storage systems. It operates as a system-wide curtailment term that cannot be accounted as curtailment of a specific power generation technology.

$$\begin{aligned}\sum_i P^{\text{elec}}_{\text{gen},i,r,t} + P_{\text{trans},r,t} + \sum_i P^{\text{discharge}}_{\text{storage},i,r,t} &= P_{\text{demand},r,t} \\ &+ \sum_i P^{\text{charge}}_{\text{storage},i,r,t} + P^{\text{in}}_{\text{PtG},r,t} + P_{\text{excess},r,t} \quad \forall r \in R, t \in T\end{aligned} \tag{3.19}$$

where

electricity that flows from the transmission system in to a region r.

$P_{\text{demand},r,t}$ electricity demand in region r and time step t

$P_{\text{excess},r,t}$ system-wide excess electricity in region r and time step t

3.5.6 Domestic supply rate

The model allows limiting the electricity imports on an annual basis for a region by defining a domestic supply rate. The domestic supply rate is defined as the ratio of annual electricity generated in a region to annual electricity demand in that said region; considering such a rate takes place by defining an upper limit for exchange electricity for each region. Annual electricity exchange $\sum_t P_{\text{trans},r,t}$ is bounded to domestic supply ratio DS_r times the annual electricity consumption in region r (see Equation (3.20)).

$$\sum_t P_{\text{trans},r,t} \leq DS_r \cdot \sum_t P_{\text{demand},r,t} \tag{3.20}$$

3.5.7 GHG emission constraint

A decarbonization pathway towards an almost zero-carbon electricity supply system in Europe by 2050 is marked by GHG emission reduction targets on a five-years scale. During a scenario run the emission limit is constantly updated for each interval along this scale as illustrated by Equation (3.21). Thus, annual GHG emissions related to electricity generation must not exceed the according reduction target. This thesis only considers GHG emissions related to electricity generation. Emissions related to the infrastructure are neglected.

$$\sum_i \sum_r \sum_t \rho_i \cdot P^{\text{elec}}_{\text{gen},i,r,t} \leq \Upsilon_{year} \tag{3.21}$$

where

ρ_i CO_2 emissions induced by generation of 1 kWh electricity by technology i

Υ_{year} total annual allowed CO_2 emissions in a certain year

The total annual allowed GHG emissions define as percentage of 1990 GHG emissions as presented in Equation (3.22).

$$\Upsilon_{year} = \Upsilon_{1990} \cdot \upsilon_{year} \tag{3.22}$$

where

υ_{year} allowed GHG emissions in percent for a specific *year*

3.6 Software implementation and solver

The software implementation of the model is called *elesplan-m* which is an application built upon a predecessor of *oemof*. This modeling framework, intended to provided a solid basis for energy system modeling in the heat and electricity sector, was lastly merged to the open energy modeling framework (oemof). The latter is a more generalized framework for modeling of energy systems that is published under open-source license and still actively developed (Hilpert et al., 2017).

The above described electricity system model generates a linear optimization problem of the size 4.8 M variables that are bounded by around 5.3 M constraints. The problem has 15.4 M non-zeros. Determination of exact solution for such large-scale linear optimization problems via the simplex method (Dantzig et al., 1955) is not possible. Therefore, numerical approaches have to be considered. The initial interior point algorithm for solving linear programming problems, proposed by Neumann (Dantzig and Thapa, 2006), was not faster compared to the simplex method. Karmarkar (1984) published a new interior method allowing to solve linear problems faster than by simplex method. This marked a fundamental turning point in development of interior point algorithms for efficient solution of large-scale LP (Lustig et al., 1994; Terlaky, 2013). Interior point methods, often also called barrier methods, are suitable to solve large-scale in particular sparse linear problems (Karmarkar and Ramakrishnan, 1991). The solver suite GUROBI is used in this thesis to solve the linear optimization problem that uses the primal-dual interior point method (Gurobi Optimization, Inc., 2017; Wright, 1997). It is further parametrized to use a barrier method only without identifying a basic solution afterwards (realized by setting GUROBI parameter *crossover* to zero). The algorithm used is a barrier homogeneous algorithm (achieved by using GUROBI's *BarHomogeneous* parameter). The model is computed on an eight core machine with 32 GB RAM.

Validation of an energy system long-term planning model is a challenging task (Hodges and Dewar, 1992). In the case of this thesis, this would require re-analyzing past development of the energy supply system including consideration of structural changes and disruptive events. These, for example, are the feed-in tariff for RES power supply introduced in Germany in 2000 (structural change) or disruptive events like the first oil crisis in the beginning of the 1970s or the political motivated nuclear phase-out in Germany. To include such aspects in the model is challenging. Thus, a long-term planning model cannot be validated appropriately but cross-checked by analyzing different scenarios, and therefore also contributes to the identification of bugs through this process.

4 Base scenario and model parameters

The electricity system model *elesplan-m* needs to be parametrized by economic and technical data. These data reflect cost for operation of and investment into electricity system infrastructure, technical characteristics of considered technologies, electricity demand, availability of electricity supply by RES technologies, and electricity system infrastructure capacity data that describes the status quo. This thesis takes one *base scenario* as central point of the analysis complemented by 12 scenario variations to study sensitivity of findings obtained from model-based calculations. These scenarios are constructed applying the approach of *intuitive logics* similar to the proposed method by Schwartz (1991). In particular, the selection of scenario variations is inspired by Schwartz et al.. Alternative development of most important and most uncertain factors is studied by the scenario variations. The *base scenario* reflects the most probable and reliable set of parameters and assumptions to describe present and future electricity supply. This chapter provides an overview of assumptions underlying the model calculation in this thesis and on the parameters that constitute the *base scenario*.

Schröder et al. (2013), who provide a concise review of energy system modeling parameters, argue that choice of individual parameters (or even set of parameters for certain technologies) should not be conducted by blindfold averaging values available in different literature. Often, data sets are consistent as a whole dataset (in particular on estimations over a period of decades in the future). For example, data is generated by model-based calculations that take certain circumstances and assumptions into account. Thus, selecting data by best guesses is advantageous compared to simple average values. Therefore, the selection of parameters largely considers the review report provided by Schröder et al. (2013). The following sections elaborate on the selection of model parameters and data which constitute the *base scenario*. Alternative development of model parameters and different circumstances that affect the electricity system design are covered by scenario variations that are presented in Section 4.11.

4.1 Fundamental economic parameters

As the modeling approach of this thesis seeks for cost-optimal solutions, input parameters reflecting economic aspects have significant impact on results. Thus, these need to be compiled concisely. A central parameter is weighted average cost of capital (WACC) that has strong effects on cost-optimal design of electricity supply systems (Ondraczek et al., 2015). The following describes how WACC is determined and how cost data is aligned for one reference year.

4.1.1 Weighted average cost of capital

The WACC describes cost of capital regarding project financing. It represents cost or risk of investments in specific technologies (projects) in a specific area (country or larger region). Equation 4.1 describes the calculation of WACC by cost of equity and debt.

$$WACC = Equity_{\text{ratio}} \cdot (k_e - k_d) + k_d \tag{4.1}$$

where

$WACC$	Weighted average cost of capital
$Equity_{\text{ratio}}$	Ratio of equity to total capital
k_e	cost of equity
k_d	cost of dept

Equity-to-capital ratios ($Equity_{\text{ratio}}$) in the electricity sector range from 30 % to 55 %[1] (Larsson, 2012; Taylor et al., 2015). Based on this range, in this thesis, an average equity-to-capital ratio of 40 % is used.

Cost of equity k_e varies significantly among several projects in the electricity sector. Vertically integrated energy companies typically have k_e of 9.6 % to 10.3 %, whereas cost of equity of 9.3 % to 11 % is realistic for stand-alone electricity supply companies (Competition & Markets authority, 2015). Cost of equity of 6.94 % is identified by Damodaran (2015) for preliminary electricity sector projects of fossil power generation. A review of electricity

[1] 30, 50, 55 % reported by Larsson (2012); 33 % to 44,4 % reported by Taylor et al. (2015)

production cost assessment reveals 10 % and 12.5 % for these parameters (Larsson, 2012). The International Renewable Energy Agency (IRENA) investigated several wind and PV power projects in the United states of America (US) in the years 2009 to 2011. On average, they found cost of equity at around 12 % for PV and wind power plant projects. Based on the above findings, cost of equity of 9.5 % for mature technologies[2] and cost of equity of 12 % for new technologies[3] are applied in this thesis. Cost of dept k_d is taken from the average in the EU area. Overall economy average cost of dept from the last decade (October 2005 to September 2015) totals to 3.67 % (Euro area statistics, 2015). The parameters above result in different WACC for mature and new technologies as presented in Table 4.1.

Table 4.1: Weighted average cost of capital WACC of mature and non-mature technologies

	Technologies	WACC in %
Mature	Coal and gas power plant, hydro power, PHS transmission system, gas storage	6.0
New technologies	PV, wind, electrolysis & methanation, energy storage systems, nuclear	7.0

4.1.2 Cost data reference year

Economic parameters need to have a common basis in order to be comparable when applied within one model. Therefore, the year 2015 is chosen as as reference for economic parameters. Economic parameters provided in literature are provided in the monetary value of a specific year. Parameters provided in monetary value of year prior to 2015 are discounted exponentially discounting to the reference year 2015 as described by Equation 4.2. As interest rate, the average inflation $\bar{i}$ in the EU of the past decade of 2.12 % (EUROSTAT, 2015) is used.

$$cost_{2015} = cost_{year} \cdot (1 + \bar{i})^{(2015-year)} \tag{4.2}$$

where

[2] comprises fossil power generation technologies (coal and gas power plants, transmission grid and underground gas storage)

[3] comprises RES technologies (PV and wind power), battery storages and PtG components

$cost_{year}$ Actual year cost are defined for

$\bar{i}$ Average inflation

4.2 Power generation technologies

Power generation technologies in *elesplan-m* are characterized by technical parameters (conversion efficiency, expected lifetime) and economic parameters (CAPEX, OPEX_{fix} and OPEX_{var}). Two gas-fueled power plant technologies are distinguished: open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT). Coal-fired power plants are represented by one technology reflecting hard-coal and lignite technologies without CCS equipment. Parameters for coal power generation technologies reflect a technology mix of lignite advanced and pulverized hard coal super-critical processes. Other technologies such as IGCC and those equipped with CCS are neglected in this study. Schröder et al. (2013) compiled a set of energy system modeling data (technical and economic parameters) where most data is taken from. This dataset bases on a comprehensive literature review and is prepared with a consistent set of assumptions.

Table 4.2 presents data for capital expenditures (CAPEX) used in the *base scenario*. Conventional thermal power plant technologies and hydro power are assumed to have constant cost, whereas capital expenditures of RES technologies wind and PV show a cost reduction over investigated period of time. Because data by Schröder et al. (2013) may overestimate cost reduction potential of PV power, a slightly less ambitious cost reduction potential of PV is assumed, provided by Zickfeld et al. (2012). These values are in line with other literature (i.e. IEA (2014); Knopf et al. (2015)). The review on economic data on power generation shows that a wide range of cost for nuclear power technologies is reported by literature. Considering safety aspects (i.e. 3$^{\text{rd}}$ generation reactors) and decommissioning in capital cost, results in cost of 6,664 $€_{2015}$/ kW (Schröder et al., 2013) that are twice the cost reported by VGB PowerTech (2012).

Cost of operation and maintenance are divided into fixed operational expenditures (OPEX_{fix}) and variable operational expenditures (OPEX_{var}). The term OPEX_{fix} includes all annual cost per unit of installed capacity. Cost associated with a unit of generated electricity are included in OPEX_{var}. The parameters OPEX_{fix} and OPEX_{var} are included in the review of Schröder et al. (2013) as well. It is assumed that operational expenditures do not change over time (cf. Table 4.3).

Lifetime of power plants is difficult to assess a priori and data provided in literature varies

Table 4.2: Capital expenditures (CAPEX) of power generation technologies presented in €/kW. Values taken from Schröder et al. (2013) except for data of PV power that is taken from Zickfeld et al. (2012).

Technology	2020	2025	2030	2035	2040	2045	2050
Wind	1,377.1	1,343.8	1,312.7	1,281.6	1,251.6	1,222.8	1,193.9
PV	1,000	900	800	780	760	740	730
Nuclear	6,663.5	6,663.5	6,663.5	6,663.5	6,663.5	6,663.5	6,663.5
Coal	1,554.8	1,554.8	1,554.8	1,554.8	1,554.8	1,554.8	1,554.8
CCGT	888.5	888.5	888.5	888.5	888.5	888.5	888.5
OCGT	444.2	444.2	444.2	444.2	444.2	444.2	444.2
Hydro power	3,331.8	3,331.8	3,331.8	3,331.8	3,331.8	3,331.8	3,331.8

Table 4.3: Expected lifetimes $opex_{\text{fix}}$ and $opex_{\text{var}}$ for power generation technologies.

Technology	Lifetime in a	opex_{fix} in €/kW·a	opex_{var} in ct€/kWh$_{\text{th}}$
Wind	25	38.87	0
PV	25	20.23	0
CCGT	30	22.21	0.444
OCGT	30	16.66	0.333
Nuclear	40	133.27	0.888
Coal	40	31.1	0.722
Hydro power	60	66.64	0

significantly. At the same time, it's a crucial parameter for economic analysis as it influences the annuities. Lifetime of gas-fueled power generation technologies (open and combined-cycle) is reported ranging from 25 years (VGB PowerTech, 2012) to 40 years (Knopf et al., 2015; Schröder et al., 2013). The spread for coal power plants is even larger. Their lifetime ranges from 25 years (VGB PowerTech, 2012) up to 60 years (IEA, 2010; Knopf et al., 2015) according to literature. Despite this large range, according to a review of energy system modeling parameters, most studies refer to a lifetime of 40 years for coal power (Schröder et al., 2013). Reported lifetime of nuclear power plants ranges from 40 years (VGB PowerTech, 2012) to 60 years (IEA, 2010). Lifetime of PV and wind power is seen between 20 and 30 years in literature (Schröder et al., 2013). The majority of studies agree on 25 years for both technologies, wind and PV power (VGB PowerTech, 2012; Zickfeld et al., 2012; Schröder et al., 2013). This thesis assumes a lifetime for open and combined-cycle gas power (OCGT and CCGT) of 30 years (IEA, 2010), for coal of 40 (Zickfeld et al., 2012; Schröder et al., 2013), for nuclear of 40 years (VGB PowerTech, 2012), and for wind and PV power of 25 years (VGB PowerTech, 2012; Zickfeld et al., 2012; Schröder et al., 2013). An overview on chosen lifetime assumptions is shown in Table 4.3.

Table 4.4: Efficiency of power generation technologies presented in %. All values taken from Schröder et al. (2013). Efficiencies of all technologies are expected to increase slightly over investigated period of time.

Technology	2020	2025	2030	2035	2040	2045	2050
Nuclear	33.3	33.5	33.7	33.8	34	34.2	34.3
Coal	45.05	45.3	45.55	45.85	46.1	46.35	46.65
CCGT	60.5	60.7	61	61.2	61.5	61.7	61.9
OCGT	39.2	39.2	39.3	39.4	39.5	39.5	39.6

A study on efficiency of thermal power plants of the past two decades in eight countries reveals a range of 27 % to 53 % (Hussy et al., 2014). As Schröder et al. (2013) provide thorough review on efficiency parameter for important power generation technologies including an outlook for the upcoming four decades, those values are taken into account in this study. Efficiency parameters for thermal power plants are presented in Table 4.4. Efficiencies for PV and wind power are missing in here, as these are included in the feed-in time series data (cf. Section 4.9).

4.3 Fuels

Forecasting fuel cost for the upcoming three decades is challenging and inherently associated with significant uncertainty (Rout et al., 2011). For this study, fuel cost assumptions are taken from Knopf et al. (2015). It provides an outlook on fuel cost per fuel type in 5-years steps until 2050. Table 4.5 summarizes fuel cost data applied in this study.

Cost of all types of fuels are expected to increase. Cost of uranium will quadruple, cost of coal shows an increase of about 25 %, whereas cost of natural gas are assumed to increase about 17 %.

Table 4.5: Expected development of fuel cost for the upcoming three decades. In this context, coal refers to a mix of lignite and hard coal. Values are provided in €/ $\mathrm{kWh_{th}}$, which refers to the resource's lower heat rate, and rely on Knopf et al. (2015).

Technology	2020	2025	2030	2035	2040	2045	2050
Coal	0.0072	0.0072	0.0074	0.0078	0.0082	0.0086	0.0080
Uranium	0.0028	0.0032	0.0040	0.0048	0.0056	0.0068	0.0090
Natural gas	0.0276	0.0284	0.0292	0.0288	0.0288	0.0284	0.0280

4.4 Energy storage systems

This study considers three types of energy storage systems in the electricity system model: pumped hydro storage (PHS), battery energy storage systems (BESSs), and power-to-gas (PtG) systems. Whereas PHS is a mature technology, used for a long time in electricity supply systems, the latter two are relatively new technologies. The subsequent sections present technical and economic parameters of these technologies that are used in the *base scenario*.

4.4.1 Batteries and pumped-hydro

Brinsmead et al. (2015) undertook a review of future cost and performance of energy storage technologies. Based on a *Global And Local Learning Model*, economic and technical key parameters for the upcoming two decades are derived for a plenty of BESS technologies (Brinsmead et al., 2015). A strong cost reduction is carried out for all investigated BESS technologies. According to Brinsmead et al., zinc-bromide flow batteries will reach lowest cost. Therefore, this study uses parameters of the zinc-bromide battery technology and the term battery refers to this technology in the following. Nevertheless, other battery technologies (other redox-flow batteries or NaS) have similar technical characteristics and cost. These could be considered alternatively and should reveal similar findings.

Based on the report of Brinsmead et al. (2015), cost parameters are chosen as presented in Table 4.6. These costs reflect cost of battery itself and auxiliary equipment such as inverters. Cost reported for the year 2035 are treated as final cost reduction potential and are extrapolated until 2050, staying on the same level of cost. In summary, cost of batteries are expected to decrease by the factor 4. Pumped-hydro storage is seen as a mature technology with no potential for further cost reduction (Schröder et al., 2013).

Table 4.6: Development of capital expenditures of battery energy storage systems (zinc-bromide) and PHS. Capital expenditures of BESS are given including inverter cost (Brinsmead et al., 2015). Parameters for PHS are taken from Schröder et al. (2013). Capital expenditures presented are to be understood as cost in €/kWh of effective storage capacity (DoD is considered in cost).

Technology	2020	2025	2030	2035	2040	2045	2050
Battery	552	230	194	172	172	172	172
PHS	277.6	277.6	277.6	277.6	277.6	277.6	277.6

Further technical and economic parameters (refer Table 4.7) are assumed to remain at a constant level. Lifetime of PHS is assumed with 60 years according to Schröder et al. (2013), but this may differ from lifetime observed in real-world settings significantly. Many factors have influence on this parameters, such as topology, geology, mode of operation, and consideration of a potential complete overhaul. Nevertheless, 60 years are a compromise when lifetime of European PHS systems have to be represented by a single parameter.

Table 4.7: Technical and economic parameters of energy storage technologies: zinc-bromide parameters taken from Brinsmead et al. (2015) and parameters for PHS taken from Schröder et al. (2013). Cycle efficiency of both technologies is translated to equal charge and discharge efficiency η_{in} and η_{out}.

Parameter	Battery	PHS	Unit
Lifetime	10	60	a
$Opex_{\text{fix}}$	0.618	2.78	EUR/ kWh_{Cap}
OPEX_{var}	0	0	EUR/ $\text{kWh}_{discharge}$
Efficiency η_{in}	86.6	86.6	%
Efficiency η_{out}	86.6	86.6	%
Capacity/Power	6.5	8	kWh/kW

4.4.2 Power-to-gas

As power-to-gas (PtG) is a relatively new technology and its diffusion is still on a low level, predictions about future development of economic and technical parameters of this technology are difficult. The system efficiency that comprises all process steps of converting electrical energy to synthetic methane ranges from 48 % (Reiter and Lindorfer, 2015) to 65 % (Jentsch et al., 2014). Based on the wide spread of values provided by literature, parameters provided by Götz et al. (2015) seem to be reasonably studied and are applied in this thesis. Energy demand and cost for CO_2 supply directly affect the resulting cost of SNG. Therefore, a CO_2 source with low energy demand and low production cost is preferred. Two sustainable options for CO_2 supply are available: CO_2 capture from ambient air and CO_2 capture from SNG-fueled gas power plants as described in Belderbos et al. (2015). CO_2 capture from gas power plants is associated with an additional energy demand of 2.9 MJ/kg_{CO_2} (0.8 kWh/kg_{CO_2}) taking post-combustion capture into account (Reiter and Lindorfer, 2015). Cost for carbon capture is estimated to range from 59 €/t_{CO_2} to 101 €/t_{CO_2}. This process allows to capture up to 90 % of CO_2 from exhaust gas (Reiter and Lindorfer, 2015). Looking at CO_2 capture from ambient air, specific electrical energy demand ranges from 5.4 MJ/kg_{CO_2} (1.5 kWh/kg_{CO_2}) to 9.0 MJ/kg_{CO_2} (2.5 kWh/kg_{CO_2}) and specific cost reach 150 €/t_{CO_2} to 320 €/t_{CO_2} (Reiter and Lindorfer, 2015). Even higher cost and energy demand for CO_2 from ambient air of 1000 €/t_{CO_2} and an electricity demand of 3 to 5 kWh/kg_{CO_2} are reported (Schiebahn et al., 2015). Lackner et al. (2012) refer to cost of 450 €[4]/t_{CO_2}.

In order to keep CO_2 supply sustainable, a maximum of 90 % of the CO_2 stream is allowed to be captured from exhaust gas of SNG-fueled gas power plants. The remaining 10 % must be captured from ambient air for realizing zero net CO_2 emissions. Equation (4.3) denotes electrical energy demand of PtG including CO_2 capture.

$$E_{el,PtG,total} = E_{PtG,conv.} + E_{CO_2,capture} \tag{4.3}$$

where

$E_{el,PtG,total}$	total electricity demand of PtG conversion
$E_{PtG,conv.}$	electricity demand of electrolysis plus methanation
$E_{CO_2,capture}$	electricity demand of CO_2 capture

This can be transformed in order to express efficiency η_{PtG} including expenses for CO_2 supply (see Equation (4.4)).

$$\eta_{PtG} = \frac{1}{\frac{1}{\eta_{PtG,conv.}} + E_{CO_2,capture}} \tag{4.4}$$

[4]with exchange rate of 1 \$ = 0.75 €

where

η_{PtG} system efficiency of PtG unit

$\eta_{PtG,conv.}$ efficiency of PtG conversion (electrolysis plus methanation)

The electricity demand for mixed CO_2 capture (90 % exhaust gas and 10 % from ambient air) totals to 0.92 kWh_{el}/kg_{CO_2}. This assumes an electricity demand of 0.8 kWh_{el}/kg_{CO_2} for capturing CO_2 from gas power plant exhaust gas and 2 kWh_{el}/kg_{CO_2} for capturing CO_2 from ambient air. Taking the conversion efficiency $\eta_{\mathrm{PtG,conv.}}$ of 55 % (Götz et al., 2015) into account, the efficiency including CO_2 supply results to 50.0 % in case of mixed CO_2 sources. Additional cost for CO_2 supply are assumed with 0.08 €/kg_{CO_2} (Reiter and Lindorfer, 2015) for capturing from exhaust gas and 0.45 €/kg_{CO_2} (Lackner et al., 2012) for capturing from ambient air. Variable cost for mixed sources CO_2 supply adds up to 0.0231 €/kWh_{CH4}. Table 4.8 provides an overview of parameters for the PtG system applied in this thesis.

Table 4.8: Variable cost of CO_2 and system efficiency of PtG unit considering losses and expenses providing CO_2. Efficiency of electrolysis and methanation is taken from Götz et al. (2015), cost of CO_2 originates from Reiter and Lindorfer (2015) (gas power plant) and Lackner et al. (2012) (ambient air), and additional energy demand for capture CO_2 taken from Reiter and Lindorfer (2015). The last row describes a combined use of CO_2 from gas power plants (90 %) and ambient air (10 %). CO_2 from ambient air is used to compensate the capture rate of 90 %.

CO_2 from	$E_{CO_2,capture}$ kWh_{el}/kg_{CO_2}	$E_{CO_2,capture}$ in kWh_{el}/kWh_{CH_4}	η_{PtG} in %	Cost CO_2 in €/kg_{CO_2}	Var. cost of CO_2 in €/kWh_{CH_4}
Gas power plant	0.8	0.158	50.6	0.08	0.0158
Ambient air	2	0.395	45.2	0.450	0.0889
Gas power plant & ambient air	0.92	0.1817	50.0	0.117	0.0231

Data on future cost of PtG systems in five years intervals along the pathway is not available. Baumann et al. (2014) provide an outlook on future CAPEX of PtG systems up to 2050. Based on this outlook, missing data is obtained by quadratic regression (see Equation 4.5). Capital expenditures for PtG systems of the upcoming three decades are presented in Table 4.9. Additionally, the PtG system is characterized by fixed operational expenditures $Opex_{\mathrm{fix}}$ of 4 % of CAPEX and a lifetime of 25 years (Jentsch et al., 2014).

$$Capex_{\mathrm{PtG}} = 0.762359 \cdot y^2 - 3127.34 \cdot y + 3.20774 \cdot 10^6 \tag{4.5}$$

where y represents the year.

Table 4.9: Development of capital and operational expenditures of PtG system including all required components such as electrolysis, H_2 storage and methanation

Technology	2020	2025	2030	2035	2040	2045	2050
Capex	1,356	1,025	782	703	600	534	522
$\mathrm{Opex_{fix}}$	54.24	41	31.28	28.12	24	21.36	20.88

4.4.3 Gas storages

Underground natural gas storage facilities are the most common storage technology of natural gas (Barnes and Levine, 2011). Parameters provided in Table 4.10 assume a technology mix of 50 % underground storages at sites of depleted oil or gas reservoirs and 50 % underground storages constructed at sites of salt caverns.

Table 4.10: Parameters of gas storages. Capital and operational expenditures are taken from Favret (2004), lifetime of gas storages is assumed based on Barnes and Levine (2011), and the efficiency originates from Kloess and Zach (2014).

Capex €/ kWh_{th}	$Opex_{\mathrm{fix}}$ €/ $\mathrm{kWh}_{th} \cdot a$	Lifetime a	Efficiency %
0.027	0.00289	100	97

4.5 Transmission system

The transmission system – reflecting cross-border transmission lines in an aggregated manner – are parametrized by cost data, lifetime, transmission efficiency, and a limit on annual capacity extension. According to Hagspiel et al. (2014) and Fürsch et al. (2012) the extension of NTC of an AC system adds up to cost of 0.494 €/ kW·km. O & M cost ($OPEX_{fix}$) total to 0.6 % of capital expenditures as stated by Zickfeld et al. (2012). The lifetime of transmission lines can be assumed with 50 years and losses on average amount to 7 % of electricity transmitted per 1000 km (Haller et al., 2012b). Table 4.11 summarizes parameters applied to the transmission system in *elesplan-m*.

Table 4.11: Technical and economic parameters of transmission system. These values aim to reflect "an average transmission capacity" between two countries.

Parameter	Value	Unit
NTC expansion cost (CAPEX)	0.494	€/ (kW · km)
O & M cost ($Opex_{fix}$)	0.6	% of investment
Losses	7	% /1000· km
Lifetime	50	a

Schmid and Knopf (2014) discuss a limit of transmission capacity extension that is set as another constraint in the model. They apply an annual grid extension limit of 0.5 GW/a per cross-border transmission capacity in the analysis. In the light of past extension rates (current cumulative ENTSO-E transmission capacity adds up to around 53 GW) this assumption is quite progressive. Knopf et al. (2015) further argue that 0.2 GW/a cross-border transmission capacity extension can be seen as realistic. Consequently, this value is applied here. Hence, analyzing future electricity supply in five years steps, in each of the planning intervals 1 GW/a extension of each cross-border transmission capacity is allowed.

4.6 GHG emissions of power generation

Ideally, the assessment of GHG emissions is conducted on the basis of life-cycle emissions in order to respect all relevant emissions associated with electricity generation of certain technologies (for example Peng et al. (2013) provides a comprehensive example for photovoltaics). This incorporates infrastructure and supply chain emissions. In particular for RES technologies, these represent the majority of emissions (Amponsah et al., 2014). Achieving deep decarbonization targets in 2050, requires strong decarbonization of infrastructure and supply chain as well (Weisser, 2007). Nevertheless, assessing these parameters would exceed the scope of the thesis. Therefore, infrastructure and supply chain emissions are not incorporated in this thesis; only direct emissions are considered.

Table 4.12: Emission factors of power generation technologies as applied in this thesis. Emission factors given in $kg/\,kWh_{th}$ in relation to the lower heat rate of the fuel.

Fuel type	Emission factors (fuel related) (Herold, 2003) $kg/\,kWh_{th}$
Hard coal	0.34704
Lignite	0.37548
Coal (average)	0.36126
Natural gas	0.20376
Uranium	0.1403
Renewable energy sources	0

Despite actual GHG emissions related to electricity supply by nuclear power (Sovacool, 2008), these are not considered in this thesis, because these typically arise in uranium mining countries outside Europe. Reported emissions by fossil-fueled technologies vary significantly in literature (Turconi et al., 2013). Emissions related to hard coal based electricity supply range from 0.17 kg/kWh_{th} to 0.45 kg/kWh_{th}, lignite cause emissions of 0.33 kg/kWh_{th} to 0.51 kg/kWh_{th}, whereas power generation based on gas power plants emits 0.21 kg/kWh_{th} to 0.31 kg/kWh_{th} (Turconi et al., 2013). Emission factors applied in this thesis are in line with those used in EU-ETS monitoring reports (Herold, 2003) and are presented in Table 4.12.

4.7 GHG emission constraints

European Union energy policy aims for climate change mitigation and provide targets for GHG emissions (cf. Section 2.2.4). Detailed targets (shown by Table 2.1) are available for the years 2030 and 2050. Remaining targets for each five year interval between 2020 and 2050 are derived by Figure 1 of a communications paper by the European Commission (2011a). There, intermediate targets for moving towards 80 % to 95 % mitigation goals by 2050 are sketched and broken down to sectoral targets. These targets that are applied in this thesis are presented by absolute and relative numbers (to 1990 levels) in Table 4.13.

Table 4.13: EU GHG emissions reduction targets in % relative to 1990 levels and in absolute numbers in the electricity sector from now to 2050 in five-year steps based on European Commission (2011a).

Year	2020	2025	2030	2035	2040	2045	2050
% to 1990	70.6	49.2	37.1	24.2	12.1	4	1.6
Mt CO_2eq	1039	724	546	356	178	59	24

4.8 Electricity demand

The current situation of European electricity supply is sketched in Section 2.2.1. The spatial distribution of electricity demand in 2012 is illustrated by Figure 2.5. In retrospect, a continuous growth of electricity demand is observed. Between the years 1990 and 2003, electricity demand grew by an average annual growth rate of 1.6 % (Mantzos et al., 2003). Despite energy efficiency ambitions by the European Commission (European Commission, 2011b, 2014), a continued growth of electricity demand is assumed by Fürsch et al. (2013). Fürsch et al. (2013) provide projections on future electricity demand in EU-27 plus Norway and Switzerland up to 2050. The data covers annual demand for each country of each decade. Projected, cumulative electricity demand growth for the study region EU+ is shown in Table 4.14. Electricity demand of 3,294 TWh/a in 2012 adds up to 4,474 TWh/a by 2050. The total increase up to 2050 of 36.8 % calculates to average annual growth rate of around 1 % which is below observed historical growth rates (Mantzos et al., 2003). This data is supplemented by monthly data reported by ENTSO-E (2012b) and by EIA (2015). An interpolation produces a dataset with 5-years resolution. Determined values of detailed projection can be found in Table A.1.

The applied energy system model *elesplan-m* relies on electricity demand time series provided in hourly resolution (for details refer to Section 3). Hourly historic electricity demand data

Table 4.14: Average electricity demand growth expectations for defined region of investigation; in absolute and relative numbers to the year 2012. Data is based on growth projections provided by Fürsch et al. (2013).

	2012	2020	2025	2030	2035	2040	2045	2050
Electricity demand in TWh	3,294	3,510	3,670	3,830	3,987	4,144	4,309	4,474
Growth rate relative to 2012 in %	0	7.4	12.3	17.2	22.0	26.8	31.8	36.8

is provided by ENTSO-E (2012a). The ENTSO-E data does not include every country investigated by this thesis, data is not available for Albania, Andorra, Kosovo, Monaco, San Marino, and Vatican state. Data of Kosovo, San Marino, Vatican State, and Monaco are not explicitly contained by the dataset because these are contained in other countries' demand. Electricity demand of Kosovo is, due to historic reasons, included in the dataset of Serbia. San Marino, and Vatican State are represented by Italy's electricity demand profile (IEA, 2015), whereas France's electricity consumption includes Monaco's electricity demand as well (Monaco IQ, 2015). Consumption time series of electricity in Albania and Andorra is entirely unavailable. Assuming a similar shape of the profile, Albania's electricity consumption profile is represented by the one of Macedonia. Similarly, the consumption profile of Andorra is reflected by Spain's electricity demand profile.

The ENTSO-E hourly electricity demand data (ENTSO-E, 2012a) does not cover the entire consumption. Schumacher and Hirth (2015) observed a significant deviation from hourly data to ENTSO-E data provided on a monthly basis. Demand data on a monthly basis by ENTSO-E (2012b) reflects annual demand in higher detail. To achieve correct consumption data in hourly resolution, hourly demand data is scaled by annual demand given by monthly data. In order to anticipate further growth of electricity demand until 2050, the data is further scaled by demand projections provided by Fürsch et al. (2013).

4.9 Renewable energy sources based supply

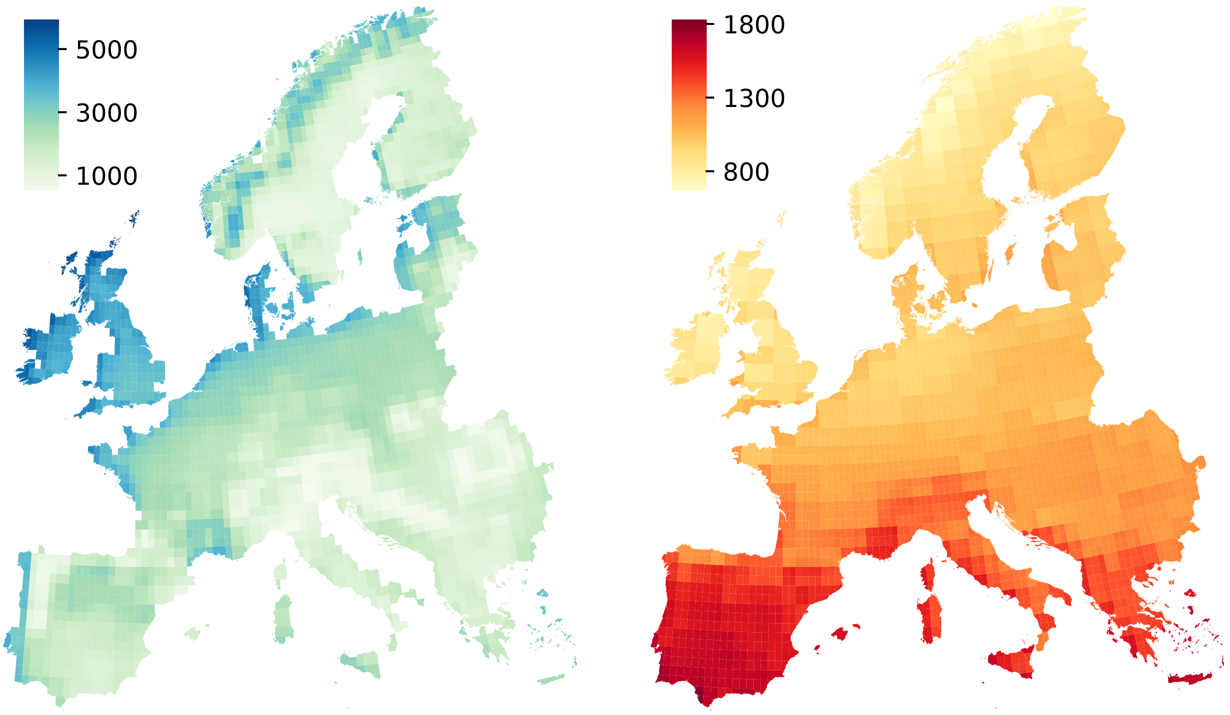
The patterns of electricity supply by RES technologies wind, PV, and hydro power are prescribed by the patterns of weather events. Describing RES supply successfully in the electricity system model, requires time series for each of these technologies at a temporal resolution of one hour and a spatial resolution at region level. Due to data availability and ease of modeling, different approaches for wind and PV power and hydro power are used.

While modeling of wind and PV power supply time series founds on re-analysis climate data, hydro power generation modeling relies on measured historical supply data.

The basis of wind and PV generation time series used in this study are wind speed and irradiation data at a spatial resolution of 1°×1° covering the entire area of Europe. This dataset itself is based on the re-analysis dataset *Surface Meteorology and Solar Energy SSE Release 6.0* provided by (Paul W. Stackhouse and C.H Whitlock, 2008). This dataset, covering the whole world and a period of multiple decades, provides weather data at a temporal resolution of six hours. Gerlach et al. (2011a) converted a period of 22 years (1984 to 2005) into one-hourly resolved time series data. This dataset comprises of wind speeds at 50 m height and solar irradiation provided as global horizontal irradiance (GHI). The wind speed data is converted to hourly electricity generation data using a wind turbine model. This model uses a manufacturer's wind turbine power curve. In this case, it is characterized by the popular turbine type Enercon E101 at 100 m hub height. To process solar irradiation data to PV power feed-in data, the modeling approach of Huld et al. (2008) is applied. This model allows to calculate PV power electricity generation data based on GHI data for the entire spatial extent of Europe. It focuses on describing the conversion efficiency of crystalline silicon modules (c-Si), the most popular PV technology nowadays. The model is applied assuming fixed mounted, optimally tilted (optimal regarding annual generation) PV modules. Thereof, two datasets result that describe the electricity generation potential of wind and PV power in Europe at a spatial resolution of 1°×1° and at a temporal resolution of one hour. Figure 4.1 illustrates annual electricity generation of wind and PV normalized to nominal power in the study region.

In order to reflect potential site selection of wind and PV installations, a single time series for each of the 18 regions is constructed based on the assumption that sites of high annual generation potential are preferred. Therefore, the 2/3 best sites of each region are selected individually for both technologies using geographical information systems (GIS) methods. These time series are spatially resampled to one time series for each region representing the average local characteristics. This results in eighteen time series for each of the technologies wind and PV power. Its annual full-load hours (FLH) are presented in Figure 4.2.

Time series describing the cumulative electricity generation by hydro power at regional level is determined from historical generation data. The ENTSO-E reports hydro power generation data on a monthly basis for each of its member countries (ENTSO-E, 2012). These data are converted to time series representing hydro power feed-in for each of the 18 model regions. The data is cross-checked with reference data from the Eurostat database (Eurostat – Statistical Office of the European Union, 2012) and from Bundesamt für Energie (BFE) Sektion Wasserkraft (2015) for Switzerland. In general, it shows an accurate representation



(a) Wind power

(b) Solar PV power

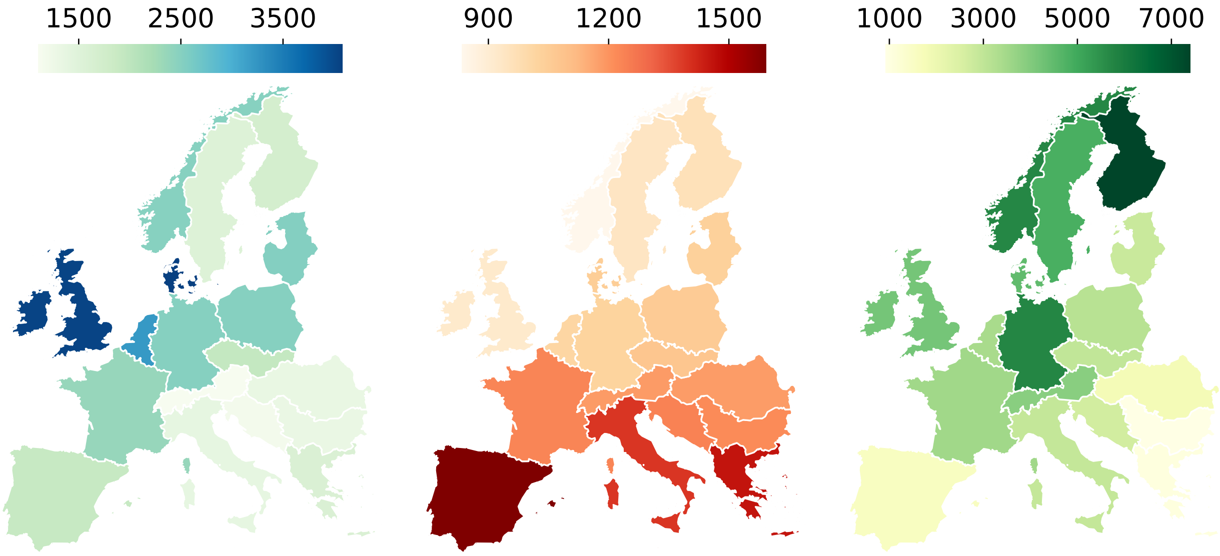
Figure 4.1: Annual electricity generation by wind and PV power in kWh/kW$_p$ resolved on a 1°×1° grid across Europe. Data is based on the *Surface Meteorology and Solar Energy SSE Release 6.0* (Paul W. Stackhouse and C.H Whitlock, 2008) dataset and represents the year 2005.

of annual hydro power generation.

4.10 Power plant and transmission capacity

Decarbonization pathway modeling of power system requires high-quality representation of current power plant and transmission system capacities. Present capacity is the basis for capacity extension and has impact on capacity extension decisions. This data must provide a decent representation of present power plant inventory in order to determine refurbishment and needed capacity extension. Required information on power plant fleets includes technology, capacity, location, commissioning year, and coverage.

Power plant information for this work must distinguish technologies according to distinction in Chapter 3. The coarse spatial representation of at maximum country level in *elesplan-m* is sufficient on this level. Nevertheless, details on commissioning date are required as per



(a) Wind power (b) Solar PV power (c) Hydro power

Figure 4.2: Annual regional full-load hours of wind, PV, and hydro power.

single power plant. Lastly, to be confident with the power plant data, the coverage of the dataset is an important criterion.

4.10.1 Power plants

Platts (2012) is a high-quality commercial database of power plant infrastructure. It offers high coverage of power plant capacity data. Furthermore, power plants are included with information about geographic location and commissioning year, as well as with high technology distinction. As Platts (2012) has gaps in small scale RES power plants, data is supplemented by RES capacity data from EurObservÉR (2015); Pierrot (2015); British Petroleum (BP) (2014). Using GIS methods, the data is filtered by commissioning date of power plants, considering the declared expected lifetime of each technology (cf. Table 4.3). Subsequently, the wide-spread technology distinction of the original data is aggregated to fewer technologies than described in Section 3.2. Thereof, the electricity system infrastructure data is derived that is considered as a starting point for capacity extension evaluated by model runs. The cumulative capacity for each technology is presented in Table 4.15.

Table 4.15: Cumulative power plant capacity in the study region.

Technology	Capacity in GW
Nuclear	128.5
Coal	169.8
Combined cycle gas turbine	99.9
Open cycle gas turbine	106.1
Hydro power	148.5
Wind power	118.0
Solar power	79.6

4.10.2 Transmission system

The representation of the grid infrastructure by the modeling approach of this thesis is limited to reflect cross-border capacity of the transmission system. Net transfer capacity (NTC) values of transmission system from Entso-E (2011) serve as initial cross-border capacity. In regard to the 18 regions defined for model calculations, these cross-border capacities connecting countries are converted to 31 cross-border capacities reflecting the transmission system in the 18-regions model. This conversion summarizes cross-border capacity of country pairs according to the 18 model regions. Likewise, cross-border capacity of countries represented by the same region are neglected. Cumulatively, transmission capacity of 31 cross-border capacity within the 18-regions model adds up to 52.1 GW. Length of aggregated cross-border capacity is determined by the centers of regions. Table A.2 in the appendix presents detailed cross-border transmission capacity data including its lengths.

4.11 Scenario definition

Scenario planning was developed during the 1950s and 1960s by strategists that were concerned about uncertainty regarding future development in various situations (Meinert, 2014). In particular, Herman Kahn is seen as the creator of this method. He developed and applied this method during his work at the US ministry of defense and RAND corporation. Pierre Wack brought scenario planning into business strategy during his work at SHELL in the 1970s (Chermack, 2017). The report *The Limits of Growth* by the Club of Rome acquired broader public perception to scenario planning through the publicity of the report. Two decades later, scenario techniques were widely used in policy, industry, organizations, and science. For example, Schoemaker (1995) describes scenario planning as an outstanding tool for managers to cope with overconfidence and tunnel vision in order to identify the most relevant trends and uncertainties. Gausemeier et al. (1998) named three techniques that are commonly used for scenario development: *intuitive logics*, *trend-impact* analysis, and *cross-impact* analysis. According to Wright et al. (2013), the scenario development technique *intuitive logics* is a well-established method in organizations to explore "limits of possibility" for future development. The method includes three steps for developing scenarios: identification of the driving forces, determining possible and plausible range of forces, and understanding interactions. As scenario planning is mostly described in the context of business strategy involving entire groups develop scenarios, a simplified method is applied in this thesis. Inspired by *intuitive logics* ((Schwartz, 1991; Wright et al., 2013), the selection of scenario variations is motivated by analyzing the effects of most important and most uncertain aspects regarding long-term electricity system planning. Therefore, scenario variations are intended to explore the solution space around the *base case* by studying three main aspects and their effects on the results. Uncertainty regarding future cost of certain important technologies, technical and political boundary conditions, and a different methodological approach of power system planning. This covers the first two steps of scenario development as described by Wright et al. (2013). The last step, understanding interactions, is not entirely addressed due to a limited number of scenarios that can be calculated which is explained by large model computation time. In total, 12 scenarios are defined in addition to the *base scenario*. In the following sections, details about scenario variations that are considered to study each of these aspects are explained. An overview on the scenario variations is given in Table 4.16.

4.11.1 Sensitivity on economics

Using a model-based analysis to study the transformation of the European electricity supply in the upcoming three decades involves a high level of parametric uncertainty. Although parameters were selected based on a detailed literature review, the actual development of each parameter remains uncertain. In order to study the effects of uncertainty regarding economical parameters, cost parameters of future key technologies are varied in six additional scenarios for testing their effect on important output variables. In these scenarios, stronger and lower cost reduction of the RES technologies wind and PV power, lower cost reduction potential of battery energy storage systems, and cost variations of the PtG technology are analyzed. Table 4.17 provides an overview on parameters for scenario variations that are different from the *base scenario*.

The effects of alternative developments of cost for wind and PV power in comparison to the

Table 4.16: Scenario overview

No.	Scenario	Parameters altered	Description
1	Base scenario	*none*	Represents the *base case*
2	RES progressive	Capex and Opex of PV, wind power	Higher cost reductions of RES technologies PV and wind power are assumed
3	RES conservative	Capex and Opex of PV, wind power	Lower cost reductions of RES technologies PV and wind power are assumed
4	PtG conservative	Capex and $OPEX_{fix}$ of PtG	Lower cost reduction of PtG technology is assumed
5	PtG CO_2 from air	Efficiency of whole PtG process and cost for CO_2	Additional energy demand and cost to capture CO_2 from ambient air: 9.0 MJ/kg_{CO2} (2.5 kWh/kg_{CO2}) + 320 EUR/t_{CO2} are added
6	Batteries conservative 50	Capex of batteries	Cost reduction of batteries is diminished to 50 % of cost reduction in *base scenario*
7	Batteries conservative 75	Capex of batteries	Cost reduction of batteries is diminished to 75 % of cost reduction in *base scenario*
8	Domestic supply 80 %	Domestic supply ratio $\geq$ 80%	respectively, each region can have max. 20 % imports (on annual basis)
9	Domestic supply 100 %	Domestic supply ratio $\geq$ 100%	Entire domestic demand has to be met by domestic generation (on annual basis)
10	Transmission extension +100 %	Transmission apacity extension limit	Transmission grid capacity expansion is limited to twice the current levels (+100 %)
11	Transmission extension +50 %	Transmission capacity extension limit	Transmission grid capacity expansion is limited to +50 % relative to the current levels
12	No Transmission extension	Transmission capacity extension limit	No expansion of transmission capacity beyond current levels allowed
13	*Snapshot planning 2050*	Single year modeled	Electricity supply system planning for 2050 from scratch with 2050 parameters of the *base case*

base case is studied by two scenarios. The range of cost developments reported by researchers is widespread. Thus, these scenario variations analyze the extrema. The scenario *RES progressive* assumes a stronger cost reduction of wind and PV power technologies of + 50 % increased cost reduction compared to the *base scenario*. *RES conservative* analogously reflects a cost reduction of RES technologies decreased by -50 %. The future economic performance of PtG systems and, hence, its role in the European electricity supply structure is especially uncertain regarding two aspects. First, its future cost development is very difficult to assess, due to the early stage of this technology. The scenario *PtG conservative* provides a case for lower cost reduction of PtG technology to cope with this uncertainty. Capital expenditures and related $OPEX_{fix}$ have diminished cost reduction of 50 % compared to *base case*. Second, the preferred technological choice to conduct PtG processes has not been identified yet. The most conservative approach is to simply capture CO_2 from ambient air. The scenario *PtG CO_2 100 % from air* therefore assumes that CO_2 is entirely captured from air and no other CO_2 source is used. This affects two parameters: the energy demand for CO_2 capture rises, which results in a lowered electricity-to-SNG efficiency of 45.2 %. Additionally, CO_2 capture cost increase to 0.0889 €/kWh_{CH4}. Both parameters for this scenario are provided in Table 4.8. The *base scenario* assumes a strong cost reduction for capital expenditures for battery energy storage systems. Two scenarios are designed to investigate the effect of less cost reduction of batteries. *Battery conservative 50* represents only 50 % cost reduction of the considered battery technology. *Battery conservative 75* defines a cost reduction of 75 %, relative to cost reduction in the *base scenario*.

4.11.2 Technical and political boundary conditions

A strong increase of electricity imports by transmission capacity extension might be contradicted by the interest of certain regions to maintain an independent electricity supply. Secondly, although the capacity extension of the transmission system is limited to 0.2 GW/a increase per cross-border capacity as suggested by Knopf et al. (2015), it is disputable that this number can be achieved bearing in mind the present cross-border transmission capacity of 54 GW. Thus, two aspects that might be induced by the political or technical boundaries are analyzed in the following five scenario variations: first, a potential political interest to have certain amount of electricity demand served by domestic power generation. This is reflected by a minimum coverage of 80 % and 100 % of its regional electricity demand by domestic power generation. This does not exclude electricity exchange among regions, as the percentage is calculated on an annual basis which allows balancing of imports and exports within one year. Second, limited extension of transmission capacities due to a long planning process, uncertainty of investors regarding the return on investment and large efforts that are

Table 4.17: Overview on cost assumptions variations in scenario variations. Unless otherwise indicated, provided numbers refer to CAPEX in Euro.

	2020	2025	2030	2035	2040	2045	2050
				RES progressive			
Wind	1,361.0	1,311.1	1,264.4	1,217.8	1,172.8	1,129.5	1,086.2
PV	850.0	700.0	550.0	520.0	490.0	460.0	445.0
				RES conservative			
Wind	1,393.2	1,376.6	1,361.0	1,345.5	1,330.5	1,316.0	1,301.6
PV	1,150.0	1,100.0	1,050.0	1,040.0	1,030.0	1,020.0	1,015.0
				Battery conservative 75			
Battery storages	633.9	392.2	365.6	349.3	349.3	349.3	349.3
				Battery conservative 50			
Battery storages	715.8	554.7	537.0	526.1	526.1	526.1	526.1
				PtG conservative			
PtG (Capex)	1,460.5	1,295.0	1,173.5	1,134.0	1,082.5	1,049.5	1,043.5
PtG (OPEX$_{\text{fix}}$)	58.42	51.8	46.94	45.36	43.3	41.98	41.74

related to such projects is considered here. As Knopf et al. argue, an expansion up to twice the current capacity levels could be feasible (Knopf et al., 2015). Doubling of transmission capacity marks the upper limit in these transmission expansion scenarios. Limited ability of transmission capacity expansion is studied by three scenarios: (a) transmission capacity expansion up to twice the current levels (200 %); (b) transmission capacity expansion up to 150 % of current levels; and (c) no transmission capacity expansion, only refurbishment.

4.11.3 Snapshot planning

Energy system modeling using a *snapshot planning* approach is popular for least-cost investment planning. This modeling approach is often used to study very similar goals as in this thesis: greenhouse gas emission constraint electricity supply or the integration of RES technologies. In both cases, typically, a cost-optimally designed electricity system compliant with the external defined targets is revealed. The approach of *snapshot planning* typically determines an electricity system built from scratch for a certain point in time far in the future. Existing electricity supply infrastructure is neglected in such an approach, which is justified by the very long planning horizon. The scenario *Snapshot planning 2050* is designated for a comparison of results obtained from the pathway planning approach with the *snapshot planning* approach. It studies least-cost electricity supply by 2050 and is parametrized with the parameters used in the *base scenario* for the planning interval from 2050 to 2054. In distinction from the *base scenario*, existing infrastructure is not considered. Comparable results regarding transmission capacity expansion are obtained limiting this to 7 GW for each cross-boarder capacity ($\widehat{=}\,0.2\,\mathrm{GW/a}$). In sum, the scenario *Snapshot planning 2050* is intended to benchmark the pathway modeling approach against often-used snapshot planning approach. Results from this scenario are discussed comparatively to the *base case* in Section 6.6.

5 Results – A decarbonization pathway towards 2050

This chapter presents a techno-economic optimized pathway of decarbonizing the European electricity supply sector following the greenhouse gas emission reduction targets determined by the EU commission. Results presented here are derived from a model calculation with *elesplan-m* (cf. Chapter 3) based on the presented input parameters in Chapter 4. This European electricity system model plans a cost-optimized power system transition towards mitigation goals set for 2050 by analyzing the pathway in 5-years intervals. Hence, a transition pathway is carried out that is characterized by: (1) the electricity generation mix and related GHG emissions, (2) integration of energy storage system technologies, (3) extension of transmission system capacity, (4) related investments needs, and (5) resulting cost of electricity supply. The decarbonization pathway described in this chapter is called the *base case* as it founds on data and parameters defined for the *base scenario* (details to be found in Chapter 4). In a nutshell, this chapter presents a cost-optimal pathway for electricity system infrastructure investment and decommissioning decisions, that would lead to a decarbonization compliant with the EU GHG emission reduction targets. This is followed by a chapter detailing about scenario variations that highlight effects of uncertainty related to the findings of the *base scenario*. Key assumptions and parameters are varied in order to reveal potential uncertainty, study alternative pathways and investigate robustness of findings of the *base scenario*.

Within the *base scenario* the different policy goals according to the energy supply triangle are met. Reliability is ensured as the entire assumed electricity demand of the upcoming three decades is covered. At the same time sustainability is achieved as EU GHG mitigation targets are fulfilled. Greenhouse gas emissions decline from initial emissions of 1039 $\mathrm{Mt.\,CO_2}$ in 2020 to 23.6 $\mathrm{Mt.\,CO_2}$ by 2050 (cf. Figure 5.1) according to the EU GHG mitigation goals (European Commission, 2011a) (cf. 4.13). The first decade of the analyzed period is dominated by GHG emission related to power generation of coal-fired power plants. However, the composition of emission origins changes over time. Increasingly stronger GHG emission reduction targets force a shift from fossil-fueled power generation to gas-fired technologies, as they typically operate with lower specific emissions. Finally, the pathway follows a least cost approach. Even as the LCOE increase it is still the most economic pathway meeting the reliability and ecological constraints.

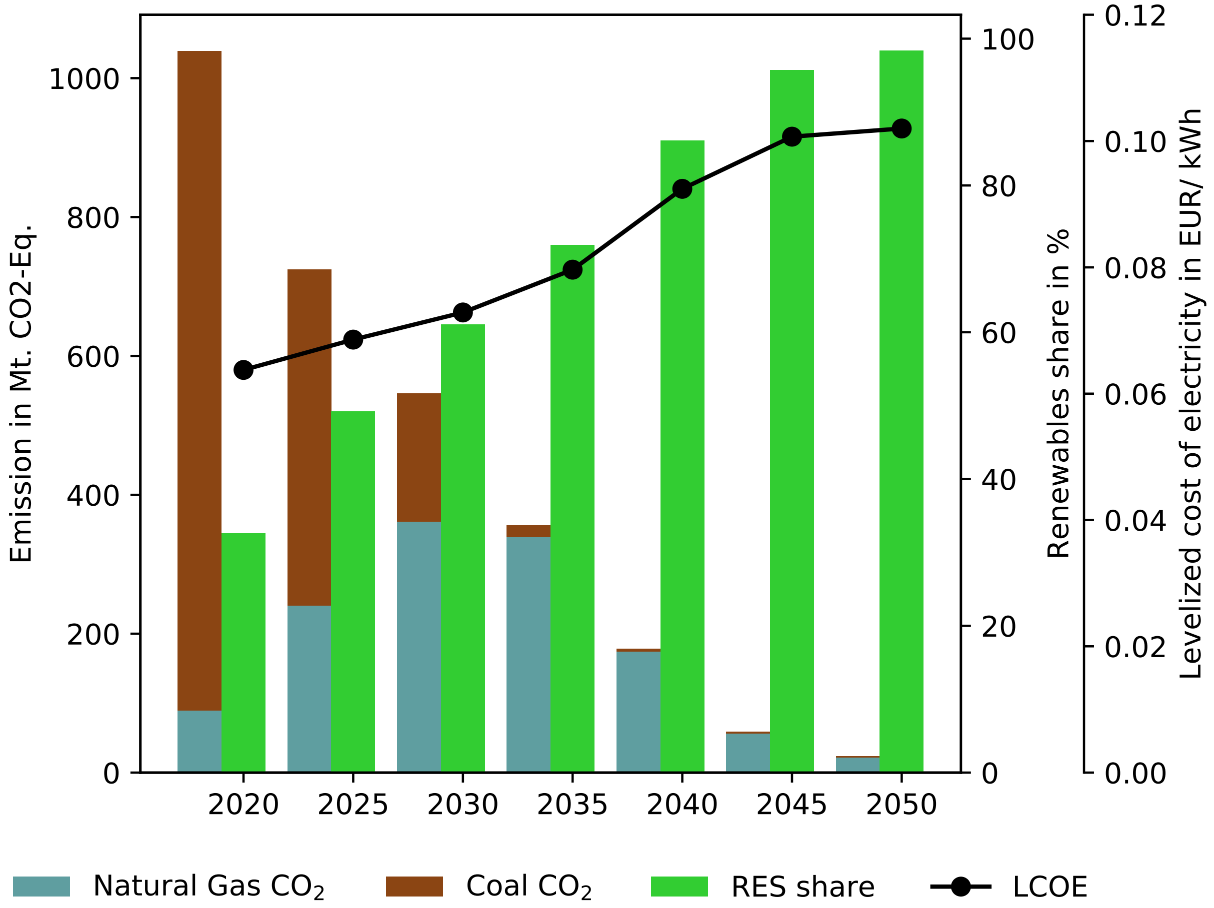


Figure 5.1: Overview on the transition pathway. Greenhouse gas emissions in the power sector are given as per source (left bars). Resulting RES (green bars on the right) share and levelized cost of electricity (LCOE) (black line) are shown for each *decision year*.

The transformation of the power supply sector results in an increased share of RES on total power supply and increased LCOE. The European average share of RES in 2020 adds up to 32.6 % and increases to 98.3 % by 2050 (cf. Figure 5.1). This increase of RES share moreover sketches a shape of a logistic growth curve: First, the increments of increasing RES share are relatively large and decline over time. Levelized cost of electricity escalates to about 59 % from 0.064 EUR/kWh in 2020 to 0.102 EUR/kWh by 2050. Details about the technological change in terms of electricity generation, the upcoming integration of energy storage system, the need for transmission capacity extension, and spatiality of future power supply as well as required investments along this decarbonization pathways are provided in the following.

5.1 Power generation and capacity

The limit on GHG emissions due to power generation is deciding factor for determining the mix of technologies in the future power supply system. Electricity generation by carbon-intense technologies gradually decreases while the amount of electricity supplied by RES technologies increases. For each planning period, *elesplan-m* reveals an updated mix of power generation technologies that is adapted to the corresponding electricity demand and the changed GHG emission limit.

By 2020, fossil-fueled and nuclear power generation technologies constitute around the half of Europe's power generation capacity. Nuclear power, coal-fired and gas-fueled power generation represents 54 % of in total 892 GW power generation capacity (see Figure 5.2). The remaining capacity is spread among 183.4 GW of wind power (20.5 %), 148.5 GW of hydro power (16.6 %), and 79.7 GW of PV power (8.9 %). In terms of shares of electricity generation, the dominance of nuclear and fossil technologies in the 2020's power supply mix is even more pronounced. These technologies provide 66.8 % (2353 TWh/a) of total power supply. Coal power and nuclear power provide the majority of electricity generation until 2020 (see also Tab. A.6). Gas power generation technologies play a minor role with a share of 7.2 % on electricity generation during this period. The remaining third of the electricity is provided by hydro power (15.3 %), wind power (15.3 %) and PV power (2.7 %).

As demand increases from 3490 TWh/a to 4448 TWh/a between 2020 and 2050 (see Figure 5.3), total generation increases from 3523 TWh/a to 5941 TWh/a. The cumulative generation capacity adds up to 3184 GW in Europe by 2050. This shows a relative growth of about +257 % between 2020 and 2050 (capacity extension for each 5-year interval is provided in Tab. A.5). The growth rates vary among generation technologies and across time. In particular wind and PV power undergo a large capacity expansion. Wind power capacity increases in total by +580 % to 1428 GW by 2050. Generation capacity of PV power grows by +1380 % adding up to 1259 GW by 2050. On average, this translates to annual capacity increase of 48 GW/a for wind power and 39.7 GW/a for PV power. The largest capacity extension occurs in 2040, when 71.2 GW/a of wind power and 83.6 GW/a of PV power are being installed. From 2025 onwards, wind power takes over the role of largest electricity supply technology among all power generation technologies. By 2050, wind power is the largest

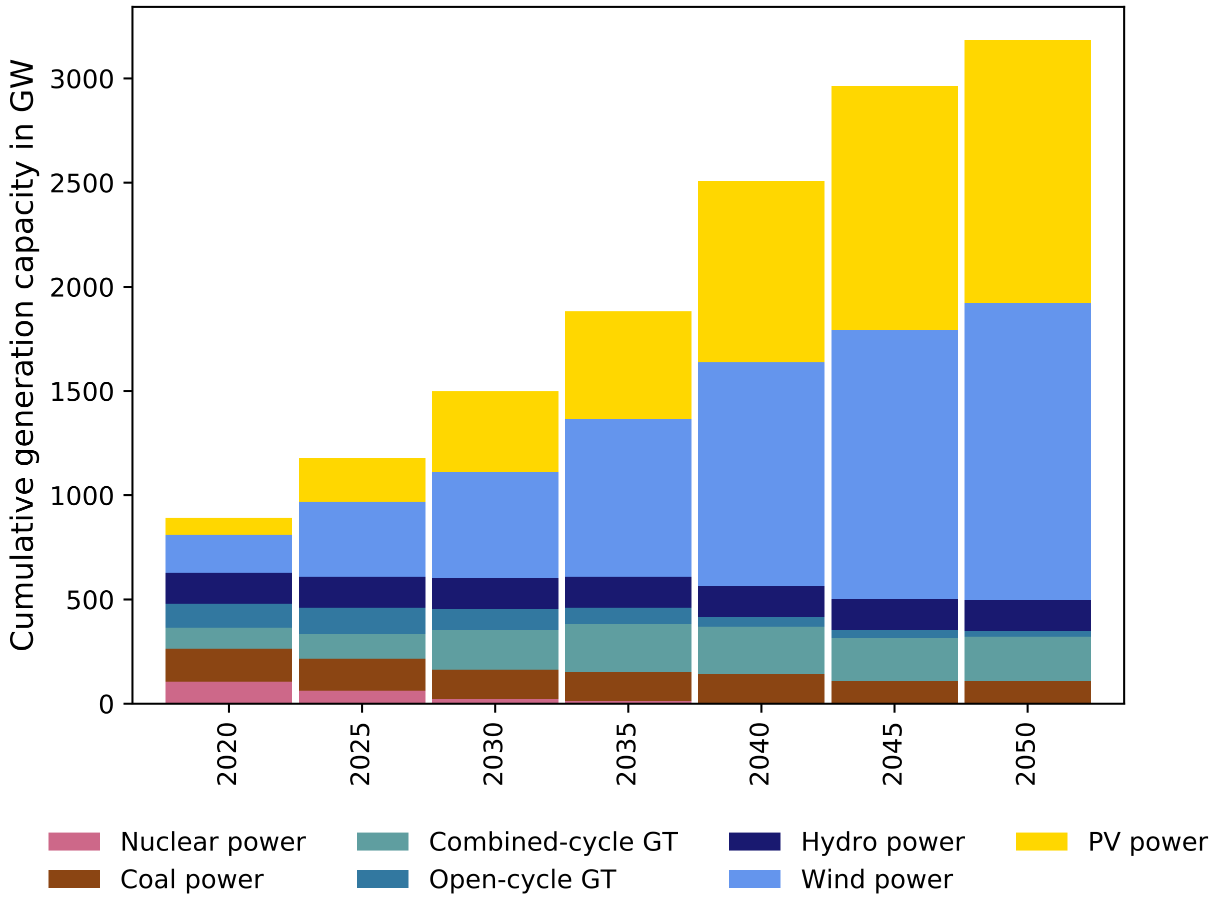


Figure 5.2: Power generation capacity mix.

supplier by far. The generation of 3478 TWh/a by wind power represents 58.5 % of total power generation. Photovoltaic power supplies 1619 TWh/a by that time. With a share on total generated power of 27.2 % PV is second largest supplier in 2050. Hydro power capacity remains on a constant level of 148.5 GW with unchanged power generation of 539 TWh/a from 2020 to 2050, as no further capacity extension of hydro power is considered. A certain mix of electricity generated by PV and wind seems to be optimal. Diurnal supply patterns of PV power technology and the stochastic supply pattern wind power in combination are optimal to meet the demand pattern. Gerlach et al. (2011b) already discussed complementary and spatially varying optimal combination of PV and wind based electricity generation. Their results are reaffirmed here.

Unlike RES technologies' capacity extension, cumulative capacity of nuclear and fossil fuel technologies decline to around 11 % of total generation capacity by 2050 (see Figure 5.2). The extension and rebuild of nuclear power generation capacity is prohibited in *elesplan-m*. The share of generation of largest producers in 2020 is dwindling fast: nuclear power generation would decrease rapidly in the first decade. In 2040 it generates only 45 TWh/a, 1 % of the demand. This further reduces to 10 TWh/a (0.2 % of total power generation) by 2045 and to 5 TWh/a (0.1 % of total power generation) in 2050. Power generation based on coal decreases even faster. Due to its high carbon intensity, large amounts of electricity generated by this technologies cannot be considered beyond 2020. Its share on power generation adds up to only 0.5 % in 2035. From 2040 this further declines to about 0.1 % by 2050. Despite the small amount of electricity generated by nuclear and coal power, its capacity is still present for decades. In particular, a large capacity of coal power plants remains in the power system until 2050. The generation capacity of 160 GW in 2020 gradually declines to 108 GW by 2050. The capacity of nuclear power declines faster: after 2035 only 7 GW are available which further reduces to 1 GW by 2050 (see Tab. A.4). Quickly diminishing electricity generation but long remaining generation capacity, leads to reduced FLH of nuclear and coal power. Average FLHs of fossil-fueled and nuclear power generation are presented in Table 5.1. While FLH of nuclear only decline to around 6000 h/a, those of coal power reduce further to almost zero by 2050. It reaches 1630 h/a by 2030 and 155 h/a by 2035. This illustrates the lacking economic attractiveness of coal-fired power generation on medium term in times of increasingly strong GHG emission reduction targets.

Table 5.1: Average full-load hours of nuclear and fossil-based power plants over the observed period of time.

	2020	2025	2030	2035	2040	2045	2050
Coal	7399	4009	1630	155	39	28	19
Nuclear	8696	8394	7823	6843	6332	6730	6082
CCGT	2292	5729	5710	4253	2550	1716	1386
OCGT	207	159	74	287	230	172	145

In contrast to diminishing total nuclear and fossil-fueled power generation capacity, the capacity of CCGT almost doubles (+ 112 %) within the analyzed time frame (cf. Table A.4). Annually generated electricity of this technology increases as well. The electricity supply by gas power plants technologies supply adds up to 298 TWh/a by 2050. With OCGT's capacity declining, its contribution to serve demand in 2050 is relatively low. Only 4 TWh/a are supplied by OCGT in 2050 (cf. Table A.6). As total power generation almost doubles, the share of gas-fired power generation decreases from 7.2 % to 5 % within investigated three decades even if actual power generation of gas-fueled technologies increases. In 2035 CCGT capacity peaks at 231.5 GW after which the capacity declines to 212.6 GW by 2050.

Combined-cycle gas power plant technology takes advantage of two effects. First, generation capacity shifts from coal to gas due to the pressure put by the GHG reduction targets. Second, PtG technology comes up in 2040 (refer Section 5.2) and creates a need for re-electrification capacity of produced SNG. Thus, starting by 2040 and increasing over time, the fossil based share of power generation by gas-fueled power plants declines. This has to be considered while reading Figure 5.3. Gas-fueled power generation takes over large shares in the decade between 2030 and 2040. Power generation by gas-fueled technologies adds up to 1077 TWh/a in 2030 and 1007 TWh/a in 2035. Open-cycle gas turbines in general play a minor role.

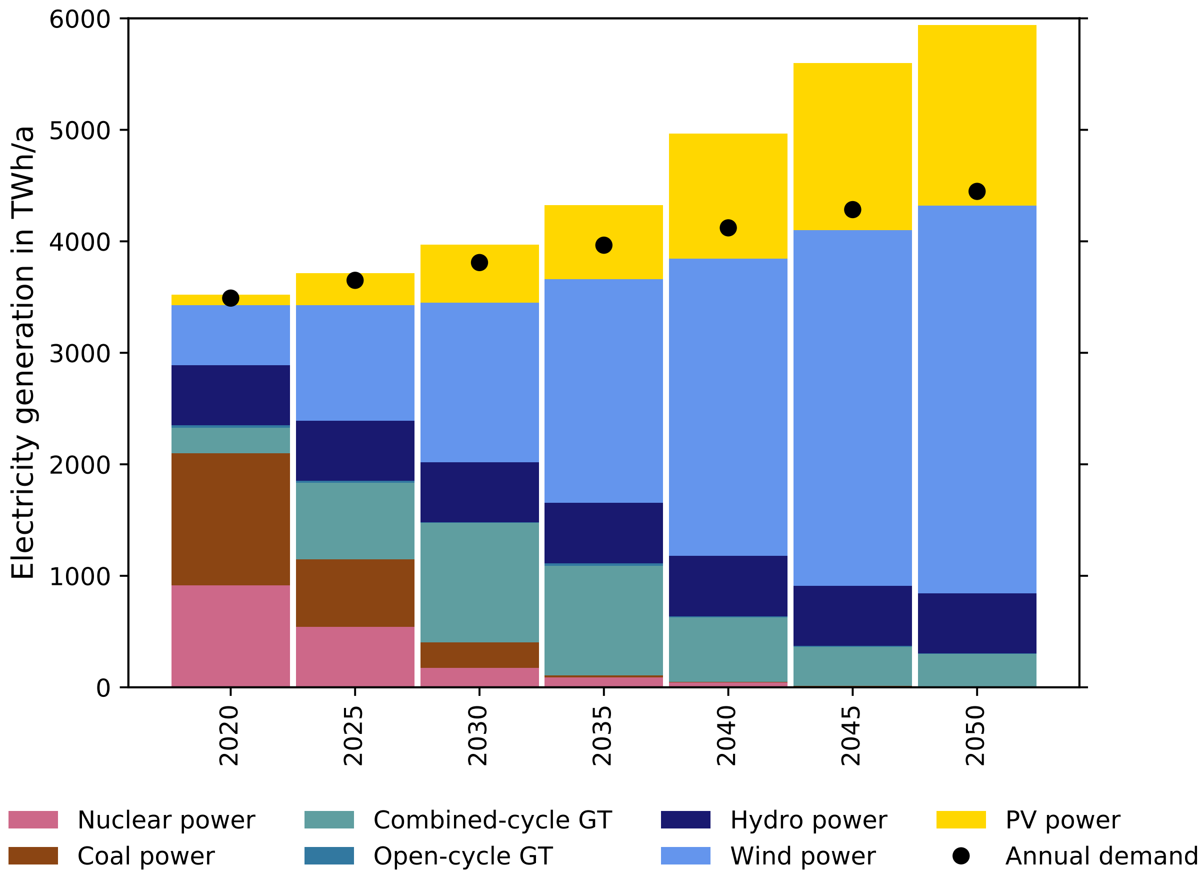


Figure 5.3: Annual electricity generation and demand in each planning interval. Generation is disaggregated per technology.

In summary, to achieve the GHG emission targets by 2050, the electricity generation mix would have to change. Carbon-intense technologies, such as coal, would have to be replaced first. RES based electricity generation technologies become more important during the transition and provide the largest share of the electricity supply in 2050. Gas power plant technologies support the transition by providing less carbon-intense and flexibly dispatchable capacity.

5.2 Energy storage systems

As outlined in Section 5.1, dispatchable supply capacity capable of following the pattern of the electricity demand, that is provided by nuclear and fossil-fueled technologies, diminishes. In addition, there is an increased requirement for additional balancing capacity due to higher shares of wind and PV power. Energy storage systems are considered in the power supply system to compensate for dwindling flexible capacity and provide additional balancing capacity. Beginning in 2035, existing PHS capacity is supplemented with BESS and PtG capacity (see Figure 5.4). By 2050, flexible power supply capacity including energy storage systems adds up to 618 GW: capacity of conventional power generation technologies of 354.8 GW. This is also complemented by an energy storage discharge power comprising of 43.2 GW of pumped-hydro power and 226 GW of batteries. Negative balancing power (charge power) increases at the same time. The charging power of 43.2 GW PHS is complemented by 227 GW of battery storage capacity and 261 GW are provided by the PtG system (cf. Tab. A.8).

Energy storage systems play an increasingly important role alongside the integration of RES. Nowadays, pumped-hydro storages is the only large-scale energy storage technology present in the European electricity supply system with a cumulative conversion power of 43.2 GW (respectively 345.2 GWh of energy storage capacity). As new installations are limited to refurbishment of existing capacity, the capacity of PHS remains constant over the three decades that are analyzed. Until the year 2035, *elesplan-m* does not consider investments into further ESS capacity. From the social-planning perspective there is no economically viable case for investments in ESS technologies at that time. By 2035, a battery energy storage system capacity of 3.2 GW is considered in the cost-optimized power supply system. Five years later, it is supplemented with additional 117.6 GW of BESS capacity, plus 66.8 GW of PtG capacity. In this case, the capacity of PtG refers to electrical nominal capacity of electrolyzers. The capacity of ESS increases further in the last decade of the analyzed period. Battery energy storage systems' capacity almost doubles to 212.4 GW by 2045 and slightly increases to a cumulative capacity of 227 GW of battery energy storage systems by 2050. Power-to-gas capacity increases rapidly in the last decade. While in 2045 a conversion capacity of PtG of 206 GW is required in the cost-optimized power system, it is further extended to 261 GW by 2050. Including the PHS capacity at current levels, cumulative energy storage charging power adds up to 531 GW by 2050.

The identified least-cost electricity supply system considers for a mix of energy storage system technologies. The integration of BESS extends the balancing capacity of PHS that typically operate on short to medium term (hours up to days). Battery energy storage systems and PHS have a similar energy-to-power ratio (BESS (zinc-bromide): 6.5 kWh/kW; PHS: 8 kWh/kW). Whereas PtG energy storage systems have a flexible energy-power-ratio which allows to size the energy storage capacity independently from the conversion power. This feature is used by *elesplan-m* to optimally size components of the PtG unit: the electricity conversion unit (electrolyzer plus methanation), the gas storage and the re-electrification unit (gas power plants). Furthermore, the PtG system has comparatively low cost for the gas storage. This makes it suitable for storing electricity on long term (weeks up to months). It turns out that the optimal ratio of gas storage capacity to electrical conversion power of the PtG is significantly larger than the energy-power-ratio of BESS and PHS. This ratio does not remain constant over the investigated period of time. Until 2040, an optimal energy-power-ratio for PtG of 1427 kWh/kW is identified. In the next planning period it decreases to 493 kWh/kW and by 2050 decreases further to 401 kWh/kW. This is about 50 to 60 times higher than for the other ESS technologies.

In total, 106.3 TWh of energy storage capacity corresponds to storage power by 2050. The largest amount is provided by gas storages that store SNG produced in PtG units. Its capacity add up to 104.4 TWh. This accounts for 98.3 % of the total energy storage capacity. Battery storage capacity adds up to 1,473 GWh by 2050. This is complemented by 345.2 GWh of PHS storage capacity. Long operational cycles (up to seasonal) of the PtG system cause a need for large gas storage capacity. This explains gas storage capacity to be higher compared to other energy storage system technologies.

5.3 Spatiality, transmission capacity and power exchange

Electricity demand, electricity generation, and generation mix has large regional differences. Figure 5.5 illustrates power generation disaggregated by generation technology, and the demand in each region for 2050. The regional annual electricity generation is determined by the regional demand, available power generation capacity and the local RES potential. The latter determines the extension of RES generation capacity, and thus, the electricity generation mix in systems of high RES supply. Power generation in half of the regions is dominated by wind power. Photovoltaic power is the major supply technology in two

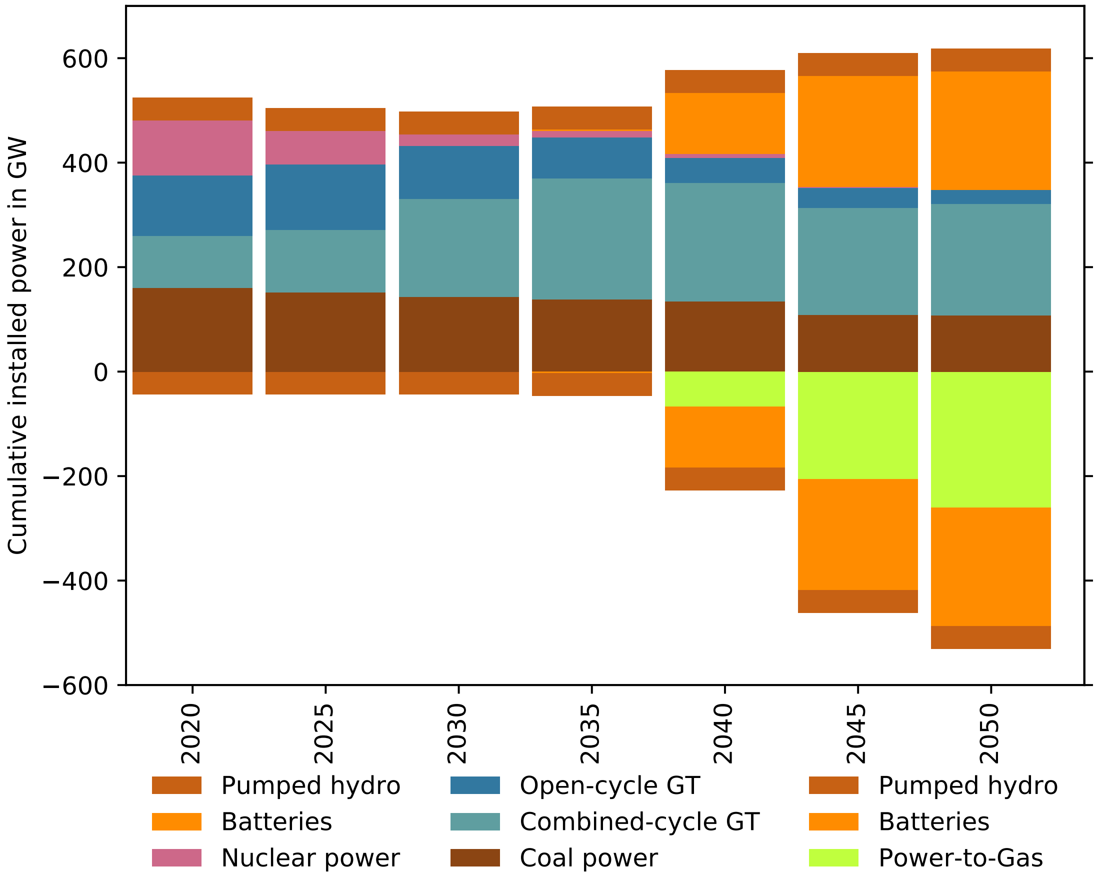


Figure 5.4: Positive and negative flexibility capacity provided by power plants and energy storage systems. Positive flexibility refers to power generation and storage discharge capacity. Negative flexibility capacity is related to storage charging power.

large power generation regions (Iberia and Italy) and in five small power supply regions (Eastern Balkans, Hungary-Romania, Southern Balkans, Western Balkans). Alpine Region, Sweden and Norway constitute an exception where hydro power generation serves most of the demand. The regional preference for a certain electricity generation technology can be described as follows. In the south, due to high solar power potential, PV power is the preferred technology. Northern regions predominately rely on electricity generation by wind power if their demand is not sufficiently covered by hydro power generation. Regions with cumulative power generation smaller than annual electricity demand are supplied by neighboring regions. A small amount of power generation by gas power plants is present in every region. Due to the strict GHG emission constraint in the year 2050, the volume of gas-fueled power generation is small.

Figure 5.6 presents annual the net cross-border power flows for 2050 resulting from the regional demand and supply mismatches. As the figure shows, regions can act as both, as

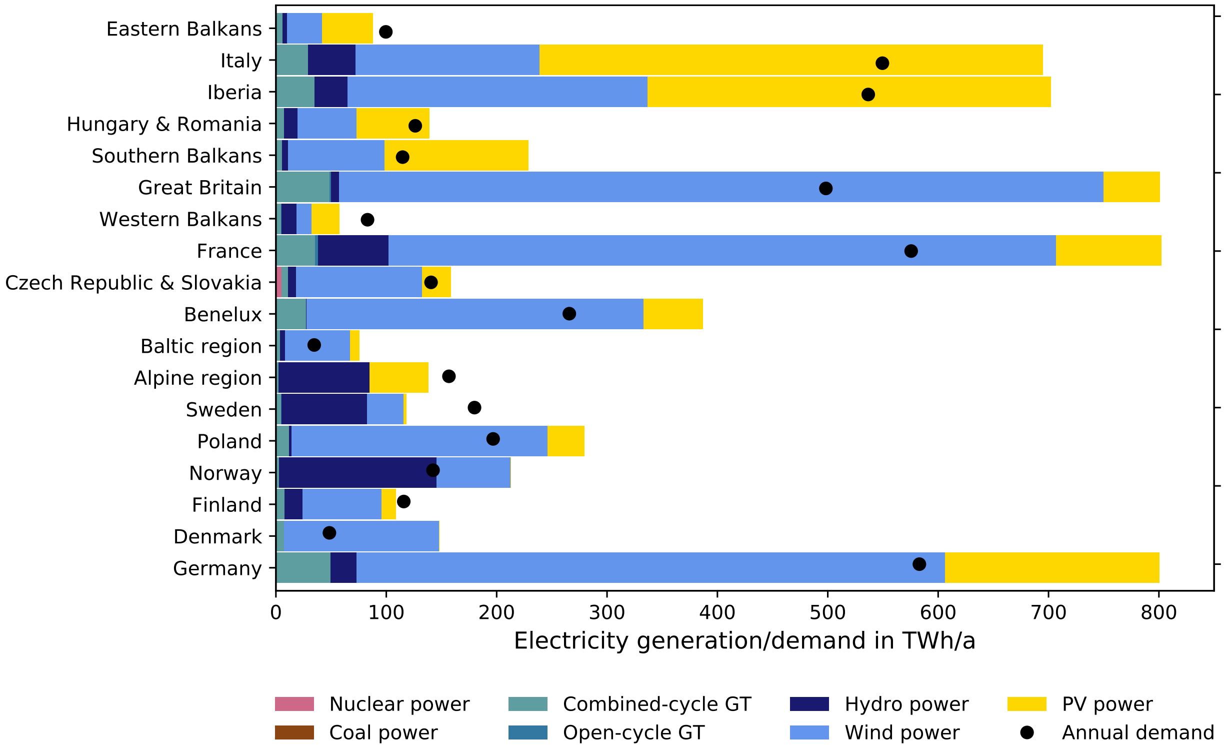


Figure 5.5: Spatially disaggregated annual electricity generation and electricity demand by 2050. Black dots reflect regions' electricity demand.

a net supplier or as a net consumer. Furthermore, regions can serve as hub for exchanging electricity among non-adjacent regions with a net power exchange close to zero. Half of the regions extensively use electricity exchanges via the transmission grid for balancing supply and demand. Four of these export more than 35 % relative to their annual electricity demand (cf. Tab. A.11). Denmark significantly stands out with annual net electricity exports of 129 % of its annual demand. The Southern Balkans are the largest exporting region with an annual net electricity export of 67 TWh/a. Norway produces annual net exports of 52 TWh/a which is 37 % of its annual electricity demand. France exports around 6 % relative to its annual. Due to its relatively high annual demand this adds up to 37 TWh/a. On the other hand, five regions cover their annual electricity demand by more than 19 % based on electricity imports. Sweden is the largest consuming region by far. The annual electricity demand is covered by 44 % based on imports which adds up to 79 TWh imported electricity per year. Western Balkans the second largest consuming region based on the absolute net electricity imports of 35 TWh/a that serves about 42 % of its electricity demand. Electricity imports on demand coverage of the other three large scale importing regions ranges between 19 % and 28 % (26 TWh/a to 32 TWh/a). In between these major exporting and importing regions, nine regions exist whose annual electricity exchanges do not exceed 7 % of their annual electricity demand (cf. Tab. A.11). Nevertheless, its annual balance of electricity exchanges adds up to 37 TWh/a as in the case for France.

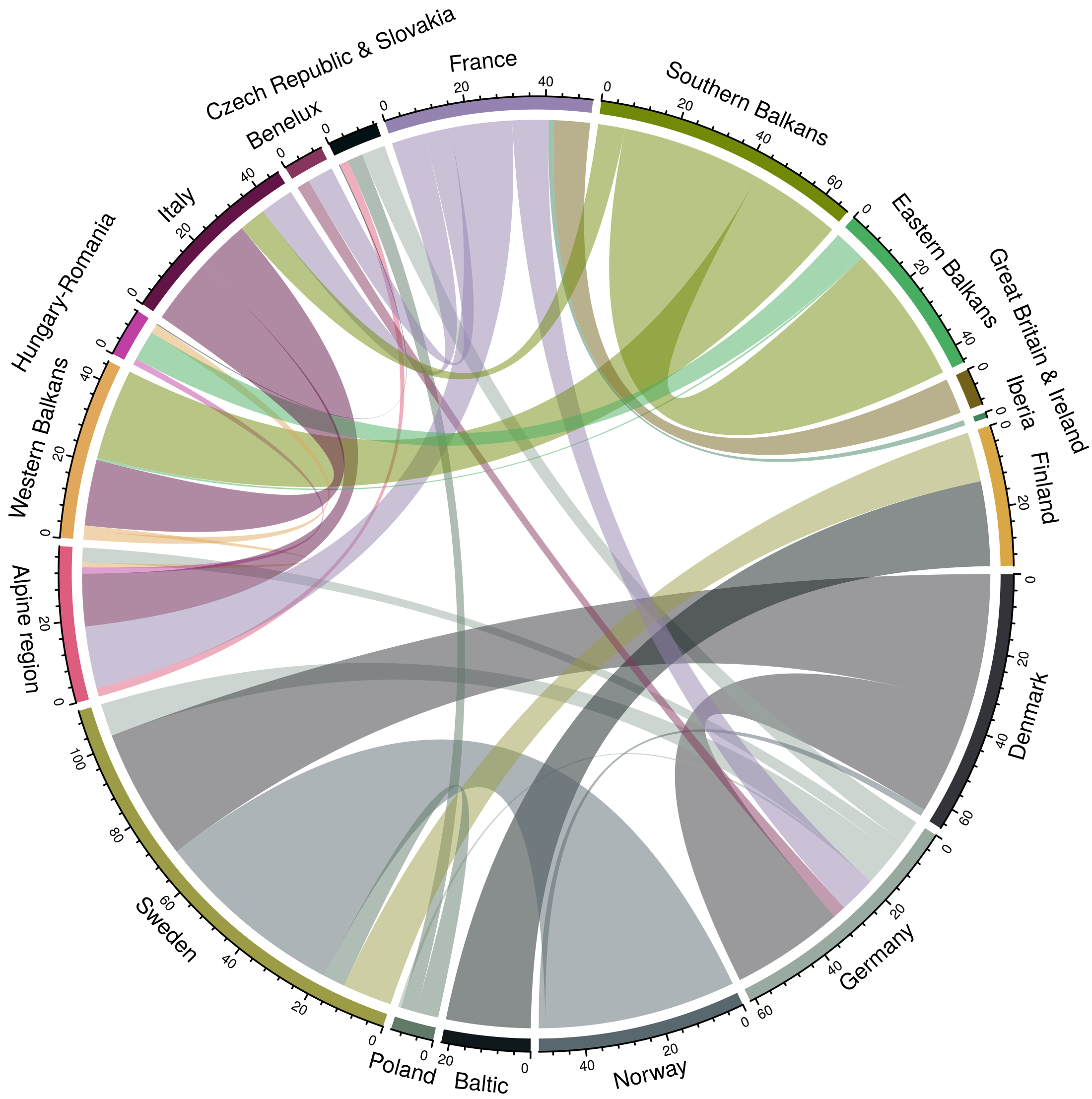


Figure 5.6: Annual exchange electricity between regions in TWh/a. A sector represents regions' cumulative import and export electricity exchanges with neighbored regions. Colored tracks linking the sectors reflect net electricity exchanges betweens these regions. Tracks with same color as the sector, that they are attached to, represent exported electricity from this region.

No global trend of location could be observed by looking at electricity imports and exports of regions. Exporting regions are located in the north (Norway and Denmark) where power supply benefits of good RES conditions. Norway's power generation mix relies on wind and hydro power whereas Denmark generates electricity almost entirely based on wind power (refer Figure 5.5). Southern Balkans on the other hand generate power mostly based on PV technology. Major importing regions are spread over entire Europe: in the north (Sweden, Finland), central (Alpine Region) and south (Western Balkans). Sweden is an extreme example of region's dependency on electricity imports. The analysis seeking for a least-cost power system design compliant with GHG mitigation targets can result in such extreme supply situations. Although the analysis suggests these supply configurations involving large-scale power exchanges, decision-makers in the affected countries may insist on limiting their dependency on electricity imports.

Aside from electricity exchanges on an annual basis, regions can act as a hub, transmitting electricity from one neighbor to another. These hub regions are found among net exporting, net importing, and balanced regions that serve their electricity demand almost entirely by domestic generation. Their annual transmitted electricity ranges from 0 TWh/a up to 40.6 TWh/a (see column *Pass through* in Tab. A.11). Germany and France transmit the largest amount of electricity. The lowest electricity transmission of 0 TWh/a is found in regions that are at the edge of Europe. The Baltic, Great Britain & Ireland, Iberia and the Eastern Balkans. With the exception of the Eastern Balkans, these regions are linked to only one other region, which gives them no reason to transmit electricity. The major hub regions are located in the center of Europe connecting many countries. Besides Germany and France, four other regions (Benelux, Alpine region, Denmark and Sweden) show relatively large amounts of transmitted electricity ranging from 25 TWh/a to 30 TWh/a. Denmark and Sweden may not seem to be located in central Europe, but from the perspective of the European transmission system topology they are. Sweden is connected to five neighboring regions which makes transmission of electricity likely. Denmark connects Norway, a large scale electricity exporting region, to central Europe.

The large-scale electricity exchange in 2050 is enabled by massive transmission capacity extension. In total, transmission capacity adds up to 179 GW by 2050. Transmission capacity extension takes place at every transmission point, but its amount spreads differently among them. Figure 5.7 presents resulting transmission capacity for each cross-border transmission system. Centrally located regions are strongly connected to northern, western and south-western regions. Most of these transmission links are extended to a capacity of 6 GW or up to 7 GW (for details see Table A.10). Only in the south-east of Europe transmission extension is moderate.

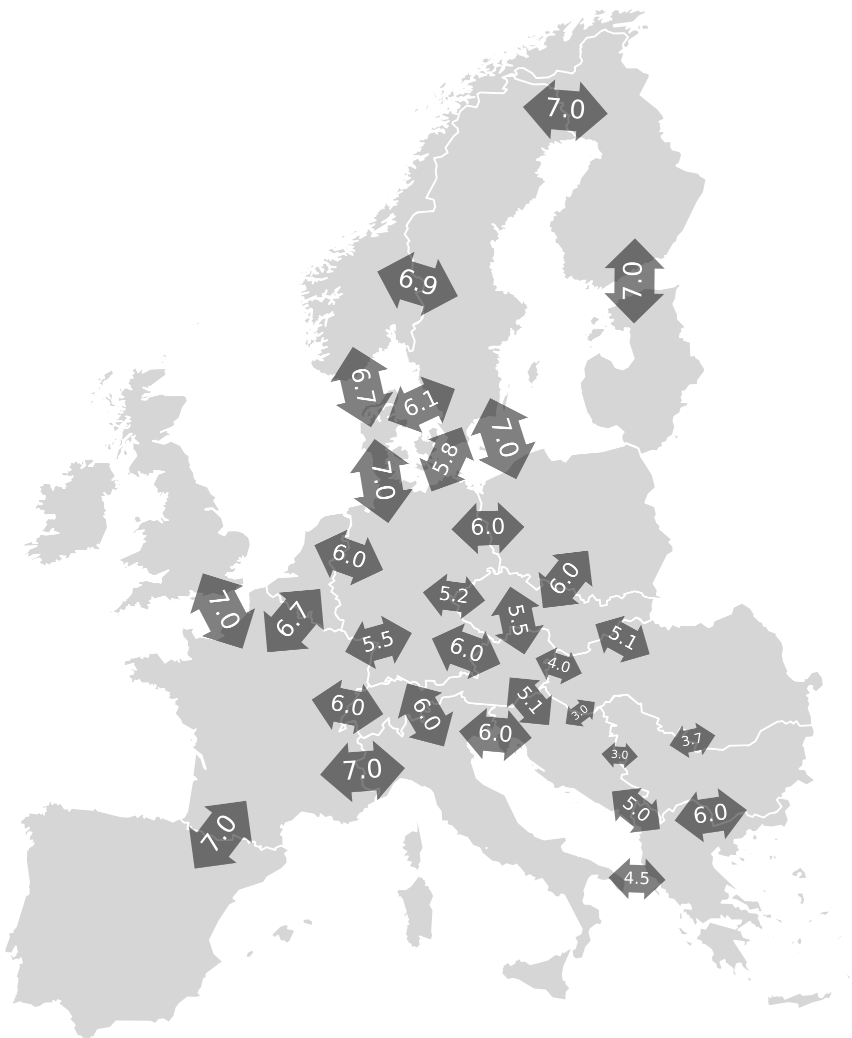


Figure 5.7: Cross-border transmission capacity resulting for 2050 in GW.

5.4 Excess electricity and losses

Energy losses in power supply systems can have several origins. Besides losses associated with conversion of primary energy to end-use energy, power transmission and use of energy storage systems (ESSs) incorporate energy losses. Additionally dumping of energy in terms of excess electricity (actually the curtailment of power generation) is a viable option to keep the balance between supply and demand. In this study, total losses are defined to comprise of transmission losses, losses in PHS, losses in battery energy storage system, losses associated with conversion in the PtG process, and excess electricity that cannot economically be used. Electricity losses associated to energy storage systems consider the round-trip efficiency of these systems.

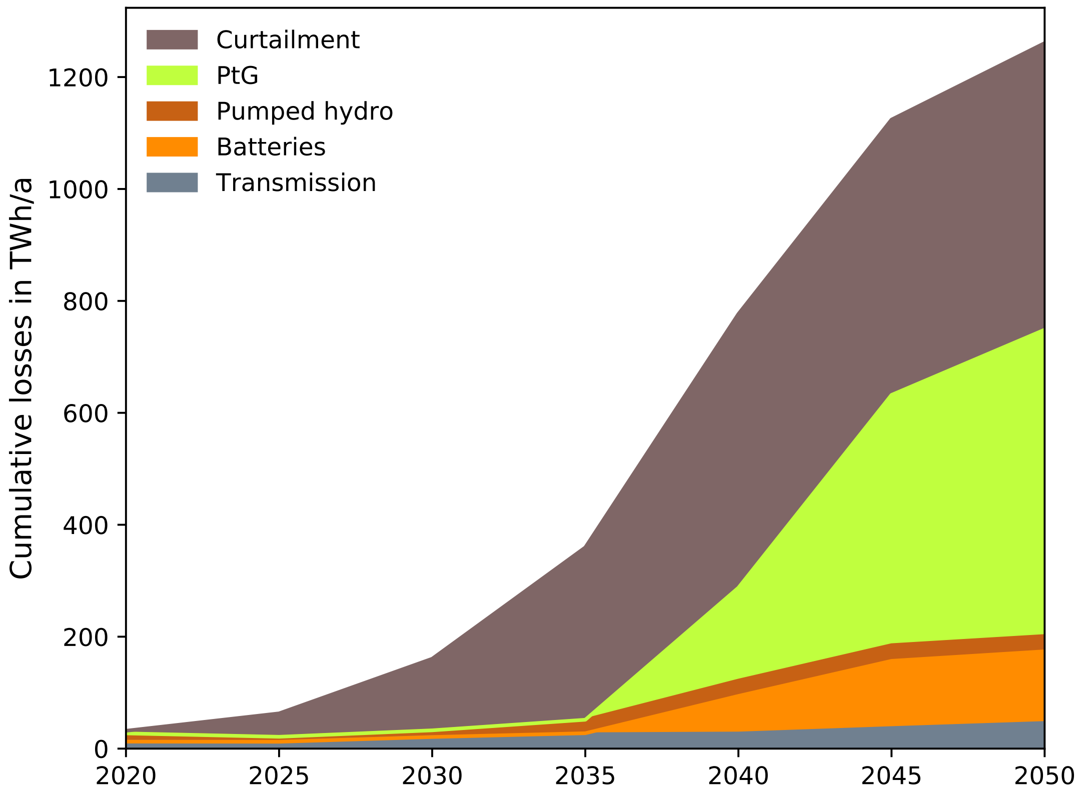


Figure 5.8: Energy losses in energy storage systems, transmission system and excess electricity.

In 2020, total losses add up to 32 TWh/a. These are related to pumped hydro storage (46 %), transmission (39 %), and a small amount of excess electricity (15 %) (cf. Fig. 5.8 and Tab A.12). Enlarged RES based power supply increase excess electricity. By 2035, when additionally installed energy storage power of batteries and PtG is still negligible, total losses sum up to 359.5 TWh/a. Dumped electricity accounts for the majority of electricity losses. By this time 85.6 % of these losses originate from dumped electricity that cannot be used to supply demand nor be stored in energy storage systems as this would require capacity extension which is not economically viable at that time. In the next one and a half decades cumulative losses increase dramatically (see Figure 5.8). The increasing share of RES power supply creates extended balancing needs and thus drives extension of energy storage system capacity. As the balance between supply and demand cannot be kept entirely by ESS, this results in additional dumped electricity. Operation of extended storage capacity leads to higher efficiency losses at energy storages. By 2040 excess electricity escalates to 490 TWh/a. At the same time, energy storage system capacity extension of batteries and PtG creates additional losses of around 230 TWh/a. Losses associated to PHS and transmission only increase slightly by 2040. Compared to other losses, this is negligible. The next decade is characterized by increasing losses at batteries and PtG whereas excess electricity remains almost at a constant level. In 2050, losses related to transmission of power add up to 46 TWh/a. Analogous to energy storages, increased transmission losses are related to the extension of transmission capacity and increased cross-border power flows (cf. Section 5.3). Nevertheless, this is negligible compared to increasing losses of battery storages and in particular of losses related to PtG. By 2050, the majority of cumulative electricity loss of 1260 TWh/a is associated to PtG (43.4 %) and dump of surplus electricity (40.6 %). Battery storages account for around 11 %, transmission losses for 3.6 % and 2.2 % of losses are related to PHS.

5.5 Cost and investment needs

The shift from nuclear and fossil-fueled power supply to sustainable supply based on RES technologies is associated with higher levelized cost of electricity (LCOE). Those, at 6.4 cent€/kWh in 2020, increase to 10.2 cent€/kWh by 2050, which is a plus of 59 %. Figure 5.9 illustrates the breakdown of LCOE to generation technologies, energy storage technologies and the transmission system (cf. Tab. A.13). Fractions of LCOE as illustrated in Figure 5.9 are calculated as total cost of each technology divided by total demand.

In 2020, fossil-based power generation technologies dominate the cost composition. In particular nuclear power holds a large share on power generation cost of around 2 cent€/kWh. The picture changes in 2030 when RES technologies account for 63 % of total generation. Consequently, these cause the majority of cost – 56 % of LCOE are related to power generation by RES technologies. Besides PHS, cost associated to energy storage system become just visible by 2040. As then all three energy storage technologies account for less than one cent€/kWh, their amount on LCOE adds up to 1.2 cent€/kWh by 2050. Cost related to batteries represent the lion's share and add up to four times more the share of PtG at LCOE.

As wind power constitutes the largest share on generation (58.5 %), it dominates cost composition of 2050 as well. Photovoltaic power as second largest supplier is responsible for 2.4 cent€/kWh which is around the half of wind power's contribution to total LCOE. The share on LCOE of hydro power and PHS remains almost constant. As its capacity remains constant and demand increases the relative share slightly declines over time. The proportion of CCGT at LCOE resembles annual power generation by this technology. This mostly originates from the strong dependency on variable cost. Coal still induces cost until 2050, even though it does not produce electricity anymore. These cost are related to annuities of earlier investments into coal technology that have to be paid during the entire lifetime.

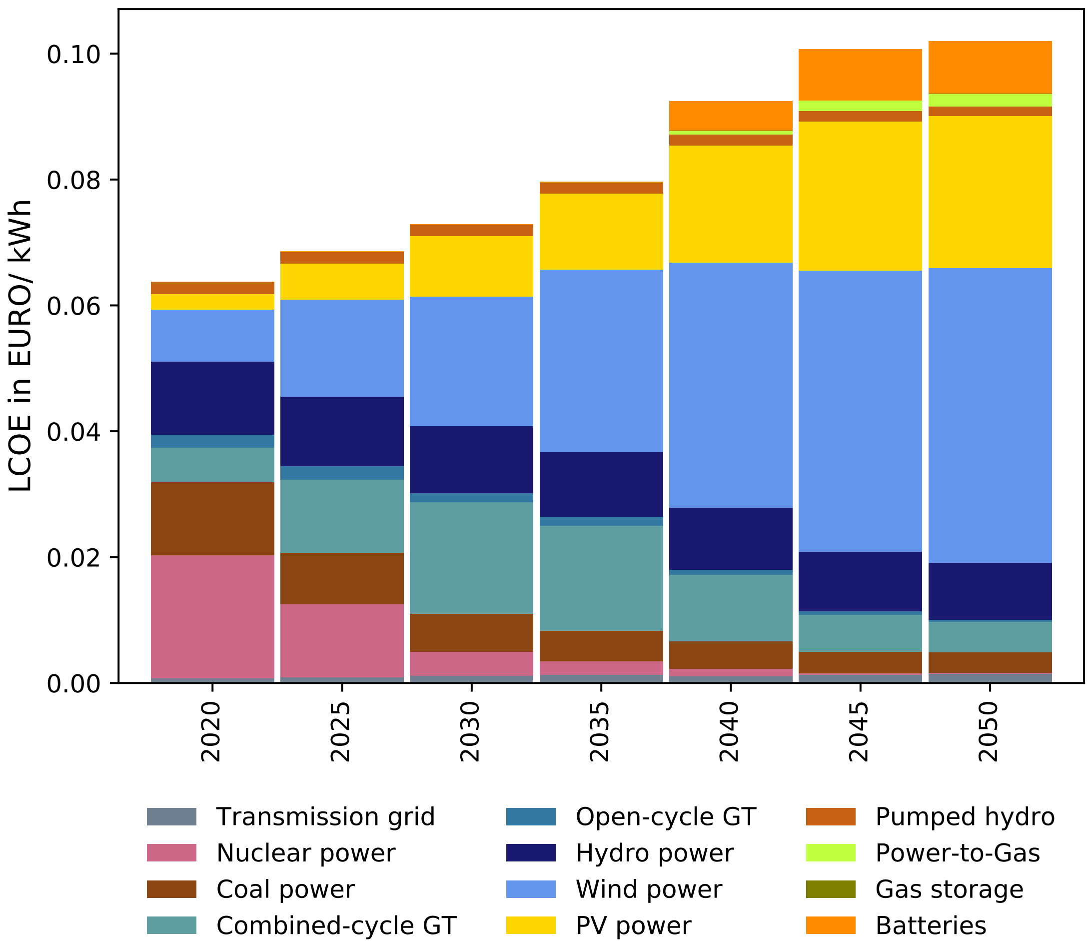


Figure 5.9: Breakdown of resulting levelized cost of electricity for each planning interval.

Following the above outlined transition pathway, and thus, adhering to GHG mitigation targets until 2050, requires a total investment in the electricity supply infrastructure of 4,021 bn. € (see cumulative investment needs indicated by a black line in Fig. 5.10). This includes investments into newly built capacity as well as refurbishment of existing power plant, energy storage system and transmission capacity. Broken down to average investment needs per year these add up to 118 bn. €/a. Figure 5.10 reflects investments into new capacity (extension and refurbishment) that are associated with the outlined transition pathway (cf. Tab. A.14). Investments into fossil-fueled technologies diminish along with the decarbonization of European power supply. In 2020, a large investment into coal technology occurs. Afterwards only relatively small investment needs are determined for CCGT. Cumulative investments into fossil-based power generation technologies add up to 475 bn. € over the entire period of time. Remaining investment needs of 3,646 bn. € split across RES technologies, energy storage technologies and new transmission capacity. Wind power requires 2120 bn. €, PV power 1068 bn. € and as third largest technology battery energy storage systems require investments of 386 bn. €. In the planning interval beginning by 2040, cumulative investment needs peak at 184 bn. €/a. This is caused by newly built RES capacities and additionally upcoming significant investments into energy storage system technologies. Fuel cost, which have high impact on cost in the first decade decreases, and expenses in annuities of RES power generation capacity gain importance.

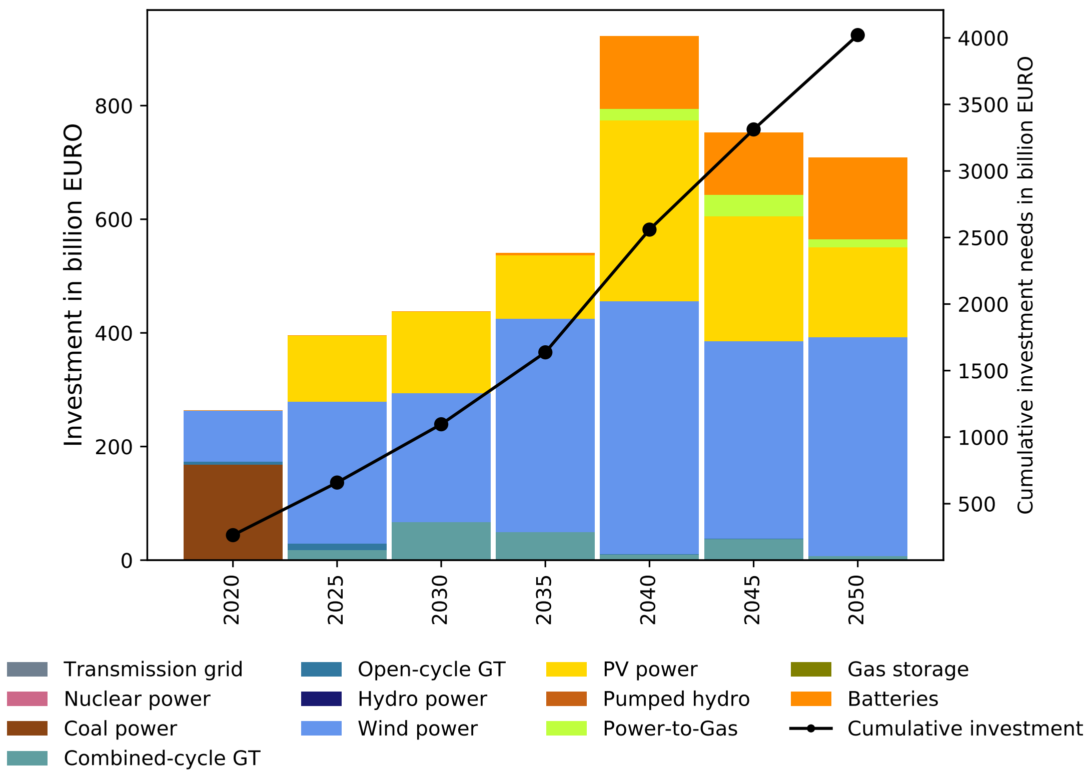


Figure 5.10: Breakdown of investment needs associated with presented transition pathway. The cumulative investment needs are indicated by the black line.

6 Results – Alternative pathways

The *base scenario* presented in Chapter 5 describes one optimized least-cost pathway for the transformation of the European electricity supply system towards a decarbonized electricity supply by 2050. The pathway is determined by model calculations based on the most reliable selection of parameters and assumptions. In order to test findings from the *base scenario* against parametric uncertainty and different boundary conditions, alternative scenarios are developed in Section 4.11. First, an overview on scenario results is presented. The subsequent sections compare results from scenario variations with the *base scenario* regarding electricity generation, the integration of energy storage systems, the spatial dimension of electricity supply and the transmission system, as well as cost of electricity. In addition, in Section 6.6 a comparison with a different methodological approach of electricity system planning is examined.

6.1 Overview on scenario results

The analysis of scenario variations shows that targeted GHG emission reductions can be achieved by pursuing different decarbonization pathways which consequently lead to different technological electricity system structures by 2050. These systems structures differ in the total annual electricity generation, the technological mix, the regional distribution of electricity generation, capacity of energy storage systems including its technological mix, the amount of transmission capacity extension, and finally levelized cost of electricity (LCOE). Figure 6.1 provides an overview on results of alternative scenarios by three indicators: LCOE, share of RES on electricity demand and the ratio of electricity supply by PV and wind power. The comparison of scenario results is based on results obtained for the year 2050. Levelized cost of electricity vary in a range of -10 % (0.092 EUR/kWh) to +10 % (0.112 EUR/kWh). Only one scenario results in significantly lower LCOE compared to the *base scenario*. Although the technological mix of electricity generation distinguishes significantly between scenarios, the resulting share of RES on power generation is almost the same throughout the scenarios. In particular for 2050, the constraint on GHG emissions provides a narrow

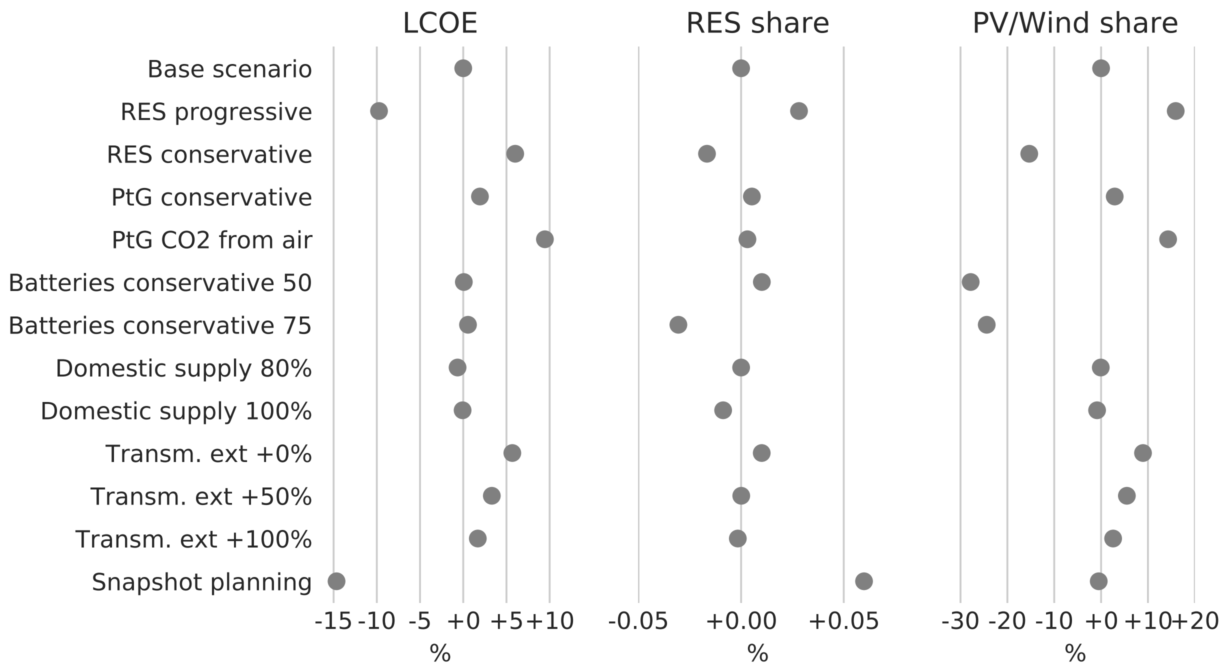


Figure 6.1: Scenario key indicators for 2050 at a glance: Levelized cost of electricity (LCOE), renewable energy sources (RES) share, and PV-wind-power ratio. Numbers for scenario variations are provided as relative deviation to the *base scenario*.

range for variations in RES share. The ratio between wind and PV power generation is affected significantly by parameter variations. The PV to wind power generation share varies from 23 %/ 77 % to 37 %/ 63 % among the analyzed scenarios. In comparison to the *base scenario* these are deviations of about -30 % to +15 % (see Figure 6.1). Nevertheless, wind power dominates power generation by 2050 in all scenarios.

Other variations among results of scenario variations, for example the effect on the spatial distribution of electricity generation, are presented in the following. In summary, a broad plateau of feasible solutions for future European power supply compliant with decarbonization targets is identified. Most strongly varying aspects of decarbonized electricity supply are the technological choice between wind and PV power, the spatial distribution of electricity generation, and energy storage systems' capacities as well as its technological structure.

6.2 Generation mix

In this section the influence of parameter variations the different scenarios are shown. The sensitivity of model parameters and the assumed technical and political boundary conditions affect the generation mix of future electricity supply systems as well as the total annual electricity generation. Total annual generated electricity ranges from 5,886 TWh/a to 6,330 TWh/a among the studied scenarios (see Figure 6.2 that shows total electricity generation by technology for the year 2050). The bulk of electricity generation are provided by wind, PV, CCGT, and hydro power. Other generation technologies (OCGT, coal and nuclear power) do not play a role in future European electricity supply for all scenarios (cf. Tab A.7). Similarly to findings of the *base scenario*, wind and PV are the major supply technologies by 2050. Electricity generation by hydro power remains constant in all scenarios as the restriction on capacity extension applies for all of these. Generation by gas power technologies – in particular by CCGT – varies across scenarios, but is present in each of these. This technology is required to provide power in times of low supply by wind and PV power at reasonable cost. The absence of electricity generation by coal power underlines that this technology is unsuitable for achieving climate change mitigation goals. Parameter variations in different scenarios affect the ratio of electricity generation by wind and PV power. Whereas electricity generation by PV power in the *base scenario* adds up to 27.2 % it is significantly lower in scenarios that assume higher cost for battery energy storage systems (*Battery conservative 50* and *Battery conservative 75*) and RES technologies (*RES conservative*). Scenarios that assume lower cost for wind and PV power (*RES conservative*) and higher cost for PtG technology (*PtG CO2 from air*) result in higher shares of electricity generation by PV power. Limited transmission capacity extension (in scenarios *Transmission ext. 0 %/+50 %/+100 %*) lead to increased power generation by PV power as well. The ratio of 32 % (PV to wind) revealed for the *base scenario* is encompassed by a range of 23 % up to 37 % in the scenario variations. In particular, cost parameters strongly affect this ratio, but wind power remains the dominating RE source for all scenarios.

A constraint on domestic electricity supply is almost ineffective regarding the power generation mix of future electricity supply. Neither the total annual electricity generation changes significantly nor the electricity mix does. Similarly, transmission capacity extension limits have little effect on the electricity generation mix. The total amount of electricity generated increases slightly compared to the *base scenario*. The generation mix almost remains the same. Cost of RES technologies and ESSs technologies influence the future electricity mix most strongest. Lower cost for wind and PV reveal a cost-optimal electricity system comprising of larger shares of PV power whereas systems with higher cost tend to prefer wind power. Higher cost for battery energy storage systems result in increased total annual electricity generation including a clear preference for electricity generation by wind power. Due to the diurnal supply pattern of PV this technology seems to interact best with BESS. Conversely, wind power generation interoperates best with PtG energy storage technology. Further technological improvements and the development of cost of PtG technology affect

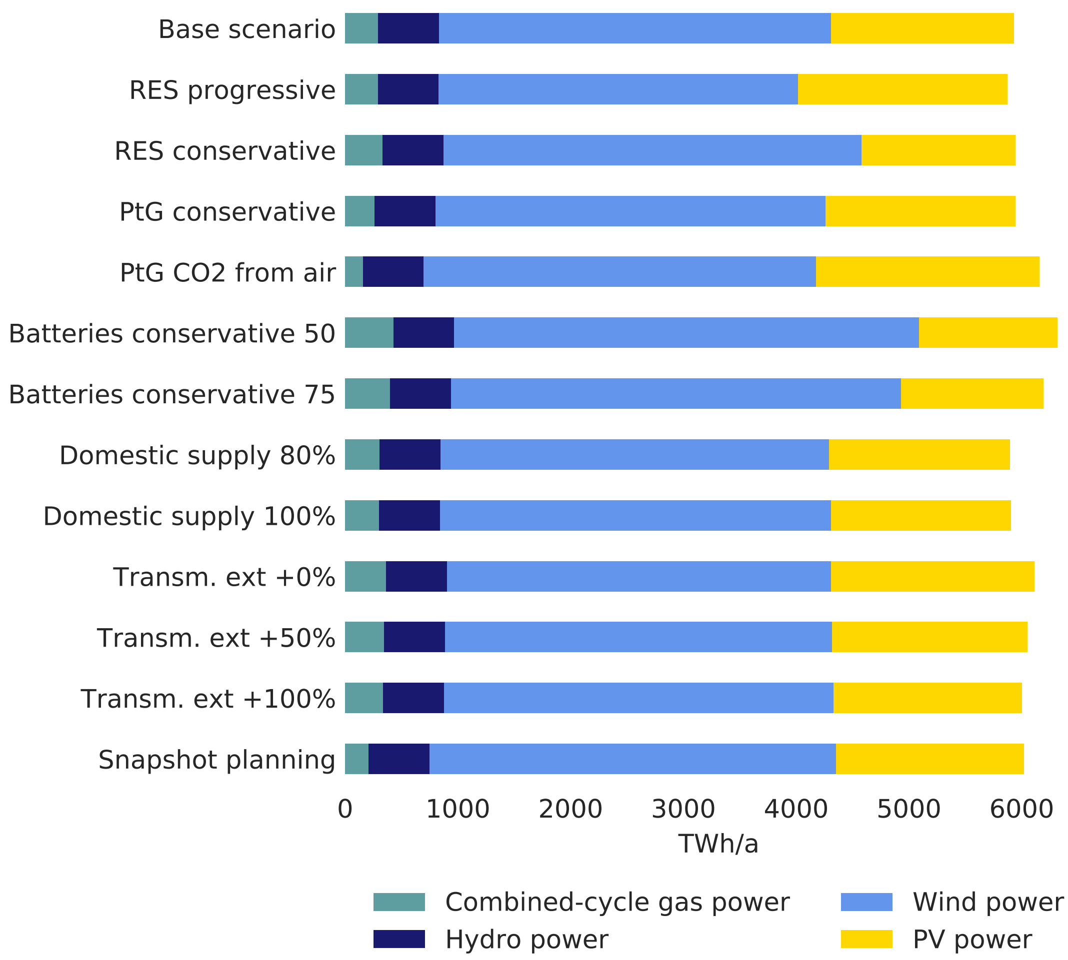


Figure 6.2: Scenario results on electricity generation mix for 2050.

generation by gas-fueled power plants. Uncertainty associated to technological and cost development of PtG furthermore affect electricity by gas-fueled power generation. Whereas higher CAPEX of PtG technology do not change the power generation mix significantly, CO_2 purely from ambient air (scenario *PtG CO_2 from air*) has larger effects on resulting power generation mix. The latter scenario with notable higher variable cost and lower efficiency of PtG systems requires increased total generation with reduced shares of electricity from wind power. Due to the reduced use of PtG in the latter scenario, electricity generation by CCGT is affected as well. Gas power generation technologies are almost entirely fueled by SNG, thus the decreased production of SNG reduces electricity generation by gas technologies as well.

In conclusion, the cumulative electricity generation by 2050 fluctuates around 6,000 TWh/a with the highest generation in scenario *Battery conservative 50* and *Battery conservative 75*. The shares of electricity generation from individual technologies vary, in particular those of wind and PV power. Changed cost for BESS and RES technologies affect shares of generation most in comparison to all other scenarios.

6.3 Energy storage systems

Aside from pumped hydro storage, the capacities of energy storage systems vary throughout the analyzed scenarios. Whereas in the *base scenario* cumulative input conversion power (or charge power) of energy storage systems adds up to around 530 GW by 2050, it ranges from 458 GW (*Battery conservative 50*) to 656 GW (*No Transmission extension*) in other scenarios (cf. Figure 6.3 showing charge and discharge power for the year 2050). The cumulative energy storage system capacity ranges from 93 TWh to 808 TWh (cf. Table A.9 showing charge/ discharge power and energy storage capacity by 2050 for all scenarios).

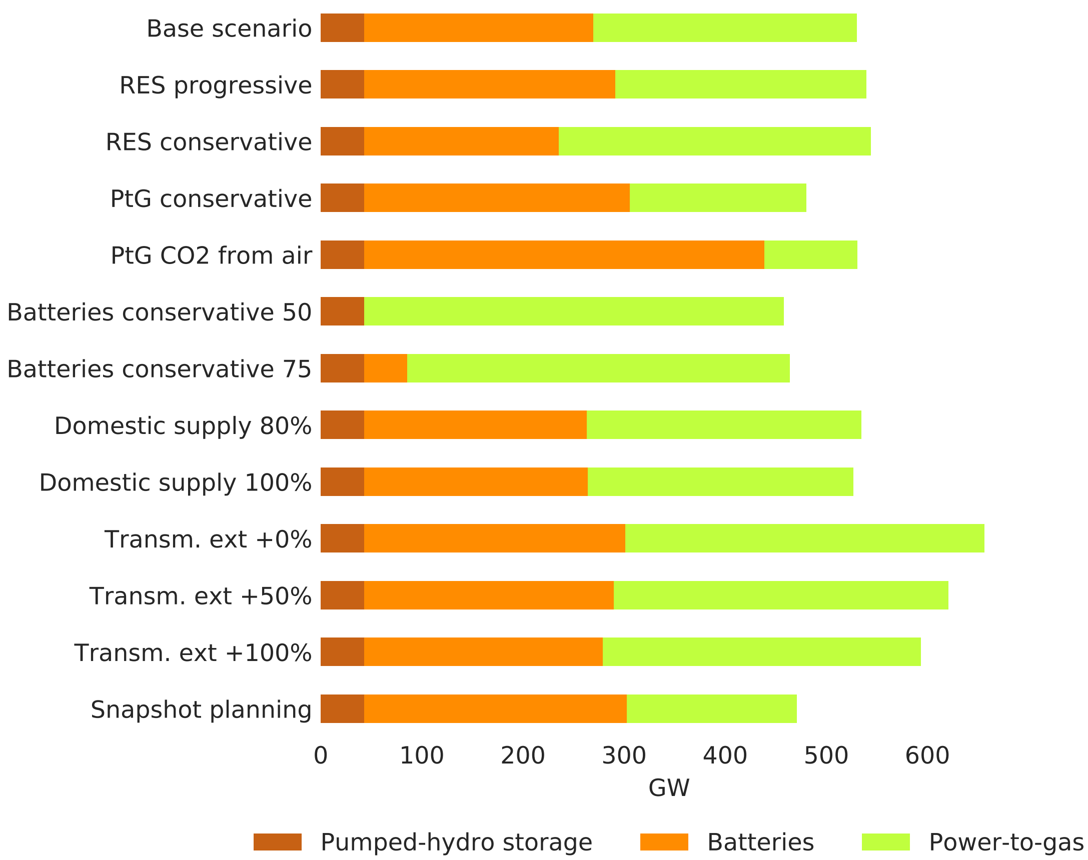


Figure 6.3: Energy storage input conversion power among the scenarios for the year 2050.

The cost-optimally determined capacity of energy storage systems for 2050 as well as its technological structure in future power supply systems is sensitive to the power generation mix, assumptions on cost of electricity generation technologies and energy storage systems, and further constraints like a cap on transmission capacity extension. Scenarios assuming a lower cost reduction potential of battery storage systems (cf. *Battery conservative 50* and *Battery conservative 75*) result in the smallest cumulative energy storage systems capacity among analyzed scenarios. Moreover, the ESS technology mix is affected most in these scenarios. Assuming a cost reduction potential for battery systems of 75 % compared to the *base scenario* results in 43 GW battery energy storage system charging power by 2050, which is -82 % lower then in the *base case*. Pumped-hydro storages and BESSs are complemented by PtG storage system's conversion power of 378 GW. Higher cost for BESS (as reflected by *Battery conservative 50*) results in a capacity of BESS of zero. The energy storage system capacity in such a scenario comprises only of PHS and PtG technology. The missing BESS capacity is compensated by extended PtG capacity. Its capacity adds up at 415 GW. Scenarios analyzing higher cost for PtG systems reveal an energy storage system technology mix shifted towards larger BESS capacity compared to the *base scenario*. Compared to the scenarios that analyze higher cost for BESS the shift in technological preference for certain ESS technologies is significantly less expressed. These scenarios identify the largest capacities of BESS among scenarios and at the same time the smallest capacities of PtG systems (cf. Figure 6.3). A 50 % lower reduction potential of PtG's capital expenditures (*PtG conservative*) results in BESS capacity of 263 GW and 174 GW of PtG conversion power. Operating PtG with CO_2 captured from ambient air (cf. scenario *PtG CO_2 from air*) results in 396 GW of battery energy storage charging power that is complemented by 92 GW of PtG which are at the same time the highest BESS and the lowest PtG capacities. Energy storage system capacity determined by the *Snapshot planning* scenario is comparable to the *base scenario* regarding the technological composition, but the cumulative energy storage system capacity is significantly smaller. Hence, planning the electricity system design included ESS from scratch leads to smaller required energy storage capacity.

Changes in cost for RES technologies slightly increase the cumulative ESS capacity and influences the technological structure. For both, reduced and increased cost, the cumulative capacity of ESS increases. In case of reduced cost of RES (*RES progressive*) the electricity supply system design considers a larger PV capacity which results in a higher capacity of BESS. This effect can be observed inversely in the scenario *RES conservative*: a larger capacity of wind power goes along with more PtG capacity. This suggests, that a fruitful relation between diurnal power generation patterns of PV and the operation battery energy storages exist. Likewise, the stochastic characteristics of wind power based electricity generation is complemented best by PtG storage systems with their cost-effective mid to long term storing capability. The interdependency between PtG and wind power generation affects gas-fueled technologies as well. As gas power plants are used to re-convert SNG to electricity, its capacity transitively depends on the amount of wind power in the electricity system. A constraint on domestic supply of regional electricity demand does only marginally affect energy storage capacities. Battery storage capacities in those scenarios are slightly smaller compared to the *base scenario*. Scenarios analyzing the impact of transmission extension caps show a clear trend. The more the transmission capacity extension is capped, the more storage capacity is required. Both battery storage and PtG based storage capacity show extended capacity compared to the *base scenario*. These variations present highest energy storage system capacity needs among all scenarios investigated in this study.

To sum up, after the analysis of scenario variations it is revealed that energy storage systems are required for a successful transformation of European electricity supply in all scenarios. A mix of energy storage system technologies is favorable in electricity supply systems with high shares of RES in order to cope with balancing needs on short and long time scale. The cumulative energy storage systems capacity and its technological diversification in the European electricity supply of 2050 strongly depend on by cost of energy storage systems, the electricity generation mix and the level of transmission capacity extension. Regarding the technological mix of ESS technologies, cost variations of these have the largest influence. The analysis of scenario variations has shown PHS capacity is complemented by battery energy storage system and PtG systems except for one scenario that only considers PtG. This leads to the conclusion that PtG is mandatory in electricity systems with high shares of RES and that it's highly likely that BESS are required and useful to be integrated as well. Compared to other results that are discussed in this chapter, ESS technologies show largest sensitivity to the changed input parameter set.

6.4 Regional distribution and transmission

By the analysis of spatial distribution of electricity supply in the *base scenario* net importing and net exporting regions were identified (cf. Figure 5.6 and Tab. A.11). Conducted scenario variations show similar results. The balance of electricity imports and exports – the annual net electricity exchanges – considering high shares of RES electricity generation are a good indicator for the competitiveness of domestic electricity supply. Large shares of electricity imports indicate a low regional RES potential and vice versa. Figure 6.4 shows net annual electricity exchanges among regions resulting by 2050. In general, scenario variations retain the regions' roles regarding net electricity imports/exports. Major net exporting regions are Denmark, France, Norway and Southern Balkans. Scenario variations that introduce a limitation of transmission capacity extension and the scenario *Domestic supply 100 %* limit the net exchange in total, main export and import regions remain the same. All other scenarios reveal a similar picture of the spatial distribution of net importing and exporting regions. Only the specific amount of electricity exchanged for individual regions changes. Four scenarios differentiate themselves from the others regarding the annual net electricity exchange: *Transm. ext. +0 %*, *Transm. ext. +50 %*, *Transm. ext. +100 %* and *Domestic supply 100 %*. Whereas a limit on annual net electricity imports of 80 % does not affect the general picture of exporting and importing regions, net electricity exchanges in the scenario *Domestic supply 100 %* change completely. Electricity exchanges in this scenario are reduced significantly compared to the *base scenario*. The limitation of transmission capacity extension (applied in scenarios *Transm. ext. +0 %/ +50 %/ +100 %*) results in smaller annual electricity exchanges for all regions. As expected, the scenario *Transm. ext. +0 %* yields the smallest exchanges in all regions after *Domestic supply 100 %*. Allowing the doubling of current transmission capacity (*Transm. ext. +100 %*) leads to very similar electricity exchanges for most of the regions as in the *base scenario*.

Major electricity exporting regions as identified in the *base scenario* – Denmark, the Southern Balkans and France – are almost unaffected by most scenario variations. Similarly, neither the picture of the regions of largest imports (Sweden, Western Balkans, Finland, Alpine region, Eastern Balkans) changes significantly. Only the three scenarios that reflect a limited transmission capacity extension and *Domestic supply 100 %* show a changed picture of regions' annual electricity exchanges. The electricity exchange for some regions is notably different in these scenario variations. Italy is a prominent example. In the *base scenario* Italy takes on an electricity exporting role. In the variations, its annual net electricity exchange varies between 33 TWh/a of imported electricity up to 36 TWh/a of exported electricity. Primarily, Italy is an electricity exporting region. Only in four scenarios that have been studied here, Italy's role changes to an electricity importer.

Electricity exchanges and transmission capacity extension are naturally linked phenomena. Only the extension of current transmission system capacity allows the exploitation of high RES potential in some regions for serving demand of others. Most scenarios consider large transmission capacity extensions very similar to those identified in the *base scenario* (see Fig. 6.5). Observed cumulative transmission capacity for 2050 ranges in between 173 GW and 183 GW for these scenarios. Exceptions appear for the three scenarios that analyze a transmission capacity extension limit. In these, the limits of transmission capacity extension are exploited. The scenario *Transm. ext. +50 %* leads to a cumulative transmission capacity of 83 GW by 2050. When the doubling of transmission is allowed, the model used this option

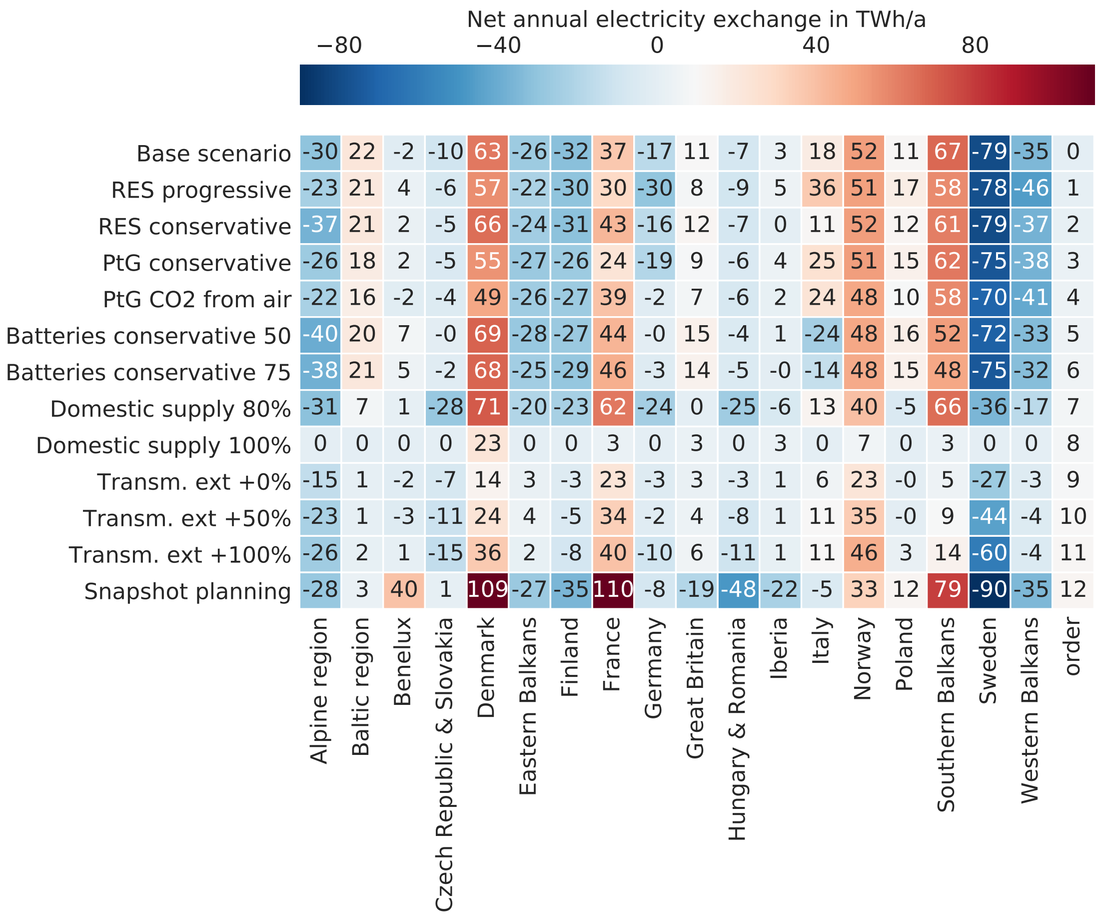


Figure 6.4: Annual electricity exchanges via transmission system for the planning interval 2050 in TWh/a. Positive electricity exchange represents power supply to the transmission system whereas negative number indicate supply of demand by electricity imports from the grid. Transmission losses are considered in electricity imports by this figure.

and extended the capacity up to 108 GW by 2050 as in the scenario *Transm. ext. +100 %*.

To conclude, for most European countries the analysis shows that different pathways towards a decarbonized electricity supply do not change their situation much in regard to importing and exporting electricity. Even when key model parameters such as cost for RES technologies or energy storage systems are varied, the general picture does not change. There is a clear trend for regions being net exporting or importing countries, mostly determined by the local RES potential. The most remarkable effect on the electricity exchange situation is introduced by technical or political boundary conditions. Those analyzed here – a limitation of transmission capacity extension and a limit on electricity import – change electricity exchanges among European countries completely as well as the spatial distribution of electricity generation. More precisely, it reduces electricity exchange to a significantly lower

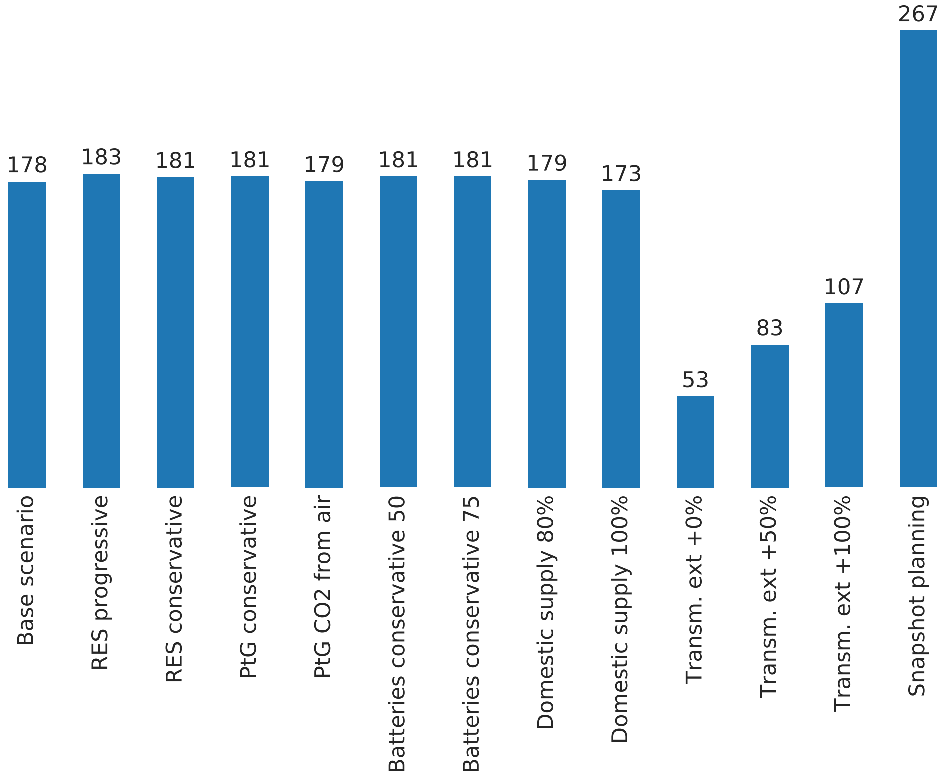


Figure 6.5: Cumulative transmission capacity for scenario variations by 2050 given in GW.

level which leads to higher domestic electricity supply. Finally, it should be mentioned that the amount of electricity exchanges is directly connected to the spatial distribution of power generation. Less electricity exchanges in general go along with a more demand orientated allocation of RES facilities.

6.5 Levelized cost of electricity

As levelized cost of electricity is one key indicator to evaluate the performance of potential decarbonization pathways, its sensitivity on changed input parameters needs to be studied. In this case, it includes parametric uncertainty related to model input data and potentially changed circumstances due to technical and political reasons. Therefore, resulting LCOE of scenario variations that are defined in Sec. 4.11 are surveyed.

Figure 6.6 presents the development of LCOE along the decarbonization pathway for all scenarios. Without any exception, cost of electricity supply increase in all of the studied scenarios. By 2020, LCOE adds up to 6.4 ct€ for all variations. With increasingly stronger GHG emission reduction limits along the pathway the cost of individual scenarios spread more and more. By 2050, LCOE of scenario variations range from 8.7 ct€ to 11.16 ct€. The majority of scenario variations yields LCOE ranging from 10 ct€ to 11 ct€. Three scenarios result in LCOE outside this range. Levelized cost of electricity for *PtG CO_2 from air* adds up to a overall maximum cost of 11.16 ct€ by 2050. The scenarios *RES progressive* and *Snapshot planning* yield 9.2 ct€ respectively 8.7 ct€ and are therefore the only scenarios resulting in LCOE lower than the *base scenario*. The contrasting scenario to the first one, *RES conservative*, leads to LCOE of 10.8 ct€ by 2050. This is a non-symmetrical spread of cost between *RES progressive*, *base scenario* and *RES conservative*.

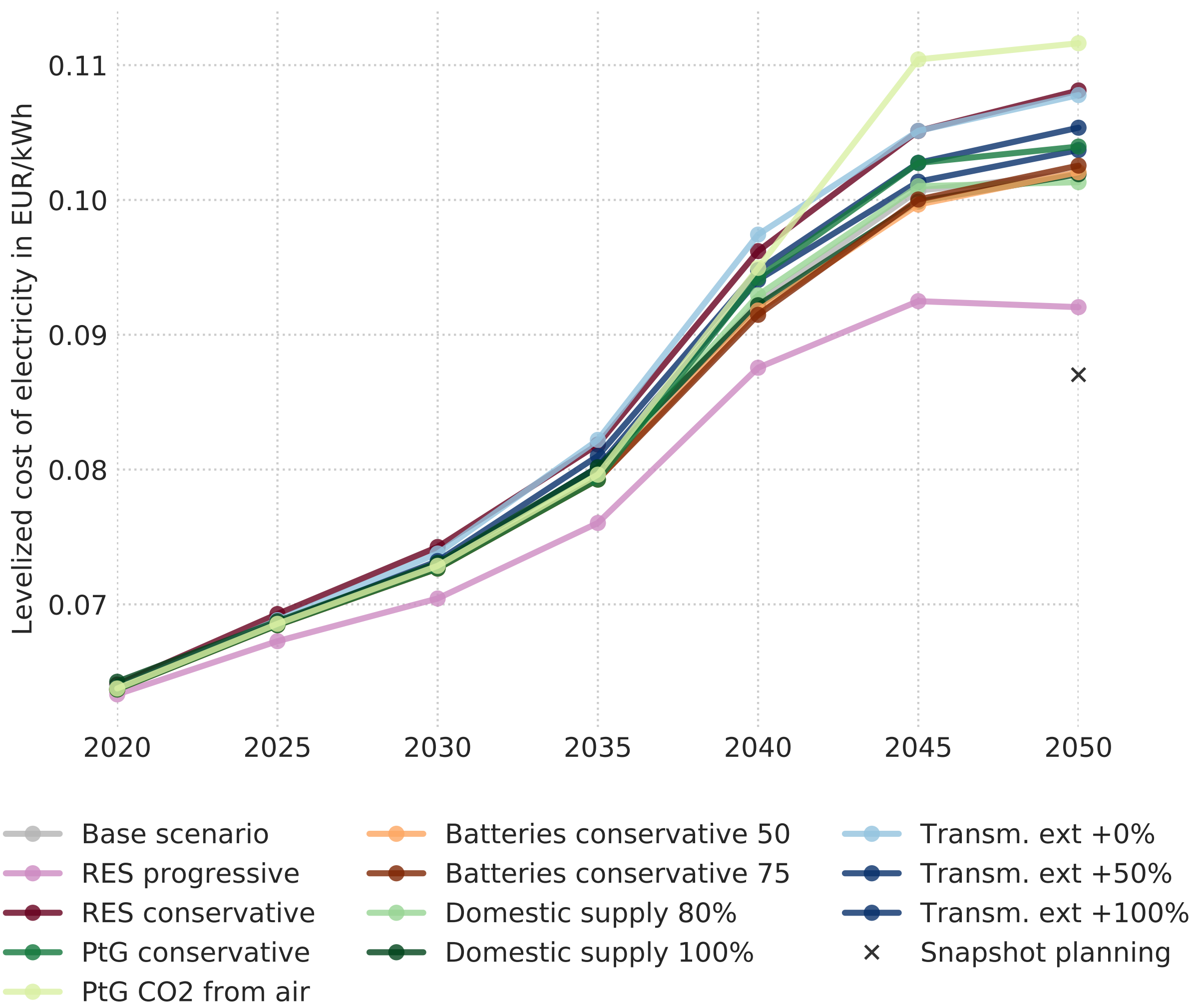


Figure 6.6: Development of LCOE in scenario variations.

Higher costs for battery energy storage systems, as studied by *Battery conservative 50* and *Battery conservative 75*, do not affect LCOE much. Despite marginal deviations, LCOE can be seen as equal to the *base scenario*. Attention should be paid to the scenario investigation of parametric uncertainty related to the cost of PtG technology. The scenario *PtG conservative* examined the case of higher capital expenditures for PtG, which would increase LCOE only by about 0.2 ct€ compared to the *base scenario*. Uncertainty related to variable cost of this technology would affect resulting LCOE more. The scenario *PtG CO_2 from air* investigates the worst-case of CO_2 supply for PtG facilities when this is captured from ambient air in order to provide a source of sustainable CO_2. Supplying the PtG process with CO_2 from ambient air would increase LCOE to 11.16 ct€. The scenarios that analyze the effects of the politically defined boundary condition that asks for a certain share of domestic electricity supply result in very similar cost compared to the *base scenario*. This shows that a higher degree of self-supply is not necessarily much more expensive. Scenarios that study a limited capability of transmission capacity extension result in higher LCOE than the *base scenario*. Allowing transmission capacity extension up to twice the current levels (*Transm. ext. +100 %*), results in a cost increase of only 0.17 ct€. Less capacity extension of up to + 50 %, as represented by the scenario *Transm. ext. +50 %*, ends up in twice the cost increase of 0.34 ct€. The most stringent transmission capacity extension limit of zero capacity increase leads to LCOE of 10.78 ct€ which equals a cost increase of 0.58 ct€ (+5,7 %) compared to the *base scenario*.

In summary, the investigated scenario variations show an increase of LCOE towards 2050. Hence, a cost increase for electricity supply in order to achieve GHG reduction goals is very likely. The evaluation of different pathways towards low-carbon electricity supply by 2050 identified cost of RES technologies as key leverage to achieve low LCOE. Conversely, a strong increase of cost of electricity may be induced by additional cost for CO_2 supply for the PtG process. Despite all variations in results discovered by studying several scenarios, an important key output, levelized cost of electricity, remains in a relatively narrow range. Its variations do not exceed +/-10 % of cost determined in the *base case* (neglecting *Snapshot planning*). Thus, results can be interpreted as robust to a certain extent. Leaving *the optimal pathway* to some extent is negligible with regard to resulting cost of future power supply. In particular, uncertainty associated to parameters of technologies with fast developing technical progress and declining cost have potential to drive the transformation pathway into different directions. As investigated by several scenarios, the risk of large effects on future LCOE can be seen as acceptable.

6.6 Snapshot power system planning

A common approach of energy system modeling and in particular long-term investment planning is the so-called *snapshot planning* method which is also known as *greenfield planning* approach. The scenario *snapshot planning* uses this approach to benchmark results obtained from the *base scenario*. In general, it is worth to consider the transition pathway when conducting an analysis about least-cost investment study aiming for a low-carbon electricity supply system. The scenario *snapshot planning* neglects important information about the existing electricity supply infrastructure. This affects future investment decisions. A prominent example in the context of this thesis is the coal power generation capacity. In 2020, investments into this technology take place (refer Sec. 5.1) resulting in available coal-fueled power generation by 2050 that cannot be used due to stringent CO_2 emission limits. Regardless of the amount of electricity generation by this technology, the annuities for the investment are still accounted for in the cost of electricity supply. As this capacity is not present in the *snapshot planning* scenario, cost are systematically underestimated by this approach. Furthermore, using a pathway approach allows the assessment intermediate steps of the transition towards a low-carbon electricity supply system.

In comparison to the *base scenario*, the scenario *Snapshot planning* has larger annual electricity generation (6022 TWh/a), produces more excess electricity (1433 TWh/a), extends the transmission system capacity most (cumulatively 267 GW), but determines a structural similar electricity system design for 2050 regarding shares of power generation technologies on cumulative annual generation. In both cases, electricity generation by the major generation technologies wind and PV power splits 2/3 to 1/3. The scenario *snapshot planning* yields the lowest LCOE of 8.7ct € among all scenarios. At the same time the least cumulative investment cost of 3,154 bn. € are realized by this scenario. It saves 492 bn. € compared to the *base scenario*. This as an example shows how studies using a *snapshot planning* approach systematically underrate cost and efforts because the model can optimally design the future electricity supply infrastructure from scratch not being affected by the burden of earlier investment decisions. Hence, the pathway approach as applied in this thesis is a more realistic representation of real-world planning processes regarding optimality of decision-making.

7 Discussion and limitations

Presented pathways of the development of the European electricity supply system towards achieving climate change mitigation targets by 2050 reveal important facts that need to be discussed. Findings include uncertainty incorporated by the modeling approach that should be emphasized as well. This chapter first presents strengths and limitations of the modeling approach, secondly, important findings are discussed in detail.

7.1 Strengths and limitations of modeling approach and data

As energy system modeling is the basis of results presented in this thesis, strengths and limitations of the modeling approach should be highlighted. Power system planning by modeling 5-years intervals reveals important information about the decarbonization pathway based on realistic capacity extension. In comparison to the so called *snapshot planning* or *greenfield planning* that is widely used in power system planning studies (i.e. Schaber et al. (2012a); Zickfeld et al. (2012); Pleßmann et al. (2014)), the modeling approach used in this thesis is capable of considering existing infrastructure and its expected lifetime, while planning the transition of the power system towards a low-carbon electricity supply system during a certain period. This allows to explicitly reveal intermediate steps of the power system infrastructural changes according to GHG emission reduction targets along the pathway. In particular, the future electricity system determined from model analyses is not optimally designed for the circumstances of the targeted year, but is a result of the temporal transition pathway.

A comparison of the pathway approach underlying in this thesis with the commonly used method of *snapshot planning* was conducted with the *base scenario* parameter settings of 2050 and is presented in Section 6.6. The final electricity system design resulting for 2050 of both approaches was compared. Both designs have in common a very similar capacity and generation mix. The *snapshot planning* approach is capable of determining an electricity system perfectly adapted to the circumstances of 2050. Power system planning with the pathway approach results in more overcapacity with low or zero FLH, i.e. coal power capacity that was built decades earlier. A major drawback of the *snapshot planning* methodology is missing information on how the optimally designed electricity supply system of 2050 can be reached. There is no information available about intermediate steps of the transition of the current electricity supply towards the low-carbon system. Thus, this approach does not support knowledge for legislative decisions on near or medium-term. Additionally, it has to be mentioned that power system planning with a *snapshot planning* approach systematically underestimates cost. In conclusion, despite the advantages of more simplified modeling and less input data needs of snapshot planning, the applied approach provides more realistic results of the electricity system transformation then the snapshot approach.

In comparison to inter-temporal modeling across decades – as for example applied in Haller et al. (2012b); Fürsch et al. (2013) – the modeling approach used in this thesis results in a less complex optimization problem and overestimates knowledge about futures circumstances less, due to a restricted foresight of five years. The limited foresight is suitable to reflect the actual planning horizon in terms of decision-making about future power system design. Decision making in five years intervals is, for example, equivalent to typical election cycles, while a 20 or 30 years optimized planning period seems unrealistically optimized.

Accurately modeling variability of RES power generation is key for studying power system transformation pathways reaching strong GHG mitigation goals (Després et al., 2015). Further, this allows to take a precise look on required flexibility capacity in the power system, such as energy storage systems. The temporal resolution of one hour can reflect the effects of weather events on the electricity supply system. A lower temporal resolution than one hour would smoothen demand and supply patterns that may lead to a underestimation of balancing needs.

Some approaches of long-term energy system modeling reduce complexity in the dimension of time by using time slices (i.e. Nahmmacher et al. (2016); Haller et al. (2012b)) or representative days (i.e. Fürsch et al. (2013)) in order to reflect variations in power supply situations of a year. Poncelet et al. (2016a) argue that the representative days technique retains intra-daily chronology and, thus, is suitable to reflect ESSs operation on short-term scale. A time slice approach that looses information about chronology of time steps is less qualified for assessing ESS demand, especially for ESS operating on seasonal time scale. Due to lost chronology on medium-term to long-term scale in both approaches, neither representative days nor time slice modeling technique is suited for assessing the demand of long-term ESSs. The modeling approach applied in thesis does not use time slices or representative days for reduction of complexity, but a full year in one-hourly increments. Thus, it is suitable to assess the demand for long-term energy storage systems, which are expected to be required to realize low-carbon electricity supply based on very high shares of RES.

As a model is always a simplified representation of the real world, results obtained from using a model come with limitations. Major reasons for these limitations are a need for reducing the model's complexity on several dimensions and the availability and quality of data. The first major limitation of this study is the single-sector modeling approach of purely analyzing the decarbonization in the electricity sector. This neglects interdependencies that are already established (heat supply by conventional power plants) and growing new interdependencies, such as battery-electric vehicles and heat pumps. The inclusion of other sectors on top of the electricity sector would provide additional potential to shift demands and to lower overall cost of electricity supply. Electricity system technologies represented by the model are incomplete. As described in Section 3.2, the power generation technologies oil power plants, offshore wind energy, CSP, geothermal, wave and tidal power, and biomass energy are not part of this study. The broad landscape of energy storage system technologies is cut down on a few technologies: pumped hydro storage that have been present in the electricity system for decades, NaS batteries for intra-day balancing, and the long-term energy storage system technology PtG. This limits the scope of potential electricity system configurations for future low-carbon electricity supply, but reduces the model's complexity. In general, it can be said that the inclusion of more technological options for future electricity supply would provide additional options to achieve lower LCOE. Nevertheless, the major electricity generation and energy storage system technologies are represented by the model and, thus, the study captures the most relevant aspects. In order to understand presented findings correctly, it has to be noted that nuclear power, hydro power, and pumped hydro storage are excluded from new investments. For hydro power and pumped hydro storage, only investments due to refurbishment at the end of lifetime are considered.

While the regional scope of the study considers the technical aspect of an interconnected European transmission system and the legislative compound of the EU, the spatial representation is imprecise to a certain degree. Up to four countries are represented by a single region in the multi-regional model. This implies an aggregation of power plant capacities in each of these regions as well as neglecting possible congestions in the grid infrastructure within these regions. Furthermore, a highly simplified representation of the transmission grid between these regions is used. It merely considers cross-border transmission capacity and aggregates those to representative capacity for each adjacent pair of regions. This may rate required grid extension too low. Moreover, distribution grids are neglected entirely. Thus, an additional fee for investment into national infrastructure and operation of it shall be considered when looking at the cost of electricity supply covering generation, transmission, and distribution in further studies.

The temporal resolution in which operation of the electricity supply system is represented affects quality of results and at the same time, it massively influences the model's complexity and resulting computational cost. The chosen 1-h temporal resolution can only reflect some important features of largely intermittent RES based power supply. Weather events on a lower time scale, such as clouds passing by, are not represented which could have impact on power system design. Variations in operation of power plants and ESS are systematically underestimated due to underrepresented very short-term balancing needs. Thus, when taking a closer look on higher temporal resolution, required energy storage capacity may increase. Neither aspects of electricity grid operation, such as voltage and frequency control, can be represented here. This would require static or dynamic AC grid modeling and a temporal resolution of minutes or even seconds for the latter. This may misinterpret the role of energy storage facilities in future power supply, as they are considered to provide ancillary grid services (Rascon et al., 2016). The implementation based on linear programming incorporates the drawback of strong simplification by only allowing a strict linear representation of electricity system components. This forbids to include non-linear features of electricity supply infrastructure, such as power plant efficiency, but is sufficiently detailed for analyzing the electricity system infrastructure of a whole continent, which is aggregated at least at country level.

Two features of the applied modeling approach lead to results that perfectly optimized and, thus, unrealistic: perfect foresight and central planning. Perfect foresight enables integrated operational and long-term planning of electricity infrastructure, but may overestimate knowledge on upcoming events in the power system. The model's nature of centrally planning the transition towards a decarbonization of the European electricity supply infrastructure neglects barriers of individual national legislation and decision making. Despite centrally provided decarbonization targets for the whole region and individual targets for each country by the EU, the implementation into national law takes place individually in each country. Thus, it can be expected that the identified *optimal pathway* for the decarbonization of Europe's electricity supply system is an overestimation of planning capabilities and cannot be exactly met. Furthermore, legislations do not have perfect efficiency, which makes is difficult to control the transformation of the power system precisely. Contrary to perfect foresight during optimization of power system operation, the step-wise investment planning in 5-years intervals is quite myopic. Investment decisions in one interval are made independently from circumstances beyond this planning period. This fact may result in sub-optimal investment decisions that lead to stranded assets and therefore sunk costs. In summary, the chosen approach assumes perfect knowledge of year input data and optimizes operation. This cannot be met in reality. Secondly, the overall economic optimization for the considered EU region is difficult to achieve, due to national or regional interests and imperfect planning. Thus, the real implemented transition pathway will most likely result in higher cost of electricity, but still an optimized pathway will be followed. A counter-effect would be to consider planning horizons larger than five years in reality to avoid sunk cost, as they are largely represented by coal power plants in the modeled results.

In addition to methodical limitations, data used with *elesplan-m* has limitations as well and brings uncertainty regarding derived findings. The demand data used in this study reflects current demand patterns and does not account for any change in these patterns despite in total consumption. A changed consumer behavior or a expectable stronger integration of other sectors in the electricity sector would change the demand profiles, which is not reflected by this study. The data underlying this study reflect an overall demand increase, but do not reflect potential changes of its shape. Data about electricity supply from intermittent RES technologies has deficits as well. First of all, those do not originate from the same year as the demand data. Second, the dataset used here tends to to overestimate the potential of wind power generation. Third, the conversion from weather data to feedin of electrical energy does not account for technological improvements of wind and PV power plants in the future. Nevertheless, the considered cost decrease of these technologies covers the economic effects of such efficiency improvements. It can be expected that the conversion efficiency in general increases and, thus, the conversion efficiency of future RES based electricity supply is underestimated. Furthermore, a consideration of potential sites where RES technically and juristically could be located would improve the quality of the study. Thus, restricted areas and areas of exclusion have to be detected and weather data from these sites must not be considered in the resulting RES feedin data. The dataset of technical and economic parameters comes with limitations as well. In this thesis, individual technical and economic parameters for each region are not considered. Instead, averaged values that are suitable to represent Europe as a whole are used. Finally, the determined techno-economically optimized power system is only tested with RES and demand data of one year. In turn, the power supply system is optimized for these specific conditions. A planning process tested against several datasets for demand and feed-in of RES would foster the value of resulting findings.

Despite these limitations, the results can be found valuable. The scenario analyses showed already the changes of results with regard to varied model input parameters to cope with uncertainties of future developments. The range of scenarios helps decision makers to identify potential implementation corridors where the results are robust against uncertainties. Resource data limitations are smoothened by the large study region which balances regional effects. The removal of identified model and data limitations will most likely increase the solutions space and therefore result in lower cost of transition. In conclusion, the presented results can be seen as a conservative approach identifying the least-cost decarbonization pathway for European countries with realistic and achievable results.

7.2 Technical and economic implications and viability of analyzed decarbonization pathways

Aside from critique regarding the methodology and data applied in this thesis, one can discuss overall findings derived from the model-based analysis and the implementability of results. Presented pathways that all meet the intended European decarbonization targets until 2050 have in common a complete change of the power supply system. Fossil fuel based power generation technologies are replaced by RES technologies (above 98 % by 2050) and ESSs become an integral part of the power supply system. The restructuring of the power supply system takes place within decades and has implications on technical, economic, political, and social level. An enormous extension of wind and PV power generation capacity is required. In order to provide electricity at affordable cost, sites of high RES potential need to be accessed, which requires a massive increase of transmission capacity. As a result, the future European electricity supply founds on extended electricity exchanges among its member countries. Large investments in the power supply infrastructure are needed and LCOE increases along the decarbonization pathway. Important aspects related to these implications are discussed in the following referring to the *base scenario* if not stated differently.

PV and wind power capacity extension The intended reduction of GHG emissions close to a zero-emissions power supply system forbids further use of carbon-intensive generation technologies, such as coal power. The future power supply primarily relies on power generation by wind, PV, and hydro power. Assuming a constant generation capacity of hydro power at current levels, wind and PV generation capacity must be extended massively. A generation capacity of 1,428 GW wind power and 1,259 GW PV by 2050 requires average annual installations of 48 GW/a (with max. 71.2 GW/a) for wind power and 39.7 GW/a (with max. 83.6 GW/a) for PV power. These are large annual capacity expansions compared to historical growth rates of cumulative power plants generation capacity. According to the power plant inventory of Platts (2012),the annual average net capacity increase of all European power plant technologies since 1960 adds up to 15.3 GW/a. Even the maximum capacity increase of 29.1 GW/a observed in this period is far below future required capacity expansion of wind and PV power. Furthermore, future required annual capacity extensions of wind and PV power exceed current manufacturing capacity by far. Nowadays, annual new installations of wind power capacities in Europe add up to 13.9 GW/a, which represents a quarter of all global new installations of 54.6 GW/a (Global Wind Energy Council, 2016). New installations of PV power capacity of 7.6 GW/a in Europe (15.8 % of globally 48.1 GW/a) are even less (IEA PVPS, 2016). Even replacement of wind and PV capacity beyond 2050 to maintain the capacity level would require annual installations of 57.1 GW/a (wind) and 50.4 GW/a (PV). Thus, today's wind and PV industry manufacturing and construction capacity is not sufficient for realizing the decarbonization of the electricity sector and needs to be increased dramatically soon. Furthermore, regulatory frameworks need to be adjusted by decision-makers in order to allow for and incentivize the realization of these wind and PV power generation capacities of the required speed.

Other studies that analyze the decarbonization of electricity supply or the integration of RES in Europe for 2050 find similar required generation capacity of wind and PV power. According to Bussar et al. (2014), a 100 % RES based power supply in the EU-MENA region can be realized with 1,090 GW wind power and 1,400 GW PV power. Similarly, Haller et al. (2012b) find a pathway to achieve 90 % GHG reduction in the EU-MENA power sector by 2050 with large shares of volatile RES power generation. Annual generation in this scenario adds up to 2,900 TWh/a by wind power and around 2,200 TWh/a by PV power and CSP. Large-scale generation by solar power in the study of Haller et al. (2012b) may be at least to some extent explained by the consideration of North Africa in that study. A complementary picture of future European low-carbon power supply is sketched by Jägemann et al. (2013). They suggest to include large amounts of nuclear and coal power generation in the 2050 power supply mix. A reduction of GHG emissions in such scenarios is achieved by equipping fossil-fueled power plants with CCS facilities. In turn, following Jägemann et al. (2013), 90 % GHG emission reduction and a RES quota of 85 % are achieved by only 100 GW of wind power and almost no solar power in Europe by 2050. The comparison with findings from other research underlines that the presented decarbonization pathway reveals realistic results. This means a significant GHG emission reduction is only possible through a full system shift towards wind and PV power. Certain implications of this shift are discussed in the following paragraphs.

Required area Another aspect of the enormous extension of wind and PV generation capacity is the space required by the installations. By constructing roads for service, a substation, grid connection, and the PV generators itself, respectively the wind turbine, land is permanently transformed. At the end of the transition in 2050, wind power installations will cover 31,6 km^2 assuming 0.0221 km^2/MW of permanently transformed area (Diffendorfer and Compton, 2014). PV installations at the same time require an area of 38,7 km^2 (based on 0.03075 km^2/MW (Ong et al., 2013)). Altogether, this would cover 1.46 % of Europe's entire land area. Thereof, 0.83 % are covered by PV power installations and 0.63 % are covered by wind power installations. The above detailed space requirements for wind turbine installations purely reflect the area that is permanently transformed and do not account for other restrictions. Typically, wind power plants are subject to distance regulations and nature conservation laws. These restrictions vary from country to country and need to be assessed further. On the example of Germany, Bofinger et al. (2011) show that a potential for the installation of 772 GW wind power according to national law is available. Thus, land availability seems to be sufficient for the transformation of the electricity supply sector.

Future role of conventional power generation technologies The role of conventional power generation technologies will change completely. Today's main power generation technologies, coal and nuclear, face a phase-out. At the same time, gas-fueled power generation enters a renaissance and gains importance. According to findings in this thesis, coal power generation cannot be further considered in Europe's power supply mix, due to increasingly strong GHG emission limits. Nevertheless, the role of coal-fueled power generation in future European power supply is discussed controversially in literature. Scenarios on future European power supply that are constrained by GHG emission reduction targets are divided into two groups. The first group of scenarios considers notable amounts of electricity generated by CCS-equipped coal power plants (i.e. Jägemann et al. (2013)). While scenarios of the other group (i.e. Haller et al. (2012b)) entirely neglect this power generation technology in a carbon-constrained world. Coal power plants can only be operated in a low GHG emission scenario if equipped with CCS facilities. Although not analyzed in this study, it is doubtable that coal power generation equipped with CCS facility could compete from an economical point of view in future European power supply. This equipment would double the investment cost and significantly lower efficiency, due to increased self-consumption for power demand of CCS process (Schröder et al., 2013). As CCS is neglected for this thesis, the coal phase-out is unavoidable from 2035 onwards. As there is currently no shift towards CCS globally, the assumption of neglecting CCS technology seems very realistic.

As nuclear power is not considered for capacity extension in this study, existing capacity is almost entirely decommissioned by 2050, due to end of its technical lifetime. One could argue that the exclusion of nuclear power from capacity extensions limits the landscape of potential future power supply system configurations and neglects an important relatively low-carbon technology. Other research sees significant shares of nuclear power generation in scenarios of sustainable power supply (Haller et al., 2012b) or even in a power system meeting 2050's mitigation targets (Fürsch et al., 2012). Nevertheless, manifold and severe risks associated with this power generation technology and the unpredictable large amount of cost, due to decommissioning of power plants and disposal of nuclear waste, make it worth to provide scenarios for decarbonizing the European power sector that do not rely on nuclear power. Even the present situation of nuclear power generation shows indications for end the of renaissance of nuclear power in Europe. For example, the British government offers subsidies 10.5 ct€/kWh for nuclear power generation, guaranteed for 35 years (The Guardian, 2015). This can be seen as indicator for lacking attractive business cases and high technological risk which is more and more realized by investors.

Gas power generation technology undergoes a renaissance on the way towards reaching decarbonization targets by 2050. According to the findings based on model calculations, it makes sense to extend gas power capacity in terms of decarbonizing the power sector. This type of power generation technology provides electricity produced at relatively low carbon emissions compared to coal technology. This feature enables gas power technology to serve as a bridging power generation technology along the decarbonization pathway of Europe's power system. The ability to convert SNG to electricity creates a second field of application. Furthermore, due to its relatively low investment cost compared to operational and fuel costs, this technology is qualified to flexibly provide power, which is required in power systems with significant shares of intermittent supplying RES technologies. Findings in this study regarding the future role of gas power technologies contrast the current economical situation of gas power plants in Europe. In today's power markets, operation of gas-fueled power plants faces economical issues. Investments into gas power technology are highly unlikely to pay off under current market conditions (Bergmann, 2016). Thus, financing schemes that allow for new investments into gas-fueled power plants need to be designed in order to appeal to potential investors.

Energy storage system capacity Aside from issues related to methodological shortcomings regarding modeling of energy storage systems that were already discussed, one can question findings concerning the needs for extension of energy storage system capacity. In order to achieve decarbonization targets defined for 2050 based on RES technologies, a cumulative energy storage charge power of 458 GW up to 656 GW is required. That is fairly large compared to today's PHS installed capacity of 43 GW. Furthermore, reaching this energy storage charge power by 2050 requires an enormous capacity extension, in particular in the last decade of the period analyzed by this study. However, this ESS capacity is needed to balance power supply and demand in systems with very high shares of RES. Bussar et al. (2014) underpin this finding by analyzing the optimal allocation of storage capacity in a 100 % RES electricity supply system of Europe. They found that 540 GW cumulative storage discharge power is required in a cost-optimal and 100 % RES based power system design with very high shares of PV and wind power. The comparability of these findings to other studies depends on boundary conditions of each analysis. Less ambitious mitigation and RES goals require less balancing power, as fossil and nuclear based power generation technologies are still available in the power supply system (Fürsch et al., 2013; Haller et al., 2012b). In general, the identified need for storage capacity is a robust finding, as the scenario variations suggest 458 GW up to 656 GW of cumulative storage power are required by 2050 in Europe.

One may criticize that this study is not sufficient to assess the optimal mix of energy storage technologies. Indeed, this thesis cannot entirely respond to the question how the optimal energy storage technology mix in a cost-optimized low-carbon electricity supply system should look like. It was shown, that findings on the required capacity of battery storage systems are highly sensitive on economic model parameters and vary vastly across the analyzed scenario variations. The spectrum of sensitivity of energy storage technology mix is not entirely captured. Hence, a more detailed study is needed here that focuses on energy storage systems in particular. Howsoever, the question of how much power-to-gas capacity is required at least to run a low-carbon power supply system based on RES, can be answered. Results of the conducted analysis suggest that required cumulative conversion power of PtG facilities ranges from 92 GW to 415 GW by 2050. Thus, analyzed scenario variations reveal a large range of potentially installed PtG capacity in the future. Although the exact required capacity of PtG cannot be precisely described, the minimum charge power of 92 GW is identified. The exact optimal capacity of PtG in a techno-economically optimized future electricity supply system depends on the power generation mix, future cost of energy storage technologies, and the availability of affordable CO_2 sources. Furthermore, viable business cases, which themselves rely on the regulatory frameworks, will largely affect the future ESS capacity installations. Nevertheless, an enormous amount of electricity has to be stored and shifted on temporal scale. Therefore, PtG is a technological option that should be kept in mind. One big advantage of this technology is the use of existing gas transport and gas power plant infrastructure and therefore huge seasonal storage capacities, which can also be used in inter-sectoral scenarios for heat supply.

Largely extended transmission capacity and spatiality of power supply Transmission capacity extension is one enabler to achieve low-carbon RES based power supply at low cost. Relatively low cost for transmission grid infrastructure allows to largely exploit best-suited RES generation sites. Purely from an economic point of view, the least-cost scenario for decarbonizing Europe's power supply system includes transmission capacity extensions far beyond current levels. Among other studies, Haller et al. (2012b) and Fürsch et al. (2012)

found comparable or even higher grid extension needs. Compared to the economically optimal transmission grid extension of 500 GW up to 2050 determined by Fürsch et al. (2012), transmission capacity extension identified in this study of at maximum 184 GW seems to be reasonable. These numbers are difficult to compare, as they consider more transmission lines due to higher resolution of the European transmission grid infrastructure. Likewise, Haller et al. (2012b) found larger transmission capacity to be optimal. The cumulative capacity is not given, but single cross-border transmission capacities add up to 35 GW. This is five times the maximum extension found in this thesis. Becker et al. neither provide a sum of transmission capacity extension, but found single lines extended up to 72 GW by 2050 (Becker et al., 2013). Even in moderate scenarios, their transmission capacity extension estimate exceeds those of this thesis. Rodriguez et al. report transmission extension by factor 5.7 in the same time as result of a constraint scenario (Rodríguez et al., 2014). In comparison to those findings, even the largest cumulative transmission extension identified in this study (in scenario *RES progressive*) seems to be reasonable and moderate. Exploiting sites of high RES potential by transmission capacity extension induces a large amount of power exchange among regions along with regional imbalances of electricity demand and generation (cf. Section 5.3). This may oppose the political aim to have a certain – but significant – amount of domestic power supply in order to be well-prepared against political extortion enabled by a dependency on electricity imports (Lilliestam and Ellenbeck, 2011). Among others, Becker et al. (2013); Haller et al. (2012b); Knopf et al. (2015) underline the benefits of transmission grid extension regarding cost effective pathways towards a low-carbon electricity supply. However, GHG emission reduction targets can be achieved without transmission grid extension. Prohibiting transmission grid extension would shift the allocation of RES generation sites towards locations of demand. The GHG emission reductions goals can be achieved without extending current cross-border transmission capacity at cost around 6 % higher than without any transmission capacity extension limit. Anyhow, based on the findings of this study, it's recommendable to consider cross-border transmission capacity extension to follow the least-cost decarbonization pathway for the European power supply system.

Excess electricity By 2050, excess electricity and losses incorporated with the operation of energy storage systems and transmission grid add up to more than 1,200 TWh/a. There is no economically viable business case for using the entire electricity provided by intermittent sources wind and PV power. Due to not perfectly matching patterns of RES based power supply and the inelastic assumed demand, dumping of excess electricity makes sense from a social-planning top-down economical perspective. Dumping of excess electricity refers to curtailment of RES based generation in reality. Even if storage and transmission capacity is largely extended, curtailing 500 TWh/a is part of the least-cost power supply for Europe in 2050. It would require to build large energy storage and transmission capacities to make use of the entire electricity generated in peak times and to provide power in times of low production by wind and PV power. As excess electricity produced by wind and PV power plants is usually curtailed in reality, it makes sense to use this energy in other sectors.

The sectoral approach of modeling only the power sector cannot further analyze the use of excess electricity and waste heat. Nevertheless, excess electricity and high-temperature waste heat (i.e. from the PtG process) should be considered for further application. A number of promising options in the heat and transport sector are available (Mathiesen and Lund, 2009; Mathiesen et al., 2011). Available electricity could be used for charging battery-electric vehicles and several power-to-heat facilities such as heat pumps (Teng et al., 2015; Papadaskalopoulos et al., 2013). Waste heat from energy storages could at least be used for district heating (Holmgren, 2006; Fang et al., 2013). Depending on temperature level, maybe even for industrial process applications. By having cross-sectoral options of energy supply already considered in the analysis, resulting power system design may be changed. According to Mathiesen et al. (2015), integrated planning of multiple energy sectors is beneficial regarding efficient use of energy and cost.

LCOE increase The increase in levelized cost of electricity of about 60 % within roughly three decades is a significant change. The study of Haller et al. (2012b) underlines this finding by identifying similar LCOE for slightly less ambitious mitigation goals of a 90 % GHG emission reduction scenario. Bussar et al. (2016) and Gils et al. (2017) underpin the findings about increase in cost of electricity supply. According to these studies, LCOE will be in the range of 9.7 ct€ to 12 ct€ for a 100 % RES based electricity supply scenario. Delucchi and Jacobson (2011), Czisch (2005), and Scholz (2012) found significantly lower LCOE for electricity supply by 2050 that are close to present cost. To exactly identify the reasons why cost of different studies deviate that largely requires large effort and is not part of this thesis. It is assumed, that these differences originate from different models, scenarios, and data that are used in each of these studies. One cause for the cost increase is the rising effort of providing low-carbon power supply with increasing RES shares. This is caused by required over-capacities and curtailment, integration of energy storage system for supply and demand balancing, as well as grid extension needs. However, the transition to a low-carbon electricity supply system avoids other costs. Namely the cost increase due to rising cost of fossil fuels (Roth and Ambs, 2004), external cost induced by impact of climate change (economic losses in agriculture, in tourism, in coastal areas, due to river floods and increased cost of health care) (Ciscar et al., 2011) and other external cost (cost induced by any socio-environmental damages related to construction, operation and dismantling of power plants), which are generally not reflected in LCOE calculations (Roth and Ambs, 2004; Larsson et al., 2014).

The cost increase of fossil fuels varies among different types of fuels. While coal and natural gas are expected to undergo a moderate change (+17 % for coal and 25 % for natural gas), cost of uranium is expected to almost quadruple in the upcoming three decades (cf. Section 4.3). Costs induced by impact of climate change are difficult to assess and depend on the severity of climate change. According to estimates by Ciscar et al. (2011), the EU's economy is affected by a 22 bn. EUR gross domestic product (GDP) loss by the impact of climate change. Aside from cost directly associated with climate change, power generation is associated with external cost that are not reflected by LCOE. These include any cost related to the fuel cycle that are not part of the electric utility cost structure. External cost associated with power generation technologies are listed in Section 2.1.1.

Re-evaluating the LCOE of a decarbonized power supply system in the light of avoided costs due to decreased use of fossil fuels, cost associated with impact of climate change, and external cost of electricity generation relativizes the picture. The decarbonization pathway avoids cost of 0.697 ctEUR/kWh, due to a switch of generation technologies and diminished used of fossil fuels (Roth and Ambs, 2004), 0.482 ctEUR/kWh due to impact of climate change and adaption (Ciscar et al., 2011), and 2.02 ctEUR/kWh due to external cost (Larsson et al., 2014). In total, avoided cost by decarbonizing Europe's power supply system according to the stated mitigation goals add up to 3.197 ctEUR/kWh. For a comparison of resulting LCOE of the decarbonization pathway with the business as usual (BAU) case, these avoided cost have to be taken into account. Considering the fuel cost increase, climate change impact cost and external cost of power supply in the reference case (power supply in 2020), the cost add up to 9.6 ctEUR/kWh. In the light of the total costs of power supply, the cost difference of LCOE including external effects for power supply compliant with climate change mitigation goals to the BAU case of 0.6 ctEUR/kWh (6.25 %) appear neglectable.

High cumulative investment needs The transition towards a decarbonized European power supply system requires cumulative investments of 4,021 bn. € until 2050. Expressed as average annual expenses, the investment needs add up to 118 bn. €/a when spread across 34 years. At first glance, these investment needs seem to be quite high, but these include cost for refurbishment of power supply system equipment including conventional generation technologies as well. For understanding the magnitude of these expenses in context of the entire European economy, a comparison to the GDP is a good benchmark. In 2016, the GDP of entire Europe added up to 13.1 trillion € (World Bank, 2016). The average annual expenses for the decarbonization of Europe's power supply infrastructure then only account for 0.9 % of the GDP. For a key infrastructure, that the electricity supply represents, this is an acceptable amount. Continuous replacement cost for retaining the 2050's electricity supply system infrastructure would add up to 153.3 bn. €/ a. Spending these annual expenses would allow to maintain the capacity of the European power system including unused capacity, such as coal power generation capacity.

An additional benefit of the decarbonization based on RES supply technologies is the change to mainly investment cost and deep cuts in operational – predominately fuel – cost. This prevents unexpected cost increases due to rising fuel cost, i.e. by shortages on the global fuel market.

8 Conclusions

Greenhouse gas emission reduction targets declared by the EU set rigid bounds for future electricity supply and enforce a radical change of the electricity system infrastructure. In this thesis, pathways for achieving these targets are assessed. These pathways describe the cost-effective transformation of Europe's electricity supply infrastructure that result in almost zero-emissions electricity supply by 2050. The pathways outlined in this dissertation specify changes in electricity generation, energy storage integration and the extension of the transmission system capacity in five years steps. These pathways were assessed using a combined dispatch and investment model that determines cost-optimal investments into and decommissioning of power generation, energy storage system, and transmission capacity. In Section 8.1 the methodological approach and findings are summarized and conclusions are presented while answering the posed research questions. Recommendations derived from findings are outlined in Section 8.2.

8.1 Responding to research questions

The thesis is framed by two main research questions introduced in Chapter 1. The first question addresses efficient methods of energy system modeling for studying the decarbonizing pathways of Europe's electricity supply system. The second question seeks cost-efficient pathways for the transformation towards a decarbonized electricity supply system. The following sections summarize the thesis' methodical approach and the findings according to these two questions.

How can decarbonization pathways of Europe's electricity supply system effectively be modeled?

This first main question targets the methodical approach applied in this thesis. For modeling Europe electricity supply system, the temporal scale, considered electricity system, and the representation of technical and economic characteristics are of particular importance. Therefore, the answer to the first main research question is divided into a discussion of requirements regarding short- and long-term modeling and the selection of electricity system technologies including the representation of its technical and economic characteristics; followed by a summary of the modeling approach including a description of further important aspects considered in the self-developed electricity system model *elesplan-m*.

Conducting a model-based analysis in how to decarbonize the European electricity supply system requires a model that covers the entire period on which the decarbonization takes place and at the same time is characterized by representing short-term effects in detail. Regarding long-term effects the model needs to represent investment cycles for successively studying decommissioning and new investments of electricity system infrastructure along the pathway of predefined GHG emission limits. Regarding necessary data, the model requires input on existing power plants, energy storage systems and transmission system inventory including information about commissioning dates. On a short-term scale a temporal resolution is required that is capable of representing demand and supply patterns in sufficient detail as well as the operation of energy storage systems and the transmission system which means a minimum of hourly increments. The detailed representation of short-term scale is necessary due to consideration of significant shares of intermittent RES based electricity generation. For evaluating the integration of energy storage systems additional requirements regarding temporal modeling arise. Describing operational characteristics of energy storage systems successfully requires information about chronology of time steps. This allows to derive the state of charge from charge and discharge events. A detailed representation of temporal scale is bounded by computational complexity of the model. Thus, compromises have to be found between detailed modeling and computational cost.

In order to delve into the second main research question, a detailed literature review on available energy system modeling approaches and implementations into a software that met the above requirements was conducted As no suitable model implementation was found, it resulted in the decision to self-develop a model for analyzing the future development of the European electricity supply system called *elesplan-m*. The requirements regarding modeling of short-term and long-term features of decarbonization were met within *elesplan-m* by finding a compromise between short-term resolution, representation of investment cycles and the entire period for which decarbonization targets are defined, and the selection of electricity system technologies including their technical aspects. The model complexity is kept relatively low by limiting technologies that are considered and largely aggregating information on the spatial scale. Electricity system technologies considered by this thesis were comprised of present and potentially future major generation technologies and energy storage system technologies as well as cross-border transmission capacity. On a spatial scale, information about the electricity supply infrastructure was aggregated to the regional level. Investment cycles were determined by deciding on decommissioning and commissioning in 5-years intervals. This was realized by applying the same model successively every five years for analyzing the electricity supply exemplary for one year with updated GHG emission limits while considering previous investment decisions. This approach of consecutive analysis revealed a new design of the electricity system every five years that is capable to meet the respective GHG emission limits. The consecutive re-evaluation of the electricity supply system infrastructure is myopic in nature, as it neglects information beyond the current planning period. This guarantees no overestimation of knowledge about the future. The model then used a temporal resolution of one hour to represent operational characteristics of the electricity supply. Thereby, the main features of intermittent electricity generation and energy storage systems operation were represented sufficiently. Further reduction of complexity through clustering on the temporal scale by using time slices or representative days is not considered. In this way, important information about chronology of time steps can be kept which is of particular importance to the modeling of energy storage systems operating on the long-term scale. In summary, for this thesis the following electricity system technologies were considered within *elesplan-m*: gas, coal, nuclear, hydro, wind and PV power plants, as well as energy storage system technologies PHS, battery energy storage system and PtG, and the transmission system. They were characterized by technological and economic factors sufficient to optimize the electricity system transformation towards GHG reduction goals at lowest LCOE.

In summary, *elesplan-m* is a long-term combined electricity system dispatch and investment planning model designed to assess the decarbonization of the European electricity supply sector. The model implements a step-wise planning process determining cost-optimal investment and decommissioning decisions in five years planning intervals at a spatial representation of 18 regions. Investment decisions are evaluated considering existing electricity supply system infrastructure. Thereby, in each of the five years planning intervals, the model optimizes the electricity system structure only considering the current input parameters and existing infrastructure. This means for example GHG emission limits beyond the current planning interval are not considered in the optimization of a certain interval. *Elesplan-m* is formulated as linear optimization approach that determines new installations of power plants, energy storage systems, and transmission capacity aiming for least cost of electricity supply. For this thesis, each planning interval was described by specific GHG emission limits derived by EU commission targets. The combined model formulation allowed to assess cost-optimal investments while considering the operation of power plants, energy storage systems and the transmission system in each of the regions. Potential investments were evaluated regarding operational characteristics that affect the economic or technical performance. This included dispatch of electricity supply infrastructure, related GHG emissions, and cost of electricity supply, storage and transmission. A linear programming approach was chosen for effectively realizing the combined model formulation resulting in an efficiently computable model. Furthermore, linear programming allows integrating a large number of variables and constraints while being solvable in decent time. Therefore *elesplan-m* can incorporate a high degree of freedom for assessing technological options to transform Europe's electricity supply system. It should also be stated that the model acts from a social-planning perspective under perfect foresight. In conclusion, the developed modeling approach can determine the least-cost electricity system design for each planning interval considering defined GHG emission limits, the existing electricity supply infrastructure and operational constraints of power plants, energy storage system and the transmission system in a multi-regional spatial representation. Thus, the developed linear programming based model is a reliable approach to model decarbonization pathways for Europe's electricity supply system.

What is the techno-economically optimal decarbonization pathway for meeting EU GHG emission targets within the electricity supply sector by 2050?

This question was answered by applying the previously described electricity system model *elesplan-m* using a set of scenarios. Decarbonization in the European electricity sector can be achieved by pursuing different pathways. Scenarios analyzed in this thesis reflect different circumstances and lead to decarbonization pathways that are suitable to meet given GHG reduction targets on time. The assessed pathways all share the goal of a massive extension of RES power generation capacity which results in a share of RES based electricity generation of 98 % by 2050. Different pathways towards a low-carbon electricity supply system distinguish themselves in cost, generation and energy storage technologies including their spatial allocation and the scale of transmission capacity extension. Based on the most reliable and likely set of parameters and assumption, the techno-economically optimized decarbonization pathway to meet the EU GHG emission goals is carried out. In the following section, this pathway is described to answer the second research question about a cost-effective transformation of the European electricity system. After that, a closer look on regional effects highlight the spatial dimension of this transformation. Finally, findings revealed from the analysis of different scenarios provide insights about sensitive results and alternative pathways.

What does a decarbonization pathway for Europe look like regarding generation capacity and supply mix, energy storage systems, transmission system, and cost of electricity supply? The decarbonization of the European electricity supply sector is inevitable without a complete change of the power generation landscape. A switch from fossil and nuclear based electricity supply to one based on RES occurs within three decades. At the beginning of the decarbonization pathway in 2020, in the cost-optimal and carbon-constrained electricity supply system design, large shares of coal and nuclear power electricity generation are considered. The total annual electricity generation of 3523 TWh/a comprises of 1184 TWh/a coal, 916 TWh/a nuclear, 539 TWh/a hydro, 538 TWh/a wind, 253 TWh/a gas, and 84 TWh/a PV power based electricity generation. Along the pathway consisting of increasingly strict GHG emission limits and with a increased electricity demand of 4448 TWh/a by 2050, total electricity generation adds up to almost 6000 TWh/a. At that time, almost 90 % of electricity generation comes from wind and PV power. Electricity generation of 3477 TWh/a by wind power and 1619 TWh/a by PV power is complemented by 539 TWh/a hydro power and 300 TWh gas based power generation. Generation by nuclear and coal power plants is neglectable. The fundamental change of the electricity generation requires large-scale expansion of wind and PV power generation capacity. In Europe, a cumulative generation capacities of 1428 GW wind and 1259 GW PV are required to achieve sustainable electricity supply according to GHG reduction goals by 2050. This requires average annual capacity extensions of more than 40 GW/a for both technologies, and respectively similar annual power plant refurbishment beyond 2050.

The modeling results of this thesis suggest that coal based electricity generation is not an option beyond 2030. This carbon-intense power generation technology is not suitable to be part of an electricity supply system compliant with the EU decarbonization goals. Operation of coal power plants must end after 2030 in order to meet targeted GHG reduction. Full-load hours already decrease dramatically even before 2035 which strongly contradicts new investments. While electricity generation by coal power plants declines, gas-fueled technologies experience a renaissance during the transformation of the electricity supply system. The increasing amount of intermittent electricity supply demands for more flexible balancing capacity as it is provided by gas power generation technology, therefore the results show the extension of gas power generation capacity. The need for new gas power plant capacity is explained by two reasons. First, gas-fueled power generation replaces carbon-intense electricity generation by coal power plants allowing the achievement of intermediate decarbonization targets on the way towards 2050 goals. Second, the integration of PtG facilities asks for gas power plant capacity to convert synthetic natural gas (SNG) back to electricity. Therefore, gas power plant capacity uptakes ahead of time by 2030 including an increase of full-load hours.

The integration of energy storage systems is important to achieve mitigation targets based on electricity generation by intermittent RES technologies. Such technologies are now beginning to be considered in the electricity supply system commencing with the year 2035 when the RES share reaches 72 %. Initially, by 2035, a small capacity of battery energy storage system (BESS) comes into play. Five years later, both BESS and PtG systems undergo a large capacity extension. By 2050, readily available PHS capacity of 43 GW is complemented by 227 GW of BESS plus 261 GW of PtG capacity resulting in a cumulative energy storage system capacity of 531 GW. The integration of the two energy storage system technologies, battery energy and PtG storage systems, shows that the consideration of multiple energy storage technologies is beneficial in terms of realizing electricity supply largely on RES based electricity generation. Whereas battery energy storage system serve short-term balancing needs (intra-day up to a few days), PtG facilities balance mismatching demand and supply on long-term (weeks up to seasonal).

Although energy storage systems and the transmission system provide balancing capabilities to match supply and demand on the temporal and spatial scale, curtailment of electricity economically makes sense in the modeled electricity supply system involving high shares of RES. It is not financially viable to provide sufficiently large ESS capacities for entirely capturing excess electricity in times of low demand and high generation. Thereof, curtailed or excess electricity of 512 TWh/a result by 2050. This fairly large amount of 11.5 % of Europe's electricity demand could be used to supply the demand in other energy sectors such as heat or transport. Nevertheless, from a single-sector and social-planning perspective that is taken for this thesis, curtailing large amounts of excess electricity economically makes sense.

Transmission capacity extension allows for cost-effective interregional RES based electricity supply. The RES potential is unequally distributed among European countries. Transmission capacity extension up to cumulative transmission capacity of 178 GW enables for a strong European integration of electricity supply providing access to high RES potential sites at large-scale. Regions of excellent RES conditions supply other regions electricity demand. In the derived least-cost scenario of low-carbon European electricity supply for 2050 Denmark and Southern Balkans both provide more than 70 TWh/a for supplying other region's demand. In the case of Denmark the electricity exports add up to 129 % of its domestic demand. On the other hand, Sweden and Western Balkans are large scale importing regions that supply more than 40 % of their annual electricity demand based on electricity imports. The dispersed RES potential accessed through strong transmission capacity extension results in large-scale electricity exchange among regions and a strong interregional dependency in terms of electricity supply.

The described decarbonization of Europe's electricity supply according to the EU Commission's GHG reduction targets of -98.4 % compared to 1990 emission levels in the electricity sector can be achieved at an increased but reasonable cost. By 2050, levelized cost of electricity amount to 10.2 ct€ which equals an increase of about 60 % compared to 2020. Cumulative investments of 4,021 bn.€ (on average 118 bn.€/a) over the entire period are required for new installations and refurbishment of available generation, energy storage system, and transmission system infrastructure. These fairly large investments represent only 0.9 % of the total European GDP. In context with the total GDP, the expenses seem to argue for the complete transformation of such an important infrastructure as the electricity supply infrastructure. The switch from a nuclear and fossil based electricity supply towards an almost zero emissions supply system avoids costs related to a fuel cost increase, cost associated to the impact of climate change, and external cost of around 3.2 ct€/kWh. Considering these avoided cost, the least-cost decarbonization pathway end up with a 6.25 % increase in LCOE compared to the BAU case.

What is the impact of decarbonizing Europe's electricity supply on regional level? The model-based analysis of cost-effective decarbonizing Europe's electricity supply sector yielded a cost-optimal solution for the compound of European countries. Decommissioning and extension of power plant, energy storage system and transmission capacity was determined such that cumulative European GHG emissions were kept below defined limits and that minimal total cost of power supply result. Nevertheless, regional differences regarding this infrastructure are identified as part of a cost-optimal solution. Investments into new capacity of power plants, energy storage systems and the transmission system were determined according to regional electricity demand and the potential of RES. By 2050, centrally located and in particular northern European countries electricity generation was predominantly based on wind power. Generation by PV power dominated the electricity supply of regions in southern Europe. Regions with good resources for hydro-power electricity generation like Alpine region or Norway extensively utilize these technologies. Regional differences in achievable full-load hours for a specific generation technology predefine its generation cost. As a result of differences in regional generation, cost large-scale electricity exchanges occurred. With considering cost for transmission system capacity extension for some regions, large-scale electricity imports for serving domestic demand was the most cost-effective supply configuration. This led to relatively large regional imbalances of demand and supply with some regions being large importers or exporters of electricity. Transmission grid extension from todays cumulative transmission capacity of 53 GW up to 178 GW by 2050 and extensive use of this infrastructure ended up in vast electricity exchanges that are part of the least-cost decarbonization case.

How do changed input parameters and boundary conditions affect results? Analyzing the impact of changed input parameters on key model outcomes revealed coherent decarbonization pathways. With regard to cost, findings on feasible decarbonization pathways can be interpreted as robust as relatively small variations of LCOE (+/- 10 %) in conducted scenario variations were found. Within the conducted scenario analysis model parameters that are expected to be the most influencing on the results and most difficult to predict were varied. This included cost reduction potential of capital expenditures of RES technologies varied by +/- 50 %, up to 50 % diminished cost reduction of battery energy storage system, higher capital expenditures for PtG, and significant cost considered for the provision of CO_2 for the PtG system. While the share of RES resulting by 2050 was marginally affected by parameter variations, the electricity generation mix – mostly wind and PV – changed slightly. Higher cost for RES technologies resulted in electricity supply system with slightly higher shares of wind power generation. Respectively, a stronger cost reduction than expected in the base case led to higher shares of electricity generated by PV power. Higher capital expenditures for PtG facilities resulted in a slight shift towards more generation by PV power. This effect strongly highlighted when cost for CO_2 were higher. Furthermore, the cumulative generation of wind and PV increased in this case. Electricity generation was most affected by variations in cost of battery energy storage systems. A diminished cost reduction potential for BESS led to higher total generation and to a shift from generation shares of PV power towards wind power.

A significantly stronger sensitivity to changed model parameters was observed for the cost-optimal technology mix of energy storage systems. The variations of key parameters revealed pathways that include a cumulative energy storage system capacity ranging from 458 GW to 544 GW comprising of very different compositions of energy storage system technologies. This includes scenarios that considers zero BESS capacity and a large amounts of PtG facilities, scenarios incorporating very similar charge power of both technologies, as well as scenarios with a strong preference for battery energy storage systems. Obviously, higher cost for PtG led to increased capacity of BESS and and higher cost for BESS to increased PtG capacity. In both cases, the cumulative capacity of energy storage systems was reduced compared to the base case. Cost of BESSs had the most impact on the technological mix of energy storage systems in future low-carbon designs of the European electricity supply system. Whereas the electricity system obtained from the base case acknowledges for a well-balanced mix of BESSs and PtG system, less cost reduction as assumed by that scenario led to substantial less BESS capacity considered in the cost-optimal supply system. Already half of the base case's cost reduction of BESS yielded a system design without BESSs being considered at all. Thus, the optimal capacity of battery energy storage systems and consequently the ideal mix of ESS technologies PtG and battery energy storage systems is most sensitive. Uncertainty related to the cost of PtG systems and sustainable CO_2 sources for large-scale application of this technology affected the energy storage systems mix as well, but significantly less distinct than uncertainty related to the cost of BESSs. Even when capital expenditures would end up 50 % higher than expected in the base case or significant additional cost and performance losses induced by the worst-case of CO_2 through ambient air, the cost-optimal electricity supply system design would still consider PtG in the system. This leads to the conclusion that PtG technology is a fundamental cornerstone of electricity supply based of high shares of RES and that a capacity of at least 92 GW PtG is required to realize the transition towards a RES supplied electricity system for achieving GHG reduction goals.

A relationship between PV generation and BESS as well as between wind generation and PtG was identified. Variations of ESS cost show a positive correlation between BESS and PV power electricity generation and PtG systems and wind power generation. Higher cost for BESS led to increased generation by wind power. Likewise, increased cost for PtG systems led to diminished generation by wind power compensated by additional electricity generated by PV power. Analogously, variations of cost for RES, which influences the electricity generation mix, changed the preference for energy storage technologies as well. Low cost for both major supply technologies wind and PV tended to include large shares of PV based power generation, whereas higher cost resulted in a system design considering for larger shares of generation by wind power. Coincidently, electricity supply system designs including larger shares of PV incorporated more BESS capacity. Conversely, in systems with high wind power based electricity generation PtG capacity was increased compared to the base case.

Boundary conditions affect the electricity system design as well. It might be the case that regions are not willing to heavily rely on electricity imports and build up interdependencies among regions for critical infrastructure such as electricity supply. This case was studied as well. Electricity supply compliant with the EU reduction targets and 0 % of electricity imports on the regional demand calculated on an annual basis is realizable as well. Electricity exchanges were significantly lowered and cost of electricity supply were marginally different in such a scenario. The composition of electricity generation and energy storage systems hardly changed by limiting electricity imports. Another case might be limited ability of cross-border transmission capacity extension due to long planning process of such projects. Technically, a decarbonization of the European electricity supply is feasible without any extension of the current transmission system capacity. Entirely avoiding extensions of the transmission system cross-border capacity would result in a 6 % increase of LCOE in comparison to the reference case of net transmission capacity extension of 134 GW. Restricting transmission capacity extension is almost ineffective regarding the electricity supply mix. However, the cumulative annual electricity generation increases along with stronger limits on transmission capacity extension. Energy storage systems' capacity has a significantly stronger correlation with transmission capacity extension. Limited transmission capacity extension led to increase ESS capacity. Increased energy storage system capacity extension can compensate transmission system capacity extension. Electricity system designs that neglect transmission capacity extension included slightly larger shares of PtG. This implies that the transmission system is used for inter-regional balancing of demand and supply mismatches that are seasonally different among the regions because the long-term energy storage system technology PtG copes best with lacking transmission capacity.

In summary, findings of the analysis of sensitive model parameters and boundary conditions suggest a broad plateau of feasible electricity system designs exists to realize the decarbonization of Europe's electricity sector. The future European electricity system may include different electricity generation mixes, different capacities of energy storage system technologies, and an uncertain amount of transmission capacity extension depending on development of cost and boundary conditions. All these electricity system designs remained within GHG emission limits and resulted in levelized cost of electricity of +/-10 % relative to 10.2 ct€ of the base case. Other findings remained untapped from parametric uncertainty and changed boundary conditions. For example, wind and PV power will be the main supply technologies by 2050 and coal based power generation is not compatible with strict GHG emission reduction targets.

8.2 Recommendations

A cost-optimal pathway for the decarbonization of the European electricity supply was identified and extensively described in the body of this thesis. Following this decarbonization pathway would lead to almost zero GHG emission electricity in Europe by 2050 according to the long-term goals of the EU. It is sketched in terms of the development of electricity generation and energy storage system capacities that are required to achieve the intended reduction of GHG emissions in Figure 8.1.

The realization of a successful transformation of Europe's electricity supply system according to the outlined pathway requires a rigorous implementation by politicians assisted by the support of private sector companies and scientific counselling. Most importantly, the realization of the decarbonization of Europe's electricity needs a coherent policy that results in effective legislation and regulation on national and international levels. Decision-makers

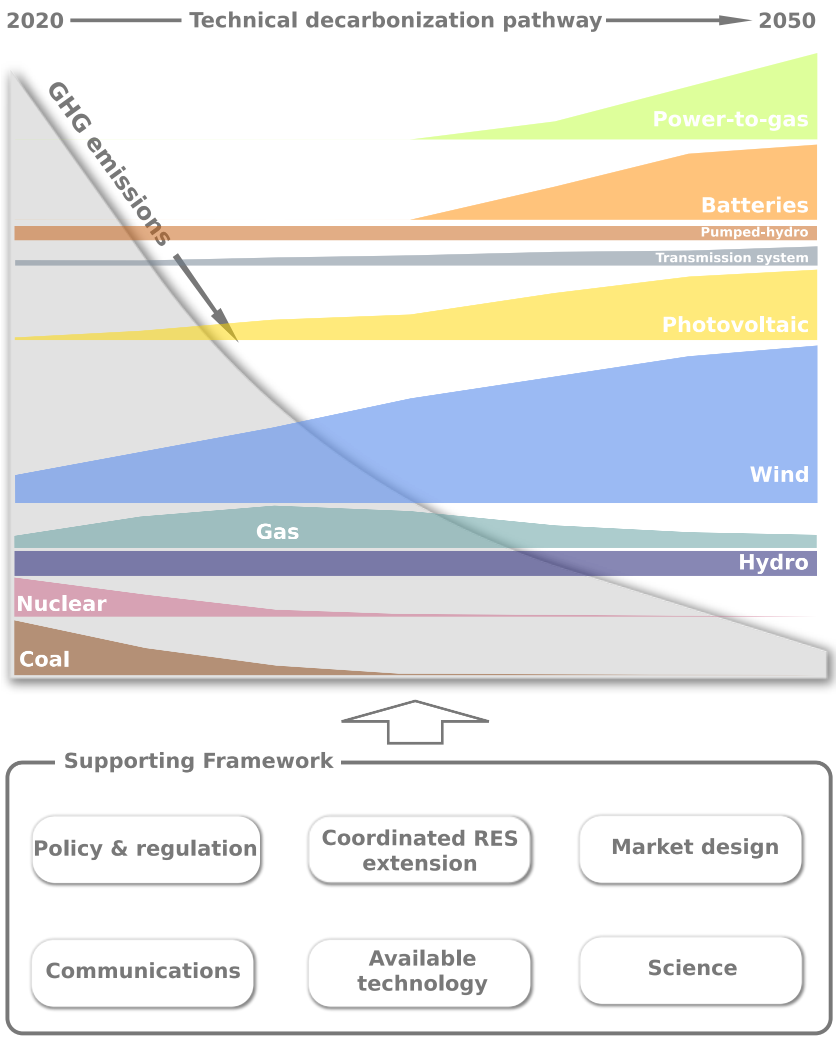


Figure 8.1: Sketch of decarbonization pathway: development of electricity generation and energy storage system capacities for realizing decarbonization in Europe.

must agree on binding GHG reduction targets for Europe as a whole and thereof derived individual national targets for the period beyond 2030. Furthermore, the policy should include a plan for coordinated RES, energy storage system and transmission system capacity expansion on international and national level. Supported by a coherent investment support program, investments into RES technologies, energy storage systems and the transmission system extension should be incentivized and, simultaneously investments into carbon-intense technologies such as coal power should be prevented. On the European level, the policy adaption for achieving decarbonization goals must include the pan-European integration in terms of electricity supply encompassing a coordinated plan for cross-border transmission capacity extension. By doing this, bounds for electricity imports and export are set which motivates the choice for a specific pathway that is to be implemented. Furthermore, the allocation of future RES generation sites are determined in accordance to the expected transmission system extensions. An important aspect for the successful operation of the electricity supply system with high shares of RES based electricity generation is to adapt the market design. The current energy-only market design lacks establishing incentivising signals for important technologies of the transition, i.e. for gas power plants. In addition, the price formation in energy only markets incorporating high shares of RES based generation is biased due to marginal cost of RES technologies of almost zero. Both aspects need to be resolved by a revision of the current electricity market design.

A successful implementation of the outlined decarbonization pathway requires certain technologies to be available in the future. This is particularly true for future principle generation technologies wind and PV power as well as for emerging energy storage system technologies battery energy storage system (BESS) and PtG. As discussed in the body of the thesis, the manufacturing capacity for wind and PV needs to be massively increased for achieving required capacity extension rates of these technologies. Regarding PtG technology, in this thesis technical improvement is assumed leading to lowered cost and increased system efficiency. Realizing this technological development might require a supportive program for research and development of PtG based storage systems. This must include large-scale CO_2 extraction from ambient air in order to achieve a sustainable operation of these energy storage systems. Transparent communication about the implications of pursuing the described decarbonization pathway is another success factor for the transition. Potential investors and other stakeholders require reliable information and a stable and moderately predictable environment for investments. In order to enhance the public acceptance, the general public needs to be informed too. For example, the cost increase needs to be explained and contrasted to the benefits of the decarbonization of Europe's electricity supply including avoided external cost, increased fuel cost and other costs due to impact of climate change. Scientific research should support the realization of decarbonization goals as well. Improvements regarding data and particular aspects of the modeling approach as well as more detailed analyses based on the output of *elesplan-m* would improve the quality of findings. Therefore, improving data required for energy system modeling, optimally, published under a suitable open data license, is highly appreciated. Scientific progress regarding inter-sectoral energy system modeling would help to further explore the benefits and bounds of inter-sectoral energy supply, but it is likely that computational cost will increase at the same time. Thus, to handle increase complexity and computational cost, further research on complexity reduction in terms of energy system modeling is required. Furthermore, energy economists should work on options for electricity market design that goes beyond capabilities of energy only and capacity markets.

In conclusion, the successful implementation of cost-effective decarbonization realizing goals for 2050 requires shared efforts from decision-makers, private sector, and the scientific community, as well as support from the general public. Through collaboration based on well designed policy making, achieving the decarbonization goals is realistic and contains great potential for sustainable and economic prosperity.

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A Appendix

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A.1 Model input data

Table A.1: Projection of annual electricity demand in TWh/a per country based on Fürsch et al. (2013); ENTSO-E (2012b); EIA (2015)

Country	2012	2020	2025	2030	2035	2040	2045	2050
France	480,0	480,0	497,3	514,6	530,5	546,4	561,8	577,2
Germany	539,9	567,0	575,6	584,2	584,2	584,2	584,2	584,2
Italy	328,2	362,9	391,0	419,1	450,4	481,6	516,1	550,7
Great Britain	333,4	387,4	401,4	415,4	428,2	441,0	453,4	465,8
Spain	267,2	298,6	321,8	344,9	370,6	396,3	424,8	453,2
Poland	140,0	140,0	148,9	157,8	167,3	176,9	187,1	197,3
Sweden	142,0	150,0	155,4	160,9	165,8	170,8	175,6	180,4
Norway	118,7	118,7	123,0	127,3	131,3	135,2	139,0	142,8
Netherlands	113,8	121,4	125,8	130,2	134,2	138,2	142,1	146,0
Finland	85,1	96,6	100,1	103,6	106,8	110,0	113,1	116,2
Belgium	84,9	92,6	96,0	99,3	102,3	105,4	108,4	111,4
Austria	65,3	65,3	67,7	70,0	72,2	74,3	76,4	78,5
Czech Republic	63,0	69,9	74,3	78,8	83,5	88,3	93,4	98,5
Romania	49,8	49,8	53,0	56,1	59,5	62,9	66,5	70,1
Greece	52,1	65,2	70,3	75,3	80,9	86,5	92,8	99,0
Portugal	49,1	55,9	60,2	64,5	69,3	74,1	79,5	84,8
Switzerland	64,8	65,4	67,8	70,1	72,3	74,5	76,6	78,7
Serbia	39,6	39,6	41,8	43,9	46,6	49,3	52,1	54,9
Hungary	38,9	40,1	42,6	45,1	47,9	50,6	53,5	56,5
Bulgaria	32,5	32,5	34,2	36,0	38,2	40,4	42,7	45,0
Denmark	34,3	40,4	41,9	43,4	44,8	46,1	47,4	48,6
Slovakia	26,8	30,1	32,0	33,9	36,0	38,0	40,2	42,4
Ireland	25,7	28,1	29,1	30,2	31,1	32,0	32,9	33,8
Croatia	17,3	22,3	23,7	25,0	26,5	28,0	29,7	31,3
Slovenia	12,6	16,3	17,3	18,3	19,4	20,5	21,7	22,9
Bosnia & Herzegovina	12,1	15,6	16,6	17,6	18,6	19,7	20,8	22,0
Lithuania	9,9	9,9	10,5	11,1	11,8	12,5	13,2	13,9
Macedonia	8,5	10,6	11,5	12,3	13,2	14,1	15,1	16,1
Estland	7,7	7,7	8,2	8,7	9,2	9,7	10,3	10,9
Latvia	7,1	7,1	7,5	8,0	8,5	9,0	9,5	10,0
Luxemburg	6,3	7,6	7,8	8,1	8,3	8,6	8,8	9,1
Kosovo	4,8	4,8	5,1	5,3	5,7	6,0	6,3	6,7
Albania	4,1	5,1	5,5	5,9	6,3	6,7	7,2	7,7
Montenegro	3,9	5,0	5,3	5,6	6,0	6,3	6,7	7,1

[htbp]

Table A.2: Initial transmission capacity of aggregated cross-border transmission systems according to ENTSO-E NTC values (Entso-E, 2011)

From	To	Capacity in GW	Length in km
Germany	Denmark	2.085	597
Germany	Poland	1.200	634
Germany	Sweden	0.610	1037
Germany	Alpine region	5.500	440
Germany	Czech Republic & Slovakia	2.300	504
Denmark	Norway	0.950	394
Denmark	Sweden	2.440	606
Finland	Baltic region	0.350	860
Norway	Sweden	3.895	415
Sweden	Finland	2.050	715
Sweden	Poland	0.600	810
Benelux	Germany	4.830	364
Alpine region	Western Balkans	0.900	470
Alpine region	Hungary & Romania	0.800	862
Alpine region	Italy	4.385	505
Czech Republic & Slovakia	Hungary & Romania	1.300	596
France	Germany	3.200	766
France	Alpine region	3.200	739
France	Benelux	3.400	582
France	Italy	2.575	863
Hungary & Romania	Western Balkans	1.200	533
Iberia	France	1.300	908
Italy	Western Balkans	0.580	493
Italy	Southern Balkans	0.500	925
Western Balkans	Southern Balkans	0.200	709
Western Balkans	Eastern Balkans	1.350	528
Great Britain	France	2.000	758
Southern Balkans	Eastern Balkans	1.660	407
Hungary & Romania	Eastern Balkans	1.900	322
Poland	Czech Republic & Slovakia	2.400	355
Alpine region	Czech Republic & Slovakia	1.000	415

A.2 Results tables

Table A.3: Key figures of *base scenario*

Year	LCOE in ct€/kWh	RES share in %	GHG emissions in CO_2eq
2020	6.4	32.6	1039.3
2025	5.9	49.2	724.3
2030	7.3	61.1	546.2
2035	8.0	71.9	356.3
2040	9.2	86.1	178.3
2045	10.1	95.7	59.1
2050	10.2	98.3	23.6

Table A.4: European total generation capacity in GW for the *base scenario*

Year	OCGT	CCGT	Coal power	Wind	PV	Nuclear	Hydro
2020	116	100	160	183	80	105	148
2025	25	20	154	361	208	65	148
2030	102	187	143	508	387	22	148
2035	78	232	138	759	514	13	148
2040	47	227	135	1073	870	7	148
2045	39	205	108	1292	1168	2	148
2050	27	213	108	1428	1259	1	148

Table A.5: Cumulative generation capacity extension in GW for the *base scenario*

Year	OCGT	CCGT	Coal	Wind	PV	Nuclear	Hydro
2020	13	0	108	65	0	0	0
2025	25	20	0	186	129	0	0
2030	0	75	0	173	180	0	0
2035	0	56	0	292	144	0	0
2040	0	12	0	356	418	0	0
2045	1	42	0	284	298	0	0
2050	1	8	0	322	220	0	0

Table A.6: Annual generation in Europe by technology in TWh/a for the *base scenario*. Numbers in parentheses for gas-fueled generation technologies indicate amount of electricity thereof generated based on SNG.

Year	OCGT	CCGT	Coal power	Wind	PV	Nuclear	Hydro
2020	24 (0)	229 (0)	1184	538	94	916	539
2025	20 (0)	685 (0)	607	1035	285	543	539
2030	7 (0)	1070 (0)	233	1432	517	172	539
2035	22 (0)	985 (0)	21	2007	664	88	539
2040	11 (2)	579 (67)	5	2670	1118	46	539
2045	7 (3.8)	351 (184)	3	3189	1497	11	539
2050	4 (3.5)	295 (229)	2	3477	1619	5	539

Table A.7: Annual generation in Europe by technology in TWh/a for for all scenarios for the year 2050.

	OCGT	CCGT	Coal	Wind	PV	Nuclear	Hydro
Base scenario	4	295	2	3,477	1,619	5	539
RES progressive	6	293	3	3,185	1,856	5	539
RES conservative	2	333	3	3,709	1,365	6	539
PtG conservative	4	263	2	3,461	1,681	6	539
PtG CO2 from air	2	158	1	3,476	1,982	3	539
Batteries conservative 50	8	431	3	4,119	1,225	6	539
Batteries conservative 75	7	401	2	3,993	1,262	6	539
Domestic supply 80%	4	307	2	3,445	1,602	6	539
Domestic supply 100%	4	302	2	3,470	1,595	5	539
Transm. ext +0%	4	365	3	3,407	1,803	6	539
Transm. ext +50%	4	348	2	3,431	1,730	6	539
Transm. ext +100%	4	337	2	3,457	1,670	6	539
Snapshot planning	3	210	0	3,605	1,666	0	539

Table A.8: Cumulative energy storage system discharge power, charge power and energy capacity.

	PHS			Battery			PtG	
	Charge in GW	Discharge in GW	Capacity in GWh	Charge in GW	Discharge in GW	Capacity in GWh	Charge in GW	Capacity in TWh
2020	43	43	345	0	0	0	0	13
2025	43	43	345	0	0	0	0	33
2030	43	43	345	0	0	0	0	57
2035	43	43	345	3	3	21	0	85
2040	43	43	345	118	118	764	67	95
2045	43	43	345	212	212	1,381	206	102
2050	43	43	345	227	227	1,473	261	104

Table A.9: Cumulative energy storage system charge power and energy capacity by 2050 for all scenarios.

	PHS		Battery		PtG	
	Power in GW	Capacity in GWh	Power in GW	Capacity in GWh	Power in GW	Capacity in TWh
Base scenario	43	345	227	1,473	261	104
RES progressive	43	345	248	1,615	248	316
RES conservative	43	345	192	1,250	309	356
PtG conservative	43	345	263	1,706	174	248
PtG CO2 from air	43	345	396	2,573	92	90
Batteries conservative 50	43	345	0	0	415	325
Batteries conservative 75	43	345	43	277	378	482
Domestic supply 80%	43	345	220	1,431	271	106
Domestic supply 100%	43	345	221	1,435	263	671
Transm. ext +0%	43	345	258	1,678	355	806
Transm. ext +50%	43	345	246	1,602	331	585
Transm. ext +100%	43	345	236	1,535	314	497
Snapshot planning	43	345	260	1,688	168	13

Table A.10: Transmission capacity for 2050 in the *base scenario*

From	To	Capacity in GW
Poland	Czech Republic & Slovakia	6.00
Norway	Sweden	6.91
Iberia	France	7.00
France	Benelux	6.68
France	Germany	5.53
France	Alpine region	6.00
France	Italy	7.00
Benelux	Germany	6.00
Germany	Alpine region	6.00
Germany	Poland	6.00
Germany	Czech Republic & Slovakia	5.20
Denmark	Norway	6.68
Denmark	Sweden	6.14
Germany	Denmark	7.00
Finland	Baltic region	7.00
Alpine region	Italy	6.00
Italy	Western Balkans	5.99
Italy	Southern Balkans	4.52
Alpine region	Western Balkans	5.07
Alpine region	Czech Republic & Slovakia	5.53
Alpine region	Hungary & Romania	4.00
Czech Republic & Slovakia	Hungary & Romania	5.15
Hungary & Romania	Western Balkans	3.00
Hungary & Romania	Eastern Balkans	3.73
Southern Balkans	Eastern Balkans	6.00
Western Balkans	Eastern Balkans	3.00
Western Balkans	Southern Balkans	5.00
Great Britain	France	7.00
Sweden	Finland	7.00
Sweden	Poland	7.00
Germany	Sweden	5.76

Table A.11: Usage of the transmission system: net electricity exchange and transmitted electricity by 2050 given in TWh/a. Positive numbers represent terawatts supplied to other regions. The relative net transmission is given as percentage value relative to the regional electricity demand.

	Electricity exports in TWh/a	Electricity imports in TWh/a	Net exchange in TWh/a	...in %	Pass through in TWh/a
Southern Balkans	69.1	1.8	67.4	58.7	23.0
Denmark	67.4	4.6	62.7	129.4	29.3
Norway	52.2	0.3	51.9	36.5	20.8
France	85.1	48.0	37.1	6.4	40.3
Baltic region	23.9	1.7	22.2	63.9	0
Italy	45.9	27.8	18.1	3.3	22.4
Poland	43.0	31.8	11.2	5.7	24.5
Great Britain	30.1	19.6	10.5	2.1	0
Iberia	23.7	20.7	3.0	0.6	0
Benelux	30.6	32.4	-1.8	-0.7	28.6
Hungary & Romania	11.8	19.1	-7.4	-5.8	14.9
Czech Republic & Slovakia	21.1	31.0	-9.9	-7.0	20.1
Germany	24.7	41.7	-17.0	-2.9	40.6
Eastern Balkans	2.3	28.6	-26.3	-26.4	0
Alpine region	9.3	39.2	-29.9	-19.1	25.1
Finland	5.3	37.2	-31.9	-27.6	15.8
Western Balkans	0.2	35.2	-34.9	-42.1	13.6
Sweden	0.1	79.2	-79.1	-44.0	26.8

Table A.12: Electricity losses and excess electricity along the decarbonization pathway.

Year	Transmission	Batteries	PHS	PtG	Curtailment
2020	13	0	15	0	5
2025	12	0	9	0	42
2030	21	0	12	0	128
2035	26	2	24	0	308
2040	27	67	27	166	489
2045	37	120	28	447	492
2050	46	128	27	547	512

Table A.13: Levelized cost of electricity disaggregated by fractions of each technology in ct €/kWh.

Year	Transmission	PV	Hydro	Wind	Batteries	PHS	CCGT	Coal	Nuclear	OCGT	PtG
2020	0.074	0.242	1.160	0.825	0.000	0.197	0.547	1.159	1.959	0.210	0.000
2025	0.089	0.575	1.110	1.537	0.000	0.189	1.162	0.822	1.164	0.207	0.000
2030	0.111	0.966	1.063	2.056	0.000	0.181	1.771	0.604	0.387	0.145	0.000
2035	0.134	1.201	1.022	2.909	0.013	0.174	1.675	0.478	0.218	0.138	0.000
2040	0.106	1.863	0.983	3.903	0.467	0.167	1.060	0.441	0.119	0.072	0.061
2045	0.129	2.374	0.946	4.468	0.811	0.161	0.594	0.341	0.027	0.050	0.168
2050	0.150	2.410	0.911	4.682	0.833	0.155	0.482	0.328	0.014	0.030	0.202

Table A.14: Investment needs for each planning period along the decarbonization pathway in bn. €.

Year	Batteries	CCGT	OCGT	Coal	Wind	PV	PtG	Hydro	PHS	Nuclear	Transmission
2020	0	0	6	168	90	0	0	0	0	0	0
2025	0	18	11	0	251	116	0	0	0	0	0
2030	0	67	0	0	227	144	0	0	0	0	0
2035	4	50	0	0	375	112	0	0	0	0	0
2040	128	10	0	0	446	318	20	0	0	0	0
2045	110	37	0	0	347	220	37	0	0	0	0
2050	144	7	0	0	385	158	14	0	0	0	0