Balancing Reserve Provision in a Decarbonized Electricity Sector

A Model-Based Analysis of Upcoming Challenges and Opportunities

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Zusammenfassung

Diese Dissertation analysiert die Chancen und Herausforderungen bei der Regelleistungsbereitstellung im dekarbonisierten Stromsektor mit Hilfe von Stromsektormodellen. Der erste Teil konzentriert sich auf mögliche Dekarbonisierungspfade für den Elektrizitätssektor. Dazu wird das dynamische Investitions- und Kraftwerkeinsatzmodell (dynELMOD) für Europa entwickelt, welches Investitionen in konventionelle und erneuerbare Erzeugungstechnologien, Speicherkapazitäten und grenzüberschreitende Kapazitäten im Stromnetz erlaubt. Es wird dabei von einem Emissionspfad eingeschränkt, welcher eine nahezu vollständige Dekarbonisierung erreicht. Die Modellergebnisse zeigen, dass im Jahre 2050 erneuerbare Energien den Großteil der Stromproduktion in Europa ausmachen werden und gleichzeitig ein Ausstieg aus der Kernenergie und fossile Brennstoffen erfolgt. Im darauf folgenden Kapitel wird dynELMOD angewendet, um die Implikationen unterschiedlicher Annahmen zur Voraussicht der Akteure auf dem Transformationspfad zu analysieren. Die Ergebnisse zeigen, dass ein hohes Risiko besteht, dass Investitionen "gestrandet" sind, wenn bei den Akteuren nicht von Anfang an ein Glaube an ein striktes Emissionsziel besteht.

Der zweite Teil konzentriert sich auf die Implikationen eines dekarbonisierten Kraftwerksportfolios auf die Regelleistungsbereitstellung. In einem ersten Schritt wird das Kraftwerkseinsatzmodell (ELMOD-MIP) entwickelt, welches es erlaubt, detaillierte Flexibilitätseinschränkungen der Kraftwerke und der Regelleistungsbereitstellung abzubilden. Analysiert wird der Einfluss eines sich wandelnden Kraftwerkportfolios auf Regelleistungspreise in Deutschland bis zum Jahre 2025 unter Berücksichtigung möglicher Regelleistungsbereitstellung durch Windkraftanlagen. Die Ergebnisse zeigen Preissteigerungen, falls keine Beteiligung von Windkraftanlagen an der Regelleistungsbereitstellung angenommen wird. Mit einer Beteiligung von zehn Prozent der Windkraftanlagen können die Regelleistungskosten um bis zu 40% reduziert werden. Das darauffolgende Kapitel untersucht verschiedene Ausprägungen grenzüberschreitender Kooperationen bei der Regelleistungsbereitstellung in Deutschland, Schweiz und Österreich. ELMOD-MIP wird erweitert, um den Austausch von Regelleistung und Regelenergie abzubilden. Die Modellergebnisse bestätigen, dass eine verstärkte Kooperation bei der Regelleistungsbereitstellung vorteilhaft ist; die Kosteneinsparungen jedoch stark vom Grad der Kooperation und den Kraftwerksportfolios der teilnehmenden Länder abhängig sind. Das letzte Kapitel erweitert die Diskussion um eine langfristige Betrachtung der Regelleistungsbereitstellung im Jahre 2050 und analysiert dazu zukünftige Entwicklungen auf Regelleistungsmärkten. DynELMOD wird erweitert um die Entwicklung der Regelleistungsbereitstellung und den Einfluss von hohen Anteilen von erneuerbaren Energien darauf zu analysieren. Die Ergebnisse zeigen, dass die Kosten für Regelleistungsbereitstellung für ein rein erneuerbares Elektrizitätssystem im Jahre 2050 gegenüber heute nicht ansteigen müssen. Lediglich für Ausnahmesituationen sind zusätzliche Investitionen in Speicherkapazitäten notwendig.

Stichwörter: Stromsektor, Investitionsmodell, Dekarbonisierung, Energiewernde, Transformationspfad, Regelleistung, Regelenergie, Open Source, Regionale Kooperation.

Abstract

This dissertation analyzes the future balancing reserve provision in a decarbonized electricity sector and therefore develops and applies electricity sector models.

The first part focuses on the pathways for a decarbonization of the electricity sector. It starts with the development of the dynamic investment and dispatch electricity model (dynELMOD) for Europe. The model decides upon investments into conventional and renewable power plants, storage capacities and the electricity grid, constrained by an emission path, that reaches almost complete decarbonization. The model results show, that until 2050 renewable energy sources will provide the majority of the electricity generation in Europe and nuclear energy and fossil fuels are phased out gradually. In the following chapter dynELMOD is applied to analyze the implications of different assumptions on the foresight of the actors, such as perfect foresight, myopic foresight, and a budgetary approach on the transformation pathway. The results reveal insights into the potential of stranded assets when future tightening of the emission target are not considered by the actors.

The second part focuses on the implications of a decarbonized generation portfolio for balancing reserve provision. It begins with a development of the unit-commitment model (ELMOD-MIP), which allows for a detailed depiction of power plant flexibility constraints and balancing capacity reservation. The model is used to analyze the influence of a changing power plant portfolio on prices and allocation of balancing reserves in Germany until 2025. Furthermore, the influence of wind power providing positive and negative reserves is analyzed. The results show a price increase, in case no new market participants are allowed to enter the balancing market. The participation of up to ten percent of wind turbines can reduce the cost for balancing provision by up to 40 %. The following chapter expands the analysis towards different degrees of cross-border cooperation within balancing reserves in the region of Austria, Germany and Switzerland. ELMOD-MIP is extended to represent cross-border interaction of balancing reserves provision and applied to scenarios with differing levels of cooperation. The model results confirms that increased cooperation in balancing markets is highly beneficial; still the degree of cost savings depends highly on the depth of cooperation and the countries' different power plant portfolios. The last chapter expands the discussion of balancing reserve provision to the long-term perspective of 2050. Possible developments in balancing reserve provision are assessed and transformed into quantitative scenarios. An enhanced version of dynELMOD is used to analyze the these developments and the influence of high renewable-shares jointly. The results show that balancing reserve cost can be kept at current levels for a renewable electricity system until 2050. Only rarely, additional storage investments are required for balancing reserve provision.

Keywords: Electricity sector, investment model, decarbonization, renewable transformation pathways, balancing reserves, open source, regional cooperation.

Rechtliche Erklärung

Hiermit versichere ich, daß ich die vorliegende Dissertation selbstständig und ohne unzulässige Hilfsmittel verfasst habe. Die verwendeten Quellen sind vollständig im Literaturverzeichnis angegeben. Die Arbeit wurde noch keiner Prüfungsbehörde in gleicher oder ähnlicher Form vorgelegt

Claudio Casimir Lucas Lorenz

Berlin, 28. März 2017

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List of Abbreviations

AC . . . . . . Alternating Current
ACER . . . . Agency for the Cooperation of Energy Regulators
aFRR . . . . . Automatic Frequency Restoration Reserve
BEV . . . . . Battery-Electric Vehicle
BNetzA . . . Federal Network Agency (Bundesnetzagentur)
BRP . . . . . Balancing Responsible Party
BSP . . . . . Balancing Service Provider
CCTS . . . . Carbon Capture, Transport, and Storage
CHP . . . . . Combined Heat and Power
CMOL . . . . Common Merit Order List
CO_2 . . . . . Carbon Dioxide
CoBA . . . . . Coordinated Balancing Area
COP . . . . . Conference of Parties
CSP . . . . . Concentrated Solar Power
CWE . . . . . Central Western Europe
DCLF . . . . Direct-Current Load Flow
DNLP . . . . Discontinuous Non-Linear Program
DSM . . . . . Demand Side Management
DSO . . . . . Distribution System Operator
E/P-Ratio . . Energy to Power Ratio
EC . . . . . . European Commission
EEG . . . . . German Renewable Energy Sources Act
ENTSO-E . . European Network of Transmission System Operators for Electricity
EPEC . . . . Equilibrium Problem with Equilibrium Constraints
EU . . . . . . European Union
EU ETS . . . European Union Emission Trading Scheme
FBMC . . . . Flow-Based Market Coupling
FCR . . . . . Frequency Containment Reserve
FLH . . . . . Full Load Hours
FRR . . . . . Frequency Restoration Reserve

GAMS . . . . General Algebraic Modeling System
GHG . . . . . Greenhouse Gas
HVAC . . . . High Voltage Alternating Current
HVDC . . . . High Voltage Direct Current
IC . . . . Interconnector
IGCC . . . . . International Grid Control Cooperation
IPCC . . . . . Intergovernmental Panel on Climate Change
kW . . . . . . Kilowatt
LIMES . . . . Long-term Investment Model for the Electricity Sector
LP . . . . . . Linear Program
MCP . . . . . Mixed Complementarity Problem
mFRR . . . . Manual Frequency Restoration Reserve
MILP . . . . . Mixed Integer Linear Program
MPEC . . . . Mathematical Problem with Equilibrium Constraints
MW . . . . . Megawatt
NC EB . . . . Network Code on Electricity Balancing
NTC . . . . . Net Transfer Capacity
O&M . . . . . Operation and Maintenance
PC . . . . . . Primary Control
PRIMES . . . Price-Induced Market Equilibrium System
PRL . . . . . Primary Balancing Power (Primärregelleistung)
PSP . . . . . . Pumped Storage Plant
PTDF . . . . Power Transfer Distribution Factor
PV . . . . . . Photovoltaic
QCP . . . . . Quadratically Constrained Program
RES . . . . . Renewable energy sources
RoR . . . . . Run-of-River Power Plants
RR . . . . . . Replacement Reserve
SC . . . . . . Secondary Control
SOAF . . . . Scenario Outlook and Adequacy Forecast
SRL . . . . . . Secondary Balancing Power (Sekundärregelleistung)
TC . . . . . . Tertiary Control
TERRE . . . Trans European Replacement Reserves Exchange
TRL . . . . . Tertiary Balancing Power (Tertiärregelleistung)
TSC . . . . . Total System Cost
TSO . . . . . Transmission System Operator
TWh . . . . . Terawatt-hours
UCM . . . . . Unit Commitment Model
UK . . . . . . United Kingdom

Chapter 1

Introduction

1.1. Motivation and research question

The need to prevent global warming and limit global temperature increase to below than 2 °C above pre-industrial levels is agreed by most governmental and non-governmental institutions and organizations (EC, 2011a; IPCC, 2014; Leader of the G7, 2015; UNFCCC, 2015). Therefore, the necessary reduction of global greenhouse gas (GHG) emissions is one of the most important goals of our current time. Already in the 19thcentury Arrhenius (1896) discovered the effect of carbon dioxide (CO_2) on the atmospheric temperature. In the the 20thcentury computers allowed Manabe and Wetherald (1967) to perform complex versions of Arrhenius's calculations and showed that a doubling of carbon dioxide would result in approximately 2 °C increase in global temperature. Still it took until 1980 for scientists to confirm this relationship entirely independent of climate models by analysis of drilled ice cores in the Antarctica (Lorius et al., 1985). To also provide policymakers with regular assessments of the current scientific basis of climate change, the Intergovernmental Panel on Climate Change (IPCC) was established in 1988. The IPCC set the scientific framework for the first conference of parties (COP) Berlin in 1995, which laid the groundwork for the Kyoto Protocol in 1997, the worlds first GHG reduction treaty (UN, 1997).

The reduction of GHG affects all areas and demands a closer look at consumption and production in its entirety. This requires a fundamental transformation in all sectors, with a special focus on the carbon intensive energy sector. The European Union (EU) confirmed this with its Energy Roadmap 2050 that foresees 80–95% GHG emission reduction compared to 1990 according to the technological and economic potential of each sector. For this target, the electricity sector has an important role: it is comparably cheap to decarbonize, provide various technological options, and the transport and heat sector can be decarbonized through it. Therefore, it has the most ambitious decarbonization targets (see Figure 1.1). (EC, 2011b)

Various renewable technology options like wind turbines and photovoltaic (PV) are deployed on a large scale already today. The intermittent feed-in of renewable energy sources (RES) was and is seen by different stakeholders as a barrier for using high shares in a decarbonized electricity system. They urge for the deployment of nuclear power or carbon capture, transport and storage (CCTS) to guarantee security of supply (Sinn, 2016). However, intermittent supply and consumption have always been part of the challenges of the electricity system. Hydro power production was one of the first electricity generation technologies and shows seasonal variations. A historical example of the deviation from planned production is shown in Figure 1.2. In 1943 large rainfalls in Bavaria and Austria lead to an unusual high production from hydro power plants that had to be integrated. The generation from thermal

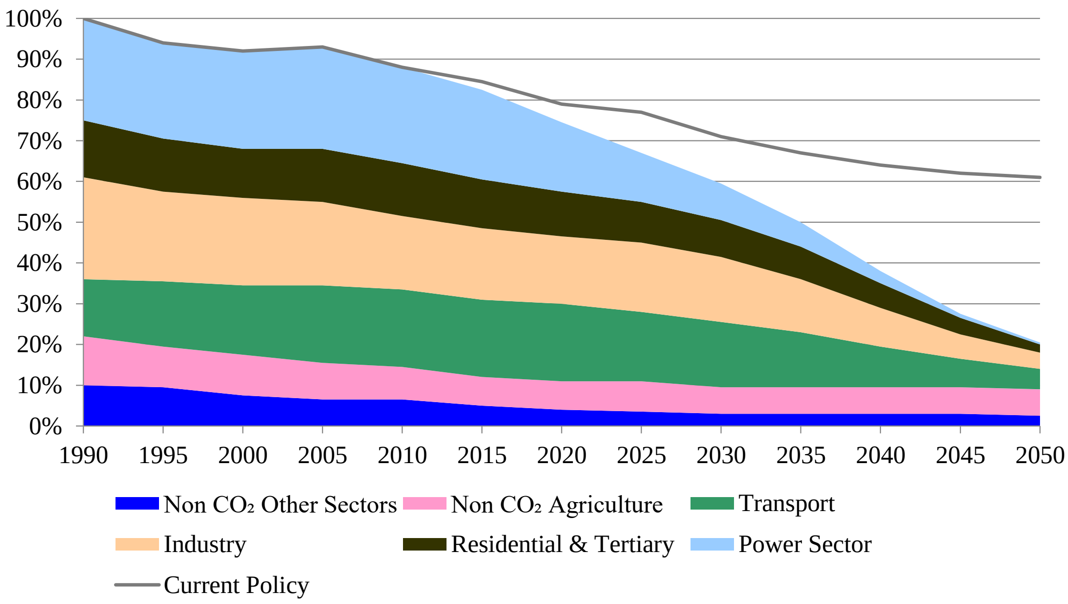


Figure 1.1.: EU GHG emissions towards an 80% domestic reduction (100% =1990)
Source: EC (2011a, p. 5)

power plants was flexible enough to include the unplanned hydro production. (Boll, 1969)

Therefore, there was always a need for excess capacity to provide short and long-term balancing of generation and supply. However, the method how these reserves were allocated and provided changed over time. The power plant dispatch in the synchronous grid of Berlin in 1929 shows an historical example of a pragmatic approach. One out of six power plants generation capacity is permanently reserved, only to provide balancing reserves to balance out generation and supply (see Figure 1.3). Today, balancing reserves are allocated mostly through markets, however the general necessity of balancing reserves remains unchanged.

The electricity system is composed of many elements which allow for a safe and cost-effective supply. Some of these elements are infrastructure such as power plants, transmission grids or substations but also ancillary services like balancing reserves or reactive power provision. Each of these elements is more or less affected by the decarbonization of the electricity system. (Boyle, 2012)

The challenges for the transformation of electricity systems can be split into long term planning and short term operation problems. Planning determines the feasible solution space for system operation and must therefore consider the operational constraints during system design. In this thesis I will look at both aspects: investments into the generation portfolio as part of the planning problem and balancing reserve provision as part of the operational problem. The decision upon a generation portfolio sets the framework conditions for the possibilities of reserve provision. However, as

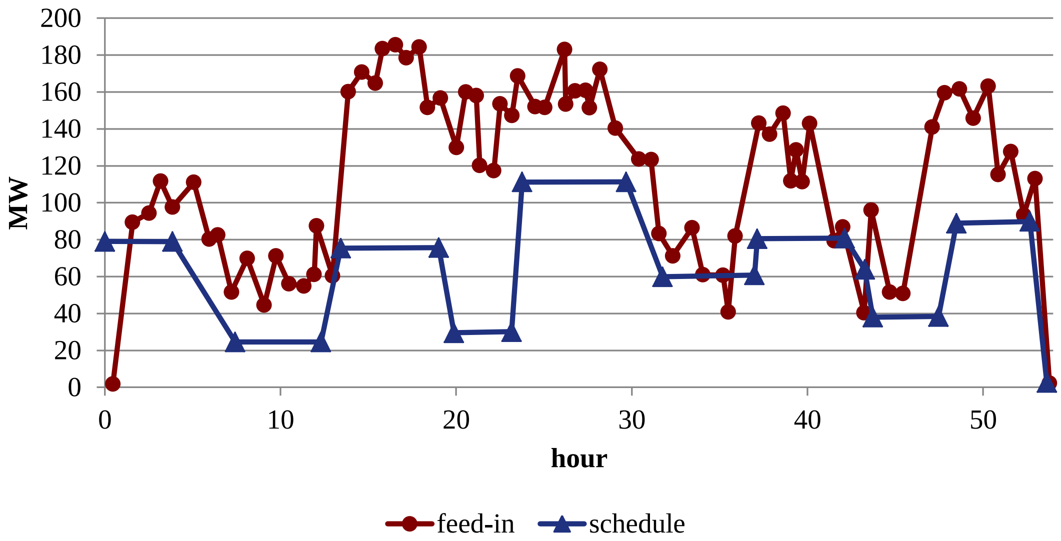


Figure 1.2.: Production schedule and generation of hydro power plants in Bavaria in 1943
Source: own depiction based on Boll (1969, p. 95)

reserves are necessary for reliable system operation, their requirements and constraints can influence the optimal generation portfolio.

This dissertation analyzes the challenges for the transformation of the electricity system applying two research questions:

- What are/determines the cost-effective pathways towards a decarbonized electricity generation until 2050? What is the influence of myopic behavior on investments? What is the influence of balancing reserve provision on the optimal electricity generation portfolio?
- What are the challenges for balancing reserve provision within a decarbonized electricity generation portfolio? Which possibilities are there for adapting the balancing reserve provision to the new framework conditions? What are the benefits of increased cross-border cooperation between balancing markets?

1.2. Pathways towards a decarbonized electricity sector in Europe

The target the European electricity has to reach, is defined: an EU-wide reduction of CO_2 emissions by up to 95% until 2050. However, the pathway to reach this target is still in discussion.

According to EU law, every member state has the sovereignty to decide upon their electricity mix (Szabo, 2016). Every member state favors a more or less individual

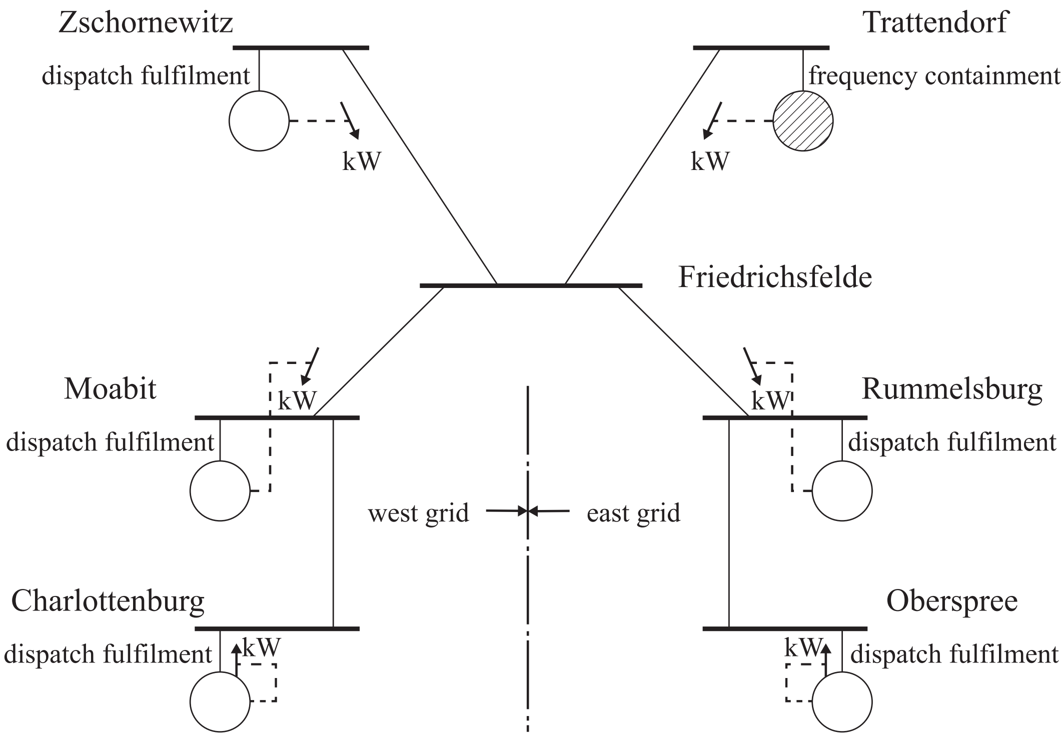


Figure 1.3.: Network diagram of coupled west and east Berlin electricity grid in 1929
Source: own depiction based on Boll (1969, p. 98)

decarbonization pathway for the electricity sector and it is these specific pathways that show the big differences between countries. While some of them rely on nuclear electricity generation (e.g. France or UK), others countries have chosen RES as their main technology for decarbonization (e.g. Germany or Denmark). At the same time, other countries seem to still expect CCTS to become a game changer (e.g. Poland). Why are those pathways so different between the countries? On one hand, for each country there is a specific interplay between different technologies and their generation and installation potential. On the other hand, the influence of the existing industry and sometimes even military interests towards a future generation portfolio can vary for each country.

Besides the different preferences of member states towards a decarbonization pathway, the scientific community also does not agree upon one transformation pathway: while for some studies nuclear electricity generation is paramount for a reliable and decarbonized electricity supply (Capros et al., 2012a,b), other studies see no problem for a 100% renewable electricity supply that is balanced out by storage and exchange capacities (Haller et al., 2012). Other studies forecast a continuation of using fossil fuels and storing their emissions under ground with the help of CCTS (Jägemann et al., 2013). Why do the studies reach such different results? Assumptions on costs and technological development are driving the results to a very large extent. However, the methodology and the model configuration can influence of the results.

1.2.1. Influence of boundary conditions

The future investment cost for generation technologies is the main drive of the resulting transformation pathway, hence these input parameters are heavily discussed. Still, assumptions regarding full load hours (FLH), variable and fixed cost, fuel cost and lifespan must also be included. In general, the future investment cost for all generation technologies are uncertain, still the degree of uncertainty is different.

Current cost for fossil and hydro fueled power plants can be estimated relatively well, due to their large scale application. Their future costs are mainly dependent on resource and labor cost developments and therefore the possible investment cost range is relatively small (Schröder et al., 2013). For CCTS this picture is more complicated: public resistance and price drops for RES have reduced the political support on this technology. Over the last three years the number of operating projects has not increased and remains very low with a total number of 15 projects world-wide. This is also represented by the CO_2 capture capacity that is expected to increase in the next five years by less than 10% (despite already being on a very low level of 40Mt CO_2 per year) (GCCSI, 2015).

For nuclear power plants the situation is more complex. Despite their large-scale application around the world, costs increased over time. Economies of scales did not apply due to individual designs for a small numbers nuclear power plants, while the technical safety requirements became more and more strict. This led to large construction delays which in return led to further increased safety requirements. The delay and cost explosions are also observable at the newest generation of nuclear power plants that are being and which should finally allow for economies of scale. As these expectations are quite questionable, the investment cost forecasts are very diverse. In addition many studies neglect the cost for power plant dismantling and waste disposal, which can go up to 15% of the investment cost. (Schneider et al., 2016)

The large scale deployment of fluctuating RES started only ten years ago (for PV) or twenty years ago (for wind onshore). Learning rates (especially for PV) were very steep and investment cost decreased much faster than expected. The question remains, if these learning rates will continue to be so high. As a comparison, concentrated solar power (CSP) and wind offshore did have lower investment cost drops as expected. (Strupeit and Neij, 2017)

Battery storage recently entered largescale applications and shows very high learning rates. Current market development shows faster investment cost reductions than forecasted and the possible development is therefore often compared to PV. Nevertheless it is not clear if the economies of scale and the high learning rates can be realized in the long term (Nykvist and Nilsson, 2015). Power-to-Gas or Power-to-Hydrogen are currently not applied nor available at large scale and cost developments are therefore highly uncertain.

1.2.2. Influence of model characteristics

Aside from the assumptions regarding the development of future cost, the applied model and its characteristics have an important impact on results. These implications have to be kept in mind, when comparing different decarbonization pathways.

Differentiation must be made between energy system models covering various sectors (e.g. electricity, heat, transport) and electricity sector models. Energy system models include the interactions between all sectors endogenously and allow to analyze resulting interdependencies (Kemfert, 2002). In order to allow for this large scope, each sector can only be depicted with few details.(Ventosa et al., 2005)

For a more thorough analysis, sector specific investment models are necessary. Large scale investment models for the electricity sector are commonly formulated as linear program (LP), quadratically constrained program (QCP) or mixed integer linear program (MILP), depending on the modeled functions and constraints included. Investment models can also be formulated as mixed complementarity problem (MCP) and mathematical problem with equilibrium constraints (MPEC) or even equilibrium problems with equilibrium constraints (EPEC) which allows to approximate strategic behavior of market participants. However, due to computational complexity they can not be used at large-scale and are focused on game theoretical applications (Gabriel et al., 2012).

When formulating the model as a MILP, it is possible to include detailed flexibility constraints with binary and integer variables. For investment models, it allows to reproduce the integer character of investments into generation of transmission assets. Binary and integer variables increase the solution time significantly. Solution time can be reduced partly by the application of decomposition methods (e.g. benders decomposition). With the help of a QCP, a linear demand function can be integrated and production and consumer rents can be determined. Model formulation as a LP limits constraint formulation but yields the fastest calculation times and therefore allows for a very large-scale applicability.

Besides the mathematical problem types, electricity sector models can be divided as deterministic or stochastic models. In the deterministic setting, no input parameters are subject to uncertainty. A stochastic model structure allows to include uncertainty about the future realization of the input parameters. Stochastic parameters in investment models are typically future cost developments or different time series. The inclusion of stochastic parameters leads to results which are less sensitive to variation of input parameters. (Conejo et al., 2016)

Apart from the chosen model, structure and features, the resolution of the model has a big impact on the possible detail level. Two categories of model resolution can be differentiated: temporal and spatial resolution.

The spatial resolution influences the possible detail level regarding transmission grid, RES potentials and time series. The resolution can go from a single node per substation up to one node representing one region of several countries. With a high spatial resolution, the electricity flows and transmission capacity can be analyzed line sharp. Additionally, installation potentials and FLH can be specified in order to allow a more realistic approximation of different spatial potentials. Furthermore locally differentiated demand and RES time series can be used, that could balance each other out, when distributed over a transmission grid; therefore, a steadier production or demand of electricity generation can be generated.

Depending on the spatial resolution, different accuracy levels for the approximation of electricity flows are appropriate. At a country resolution, a transport model normally provides sufficient approximation of electricity flows. However, power transfer distribution factors (PTDFs) can improve the results for the endogenous line investments (compare Section 2.6.4). When including a high resolution of one node per substation, a PTDF or direct-current load flow (DCLF)-approach, that accounts for loop-flows, is commonly used.(Latorre et al., 2003)

The temporal resolution determines the variability that is taken into account by the model and largely influences the calculation time. For investment models two factors determine the temporal resolution: the number of time steps (e.g. the number of years) and the number of time slices per time step (e.g. the number of hours per year). When not all time slices of a time step can be included (e.g. less than 8760 hourly time slices for a time step of a year), the full variability is not represented. Therefore, a time frame reduction technique should be applied, representing the general characteristics of the full time series but also achieving a continuous time series that captures seasonal variations. A detailed explanation of possible time frame reduction techniques is provided in Section 2.5.

The selection of the appropriate model and its configuration is always dependent on the the application and the research question. No model can include all the necessary details and can still be applicable to a large-scale data set, which is why a large variety of investment models exists A comparison of different investment models is detailed in Section 2.2.

1.3. Balancing reserves within a decarbonized electricity sector

When transforming the electricity system it is important to maintain a high level of security of supply. Different parameters must be kept within a small range in order to have a stable electricity system. One of them is the frequency, which must be kept close to its nominal value of 50 Hz. In Germany, a frequency below 49 Hz would cause load shedding, a further drop to 47.5 Hz would cause all power plants to disconnect automatically and a blackout would result.

A deviation of the frequency is resulting from an imbalance between generation and consumption of electricity. Excess consumption lowers the frequency, while excess generation increases the frequency. To balance out deviations and keep the frequency within limits, generation capacity or consumption is ramped up or down, which had been reserved before. These reserved capacities are called balancing reserves.[1]

Reasons for deviation of generation or consumption from planned schedules are manifold: i) the failure of an element of the power system (generation capacity and transmission assets), ii) the deviation of the realized load from the simplified load profiles that are included in the schedules (so called load noise), iii) the discrete step-shaped schedule, which cannot depict the ramping of consumption and generation (schedule leaps), and iv) the deviation between the forecasted and realized feed-in of fluctuating RES. (ENTSO-E, 2013b)

1.3.1. Types and allocation methods of balancing reseres

Balancing reserves are differentiated into three types depending on their response time, activation order and area. The classification varies between electricity systems and countries. The European Network of Transmission System Operators for Electricity (ENTSO-E) differentiates between frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), manual frequency restoration reserve (mFRR) and replacement reserve (RR). Figure 1.4 shows the activation procedure for balancing reserves. In the event of a deviation from the frequency, FCR are activated within seconds. The activation is triggered automatically by the frequency deviation and occurs over the entire synchronous area. Hence, all reserves are activated on a pro-rata approach. To free up the FCR for further incidents, the frequency restoration reserve (FRR) is activated to restore the balance within the control zone of a transmission system operator (TSO). FRR can be activated automatically (aFRR) or manually

[1] In the literature, different terms like balancing reserves, balancing capacity, control power, control energy are used. We will use the terms balancing reserves, balancing power and balancing energy which are used by ENTSO-E (2013a).

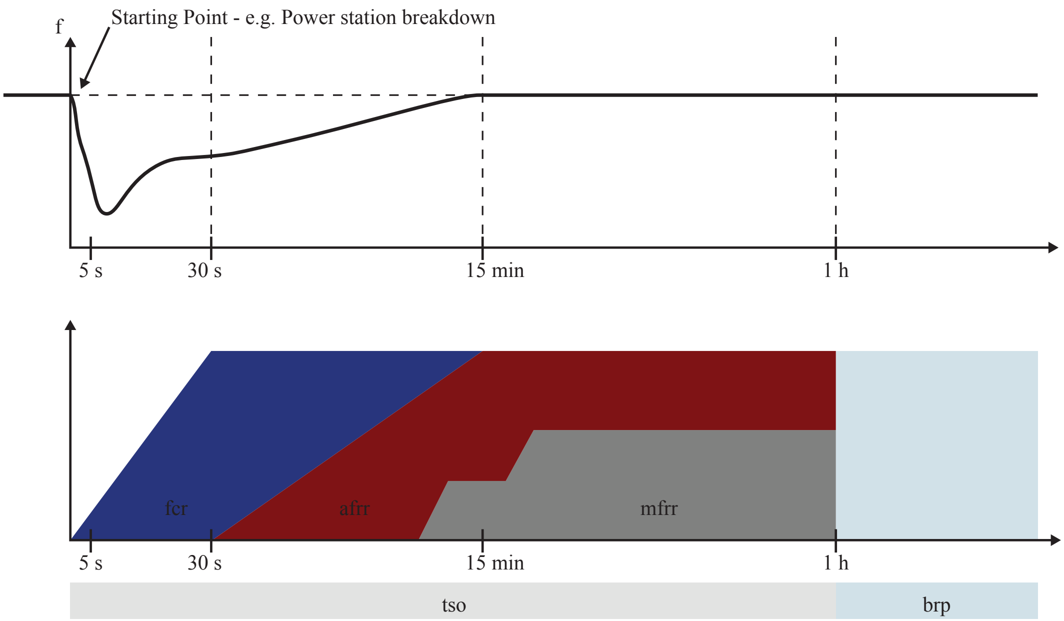


Figure 1.4.: Balancing reserve types and activation sequence

(mFRR). Their dispatch depends on the so called "area control error", which is defined as the difference between the planned and realized electricity exchange of a control zone. The activation of FRR can be based on a merit-order list or on a pro-rata basis, depending on TSO specific regulations. RR are used to relieve or support the FRR after activation, but are not employed in all countries. (ENTSO-E, 2013a)

While the products are clearly defined by the ENTSO-E there are big differences between countries regarding allocation, price settlement, cost recovery and imbalance settlement rules. The country specific regulations differ by: i) allocation of balancing reserves via auctions or obligations, ii) FCR, FRR and RR bids including or excluding the activation cost, iii) FCR, FRR and RR bids containing the same or separate price for the reservation and activation, iv) scoring rule for the auctions includes either the reservation bid or also the activation bid, v) gate closure time for the auctions and the necessary provision times for the balancing reserves of each balancing product, vi) cost for the provision of the reserves are covered by the grid users, the balancing responsible party (BRP) or by both, vii) cost for the activation of the reserves are covered by the grid users, the BRP or by both, and viii) imbalance settlement price charged to BRP can be the same (single pricing) or differentiated (dual pricing) for positive and negative imbalances. (ENTSO-E, 2012) These country specific regulations should be partly harmonized with the Network Code on Electricity Balancing (NC EB), described later in this chapter.

1.3.2. Cost components and drivers for balancing reserve provision

The cost for the provision of balancing reserves can be split into three different components: first, every unit that reserves part of its capacity for positive reserves faces the opportunity cost of not being able to use this capacity for electricity generation. The opportunity cost is dependent on the price difference between the current market price and the marginal generation cost of a power plant. Also, if the power plant has a minimum generation level and the price difference is negative, must-run costs occur for positive reserves provision, as the profit on the spot market is negative. Similar, negative reserves can be provided at not opportunity cost when the difference is positive, but must run costs occur when the difference is negative. (Müsgens et al., 2014)

Second, power plants have to operate in part-load mode to provide positive reserves. When operating in a part-load, the efficiency is reduced by up to 20% depending on generation technology (Schröder et al., 2013). Therefore, electricity generation cost increase when withholding capacity for balancing reserves.

Third, the provision of balancing reserves reduces flexibility, as the ramping capability must be limited in order to allow fast reserve activation. See Section 4.2.2 for a quantitative description of cost factors.

As the costs for balancing reserve provision are influenced by the generation portfolio, a transformation towards a generation portfolio with large shares of fluctuating RES can have different effects on the balancing reserve costs: first, a reduction of dispatchable generation capacities results in less suppliers of balancing reserves. Second, if the remaining dispatchable generation capacities are generating only during extreme events (due to large RES shares), they cannot provide balancing reserves that require fast response times. Third, the demand for balancing reserves could increase due to the increasing generation from fluctuating RES. Despite the improvements in forecast precision, fluctuating RES are expected to induce additional balancing reserve demand in the long-run. (Hirth and Ziegenhagen, 2015)

1.3.3. Developments in balancing reserve markets

The possible cost increases for balancing reserves due to a transforming generation portfolio could possibly be weighted out by cost savings resulting from developments in the balancing reserves provision. These developments include i) new market participants, ii) intensified cooperation and iii) dynamic reserve sizing.

Historically, only dispatchable power plants were used to provide balancing reserves, but more and more new providers are entering the market. Battery storage and fluctuating RES are some of them. The provision of negative balancing reserves by Wind (on and offshore) is already reality and it is expected to increase in the upcoming years. With increasing hours of excess electricity production, fluctuating RES can also provide positive reserves at no opportunity cost. Besides fluctuating RES, battery storage has also entered the balancing reserve market. Large-scale batteries are already used for the provision of FCR. The rapidly falling battery prices makes it possible that battery storage will also provide FRR in the future. See section 6.2.2 for a detailed analysis.

The Electricity grid within Europe allows not only to exchange electricity but also cooperation between TSOs when it comes to the provision of balancing reserves. Different degrees of cooperation are possible between the participating TSOs characterized by different regulatory and technical complexity. A first option is imbalance netting, that describes the process of netting the positive and negative imbalances between the cooperating control zones. More complex is joint activation of reserves that allows to use a common merit-order list for two or more cooperating balancing zones; however, only the joint procurement of balancing reserves results in a common market. It is only limited by the available transmission capacity for balancing exchanges which, in contrast to the other options, can be determined beforehand. Hence, for such a cooperation, a joint optimization of balancing and spot market interconnector (IC) capacity usage is paramount to set the cost-efficient share between the two markets. Furthermore, a harmonization of the above described and still very diverse allocation - and settlement rules for balancing reserve provision, is necessary for increased cross-border cooperation. To harmonize these rules and regulate possible cooperations, the ENTSO-E formulated the NC EB which foresees arrangements to promote cross-border exchange of balancing services with the objective of lowering overall costs and increasing social welfare. The NC EB entered the comitology process in December 2016, which should enable it to become European law. In March 2017 the NC EB was approved by the member states (EC, 2017). In line with the NC EB, there are eight pilot projects that have realized different forms of cooperation between various TSOs. See section 5.1 for a detailed analysis.

Apart from new market participants and intensified cooperation, the overall demand for balancing reserves is a major cost driver. When determining the size of the necessary balancing reserve, the aim is to dimension the reserves as small as possible in order to reduce the cost for reserving capacity, while still as big as necessary in order to reduce the risk of insufficient reserves and to balance the electricity system. Therefore, the approach and the horizon of reserve sizing methodologies is currently object of discussion. See section 6.2.1 for a detailed analysis.

1.3.4. Analyzing balancing reserves in electricity sector models

When seeing the high complexity of balancing markets and their various challenges and developments, the question of how they can be jointly analyzed arises. One possibility is the usage of electricity sector models, which can differ widely by their scope and detail and will be characterized in the following.

For a quantitative analyze of balancing reserve provision, detailed unit commitment models are common. These models do not include endogenous investments into generation or transmission capacity, but allow an accurate approximation of flexibility constraints. Most models are formulated as MILP, which allow to use binary and integer variables. They also allow the inclusion of minimum generation levels, block sharp power plant status including minimum online and offline times, part-load efficiencies, accurate combined heat and power (CHP) flexibility constraints and minimum bid sizes. Furthermore, these models can be structured as either deterministic or stochastic.

To model the interactions between spot and balancing markets, the markets are optimized jointly with the aim of total system cost (TSC) minimization. Including requirements for the reservation of generation capacity and flexibility for balancing reserves leads to increasing TSC. The effects of generation capacity reservation is furthermore dependent on the consideration of portfolios and minimum provision times for balancing reserves. In most countries, the minimum provision time for balancing reserves is more than one hour. If the balancing reserves were provided by power plants individually, this would increase the cost for balancing reservation compared to a provision of single hours. Therefore, in reality, balancing reserves bids are made by power plant portfolios which allow internal hourly (or even quarter-hourly) re-optimization of the reserve commitment. This is why it only makes sense to add minimum provision times in the model when portfolios are also included; both factors significantly increase the calculation time of the model. However, for large portfolios a minimum provision time is not a restriction, as they have large re-optimization options; in this case, including large portfolios would lead to similar results as if no portfolios and no minimum provision times would be included. (Lorenz et al., 2014)

When analyzing the balancing reserve provision, not only the reservation but also the activation of generation capacities must be considered. From a system perspective, the balancing reserve demand is previously known, while the activation volumes are uncertain. To minimize the TSC when the total activation volume is unknown, probabilities for different volumes can be included. Small amounts of balancing reserves are activated for most hours, while large volumes are only seldomly activated.

Thereby, the possible activation cost is considered when deciding upon optimal power plants for balancing reserve provision. See Section 4.2.3 for a detailed discussion.

The possibilities of analysing the interactions between balancing reserve provision and the short-term dispatch decision have been discussed above. This analysis is based on detailed unit-commitment models. However, balancing reserve providence in a long-term investment model has an influence on the investment decisions. Therefore, the interactions between balancing reserve provision and the long-term investment decision must also be analyzed. When assessing the influence of a changing technological or regulatory framework, a pure dispatch model only shows limited effects of changes because the generation portfolio is exogenous and hence can not be influenced. If a combined dispatch and investment model is used, the influence of the framework developments on the generation portfolio is included and the resulting effects of developments can therefore be much bigger. However, a dispatch and investment model only allows for a less detailed approximation of technical and regulatory constraints, because of the high computational complexity of the investment decisions. Still, these models allow to analyze the interactions between different developments in spot and balancing markets on all levels jointly. Therefore, they are especially important in order to analyze interdependencies caused by a full decarbonization of the electricity generation on the balancing markets.

1.4. Thesis overview with contributions and publications

In this doctoral thesis, I develop and apply different electricity sector models in order to analyze the future generation portfolio in Europe and the resulting challenges and opportunities for balancing reserve provision. The doctoral thesis consists of five chapters which have been submitted to or published by academic journals, working papers or conference proceedings. Table 1.1 and Table 1.2 provide an overview of my own contributions and pre-publications.

1.4.1. Two chapters on the future generation portfolio in Europe

On the path to decarbonization in the European electricity sector, the electricity generation portfolio undergoes a significant transformation to a largely renewable and GHG-emissions free system. It is likely that the ambitious climate targets can only be reached when a significant share of electricity production comes from renewables such as wind and solar power, as nuclear power and CCTS technologies might not provide safe and/or feasible options of electricity supply. Chapter 2 presents the large-scale open-source electricity sector model dynELMOD and analyzes future

Table 1.1.: Part 1 chapter overview

Chapter	Pre-publications and own contribution
2. A dynamic investment and dispatch Model (dynELMOD)	This chapter is based on DIW Berlin Data Documentation No. 88 (Gerbaulet and Lorenz, 2017). The model and data are published under an open source license. Previous versions were presented at 14th IAEE European Energy Conference 2014 in Rome, Italy, the 9th Annual Trans-Atlantic Infraday (TAI 2015) in Washington, USA, the 9th Conference on Energy Economics and Technology (ENERDAY 2014), Dresden, Germany, and the 11th International Conference on the European Energy Market (EEM 2014), Krakow, Poland, with a publication as a IEEE Conference Publication (Gerbaulet et al., 2014a). Joint work with Clemens Gerbaulet. Clemens Gerbaulet and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.
3. Scenarios for decarbonizing the European electricity sector	Previous versions were presented at the 10th Annual Trans-Atlantic Infraday (TAI 2016) in Washington, USA, and the 10. Internationale Energiewirtschaftstagung (IEWT 2017) in Vienna, Austria. Joint work with Clemens Gerbaulet, Christian von Hirschhausen, Claudia Kemfert, and Pao-Yu Oei. Clemens Gerbaulet and Casimir Lorenz conducted the model development and analysis; the writing of the manuscript was executed jointly.

electricity generation portfolio options. Scenarios for the decarbonization of the European electricity sector with regards to boundary conditions such as the planners' foresight or the emission target are conducted in Chapter 3.

Chapter 2: A dynamic investment and dispatch Model (dynELMOD)

Chapter 2 presents the open-source electricity sector model dynELMOD. It is a dynamic investment and dispatch model for Europe with the objective of minimizing total system costs before 2050. To do so, the model can decide endogenously upon investments in conventional and renewable power plants, and different storage technologies including demand side management (DSM) and the electricity grid. The investments are determined on a county level in 5-year steps with a variable foresight length. The underlying electricity grid and cross-border interaction between countries is approximated with a flow-based market coupling (FBMC) approach using a PTDF matrix. One of the main constraints of driving investments is an exogenously determined emission path, reaching almost complete decarbonization in 2050. For the investment decisions, a reduced time frame is considered, based on a self-developed time frame reduction technique. Dispatch calculations are done in a subsequent step with a full year to be able to check the system for adequacy. The time frame reduction technique allows to represent the general and seasonal characteristics of an entire year but also to achieve a continuous time series of a day for renewables feed-in and electricity demand.

The model results show that renewable energy sources will provide the majority of the electricity generation in Europe. As production from nuclear energy and fossil fuels is phased out gradually due to high costs and in order to meet the GHG emission targets, the share of renewable generation rises to meet the demand. At the same time with a rising renewables share, especially after 2040, the need for storage capacities increases.

Chapter 3: Scenarios for decarbonizing the European electricity sector

Chapter 3 applies the dynELMOD model to several scenarios of the transformation of the European electricity sector and discusses the implication of different assumptions on the foresight of the actors, such as perfect foresight, myopic foresight and a budgetary approach. The difference in investments into low-carbon technologies with respect to the planners' foresight reveals insights for the potential of stranded assets, which are built under the assumption that the decarbonization is not followed through with. When the emission target (in form of a hard emission constraint in the model) tightens, these previously built capacities cannot produce enough electricity to justify the investment and thus should not have been built at the outset. In the budgetary approach, the model is free to distribute emissions between time steps as long as a total emission budget is not exceeded. This gives insights to a lower cost path of decarbonization in the electricity sector.

1.4.2. Three chapters on the challenges and opportunities for balancing reserve provision

Chapter 4: Wind providing balancing reserves

This chapter analyzes possible price and dispatch developments in the German balancing market of 2025. As the German energy mix might change significantly in the future, the German balancing reserve markets are a good test subject for identifying how the balancing reservation and activation patterns might change. On one hand, the transformation of the generation portfolio towards fluctuating RES will progress widely. On the other hand, not only the infrastructure itself, but the auction design will likely undergo a reformation in order to allow increased market harmonization with neighboring countries and enable new market participants.

Table 1.2.: Part 2 chapter overview

Chapter	Pre-publication and own contribution
4. Wind providing balancing reserves	This chapter is based on DIW Berlin Discussion Paper No. 1655 (Lorenz and Gerbaulet, 2017) and submitted to Applied Energy. Previous version was presented at the 9th Conference on Energy Economics and Technology (ENERDAY 2014), Dresden, Germany. Joint work with Clemens Gerbaulet. Clemens Gerbaulet and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.
5. Options for cross-border balancing reserve provision	This chapter is based on Economics of Energy & Environmental Policy 3(2), 45–60 (Gerbaulet et al., 2014b); DIW Berlin Discussion Paper No. 1400 (Lorenz and Gerbaulet, 2014). Previous versions were presented at the 14th IAEE European Energy Conference 2014 in Rome, Italy, 9th Internationale Energiewirtschaftstagung 2015 in Vienna, Austria, and the 10th Conference on Energy Economics and Technology (ENERDAY 2015), in Dresden, Germany. Joint work with Clemens Gerbaulet. Clemens Gerbaulet and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.
6. Balancing reserves within a decarbonized European electricity system	This chapter is based on DIW Berlin Discussion Paper No. 1656 (Lorenz, 2017) and submitted to Renewable Energy. Previous versions were presented at the 15th IAEE European Energy Conference 2014 in Bergen, Norway, the 11th Conference on Energy Economics and Technology (ENERDAY 2016), in Dresden,Germany, and the 10th Internationale Energiewirtschaftstagung 2017 in Vienna, Austria. Single author paper.

To do this, the chapter introduces the fundamental cost-minimizing electricity sector model ELMOD-MIP. The model includes unit-commitment constraints as minimum load, part-load efficiency, time-dependent start-up restrictions, complex CHP constraints and minimum bid sizes for balancing capacity reservation. Furthermore, the model features a novel approach of modeling balancing reservation by considering activation costs possible already during the reservation phase, mimicking the activation anticipation of market participants. This also allows for the reservation, as well as activation, of negative balancing capacities.

In the future scenarios of 2025, the influence of a changed power plant portfolio on prices and allocation of reserves is analyzed. Furthermore, the influence of wind power as a new market participant for the provision of positive and negative reserves is also discussed.

The application to scenarios of the year 2025 shows an increase of prices for positive and negative reserves, in case no new market participants are allowed to enter the market. With the participation of wind turbines as a new market participant, the cost for balancing provision can be reduced down to 40 %. When wind provides both positive and negative reserves, the high price segment will be mainly reduced. This can be reached already with a relatively low share of wind participation, where wind turbines participate with five percent of the capacity. Therefore, further fostering the process of allowing wind turbines to participate in the German reserve market seems favorable.

Chapter 5: Options for cross-border balancing reserve provision

This chapter expands the analysis of balancing markets towards different degrees of cross-border cooperation in the region of Austria, Germany and Switzerland. The European electricity system undergoes significant changes, not only with respect to developments in generation and networks, but also the arrangements for the operation of the system. These are specified in the Network Codes endorsed by regulators, network operators and the European Commission with the objective to create an "Internal Energy Market." Nevertheless, cooperation on balancing markets is still under development and not as tightly integrated as spot and forward markets. Several factors make cross-border cooperation on balancing markets complex. First, balancing products are not necessarily harmonized in each country. Second, the procurement and activation procedures are implemented differently in most countries. The NC EB by the ENTSO-E should tackle this problem by harmonizing electricity balancing rules. Its objective is to foster cross-border exchange of balancing services and in turn lower overall costs and increase social welfare. The NC EB also arranges for regional cooperation between few parties, to speed up harmonization processes.

This chapter analyzes different forms of cross-border exchanges of balancing reserves with an application to the region of Austria, Germany, and Switzerland. Three scenarios with differing levels of cooperation are tested: *Imbalance Netting*, *Joint Activation* and *Full Cooperation*. The analysis is performed with the help of an extended version of the ELMOD-MIP described in chapter 4. The model is extended to be able to represent cross-border interaction and reservation and activation of balancing reserves within a multi-market environment.

The model results confirm that increased cooperation in balancing markets is highly beneficial and the degree of cost savings depends highly on the depth of cooperation. The *Imbalance Netting* scenario shows only minor cost savings, which can be largely increased by introducing *Joint Activation*. The largest benefits can be gained in the *Full Cooperation* scenario, where not only joint activation but also joint procurement of balancing capacities is conducted. However, this requires the reservation of IC capacity for balancing purposes, which could potentially influence the spot market outcome in a negative way, if too much capacity is reserved. This coordinated procurement and cross-border capacity reservation mostly shifts capacity reservation from Germany towards Austria and Switzerland. These shifts are largely driven by the countries' different power plant portfolios, as run-of-river plants, hydro reservoirs and pumped storage are used to provide balancing capacities.

Chapter 6: Balancing reserves within a decarbonized European electricity system

This chapter expands the discussion of balancing reserve provision to the long-term perspective of 2050. Most pathways for a transformation towards a decarbonized electricity sector rely on very high shares of fluctuating RES until 2050. These shares can be a challenge for the provision of balancing reserves. It is still unclear to what extent the transformation will influence the cost balancing reserve provision. There are various technical and regulatory developments of the balancing framework that influence these costs. So far, only few models allowed for endogenous investment into capacity were used to analyze the effects on balancing reserve provision. Hence, no interdependencies between investments for electricity generation and requirements and framework for balancing reserve provision were analyzed.

In this chapter these developments in balancing reserve provision are discussed and transformed into quantitative scenario assumptions. These scenarios are applied to an enhanced version of dynELMOD (**dyn**amic **El**ectricity **Mod**el), which is presented in Chapter 2 and is extended to include balancing reserve provision. The model is capable of evaluating the effects of possible developments in balancing reserve provision and high shares of fluctuating RES jointly.

The results show that balancing reserve cost can be kept at current levels for a renewable electricity system until 2050, when using a dynamic reserve sizing horizon. Apart from the sizing horizon, storage capacity withholding duration and additional balancing demand from RES are the main driver of balancing costs. RES participation in balancing provision is mainly important for negative reserves, while storages play an important role for the provision of positive reserves. However, only for very few occasions, additional storage investments are required for balancing reserve provision, as most of the time there are sufficient storage capacities available in the electricity system.

1.5. Research outlook

The first part of the dissertation focuses on determining pathways for a decarbonized electricity sector. Future research could focus on broadening the scope of the dynELMOD regarding the better approximation of the interactions with other sectors. For a successful decarbonization of the electricity sector it is important to take into account the influence of the heat and transport sector, as they could increase demand but also provide additional flexibility. In contrast to traditional energy system models, the focus should still be the electricity sector. Therefore, the heat and transport sectors should only be approximated to such an extent that just allows for modeling possible interactions. These interactions are necessary in order to asses flexibility options that are laying outside of the electricity sector. Short-term flexibility can be provided by the transport sector due to battery electric vehicles. The heat sector can provide medium-term flexibility due to the cheaper storability of heat in comparison to electricity. The transformation of electricity to synthetic hydrogen or gas allows for long-term flexibility. On one hand, its production can be stopped without problems (not without cost) and paused as long as needed. On the other hand, synthetic hydrogen or gas can be used for the decarbonization of other sectors. A possible expansion of dynELMOD that would account for the additional flexibility from heat and transport sectors while still maintaining a high level of detail for the electricity sector, would allow for a new perspective on the intensively discussed problem of necessary long-term flexibility options in order to integrate the fluctuating RES cost efficiently.

The second part of the dissertation focuses on the future challenges and opportunities for balancing reserve provision. A future research could focus on analyzing new potentials for balancing reserve provision from coupled sectors. On one hand, the heat sector already provides negative reserves and possibly needs few additional investments. On the other hand, the batteries in electric vehicles can be used to provide positive and negative reserves and, still, transactions cost could be higher. This could be analyzed in the expanded version of dynELMOD with an investment perspective, but also with ELMOD-MIP which allows for a more detailed application, but requires exogenous capacities assumptions.

Future research could also focus on the interplay between transmission grid and balancing reserves. As cross-border cooperation is increasing, also the necessary transmission capacities are becoming more and more important. When sizing reserves jointly, necessary transmission capacity must be withed from the spot market. Therefore, the cost savings on the balancing market due to joint reserve sizing should carefully be evaluated against the losses in the spot markets. The ELMOD-MIP framework could be used, as it allows detailed unit-commitment constraints and DCLF approximations at the same time.

Additionally, future research could focus on the interactions between balancing and intraday markets. The ongoing developments and harmonization of balancing markets could be a chance to align them better to the intraday markets. Adjusted gate closure and provision times for balancing reserve and intraday markets could increase efficiency of both. Last but not least, a more effective intraday market could lead additionally to less balancing reserve demand.

Part I

Pathways towards a decarbonized electricity sector in Europe

Chapter 2

A dynamic investment and dispatch model for the future european Electricity Sector (dynELMOD)

This chapter is based on DIW Berlin Data Documentation No. 88 (Gerbaulet and Lorenz, 2017). The model and data are published under an open source license. Previous versions were presented at 14th IAEE European Energy Conference 2014 in Rome, Italy, the 9th Annual Trans-Atlantic Infraday (TAI 2015) in Washington, USA, the 9th Conference on Energy Economics and Technology (ENERDAY 2014), Dresden, and the 11th International Conference on the European Energy Market (EEM 2014), with a publication as a IEEE Conference Publication (Gerbaulet et al., 2014a). Findings and policy implications of model applications are also published in the DIW Economic Bulletin 41/2015 *Future of nuclear power* (Kemfert et al., 2015), and the DIW Economic Bulletin 44/2016 *Nuclear power in Europe* (Lorenz et al., 2016).

2.1. Introduction

The future development of the European electricity system is intensively discussed with respect to the electricity network as well as the role of electricity generation and storage technologies. Renewable generation is assigned a dominant role with the underlying aim to reduce the carbon intensity of the entire electricity sector. The electricity sector is taking a vanguard role when it comes to decarbonization due to its high greenhouse gas (GHG) reduction potentials and associated costs compared to sectors such as heat and transport. According to the European Commission (EC) "the electricity sector will play a major role in the low carbon economy" (EC, 2011a).

Electricity sector decarbonization also offers the possibility to substitute fossil fuels in transport and heating. In contrast to other sectors many low carbon technologies already exist today such as wind and solar fueled technologies. This is reflected in also in the sectoral decarbonization potentials estimated by the EC (Table 2.1).

This chapter presents the open-source dynamic investment and dispatch model dynELMOD, which provides a tool to determine future pathways of the European electricity system under carbon dioxide (CO_2) emission constraints.

Many stakeholders from science and industry highlight the possibility and necessity of a fully renewable electricity system: the need of a fast switch towards such a system is analyzed in Pfeiffer et al. (2016). They show that no new investments into new GHG-emitting electricity infrastructure can be done after 2017, as these capacities would emit too much CO_2 over their lifetime to still adhere to the 2°C target. This includes the assumption, that other sectors reduce emissions in line with a 2°C target along with the electricity sector. Scenario analyses by Prognos (2014) validate this for Germany by estimating that a power mainly fueled by solar photovoltaic (PV), wind and gas backup capacities has up to 20 percent lower costs than a system containing a combination of gas and nuclear power plants, in which the costs for backup gas power plants are much lower than the cost of the nuclear power plants. Heide et al. (2010) show, that "For a 100% renewable Europe the seasonal optimal mix becomes 55% wind and 45% solar power generation." In this configuration the least amount of storage capacities are required. With a lower renewable penetration, the optimal share of wind decreases and the share of solar increases. The importance of electricity storage technologies will increase, as the amount of electricity generated by fluctuating renewable energy sources (RES) is very likely to increase in the future (see Zerrahn and Schill, 2015a).

Using Germany as an example, Agora Energiewende (2017) shows that a renewable system is cheaper and less dependent on fuel price increases than a fossil based electricity system. Even for renewable shares up to 60% percent the cost of allowing renewables into the electricity system are very low and additional storage capacities

Table 2.1.: GHG reductions and potentials in the European Union

GHG reductions compared to 1990	2005	2030	2050
Total	-7%	-40 to -44%	-79 to -82%
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%

Source: (EC, 2011a, p. 6)

are still not required (Deutsch and Graichen, 2015). Hence, for Germany additional storage capacity seems not to be necessary before 2035, when the development of renewables follows the corridor laid out in the German Renewable Energy Sources Act (EEG, Erneuerbare-Energien-Gesetz). Furthermore, the cost for renewable integration can be reduced due to spatial and technological diversification.

2.1.1. Modeling the European electricity sector

Several approaches exist that examine the future development of the European energy or electricity sector. Widely used methods are simulation and optimization models. The optimization models described in this section can be distinguished according to i) the regional coverage and spatial resolution, ii) the number and resolution of time steps (e.g. years) and whether a myopic or integrated optimization takes place, iii) the number and resolution of considered time slices within a time step, iv) the implemented sectors and model interfaces to other sectors, and v) boundary conditions and targets such as starting the optimization using a brownfield or greenfield approach or decarbonization targets. The actual model implementation is often the product of balancing accuracy in technology or economic representation, spatial and temporal resolution and computational possibilities to keep the model tractable. Connolly et al. (2010) and Després et al. (2015) give further overviews over long-term energy modeling tools and their characteristics.

2.1.2. Transparency and open source models

Traceability and transparency are very important for large-scale models as various assumptions influence the results. Only if all assumptions and data is available model results can be validated and trusted.

Apart from the need to publish all data and models for scientific credibility and transparency there is an ongoing trend to publish the data and models under open source licenses. This allows all stakeholders to base their work upon previous work and to prevents double work within the scientific community. The number of publications under open licenses has been rising in recent years. On the one hand entire models including their data set are published, see Abrell and Kunz (2015), Bussar et al. (2016), Egerer (2016), Howells et al. (2011), SciGRID (2017), Wiese et al. (2014), and Zerrahn and Schill (2015a). On the other hand complete data sets for direct use are provided by Egerer et al. (2014), OPSD (2016), and Schröder et al. (2013). dynELMOD also contributes to this trend, since both source code and all necessary data to reproduce the model results are published parallel to this publication.

The remainder of this chapter is as follows. Section 2.2 gives an overview of the existing model landscape, Section 2.3 discusses the model dynELMOD, methodological considerations of the model implementation and provides the model formulation. In Section 2.4 the data used in this application is described. Section 2.5 provides the methodology of the time-series reduction technique developed for dynELMOD. The Results are provided in Section 2.6. A critical discussion of model limitations is given in Section 2.6.5. Section 2.7 concludes.

2.2. Large variety of investment models

Despite their high complexity, the political relevance of the future development of the power mix in Europe has lead to the existence of several investment models. Models with the focus on Europe are described in this section.

The most well known model is the Price-Induced Market Equilibrium System (PRIMES) model as depicted in Capros et al. (2014, 1998). It is an integrated energy system model, which covers the EU27 European energy system. It provides the basis for the European Commission's scenarios regarding the development of the electricity sector EC (2009, 2011c,d,e, 2013, 2014). Mantzos and Wiesenthal (2016) develop the POTEnCIA (Policy Oriented Tool for Energy and Climate Change Impact Assessment) model for the EC which is in beta phase as of early 2017. It features a hybrid partial equilibrium approach which allows to analyze technology-oriented policies and of those addressing behavioral change. Ludig et al. (2011) introduce the Long-term Investment Model for the Electricity Sector (LIMES), which allows for investment in generation as well as transmission capacities. LIMES has been used to analyze different effects on the German and European electricity system in several studies (see Haller et al., 2012; Ludig et al., 2011; Schmid and Knopf, 2015). In LIMES, the cross-border flow representations interaction is implemented as a transport model. A similar methodology is applied by Pleßmann and Blechinger (2017). They adapt the linear power system model elesplan-m to model the transition of Europe's power system towards renewable energies. The electricity grid is reduced to 18 interconnected European regions using a transport model.

A different methodology regarding the characteristics of transmission networks can be found in applications of the DIMENSION (Dispatch and Investment Model for European Electricity Markets) model (Richter, 2011). To account for loop-flows, two approaches for an extension of the model are implemented in Fürsch et al. (2013) and Hagspiel et al. (2014). Fürsch et al. (2013) use a separate model of the transmission grid, while Hagspiel et al. (2014) integrate a power transfer distribution factor (PTDF)-representation, which is an approximation of flow-based cross-border coupling. Both approaches are solved in an iterative fashion, first optimizing market dispatch and infrastructure development then reviewing the effects of investment on the transmission network until both solutions converge. Applications focusing on renewable development or decarbonization of the European electricity sector until 2050 are EWI and Energynautics (2011) and Jägemann et al. (2013). Spiecker and Weber (2014) analyze the impact of fluctuating renewables on endogenous investment decisions for the European power system. They apply a power system model that allows to include uncertainty in power plant dispatch in the short run depending on the amount of renewable infeed. This allows to assess the impact of stochastic power feed-in on the endogenous investments in power plants and renewable energies. Stigler et al. (2015) introduce ATLANTIS, a European electricity sector model. It includes 29 countries of continental Europe, and a node sharp demand resolution, direct-current load flow (DCLF) calculations and a unit sharp dispatch. The open source Electricity Market Model (EMMA) by Hirth (2015) includes the Northwestern European power market for which its determines power plant investments and linear dispatch decisions. Möst and Fichtner (2010) developed the model PERSEUS-RES-E which optimizes the power plant portfolio for the EU-15 countries within a time horizon until 2030. A well-known open source energy modeling system is OSeMOSYS (Howells et al., 2011). It can be used to evaluate the future development of energy systems. As the time resolution of most applications is very low, the correct representation of flexibility options is challenging. Welsch (2013) includes flexibility constraints in OSeMOSYS, but also uses a limited time slice resolution of 8 hours.

In addition to the partial equilibrium and optimization models mentioned above, simulation models are also frequently used to answer similar questions. These models have the advantage of being able to include various non-linear calculations and constraints but must not necessarily reach an optimal solution, as they use iterative steps or the coupling of different modules to reach a solution. Wiese et al. (2014) have published a fully open source energy system model called renpass (Renewable Energy Pathways Simulation System), which uses a simulation approach to determine cost-efficient portfolios for decarbonized electricity systems.

The model GENESYS (Bussar et al., 2016) also optimizes the European power system, and does – in contrast to most models – not rely on direct mathematical optimization or simulation methods but uses a genetic algorithm.

Coupling a long-term energy system model to a unit commitment model (UCM) is done in Després (2015). Here the POLES model (Prospective Outlook on Long-term Energy Systems) is coupled with a short-term European Unit Commitment And Dispatch model (EUCAD). The dispatch model is not solved for a whole year but for six clustered days. Després et al. (2017) build on this framework and analyze the need for storage as flexibility options in Europe.

2.2.1. Model configuration is crucial

The variety of investment models shows that there can be substantial differences in the configuration of models. These effects are not easily tractable and can not be compared as easy as assumptions regarding input data. Hence, model comparisons as done in the Weyant et al. (2013) are crucial. Also Mai et al. (2015) show that model configurations and assumptions can strongly influence model investment decisions. Mai et al. analyze how model investment decisions depend on model configurations such as different assumptions regarding capacity credit or inclusion of certain model features vary. Kannan and Turton (2013) analyze the impact of increased time resolution in the TIMES model and find that improved temporal resolution greatly improves insights into electricity generation behavior, given the limitations of the TIMES model, as it can not replace a dispatch model. Nicolosi (2011) finds that in model runs with low temporal resolution, the importance of conventional power plants is overstated and that the temporal resolution of such investment and dispatch models significantly influences the result. Pfenninger et al. (2014) also address the challenges of future energy systems modeling and that the increasing complexity of the future electricity systems needs to be represented adequately.

In systems with high demand and feed-in fluctuations, the ramping and startup flexibility of the existing conventional power plant might not be sufficiently represented in linear optimization models. Some papers aim to achieve an improved representation of power plant properties through the implementation of mixed integer linear program (MILP) constraints, at the expense of a drastically higher computational complexity. Poncelet et al. (2014a) lay the groundwork for integrating a unit commitment formulation into investment models, that can (accompanied by a loss in accuracy) also used in a linearized version. The investment model IMRES (de Sisternes, 2013) also includes MILP constraints for thermal units, but is not applied in a long term application.

2.3. The model dynELMOD

dynELMOD (**dyn**amic **El**ectricity **Mod**el) is a dynamic partial equilibrium model of the European electricity sector which determines cost-effective development pathways. It i) decides upon investment in conventional and renewable generation and network capacities for the European electricity system and ii) calculates the dispatch for an entire year based on the investment result, or exogenously given capacity scenarios.

Starting point is the currently available power plant portfolio which will be phased out over time due to its limited technical lifetime. Investments into new generation capacities are done in the light of the decarbonization pathway that determines the remaining CO_2 emissions. The model optimizes the investments in a dynamic way as for each year all upcoming years with their respective CO_2, demand, fuel and investment cost developments are taken into account.

The modeling approach presented in this chapter is comparable to many of the previously described modeling approaches, as it integrates the two decision levels: market dispatch and investment in transmission and generation. It also allows for tackling the problem of loop-flows that occur in alternating current (AC) grids and includes options to limit the model foresight, to implement myopic behavior. Given exogenous scenario targets for certain technologies, it also determines the cost-minimal pathway to reach these scenario targets. Furthermore, it verifies the optimization result in a dispatch model run with 8,760 model hours. When all capacities are given exogenously, it functions as a dispatch model.

dynELMOD is currently applied to a dataset covering every European country in the period from 2015 to 2050 in five-year steps. The geographical resolution is one node per country, 33 European countries are included in the model. This covers five different synchronous areas show in different color in Figure 2.1.[2] In this application, possible points of interconnection with Northern parts of Africa are not taken into account.

2.3.1. Methodology and calculation procedure

In order to reduce complexity we separate the calculation into two steps:

First, the investment decision into power plants and grid is using a reduced time set for the dispatch calculations. Second, the optimized investment decision are fixed and the dispatch is calculated for the entire time set to calculate the final generation and to determine whether an adequate generation portfolio has been found. Both

[2] In this application we consider the high voltage alternating current (HVAC) grids of both Denmark east and Denmark west as part of the continental synchronous area.

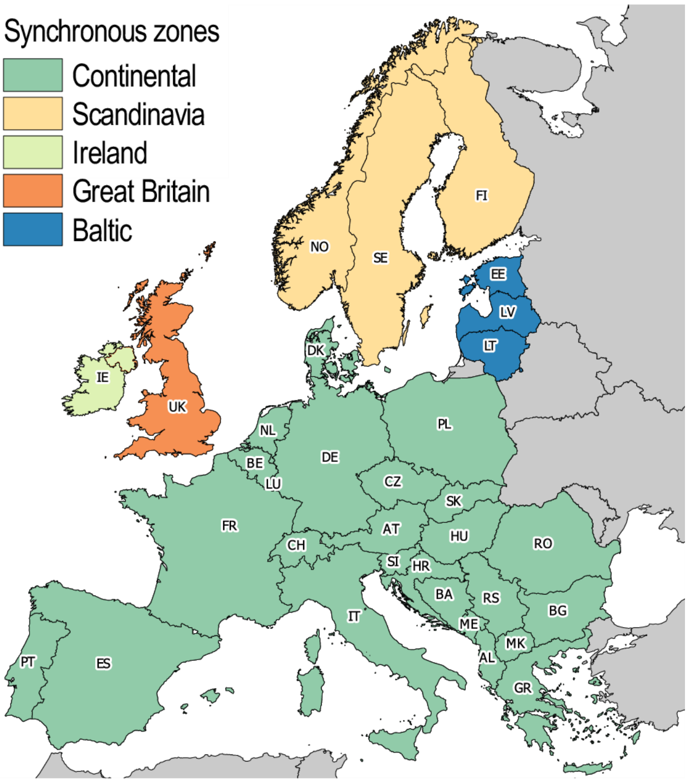


Figure 2.1.: dynELMOD geographical coverage

calculation steps use the same boundary conditions that have been derived from the input parameters.

Figure 2.2 shows an overview of the boundary conditions, calculation procedure and model outcomes and will be explained in the following. The input parameters can be classified into three categories: data about the existing infrastructure, future development assumptions and future constraints which in conjunction form the boundary conditions. The existing data consists of i) the current power plant portfolio which decreases over time as the lifetimes of the power plants are reached, ii) the existing cross-border grid infrastructure and iii) time series for load and RES production. The future developments are characterized by assumptions regarding the change of i) investment and operational cost, ii) fuel cost iii) full load hours (FLH) and iv) load. Constraints limiting the solution space are i) the European wide CO_2 emission limits, ii) regional carbon capture, transport and storage (CCTS) storage availability iii) overall and yearly investment limits and iv) regional fuel availability. Those boundary conditions are then used in both subsequent calculation steps:

1. Investment The objective of this step is to determine investments into electricity generation infrastructure, storage capacities and cross-border grid capacities. To

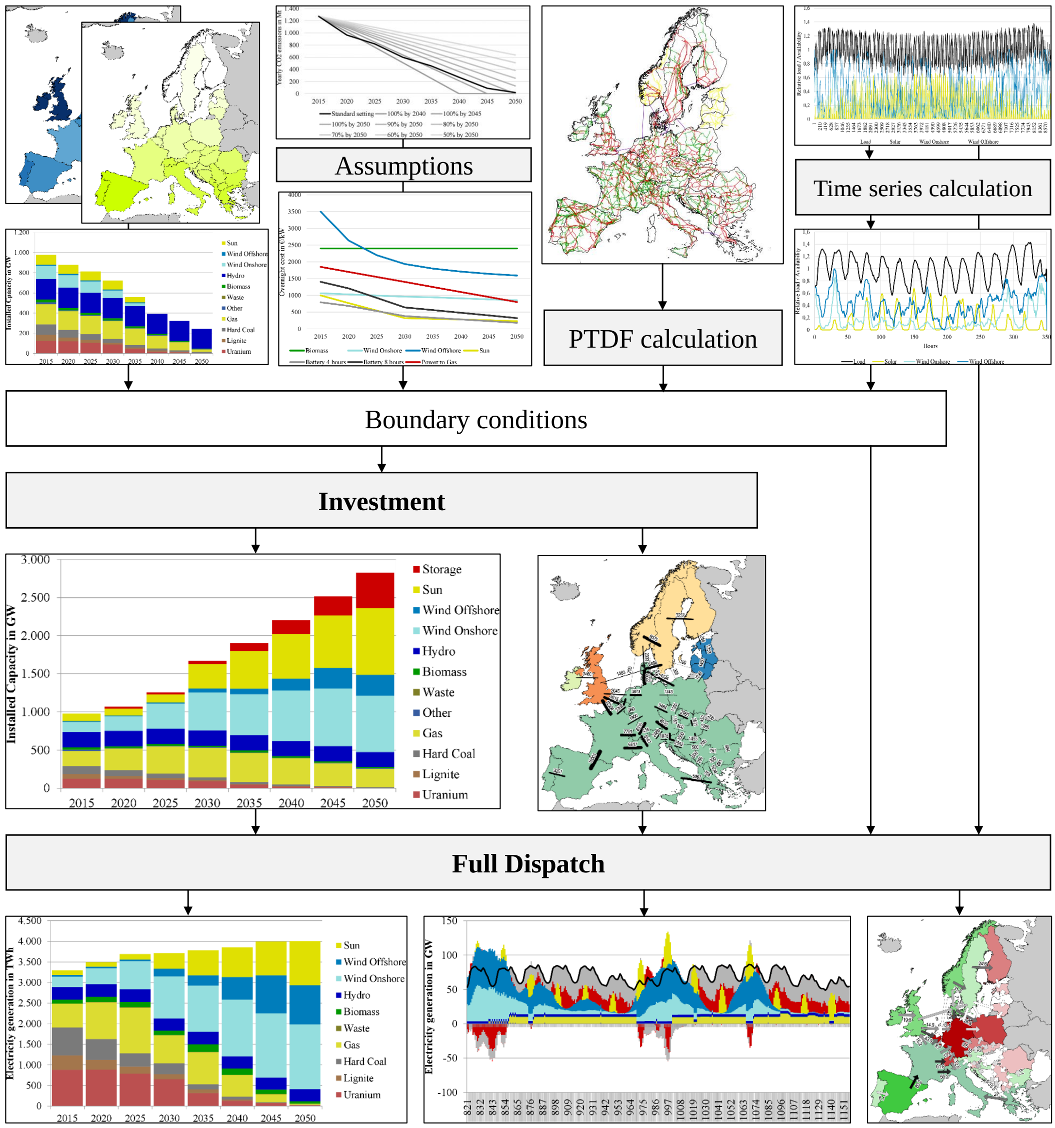


Figure 2.2.: dynELMOD calculation procedure

reduce computation complexity and allow for the representation of a large-scale geographical region we reduce the hours that will be included in the model. Instead of all 8,760 hours of one year, we only use certain hours depended on model complexity. To determine these hours, we apply a time frame reduction technique (see Section 2.5), that covers the characteristics of seasonal and time-of-day variations in the input parameters. With this reduced time frame the cost-minimal investments into the power plant portfolio are determined. In the standard setting, the length of the reduced time frame is 351 hours.

2. Dispatch After calculating the cost-minimal electricity generation portfolio, the model is solved again with the entire time set of 8,760 hours. In this step the investments are fixed. This allows us to test the reliability of the power plant portfolio in a much wider range of cases and to verify that the determined power plant portfolio ensures system adequacy.

Afterwards, the results from both the *investment* and *dispatch* runs are used to generate the model output.

2.3.2. dynELMOD model formulation

The model includes two decision levels, the dispatch and the investment in transmission and generation. These levels are reduced to one level assuming perfect competition and a central planer that minimizes total system cost. The model is formulated as a linear program (LP) consisting of equations (2.1) to (2.34) in the General Algebraic Modeling System (GAMS). It is solved using commercially available solvers such as GUROBI or CPLEX.

Objective function The objective of total system cost *cost* (2.1) include variable cost for generation $cost^{gen}$ (2.2), investment cost for new built generation $cost^{inv}$ (2.3), fixed operation and maintenance cost for existing and new built generation capacity $cost^{cap}$ (2.4), and investment cost for network expansion $cost^{line}$ (2.5). The nomenclature for all sets, variables and parameters can be found in Section B. Variable cost for existing capacity are considered on a block level, whereas new built capacities are aggregated by technology and depend on the commissioning date of the respective generation capacity. In order to ensure a consistent representation of the investment cost, annuities are calculated using a discount rate I^i. Furthermore, all cost components are discounted with the interest rate I^d which results the discount factor DF_y.

$$\min cost = cost^{gen} + cost^{inv} + cost^{cap} + cost^{line} \tag{2.1}$$

$$\begin{aligned} cost^{gen} = & \sum_{co,i,t,y,p} Cvar_{p,co,i,y} * g^{existing}_{p,co,i,t,y} * DF_y \\ & + \sum_{co,i,t,y,yy,yy \le y} Cvar^{newbuilt}_{co,i,y,yy} * g^{newbuilt}_{co,i,t,y,yy} * DF_y \\ & + \sum_{co,i,t,y,yy} Cload_{co,i,y} * (g^{up}_{co,i,t,y} + g^{down}_{co,i,t,y}) * DF_y \end{aligned} \tag{2.2}$$

$$\begin{aligned} cost^{inv} = & \sum_{co,i,y,yy,yy \le y} Cinv_{i,yy} * inv^{cap}_{co,i,yy} * DF_y \\ & + \sum_{co,i,y,yy,yy \le y} Cinv^{stor}_{i,yy} * inv^{stor}_{co,i,yy} * DF_y \end{aligned} \tag{2.3}$$

$$cost^{cap} = \sum_{co,i,y} Cfix_{co,i,y} * (\sum_{p} G^{max}_{p,co,i,y} + \sum_{yy} inv^{cap}_{co,i,yy} + inv^{stor}_{co,i,yy}) * DF_y \tag{2.4}$$

$$cost^{line} = \sum_{yy,co,coo} Cline_{co,i,y} * 0.5 * inv^{line}_{yy,co,cco} * DF_{yy} \tag{2.5}$$

The investment cost in dynELMOD are accounted for on an annuity basis. When investments occur, not the entire cost is accounted for in the year of investment, but the to-be-paid annuities are tracked over the economic life time of the investment, also taking into account the remaining model periods to ensure no distortion due to the end of the model horizon. The tracking of the remaining periods is not shown for clarity.

All equations above are also scaled depending on the length of the time frame t to represent yearly values, if necessary. This ensures a distortion-free representation of all cost-components regardless of the time frame included in the model. Furthermore, the equations (2.2) to (2.5) are scaled with a scaling parameter to ensure similar variable magnitude orders. This helps the solver to achieve fast solution times. In (2.5) the line expansion is multiplied by 0.5 as the investment is tracked on "both sides" of the line.

Market clearing The market is cleared under the constraint that generation has to equal load at all times including imports or exports via the HVAC or high voltage direct current (HVDC) transmission network (2.6). Depending on the grid approach, the equation (2.6) contains either the variables to represent the network using a PTDF and HVDC-lines or, in the case of the net transfer capacity (NTC)-Approach contains the flow variable between countries.

$$\begin{aligned} 0 = {} & Q_{co,t,y} - \sum_{i} g_{co,i,t,y} \\ & \left.\begin{aligned} & + ni_{co,t,y} \\ & + \textstyle\sum_{cco} dcflow_{co,cco,t,y} \\ & - \textstyle\sum_{cco} dcflow_{cco,co,t,y} \end{aligned}\right\} \text{Flow-based approach} \qquad \forall y, co, t \\ & + \textstyle\sum_{cco} flow_{cco,co,t,y} \qquad \Big\} \text{NTC approach} \end{aligned} \tag{2.6}$$

Generation restrictions The conventional generation is differentiated into generation of existing and newbuilt capacity and is constrained by the installed capacity, taking into account an average technology specific availability as defined in (2.8) and (2.9). For non-dispatchable technologies availability is defined for every hour and is calculated during the time series scaling described in Section 2.5. Together with the loading and release from the storage the generation from newbuilt and existing capacities is summed up to a joint generation parameter in equation (2.7). The variable representing the generation from new built capacity is additionally dependent on a second set of years which represent the year when the capacity has been built. The same holds for the variable representing the newbuilt capacity. Equation (6.9) defines the generation of renewable capacities. Here the generation can be less than the available capacity in each hour, without accumulating curtailment cost in the system.

$$g_{co,disp,t,y} = \sum_{p} g^{existing}_{p,co,disp,t,y} + \sum_{yy \leq y} g^{newbuilt}_{co,disp,t,y,yy} + stor^{Release}_{co,i,t,y} - stor^{loading}_{co,i,t,y} \quad \forall co, disp, t, y \tag{2.7}$$

$$g^{existing}_{p,co,disp,t,y} \leq Ava_{co,disp,y} * G^{max}_{p,co,disp,y} \quad \forall p, co, disp, t, y \tag{2.8}$$

$$g^{newbuilt}_{co,disp,t,y,yy} \leq Ava_{co,disp,y} * inv^{cap}_{co,disp,yy} \quad \forall co, disp, t, y, yy \tag{2.9}$$

$$g_{co,ndisp,t,y} \leq \sum_{yy \leq y} ResAva^{newbuilt}_{co,t,ndisp,yy} * inv^{cap}_{co,ndisp,yy} + \sum_{p} ResAva^{existing}_{co,t,ndisp} * G^{max}_{p,co,ndisp,y} \quad \forall co, ndisp, t, y \tag{2.10}$$

Fuel restriction Some fuels (e.g. biomass) face a limitation on their yearly consumption. Therefore the total energy output from this fuel is restricted as defined in (2.11). In scenarios where multiple technologies compete for a fuel (e.g. Biomass and Biomass with CCTS) it also determines an efficient endogenous share between these technologies.

$$\sum_{p,i,t} \frac{g^{existing}_{p,co,i,t,y}}{\eta^{existing}_{p,co,i,y}} + \sum_{i,t,yy \leq y} \frac{g^{newbuilt}_{co,i,t,y,yy}}{\eta^{newbuilt}_{co,disp,yy}} \leq Gen^{max}_{co,f,y} \quad \forall co, f, y \tag{2.11}$$

Combined heat and power The combined heat and power (CHP) constraint is implemented as a minimum run constraint that depends on the type of power plant as well as the outside temperature. Thus $g^{existing}_{p,co,i,t,y}$ has to be equal or greater than $G^{min\_chp}_{p,co,i,t}$. The constraint is only valid for existing power plants as it would have unintended side-effects when also applied to new built technologies. Due to the minimum generation constraint the new built capacities would have to produce and hence emit CO_2. This could potentially violate the emission constraint and thus investment into fossil power plants would not be possible.

$$g^{existing}_{p,co,i,t,y} \geq G^{min\_chp}_{p,co,i,t} \quad \forall co, i, t, y \tag{2.12}$$

Investment restrictions Equations (2.14) and (2.15) limit the maximum investment in conventional generation and storage technologies. The parameter $G^{max\_inv}_{co,c,y}$ is scaled according to the number of years between the time steps to account for a yearly investment limit.

$$g^{instcap}_{co,i,y} = \sum_{p} G^{max}_{p,co,i,y} + Storage^{maxrelease}_{co,i,y} + \sum_{yy \leq y} inv^{cap}_{co,i,yy} \qquad \forall co,i,y \qquad (2.13)$$

$$g^{instcap}_{co,i,y} \leq G^{Max\_installed}_{co,i,y} \qquad \forall co,i,y \qquad (2.14)$$

$$\sum_{co,i} inv^{cap}_{co,i,y} \leq G^{max\_inv}_{co,i,y} \qquad \forall co,i,y \qquad (2.15)$$

Ramping In the model, ramping of technologies is implemented in two ways: On the one hand, for some technology types, the ramping speed is limited. Here equation (2.16) and (2.17) limit the relative rate of generation output change per hour. As this model is applied on an hourly basis, this limitation only applies to a subset of generation technologies (e.g. Lignite). Further, to represent a more economic dispatch behavior regarding ramping, wear and tear of the materials within the power plant as well as additional fuel consumption for ramping are represented using ramping costs. The linear model cannot contain binary or integer variables. Thus, the assumed costs for ramping are slightly higher than in a unit commitment model to account for this model characteristic. The load change cost of ramping does not need to be tracked for each p, as the ramping speeds are tracked on a technology level (2.18).

$$g^{up}_{co,c,t,y} \leq R^{up}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{up}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co,i,t,y \qquad (2.16)$$

$$g^{down}_{co,i,t,y} \leq R^{down}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{down}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co,i,t,y \qquad (2.17)$$

$$g^{up}_{co,i,t,y} - g^{down}_{co,i,t,y} = g_{co,i,t,y} - g_{co,i,t-1,y} \qquad \forall co,i,t,y \qquad (2.18)$$

Emission restrictions In the standard setting, a yearly CO_2 emission limit spanning the entire electricity sector is implemented. The amount of available emissions represents the amount available to the electricity sector. In case a total emission budget spanning the entire model horizon is in place, the emission limit of the first and last model period will still be active. On the one hand, the power plant dispatch in the starting period – where no investments take place – should not be affected by future decisions. On the other hand, the final emission target is also adhered to.

$$\begin{aligned} Emissionlimit_y \geq & \sum_{p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{emission}_{p,co,i,y} \\ & + \sum_{co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{emission,new}_{co,i,yy} \end{aligned} \quad \forall y \tag{2.19}$$

$$\begin{aligned} \sum_{y} Emissionlimit_y \geq & \sum_{y,p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{emission}_{p,co,i,y} \\ & + \sum_{y,co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{emission,new}_{co,i,yy} \end{aligned} \tag{2.20}$$

CCTS As carbon capture and storage plans are implemented as normal generation technologies, additional constraints account for the total amount of CO_2 that can be stored. As we assume that no large-scale carbon transport infrastructure emerges in the future, the captured emissions need to be stored locally within each country. This leads to country-sharp CCTS constraints that are valid for all model periods.

$$\begin{aligned} CCTSStor^{Capacity}_{co} \geq & \sum_{y,p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{sequestration}_{p,co,i,y} \\ & + \sum_{y,co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{sequestration,new}_{co,i,yy} \end{aligned} \quad \forall co \tag{2.21}$$

Storage The operation of storages is constrained in equations (2.22 to 2.26). On the one hand the storage operation is limited by the installed loading and release capacity which can be increased by the model (2.22, 2.23). On the other hand the release and loading is constrained by the current storage level defined in equation (2.24).[3] The storage level in return is limited by minimum and maximum storage levels that can be increased by the model independently from turbine and pump capacity (2.25, 2.26). Therefore the model can decide upon the optimal energy to power ratio (E/P-Ratio).

$$stor^{release}_{co,s,t,y} \leq Ava_{co,s,y} * Storage^{maxrelease}_{co,s,y} + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \quad \forall co, s, t, y \tag{2.22}$$

$$stor^{loading}_{co,s,t,y} \leq Ava_{co,s,y} * Storage^{maxloading}_{co,S,y} + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \quad \forall co, s, t, y \tag{2.23}$$

[3]The storage level in the first modeled hour must equal the storage level in the last modeled hour, to ensure continuity at the end and the start of each year.

$$stor^{level}_{co,s,t,y} = stor^{level}_{co,s,t-1,y} - stor^{Release}_{co,s,t,y} + \eta^{storage}_{co,s,y} * stor^{loading}_{co,s,t,y} + Inflow_{co,s,y,t} \qquad \forall co, s, t, y \tag{2.24}$$

$$stor^{level}_{co,s,t,y} \leq Storage^{maxlevel}_{co,s,y} + \sum_{yy \leq y} inv^{stor}_{co,i,yy} \qquad \forall co, s, t, y \tag{2.25}$$

$$stor^{level}_{co,s,t,y} \geq Storage^{minlevel}_{co,s,y} \qquad \forall co, s, t, y \tag{2.26}$$

Demand-side-management DSM is also expected to increase the flexibility in the electricity system. In dynELMOD we focus on demand side management (DSM) where the total demand remains constant overall but can be delayed several hours. In order to keep the model structure simple, we implement DSM as a storage technology. In addition to the standard storage equations, DSM requires further constraints. Depending on the DSM technology models, usage cost occur, and the maximum hours of load shifting need to be tracked. We implement DSM based on a formulation by Göransson et al. (2014). As DSM uses the storage equations framework as a basis, most of the implementation is reversed compared to the formulation by Göransson et al. (2014). An alternative implementation by Zerrahn and Schill (2015b) would enable a slightly more accurate tracking of demand-shifts, but the computational overhead was too high to include this formulation in the model. In addition to the equations for normal storages DSM are restricted by the equations (2.27 - 2.28). The $stor^{level}_{co,dsm,t,y}$ for all DSM technologies is also tracked to be equal at the beginning and end of the model period.

$$\sum_{tt, tt+dsmratio \geq t, tt \leq t} stor^{Release}_{co,dsm,tt,y} \geq Storage^{maxlevel}_{co,dsm,y} + \sum_{yy \leq y} inv^{stor}_{co,dsm,yy} - stor^{level}_{co,dsm,t,y} \qquad \forall co, dsm, t, y \tag{2.27}$$

$$\sum_{tt, tt \geq t, tt-dsmratio \leq t} stor^{loading}_{co,dsm,tt,y} \geq Storage^{maxlevel}_{co,dsm,y} + \sum_{yy \leq y} inv^{stor}_{co,dsm,yy} - stor^{level}_{co,dsm,t,y} \qquad \forall co, dsm, t, y \tag{2.28}$$

Network restrictions When using the NTC approach, the flow between countries is defined in equation (2.29). The flow between two countries is limited by the available NTC, that can be increased by the model in (2.30) and (2.31) through investments in network infrastructure.

$$flow_{co,cco,t,y} = -\,flow_{cco,co,t,y} \qquad \forall co, cco, t, y \qquad (2.29)$$

$$flow_{co,cco,t,y} \leq NTC_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (2.30)$$

$$flow_{co,cco,t,y} \geq -\,NTC_{co,cco} - \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (2.31)$$

When using the PTDF approach a more complex framework is required. For load flow calculations we use a country-sharp PTDF matrix of the European high-voltage AC grid which is relevant in (2.32). DC-interconnectors are incorporated as well (2.33). Equation (2.34) enforces symmetrical line expansion between countries.

$$\sum_{ccco} PTDF_{co,cco,ccco} * ni_{ccco,t,y} \leq P^{max}_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (2.32)$$

$$dcflow_{co,cco,t,y} \leq Hvdc^{max}_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (2.33)$$

$$inv^{line}_{y,co,cco} = inv^{line}_{y,cco,co} \qquad \forall y, co, cco \qquad (2.34)$$

2.3.3. Model options

dynELMOD can be adjusted regarding the grid approximation or the "planners foresight" depending on the desired analysis, to be able to answer a wide range of questions.

Foresight reduction

In the standard setting, the model is solved for all years in the model with perfect foresight over all optimization periods. To mimic a more myopic behavior, the foresight of the model regarding the upcoming periods can be reduced to limit the anticipation of the planner. The model then assumes that the overall boundary conditions remain constant after the model optimization period ends.

This setting requires iterating over the set of all years included in the model, as the horizon progresses over time. Assuming the foresight period is set to 10 years, the first optimization iteration covers the time steps 2015,[4] 2020, and 2025. In the next step the investments of the year 2015 are fixed. Then the year 2030 is added to the time horizon and the optimization is repeated. Next, the optimizations of 2025 are fixed and the process repeats until the time horizon reaches the final time step.

[4]In the actual model formulation, 2015 is only included as a starting year, the power plant portfolio is not optimized for this year.

CO_2 emission restriction

A further point of discussion regarding the European Union emission trading scheme (EU ETS) is the possibility of banking certificates. Ellerman et al. (2015) show that a rationally behaving agents could minimize their emissions below the given constraint and use the banked allowances once the constraint tightens. This should minimize overall abatement cost. We include this option by replacing the yearly emission constraints by a constraint spanning the whole optimization time frame, thus freely allowing the distribution over the model periods, but keeping the total emissions constraint intact.

Grid approximation

We include the option to represent the transmission grid in our model using two different approaches: A NTC-approach and a flow-based approach using a PTDF-matrix. In both approaches, every country is represented as a single node with interconnection to neighboring countries.

NTC approach Most of the currently applied models use the NTC-approach to approximate electricity flows (Ludig et al., 2011; Richter, 2011). In this setting, the NTC-approach models the grid as a transport model without loop flows. This variant has the advantage of lower computational requirements and corresponding faster calculation times, as well as less required input data compared to the flow-based approach. However, the current developments on the European electricity markets have evolved, as the underlying grid constraints should be reflected in the market. In the Central Western Europe (CWE) region flow-based market coupling has been introduced in 2015. Therefore new long-term models should be able to include flow-based market coupling. The approach in this chapter neglects some specifications of actual flow based market coupling, as neither generation nor load shift keys, which approximate the effect of a change in generation or load in the underlying HVAC grid, are implemented.

Flow-based approach The second option, the PTDF-approach allows for the approximation of flow-based market coupling including loop-flows. This approach is computationally more complex. The calculation of the PTDF requires line-sharp data of the underlying high voltage electricity grid. The country-sharp PTDF is derived from the actual underlying high voltage AC grid of Europe as follows: We determine a node- and line-sharp PTDF based on the inverse of the network susceptance matrix $B_{n,nn}$ and the network transfer matrix $H_{l,n}$. The matrices $B_{n,nn}$ and $H_{l,n}$ are calculated using the approach based on Leuthold et al. (2012). A line- and node-sharp PTDF matrix can then be calculated using (2.35).

$$PTDF_{l,nn} = \sum_{n} H_{l,n} * B^{-1}_{n,nn} \quad \forall l, nn \tag{2.35}$$

As in dynELMOD zonal data on a country level is needed, we then calculate a zonal PTDF as shown in (2.36).

$$PTDF_{ic,co} = \sum_{n \in co} \frac{PTDF_{l,n}}{N_{co}} \quad \forall ic, co \tag{2.36}$$

Here an equal weight is given to all nodes, as the exact withdrawals and infeeds into the grid are not known to the model before the calculation. An analysis by Boldt et al. (2012) shows that giving an equal weight to the nodes when aggregating the PTDF is sufficiently accurate. The next step of the PTDF-approximation to an aggregated level is conducted in (2.37) using the line-sharp PTDF-representation obtained in (2.36). Here sums over two subsets $l1$ and $l2$ are necessary. $l1$ contains all lines that start in the country co or end in cco, while $l2$ contains all lines that start in the country cco or end in co.

$$\begin{aligned} PTDF_{co,cco,ccco} = & \sum_{l1} PTDF_{l,ccco} \\ & - \sum_{l2} PTDF_{l,ccco} \end{aligned} \quad \forall co, cco, ccco \tag{2.37}$$

The first two sets of the PTDF co, cco determine the country-country connection. The third set $ccco$ is the injecting or withdrawing country. The PTDF then serves as an input for the calculation. In contrast to Hagspiel et al. (2014), the underlying PTDF is not updated in our model although line expansion is taking place. This simplifying assumption is motivated by computational speed and justified by the small effect of the existent line expansion on the overall flow pattern (see Section 2.6), although some loop flow effects are not accounted for.

2.4. Data

For large-scale electricity system models, comprehensive input data is required. The data is derived from different disciplines including engineering, finance and meteorology and different data sources have to be combined and matched. The result are large data sets which are very hard to reconstruct for interested stakeholders.

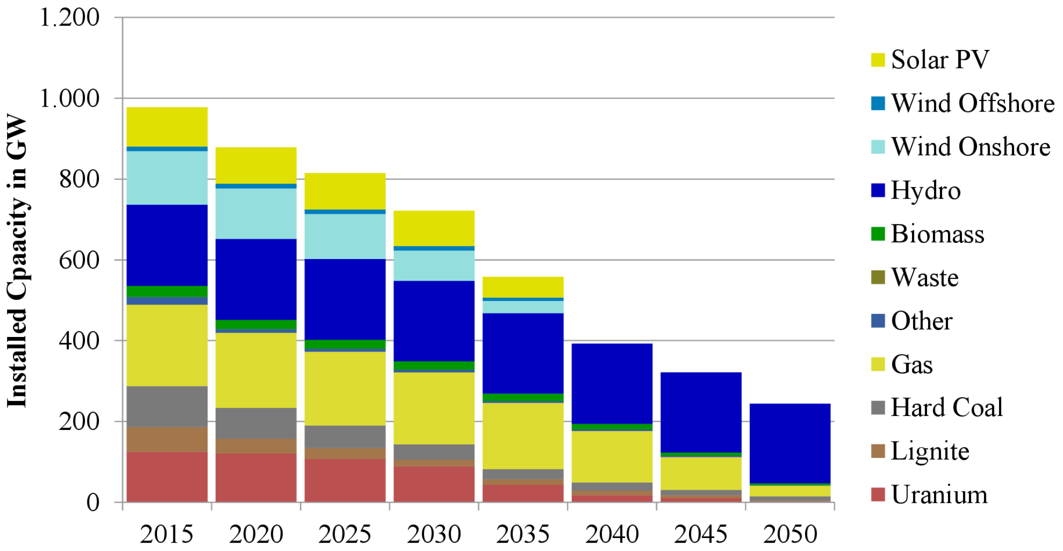


Figure 2.3.: Capacity development of the operational power plant fleet of 2015

Therefore we publish all our input data. We use open source data or own calculations wherever possible. Thereby nearly all final input data can be reproduced.

2.4.1. Generation

We include 31 different conventional and renewable generation technologies in dynELMOD. Table 2.2 shows an overview of the technologies implemented in the model, as well as relevant assumptions regarding costs, efficiencies and lifetimes.[5] Except for Germany, existing generation capacities are aggregated per technology. Existing generation capacities in Germany are included in block sharp resolution. New built capacities are implemented by technology for all countries.

New built capacity is available instantly and lasts for a predefined number of years depending on the technology. Depending on the commissioning date the thermal efficiency, costs for investment and operation and maintenance (O&M) and further characteristics are set. Annuities are calculated based on the economic lifetime. When the remaining horizon is shorter than the to-be-paid annuities or the lifetime of the capacity, this is accounted for in the model formulation to avoid distorting the results by the model horizon's ending. New conventional power plants usually last longer than the end of the model horizon, whereas e.g. batteries have a shorter lifespan.

Most efficiencies, technical lifetimes, overnight cost, load change cost, fix and variable operation and maintenance cost are based on Schröder et al. (2013). Marginal generation cost are calculated from efficiency, fuel cost and variable maintenance and

[5]Table 2.2 only shows information for 2015 and 2050. The input file accompanying the model also contains assumptions for the development over all intermediate time steps.

Table 2.2.: dynELMOD technology overview

	Technology	Overnight cost [€/KW]		Fix O&M [€/KWy]		Variable O&M [€/MWh]		Efficiency [%]		Technical lifetime [y]		Economic lifetime [y]		Storage capacity [€/KWh]	
		2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050
Fossil	Nuclear	6000	6000	100	100	9	9	0.33	0.34	50	50	30	30		
	Lignite	1800	1800	60	60	7	7	0.43	0.47	40	40	30	30		
	Coal	1800	1800	50	50	6	6	0.46	0.47	40	40	30	30		
	CCGT	800	800	20	20	3	3	0.60	0.62	40	40	30	30		
	OCGT	550	550	15	15	2	2	0.39	0.40	40	40	30	30		
	GasSteam	550	550	15	15	3	3	0.41	0.42	40	40	30	30		
	CCOT	800	800	25	25	4	4	0.60	0.62	40	40	30	30		
	OCOT	400	400	6	6	3	3	0.39	0.40	40	40	30	30		
	OilSteam	400	400	6	6	3	3	0.41	0.42	40	40	30	30		
	Waste	2424	1951	100	100	7	7	1.00	1.00	50	50	30	30		
Renewable	Biomass	2400	2400	100	100	7	7	0.38	0.38	40	40	30	30		
	Reservoir	2000	2000	20	20	0	0	0.75	0.75	100	100	30	30		
	RoR	3000	3000	60	60	0	0	1.00	1.00	100	100	30	30		
	Wind onshore	1063	851	35	35	0	0	1.00	1.00	25	25	20	20		
	Wind offshore	3500	1592	35	35	0	0	1.00	1.00	25	25	20	20		
	PV	998	230	25	25	0	0	1.00	1.00	25	25	20	20		
	CSP	5300	3200	30	30	0	0	1.00	1.00	30	30	30	30		
	Tidal	4608	2600	150	150	0	0	1.00	1.00	50	50	30	30		
	Geothermal	3982	2740	80	80	0	0	1.00	1.00	50	50	30	30		
CCTS	Lignite CCTS	3950	3600	90	90	8	8	0.30	0.33	50	50	30	30		
	Coal CCTS	3550	3200	80	80	8	8	0.31	0.34	50	50	30	30		
	CCGT CCTS	1670	1460	40	40	4	4	0.49	0.52	50	50	30	30		
	OCGT CCTS	1384	1280	30	30	4	4	0.34	0.34	50	50	30	30		
	Biomass CCTS	5630	5140	120	120	8	8	0.26	0.27	50	50	30	30		
Storage	PSP	2000	2000	20	20	0	0	0.75	0.75	100	100	30	30	10	10
	Battery	153	35	3	1	0	0	0.88	0.92	8	13	10	10	625	100
	Powertogas	1850	800	37	16	1	1	0.37	0.37	20	20	20	20	0	0
	DSM01	745	745	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSM04	835	835	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSM12	30	30	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSMLT	180	40	0	0	0	0	0.80	0.80	10	10	10	10	0	0

Sources: Data compiled form data by Schröder et al. (2013) and other sources.

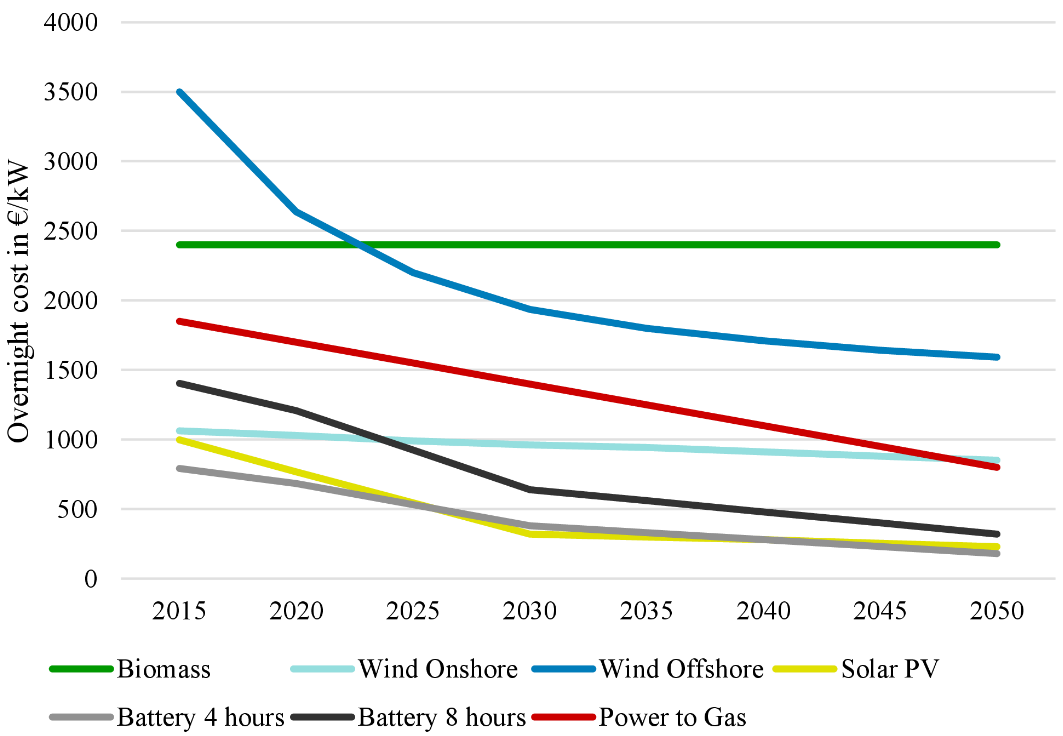


Figure 2.4.: Investment cost pathway for selected technologies

operation cost. When CO_2 prices instead of a CO_2 budget are assumed, additional cost for CO_2 certificates are added depending on emissions. Figure 2.4 shows an overview of the assumed development of overnight costs for selected technologies.

Conventional geneneration technologies

We include ten conventional generation technologies (Lignite, Hard Coal, Combined Cycle Gas Turbine, Open cycle Gas Turbine, Gas Steam, Combined Cycle Oil Turbine, Open Cycle Oil Turbine, Oil Steam, and Waste) which use nuclear fission or the combustion of lignite, coal, gas, oil, and waste for heat generation. Additional constraints apply to those who are providing heat or are equipped with a carbon sequestration technology.

We use the Scenario Outlook and Adequacy Forecast (SOAF) which provides generation capacities per country (ENTSO-E, 2015c). As those capacities only provide a snapshot of current capacities we generate a decommissioning plan for each technology aggregate and and separate per country. Based on the PLATTS (2015) database in combination with economical and technical lifetimes and efficiencies we derived technology and country specific decommissioning plans that also includes efficiency increases. For Germany a block sharp representation based on OPSD (2016) is used instead of the aggregated approach. For lignite power plants in Germany, the years of shutdown is anticipated based on estimations by Oei et al. (2015a,b). This development of the operational power plant fleet can be seen in Figure 2.3.[6] When technology aggregates are used, the decommissioning of old power plants leads to an increase in average efficiency. This is taken into account in the calculation of the technology aggregates.

Combined heat and power CHP is modeled as a minimum-run constraint on the electricity generation in dynELMOD. For each power generation technology and country a CHP share is defined. This share follows a country-specific minimum heat generation curve based on the average national temperature. For Germany, the power plant blocks with CHP have to follow this curve, as block sharp data is used. New built generation capacities are excluded from CHP minimum run constraints.[7]

Carbon capture, transport, and storage The technology CCTS is often seen as a bridge technology to allow for fossil electricity generation even under decarbonization targets. While the technology theoretically exists, no large scale power plant applications have emerged yet, and near-future adoption of this technology is highly uncertain. Still, we implement CCTS as a potential technology in the model, but at updated cost estimations from Schröder et al. (2013) as the technological development departs from the expectations in 2013.

We implement two general types of CCTS technologies: Fossil and biomass fueled generation capacities. Biomass is assumed to have no inherent emissions, so that capturing and storing carbon dioxide from biomass leads to negative emissions. For fossil fuels, the majority of carbon dioxide is assumed to be captured (88%, see Schröder et al., 2013). All captured CO_2 is tracked on a country basis. According to current legislation that does not permit the transport of pollutants and anticipation no change in this regard, captured CO_2 emissions must be stored within each country. Therefore in countries without storage potentials, no construction of CCTS plants is allowed. Storage potentials shown in Table 2.3 are based on Oei et al. (2014) to determine how much CO_2 can be stored. We include only offshore storage capacities in aquifers and depleted gas fields.

Renewables

We include nine renewable technologies (Biomass, Reservoirs, run-of-river power plants (RoR), Wind onshore, Wind offshore, Solar PV, CSP, Tidal Energy, and Geothermal

[6] We assume replacement of run-of-river and pumped storage capacities when their end-of-life is reached.

[7] If new built fossil capacities would have to follow the CHP minimum run constraint, this would effectively prevent investments into these capacities in dynELMOD, as the total CO_2 emission constraint and the minimum run constraint would interfere with each other.

Table 2.3.: CO_2 storage potential per country

Country	Storage Potential [Mt CO_2]
Germany	1,200
Denmark	2,500
Spain	3,500
Ireland	1,300
Netherlands	500
Norway	13,800
Poland	3,500
United Kingdom	22,000
Lithuania	1,300

Source: Oei et al. (2014)

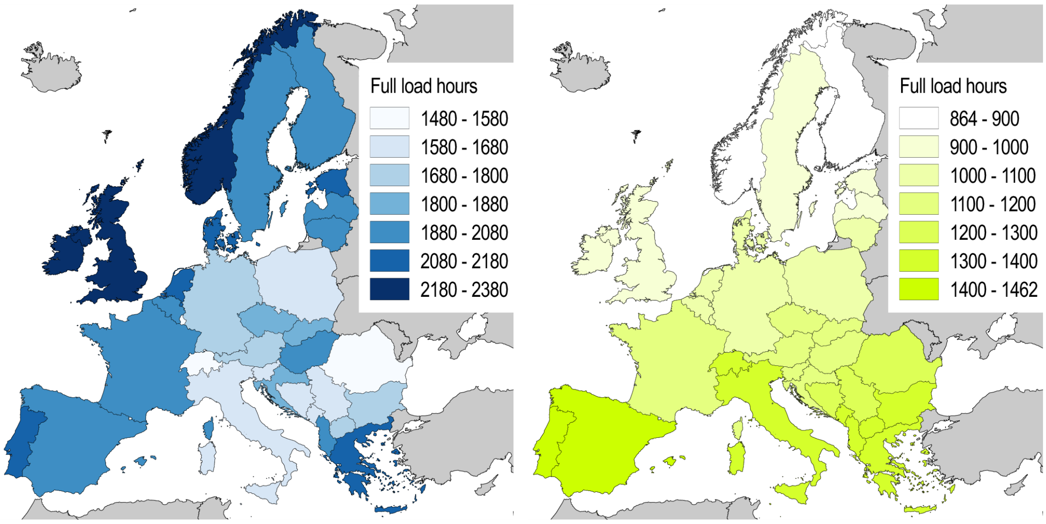
Energy) in dynELMOD, which are characterized by their cost, efficiencies, potentials, time and spatial availabilities.

Wind and solar PV The currently most promising renewables for a continued widespread adoption in the electricity system are solar PV, wind onshore and wind offshore. We limit the potential that can be installed in each country to account for spatial scarcity of space, especially at locations with high availabilities. Furthermore, the potentials are differentiated into three resource grades, similar to the approach by Nahmmacher et al. (2014). Resource grades are used to achieve a distinction between sites of different suitability. The resource grades are characterized by different FLH and thereby represent the varying quality of the potential installation sites for each country. Figures 2.5a and 2.5b show the geographical distribution of FLH for the first resource grade over the model region. As expected in southern Europe, the solar PV potential is highest, while for onshore wind the picture is more diverse.

Biomass The installation potential of biomass fueled power plants is not limited, but the amount of biomass available for electricity generation is restricted due to limits in sustainable biomass supply. This limits the use of Biomass for conventional as well as usage in a CCTS plant, without pre-defining the potential of each technology. In 2015, a thermal potential of 470 TWh_{th} that is assumed to increase to 1,104 TWh_{th} until 2050, which corresponds to an electricity production of about 400 TWh_{el}.

Hydro power plants We assume no additional new built capacity for RoR and hydro reservoirs due to limited potentials and environmental concerns. However, current capacity that comes to the end of their technical lifetime will be replaced.

For RoR and hydro reservoirs country specific monthly (in-)flows represent seasonal weather characteristics (ENTSO-E, 2016). In contrast to RoR, hydro reservoirs are implemented using the storage equation framework. Most reservoirs are characterized



(a) Onshore wind (b) Solar PV

Figure 2.5.: Exemplary full load hours for 2015

by a very high E/P-Ratio, such that the amount of storage vastly exceeds the installed electrical turbine capacity. Furthermore, most reservoirs do not have pumping capabilities as the natural inflow is sufficient for reservoir usage.[8] The seasonal inflow patterns as well as the total amount of reservoir inflow have been calibrated using historical data from ENTSO-E (2016). When solving over a reduced time frame the usable reservoir storage capacity is reduced to adequately represent the yearly reservoir storage usage pattern.[9] This accounts for the fact that the seasons are much shorter when using a reduced time frame.

Storage

We include chemical and mechanical storages that are differentiated by their installation potential, round-trip efficiency and cost assumptions. We assume a sharp decline in investment cost for chemical electricity storage technologies. As the cost for battery storage have recently been often below literature estimations our assumptions can still be regarded as conservative. Still there exists great uncertainty and diversity of assumptions between current literature and technology studies that project cost developments for battery storage. Instead of modeling different battery technologies explicitly we assume a generic battery technology that represents an aggregate of assumptions for Lead-Acid, Li-Ion, and Sodium-Sulfur. We base our assumptions on Zerrahn and Schill (2015a) and Pape et al. (2014).

[8] Such reservoirs are implemented in Austria, France, Italy, Norway, Sweden and Switzerland.
[9] The maximum storage level is reduced by the factor *model-hours*/8,760.

For existing pumped hydro storages we assume a E/P-Ratio of 8 hours. For reservoirs country-specific average values are used. In the case of new built battery storages the model is free to invest in storage as well as loading/release capacity separately, thus can decide upon the E/P-Ratio endogenously. In the the model input data the investment cost are differentiated between power €/KW and energy €/KWh to enable this distinction.

In addition to conventional and battery based storage options, power to gas is also implemented in dynELMOD. Although not an electricity storage technology in the traditional sense, we adopt the approach by Zerrahn and Schill (2015a). The E/P-Ratio is fixed at 1,000 hours, and symmetrical gasification and electrification capacities are assumed, which are both included in the investment cost.

Demand side management

Apart from storages we include three different types of DSM. They are characterized by different cost assumptions and either one, four or twelve hours of load shifting. Thereby they represent the different sectors and technologies where DSM potentials can be raised. They all feature a symmetrical discharge and recharging capacity.

We use DSM potentials by Zerrahn and Schill (2015b) for Germany and reduce them to three technology categories. For other countries the DSM potential is scaled according to their yearly load in comparison the yearly load of Germany.

2.4.2. Demand development and sector coupling

In the upcoming years an increasing coupling between the electricity, heat and transportation sector is expected (Agora Energiewende, 2015). The adoption of battery-electric vehicles (BEVs) is likely to increase in the future, and battery prices continue to decrease. At the same time, the current heat sector has a high carbon intensity, which also becomes a target for decarbonization. This decarbonization, in turn, will lead to increasing demand for electricity. As the speed of BEV adoption and interaction of the electricity and heat sector is unclear, the development of the future electricity demand is highly uncertain and might increase substantially. The level of demand also depends on the depth of sector coupling. However, the additional demand for flexibility in electricity supply might also be met directly by the sectors themselves, as the additional demand could be flexible and even provide additional value to the electricity sector.

We assume an increase in electricity demand over time based on EC (2016) as well as an increase in demand flexibility options. Direct demand flexibility is modeled as DSM. As dynELMOD covers the electricity sector only, additional flexibility resulting from other sectors is not represented directly. We model the flexibility of the other sectors implicitly using the storage and DSM equation framework with the help of a custom DSM technology (named DSMLT). This DSM technology has an asymmetrical release and loading ratio of 24 to 1, where for every hour of discharge, 24 hours to recharge are required. Thus, a very high discharge capacity is available which will cause a long but low recharging period. This artificial storage should represent a short consumption interruption (for example for charging battery vehicles or heat pumps) which in turn will result in slightly higher consumption in the following 24 hours.

2.4.3. Grid

The country to country NTC are calculated based on the average values from the monthly or daily values of available transmission capacity. As the data provided by transparency platform by ENTSO-E (2016) is not available for all interconnections, additional data based on the NTC Matrix by ENTSO-E (2013c) has been used. When only DC interconnections between countries exist, the sum of the transmission capacity is used. Cost for transmission expansion are based on ECF (2010), who assume 1000 €/(MW*km). Here the distances between the countries' geographical centers serve as a basis for the cost calculation as we are using only one node per country. To account for investments in offshore interconnectors the "distance" between relevant countries is adjusted by hand. Furthermore new transmission capacity is allowed to be built between neighboring countries where we assume future interconnections or plans for interconnectors exist. Figure 2.6 shows the initial NTC values for 2015 in megawatt (MW).

For the PTDF approach additional data is necessary. The underlying high voltage network topology as depicted in Figure 2.7 consists of five non-synchronized high-voltage electricity grids (Continental Europe, Scandinavia, Great Britain, Ireland, and the Baltic countries) with operating voltages 150 kV, 220 kV, 300 kV, and 380 kV. This data is based on the data documentation by Egerer et al. (2014). These grids are connected by HVDC cables. The European electricity grid is originally modeled in a plant-block- and line-sharp data accuracy for all EU-28 countries as well as Norway, Switzerland and the Balkan countries. As the application in this chapter is on a country-level we use relevant aggregates of the data.

2.4.4. Time series

To adequately represent variations of demand and renewable in-feed and to determine not only the need for generation capacity and and grid, but further system flexibility options, time series spanning 8,760 hours from the year 2013 are used as a basis for

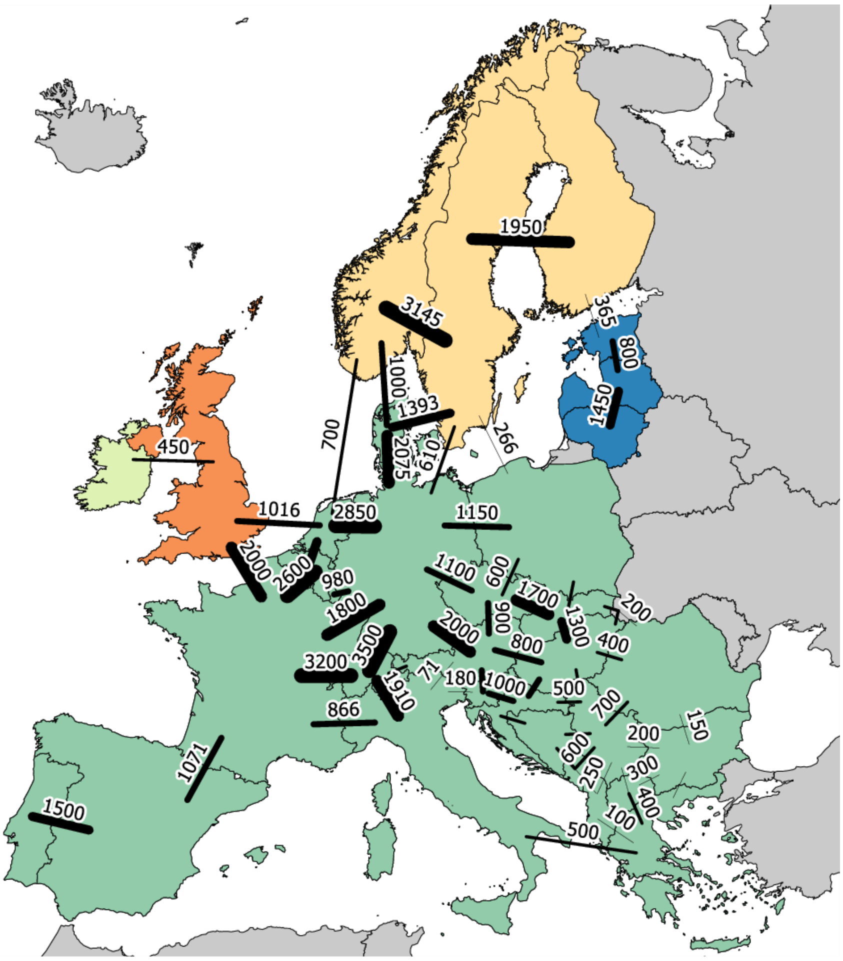


Figure 2.6.: NTC values in 2015 in megawatt.
Source: Own calculations based on ENTSO-E (2013c) and ENTSO-E (2016)

the model. As discussed earlier, not the time-series' actual value is needed in this application, but rather the spatial and temporal variation of all input parameters relatively to each other are important.

Demand time series

For electricity demand time series we use data from ENTSO-E (2014) and rescale the time series such that the average value of each country's time series is 1 before further processing. For Albania no demand time series are available. Here, an interpolation based on the time-series of neighboring countries is used.

Renewables time series

To generate renewable times series we use raw and processed data from various sources. As a basis we use meteorological data by Dee et al. (2011). We combine those

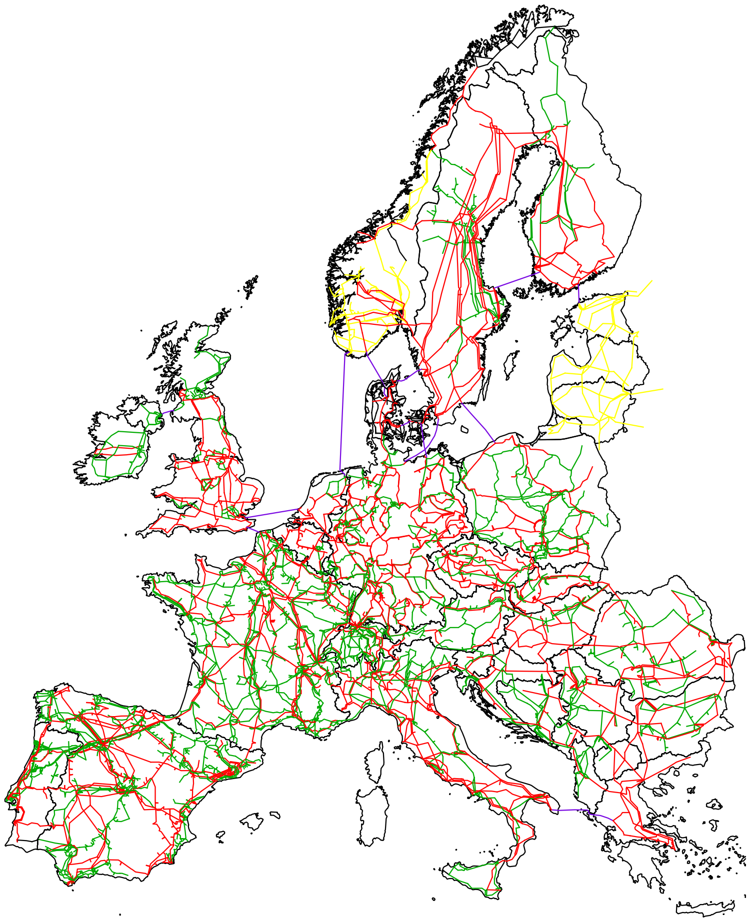


Figure 2.7.: European high voltage electricity grid in 2014
Red: 380 kV, Yellow: 300 kV, Green: 220 kV, Violet: HVDC
Source: Egerer et al. (2014)

data with Pfenninger and Staffell (2016), Staffell and Pfenninger (2016), and The Wind Power (2016) for validation. Run-of-river time series are based on ENTSO-E (2016). For Albania, Bosnia Herzegovina, Estonia, Montenegro, Serbia and Slovenia only limited data is available for run-of-river time series. Here, an interpolation based on the time-series of neighboring countries is additionally used.

2.4.5. Other

CO_2 pathway

Figure 2.8 shows the CO_2 emission pathway implemented in the default scenario. It is based on based on the scenario "Diversified supply technologies" from the European Commission's *Energy Roadmap 2050 – Impact Assessment and scenario analysis* (EC, 2011c). In this scenario and in the EU ETS more than the electricity sector

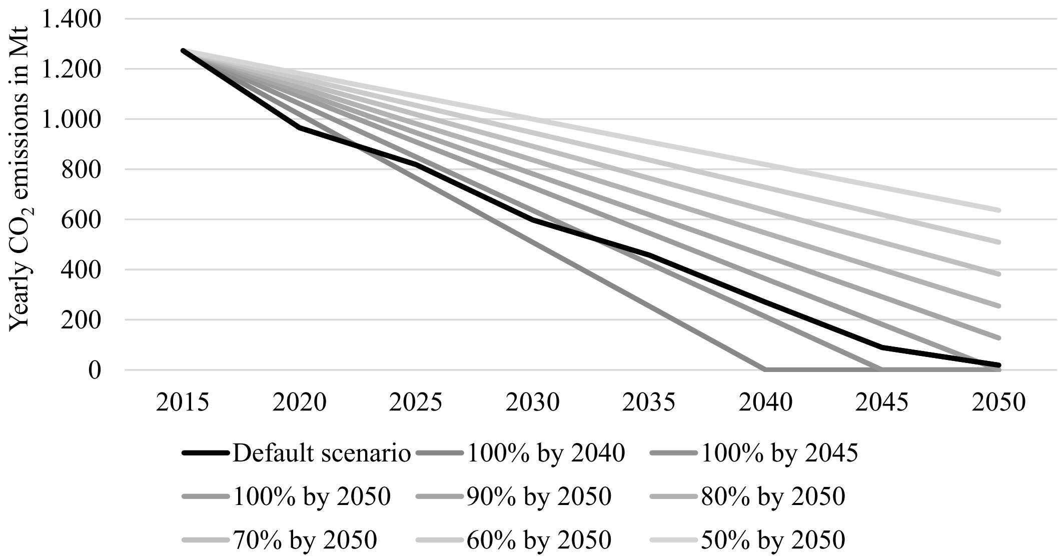


Figure 2.8.: CO_2 emissions constraints

are represented. As dynELMOD covers only the electricity sector we are using the CO_2 pathway that uses a limit on yearly CO_2 emissions designated to the electricity sector. While the overall decarbonization target covering all sectors in the scenarios currently does not include full decarbonization, the electricity sector is almost in all scenarios subject to full decarbonization. Possibly arising substitution effects can only be shown within the electricity sector. Additionally implemented CO_2 emission pathways ranging from full decarbonization in 2040 to only 50% decarbonization in 2050 are also shown in Figure 2.8.

Fuels

The development of fuel prices is important for the cost relation between gas and coal fired power plants. Prices for coal, gas and oil and their development until 2050 (Table 2.4) are based on the EU Reference Scenario 2016 by EC (2016).

Table 2.4.: Fuel prices in dynELMOD

in €$_{2013}$ per MWh$_{th}$	2015	2020	2025	2030	2035	2040	2045	2050
Uranium	3.20	3.40	3.60	3.80	4.00	4.20	4.40	4.60
Lignite	4.80	5.21	5.62	6.03	6.44	6.85	7.26	7.67
Hard Coal	4.41	6.62	7.94	8.83	8.83	9.27	10.15	10.59
Natural Gas	18.54	25.60	27.36	28.69	30.01	31.78	33.10	33.10
Oil	23.83	36.63	44.13	48.55	50.75	52.96	55.17	56.49
Biomass	8.10	9.00	9.90	10.80	11.70	12.60	13.50	14.40
Waste	8.10	9.00	9.90	10.80	11.70	12.60	13.50	14.40

Source: EC (2016)

2.5. Time series reduction

As long-term generation capacity investment models can become computationally challenging, calculations with a large number of hours are not feasible. In the investment determination step of dynELMOD the model is not solved for the time span of 8,760 hours of a whole year, but a reduced time-series is used. As we want to represent the characteristics of all time-varying input parameters, on the one hand the highly multidimensional dataset with temporal as well as spatial variations need to be represented accordingly. The model hour selection is a key assumption in such a modeling exercise. A wrong selection of time-series can lead to a distorted model outcome and a power plant portfolio that either has too much, too little, or a wrong mixture of electricity generation capacities when the model outcome is tested with a full time-series.

Recently, Poncelet et al. (2014b, 2016) quantified the effect of temporal as well as operational detail in a long-term planning model. The authors find, that a good temporal representation should take preference before implementing further operational constraints, when computational limitations are reached.

2.5.1. Previous work

In the literature, several time series reduction techniques exist. Most approaches focus on selecting a representative set of hours or days from given time-series using hierarchical or parametric clustering methods or approximating time-series characteristics e.g. using a MILP.

Clustering methods such as k-means or hierarchical clustering are often used options to extract clustered data from a time series. Green et al. (2014) use k-means to extract relevant sets of demand profiles for the British electricity system. An application to an investment problem with k-means time slice clustering is shown in Munoz et al. (2016). Nahmmacher et al. (2016) develop a new time slice selection approach. Temporal and spatial variation of time-series is reduced using a hierarchical clustering of representative days. The reduced time-series are tested using the LIMES-EU model (Nahmmacher et al., 2014). The authors show that "Six representative days are sufficient to obtain model results that are very similar to those obtained with a much higher temporal resolution" (Nahmmacher et al., 2016, p. 441). Després et al. (2017) analyze the demand of electricity storage given high levels of RES in the European electricity system using POLES (Prospective Outlook on Long-term Energy Systems). The authors also use the hierarchical clustering algorithm developed by Nahmmacher et al. (2016) with twelve representative days to capture the variability of the time-series.

Other approaches often involve the use of a MILP, to select hours given an optimization problem, to minimize the distance between the original and reduced time series. Van der Weijde and Hobbs (2012) sample 500 hours from 8,760, trying to match the original dataset, by minimizing the difference between the original time series and the reduced time series with regards to correlations, the averages as well as standard deviations of all model regions. Poncelet et al. (2015) select representative days using a MILP that also optimizes criteria based on the original time series. The authors find that the number of representative days is more important for the model result robustness, than the hourly resolution of the reduced time series, which is set at a 4-hourly interval.

De Sisternes and Webster (2013) select a number of weeks based on a given time-series by minimizing the quadratic difference between full and the reduced net load duration curves. This approach could also be applied to renewable feed-in time series. Due to limits in implementation, only five weeks can be selected using this approach.

In Integrated Assessment models the correct representation of variability of wind gains importance, as usually the hourly representation is highly aggregated and cannot reflect renewable and load variability (see Pietzcker et al., 2017). Ueckerdt et al. (2015) also use the residual load duration curve as in their approach. Here, a stylized residual load duration curve is approximated, which changes form depending on the amount of renewables introduced into the system. The authors demonstrate the effects using the REMIND-D model.

2.5.2. Our time series reduction approach

During the development of dynELMOD, the aim of the to-be-applied time frame reduction method was not only to represent the general characteristics of the full time series but also to achieve a continuous time series that also captures seasonal variations in a satisfactory manner. The approach should also preserve seasonal characteristics in the right order within the year. It is of particular importance to approximate the behavior of hydro reservoirs, where not only hourly dispatch occurs, but also the yearly cycle of inflows and the filling level plays a role over the course of a whole charging cycle, which is often an entire year. The amount of inflow in reservoirs should also be met. Especially since the seasonal variation of hydro inflows and reservoirs needs to be captured adequately and in the right order, we develop an own time reduction methodology described in this section.

The aim is to meet as many characteristics of the full time-series in the reduced time-series as possible while still achieving a manageable model size. This includes the time-series'

- daily variation structure;

- seasonal structure;
- minimum and maximum values to capture a wide range of possible situations;
- average, or for renewables the estimated full load hours given in the data;
- "smoothness" or hourly rate of change characteristic, as otherwise the need for flexibility options such as storage and ramping might be under- or overestimated.

For input time-series where only monthly data is available (e.g. aggregated generation amounts for run-of-river plants), the approach should also be able to treat the time series accordingly, that no "jumps" at the month's borders are present in the final time series.

When using a reduced time-series, occasionally occurring periods of low wind and solar in-feed need to be represented as well in the time series. Especially weather phenomena like simultaneous low wind in-feed over the whole model region for a longer time need to be accounted for. If not implemented, an overestimation of the reliability of renewable generation capacities occurs, which results in an inadequate generation portfolio with provides an infeasible generation pattern in the full calculation.

The time-series reduction process is done according to the following steps:

1. Hour selection
2. Time series smoothing
3. Time series scaling

1. Hour selection The first step consists of selecting hours that will be processed further. As a continuous development of the time series is wanted, the ordering of hours will be kept as is. Selecting an hour selects all occurrences of the multidimensional dataset, e.g. the data of renewable availability and demand for all regions will be chosen, to keep the relationship within the data structure intact. From the time series of a full year we select a subset of hours for further processing. We use a interval, determined by the desired time granularity to reach a continuous function that captures daily and seasonal variation.

In the standard case we use every 25^{th} hour of the full time series, corresponding to an N of 1, which results in a shortened time series of 351 hours. In the full calculation with 8,760 hours all hours are selected. The n^{th} hourly selection can start at all hours of the day, which gives an opportunity to test the smoothing procedure with multiple input values. In the standard case we use the 7^{th} hour for the start of the selection.

To guarantee a robust model result extreme events have to be taken into account as well. Investment models using a time reduction technique tend to overestimate the firm capacity of renewables, and in combination with storage, the model's investment decision could lead to an adequate electricity generation portfolio. Therefore we include the hours with the lowest feed-in of solar and wind into the time set, to better represent periods of low renewable feed in. The numbers of hours we include in the time set are dependent on the total calculated hours. In the standard case (a time set of 351 hours) we additionally include the 24 consecutive hours with the lowest renewable infeed. If the time set is reduced to 174 hours we only include 12 hours. These values have been derived using iterative testing on a wide range of scenarios, to neither over- or underestimate the effect of low renewable availability.

2. Time series smoothing The resulting time series of step 1 is interpolated as a continuous time series. This reduced time-series' variations are now much higher than the original time series, as day-to-day variations are now referred to as hourly variations. The next step smoothes the shortened time series. Thus artifacts can be removed by smoothing the series using a moving average function. The width of the moving average windows is specified by hand for each type of input data and length of the reduced time frame. The goal in trying to determine the window size is to keep the time-dependent characteristic in place and meeting the time series' variation target. In the full dispatch calculation with 8,760 hours no smoothing takes place except for data that is provided in a monthly resolution to reduce monthly "jumps" in the time series.

3. Time series scaling In step 3, the time series is scaled according to the targets mentioned above. Equations (2.38) to (2.40) describe the optimization problem used in the scaling process. It is solved as a discontinuous non-linear program (DNLP) using the solver CONOPT.

The objective value obj used in (2.38) determines the difference between the $target$ and reached average sum of the time series. The equations (2.39) and (2.40) enforce that the scaled time series reaches the target minimum and maximum values $mintarget$ and $maxtarget$. For RoR, solar PV and wind, the time series contains values between zero and one, with the target corresponding to the anticipated full load hours. Load time series have an average of one, here the minimum and maximum values determine the maximum upward and downward deviation from the average load. The term $\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}}$ scales the given time series to values between zero and one. These values are transformed using the power A to reach the required shape, while keeping the minimum and maximum values of the time series intact. The Variables B and C move and scale the time series to reach the desired minimum and maximum values. As the variables B and C can be determined independently from A, a model containing a dummy objective as well as the equations (2.39) and (2.40) is solved first, then the variables B and C are fixed, and the model containing the equations (2.38) to (2.40) is solved.

$$\min obj = \left(target * T - \sum_{t \in T} \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \right)^2 \tag{2.38}$$

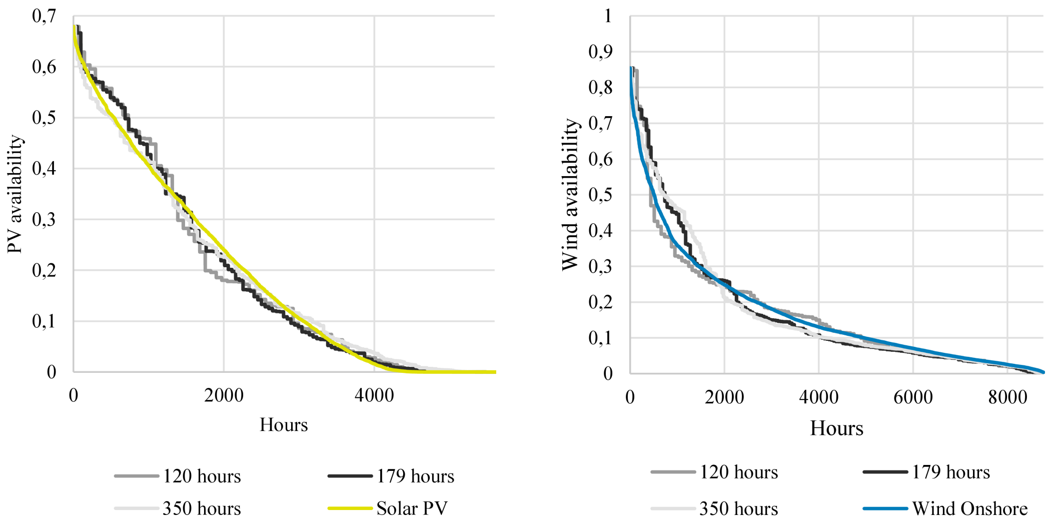
$$mintarget = \min_t \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \tag{2.39}$$

$$maxtarget = \max_t \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \tag{2.40}$$

After finishing this step, all relevant time-dependent input parameters can be calculated and put into the model.

2.5.3. Time series reduction results

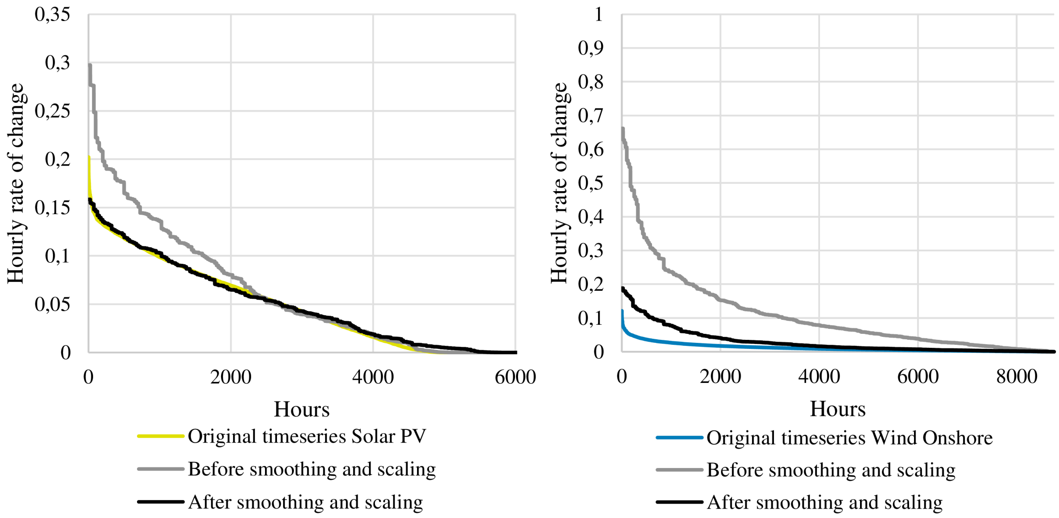
This section shows the result of the time frame scaling process for selected cases and parameter variations, using German time-series data. First, we show that the approach is able to approximate the relevant duration curves, then the smoothness of the original and reduced time series is compared, and the full time series that is used in the model is shown.



(a) Solar PV infeed duration curve (b) Wind onshore infeed duration curve

Figure 2.9.: Original and processed load and infeed duration curves

Figure 2.9 shows German solar PV and Wind onshore duration curves for the original time series as well as the resulting duration curves after the scaling process for different numbers of model hours. With a low number of model hours the original duration curve is not adequately approximated, but the model hours in this application (179 or 351) show good results. When a very low number of model hours is used the approximation worsens, but works sufficiently well for using the model with a smaller number of hours for quick tests.



(a) Solar PV (b) Wind onshore

Figure 2.10.: Time-series rate of change

The time series' sorted gradients are displayed in Figure 2.10. The original time series rate of change is overestimated before the smoothing process takes place, after smoothing and scaling a very good representation for solar PV is achieved. The approximation of the rate of change for wind also increases substantially, but is still slightly higher than in the original time series. This slightly overestimates fluctuation of wind in-feed.

Figure 2.11 shows example results of the time frame reduction technique for load, onshore and offshore wind and solar PV from German time series. Here, every 25$^{\text{th}}$ hour is used, the first included hour of the original time series is 7. The FLHs of the renewable time series have not been changed from the original input time series. In the actual calculations the FLH are adjusted to the expectations of the technological development in the future. Seasonal variation as well was the daily profile of solar PV and load are represented well, the onshore and offshore wind time-series also show seasonal as well as typical daily fluctuations.

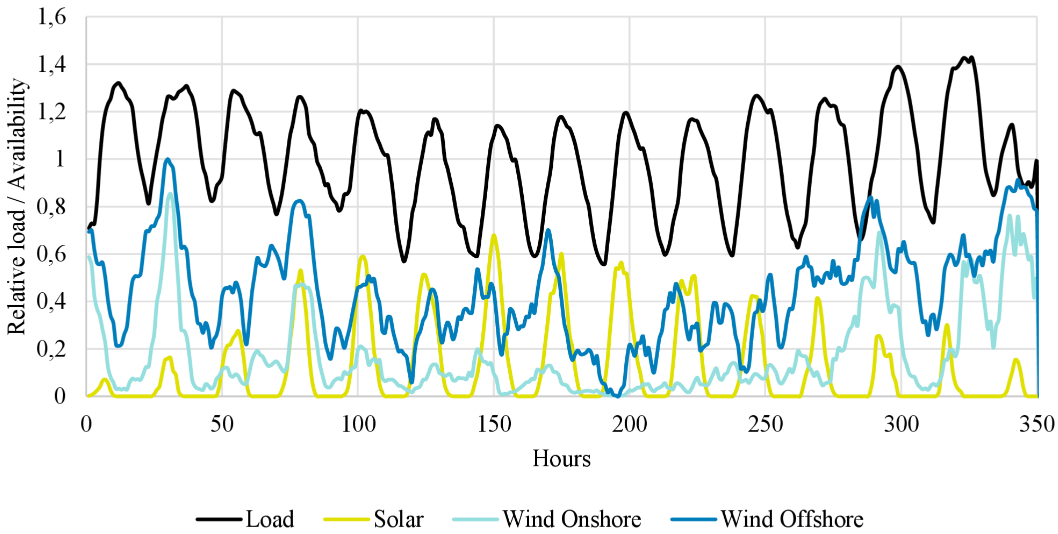


Figure 2.11.: Example time series reduction results

2.6. Results

The model results of dynELMOD provide insights into the driving forces for the future development of the European electricity sector. As the solution space is constrained by and a result of many factors such as the emission limit, capacity expansion restrictions, time related input factors such as renewable availability and assumptions about the development of costs for investments and fuels. The model outcomes analyzed in this section are the electricity generation capacity development, the resulting hourly generation dispatch, CO_2 emissions, and flows between countries.

2.6.1. Investment and generation results in the standard scenario

Figure 6.2 shows the development of the installed capacities from 2015 to 2050 in Europe. The installed capacities increase substantially from 980 GW in 2015 to 2,870 GW in 2050. At the same time, the European generation portfolio is transformed from mainly fossil fueled generation technologies to renewable generation technologies. The switch to renewable generation capacities, which usually have lower FLH, induces this overall capacity increase. In 2050 we mainly see 870 GW of solar PV and 740 GW wind onshore capacities accompanied by 270 GW of Wind offshore. No new nuclear, lignite, or hard coal fired capacities are installed which result in a nearly complete phase-out for those technologies until 2050.[10] Investments in natural gas fired power

[10]Sensitivity analyses show that investments into nuclear capacities are observed at or below overnight costs of 4,000 €/kW.

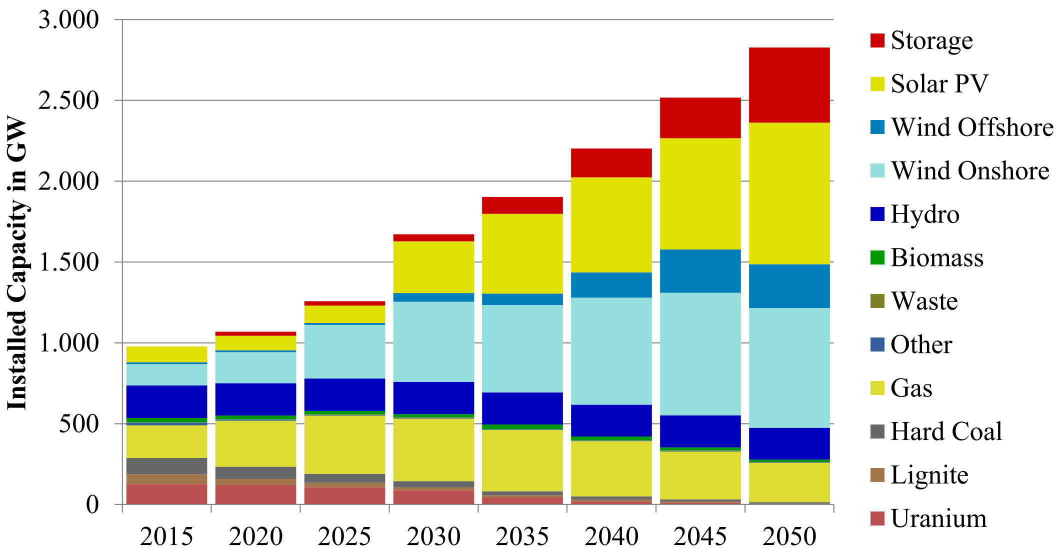


Figure 2.12.: Installed electricity generation and storage capacities in Europe 2015–2050

plant capacities take place. Their capacity in 2050 reaches 215 GW. These capacities mainly serve as backup capacities with very low yearly usage factors. Just over half (52 %) of these capacities are located in France, Germany, and the United Kingdom.

Over the years the total investments in generation capacities per year gradually increase from 40 GW per year in 2020 to 120 GW per year in 2050. From 2030 onwards these investments are primarily in wind and solar PV. The investments into storage increase until 2050, where they nearly make up a third of the total new investments. This results in a total of 465 GW storage which includes batteries, power to gas and DSM.

In line with the development of the generation portfolio, the electricity mix changes as shown in Figure 6.3. The electricity generation increases from 3,307 TWh in 2015 to 4,018 TWh in 2050. Despite the fact that in 2015 still two thirds of the electricity generation in Europe is conventional in 2030, already half of the total electricity generation is renewable. This trend continues until 2050 where more than 95 % of the electricity generation is renewable. In 2030 onshore wind power replaces gas fueled power plants as the main source of electricity for Europe with a share of more than one quarter. Until 2050 the share of offshore wind and solar PV reach also one quarter, while onshore wind stays the biggest producer with more than one third of the electricity production. While solar PV and offshore wind have similar production volumes, their installed capacity varies significantly due to their different FLH. Despite the solar PV's lower FLH, is still competitive due to its very steep cost per kilowatt (kW) decrease over time.

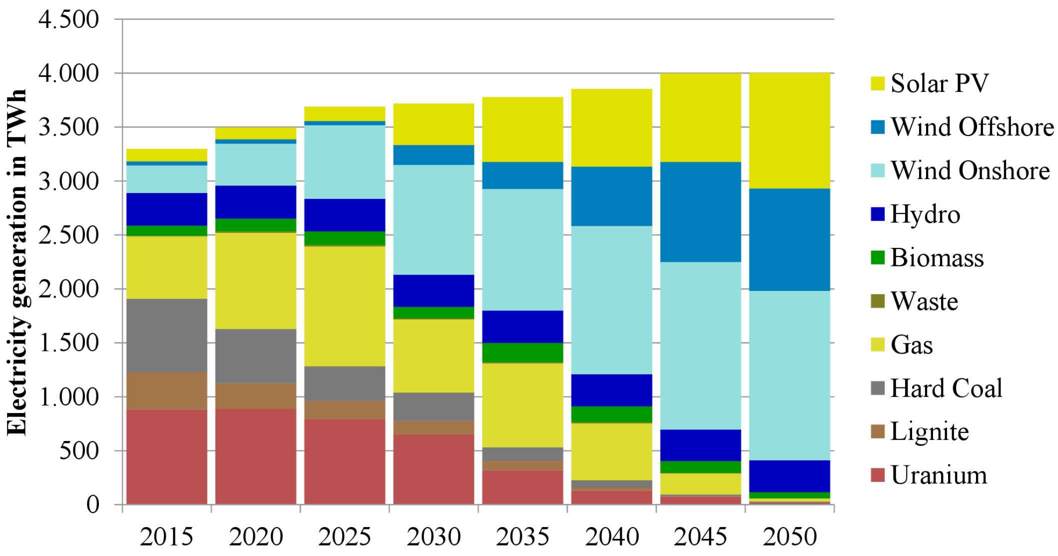


Figure 2.13.: Electricity generation 2015–2050

Figure 2.14 show the composition of the total CO_2 emissions in the European electricity sector over time. The amount of available emissions is limited by the CO_2 pathway (see Figure 2.8). Emissions decrease from 1,129 Mt CO_2 in 2015 to 18 Mt CO_2. Electricity from coal is the primary source of CO_2 emissions until 2030. As the coal phaseout occurs earlier, gas becomes the main emitter afterwards. Emissions from hard coal and lignite gradually decline from 2015 onwards until nearly zero in 2045. In contrast, emissions from gas remain stable until 2040.

The development of the implicit CO_2 price is shown in Figure 2.15. It is determined using the shadow price on the emission constraint in the model, and reflects the marginal savings of relaxing the constraint by 1 t CO_2, thus giving an indicator about the price of 1 t CO_2. Conforming with today's EU ETS, the price is very low in 2015 and in the first following periods. When the emission constraint tightens, the price increases substantially, reaching a high of 177 €/t in 2050. As only the electricity sector is included in detail in dynELMOD, interactions with other EU ETS sectors might lead to different results, when included.

2.6.2. Grid

A further source of flexibility in the electricity system can be provided by increasing cross-border interconnection capacity, which provides a comparatively low-cost solution to decrease the effect of spatial variability of demand and supply. Given sufficient transmission capacity, regionally distinct generation portfolios can complement each other, leading to an overall decrease on electricity system costs. Grid expansions in dynELMOD are represented as an increase in available NTC capacity (both in the

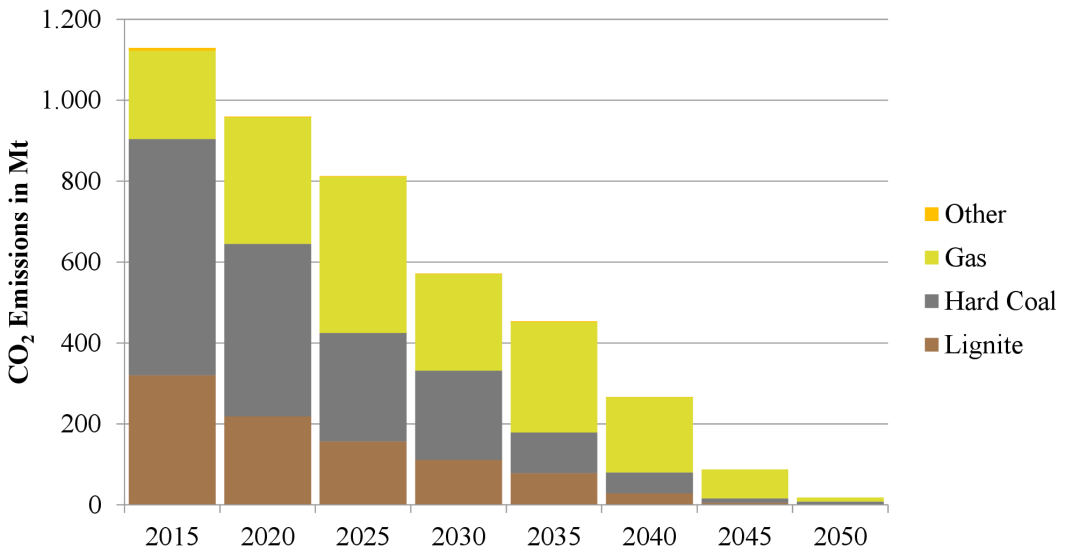


Figure 2.14.: CO_2 emissions by fuel 2015–2050

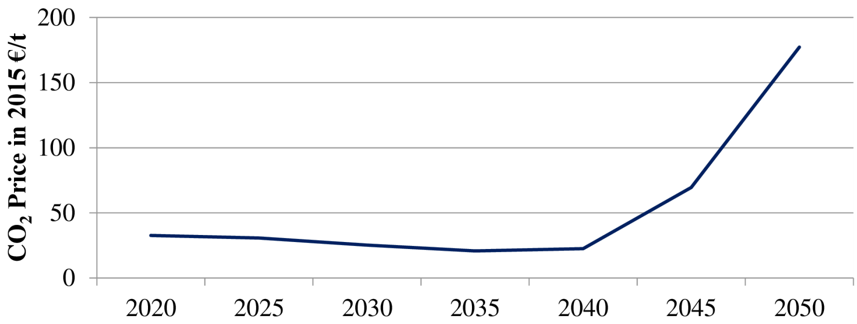


Figure 2.15.: CO_2 Price development 2015–2050

NTC as well as the flow-based approach). The final NTC values of the year 2050 are shown in Figure 2.16.

We observe a trend for transmission capacity expansion stretching out from the south (with high solar potentials) and the west (long coast line with high wind potentials) towards central and eastern Europe. France has an important position for these pathways as it connects the south and west to the central east. Accordingly the highest cross-border grid expansion is observed between France and Spain. Here, the high potential for solar PV as well as wind potential drives the need for increased interconnection between the Iberian peninsula and the rest of continental Europe. Analogous the interconnection between the United Kingdom and France (and the Benelux) is fortified to account for the high onshore and offshore wind potentials in the British Isles. Furthermore the interconnectors between Germany and Denmark and also Denmark and Sweden are expanded intensively. This creates a corridor from central Europe to the dispatchable hydro and storage potentials of northern

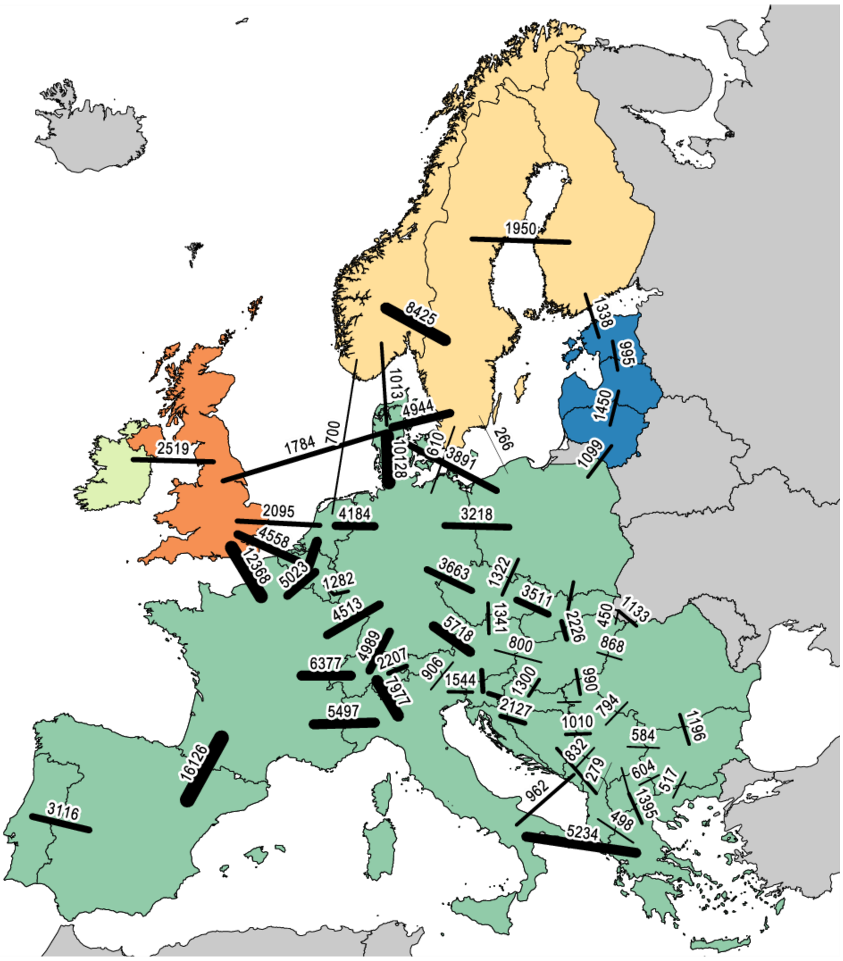


Figure 2.16.: NTC values in the year 2050 in MW

Europe. Besides these corridors, the interconnection between Italy and Greece is strengthened which results in a closed ring in the Mediterranean. To our surprise, the interconnector between Norway and Germany (which exists as an option for the model to be built) does not materialize. Also the interconnector between Sweden and Lithuania is not built.

The increased transmission capacities described in the previous paragraph allow for intensified electricity exchange between countries. Figure 2.17 depicts the sum of flows on the countries' borders in terawatt-hours (TWh). Once more we observe the expected general picture of electricity flowing from (north) west and south towards central (east) of Europe. This aligns with the transmission corridors depicted in 2.16. The countries in (north) west and the south export electricity due to their relative cost advantage in the production of electricity from wind and solar PV. The countries in central east import this electricity. Our results show that in comparison to the situation of 2015, Germany undergoes the largest overall change, as it will turn

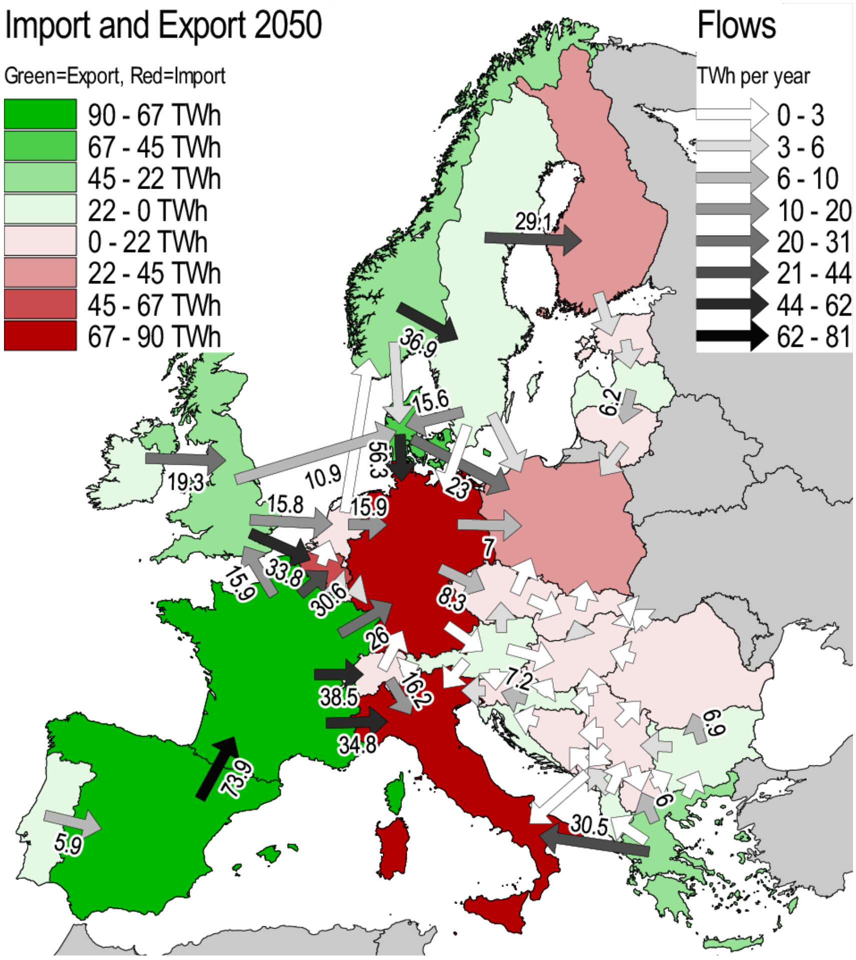
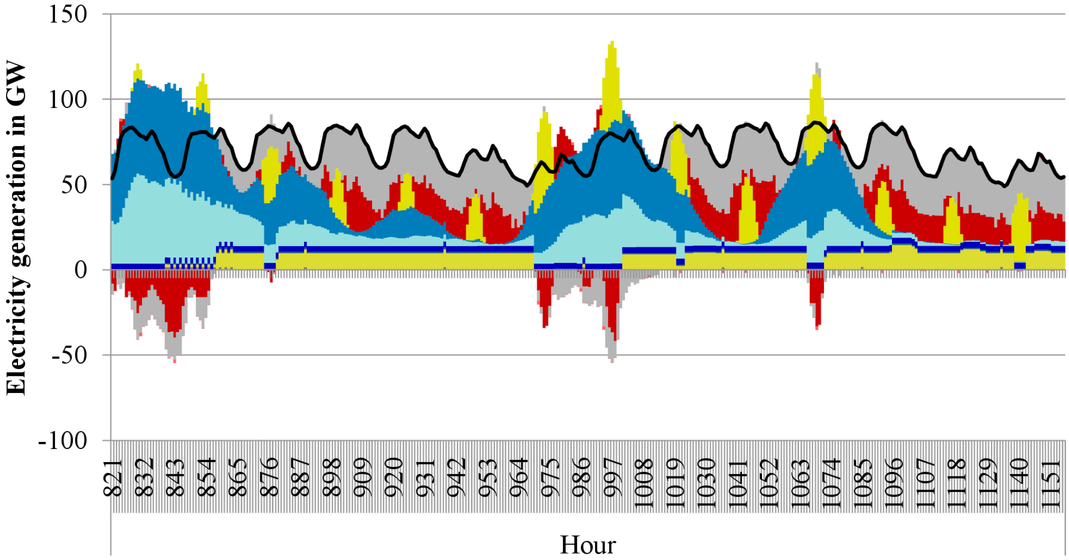


Figure 2.17.: Import and export in TWh in the year 2050

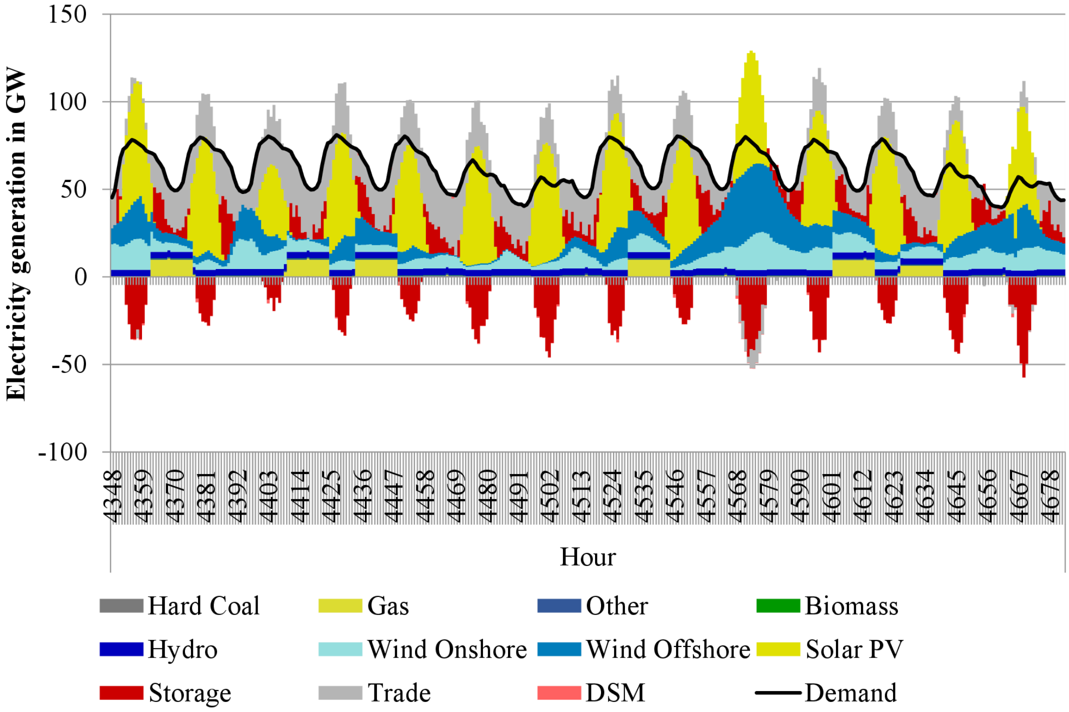
from an exporter to Europe's second largest importer. Although also in Germany substantial investments in renewable electricity generation capacities take place, dynELMOD suggests imports as a low-cost option. Import and exports in south east Europe seem balanced. As the demand and generation in this region is generally lower, small flows can result in substantial import or export shares for single countries.

2.6.3. Detailed dispatch results for selected countries

We analyze the hourly dispatch results for two consecutive winter and two consecutive summer weeks of 2050 in this section. The winter weeks are in early February (weeks 5 and 6) and the summer weeks are in early June (week 25 and 26). These weeks are characterized by low wind feed-in (in Germany) to show a situation when not necessarily enough conventional and renewable capacity is available. This is the case especially in winter, when solar radiation is reduced.

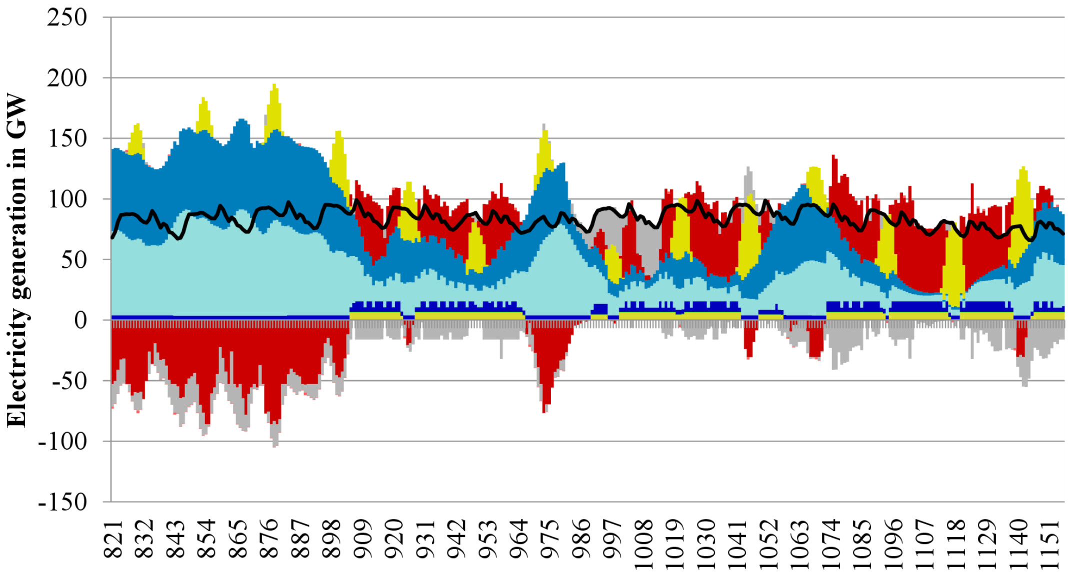


(a) Dispatch in Germany winter 2050

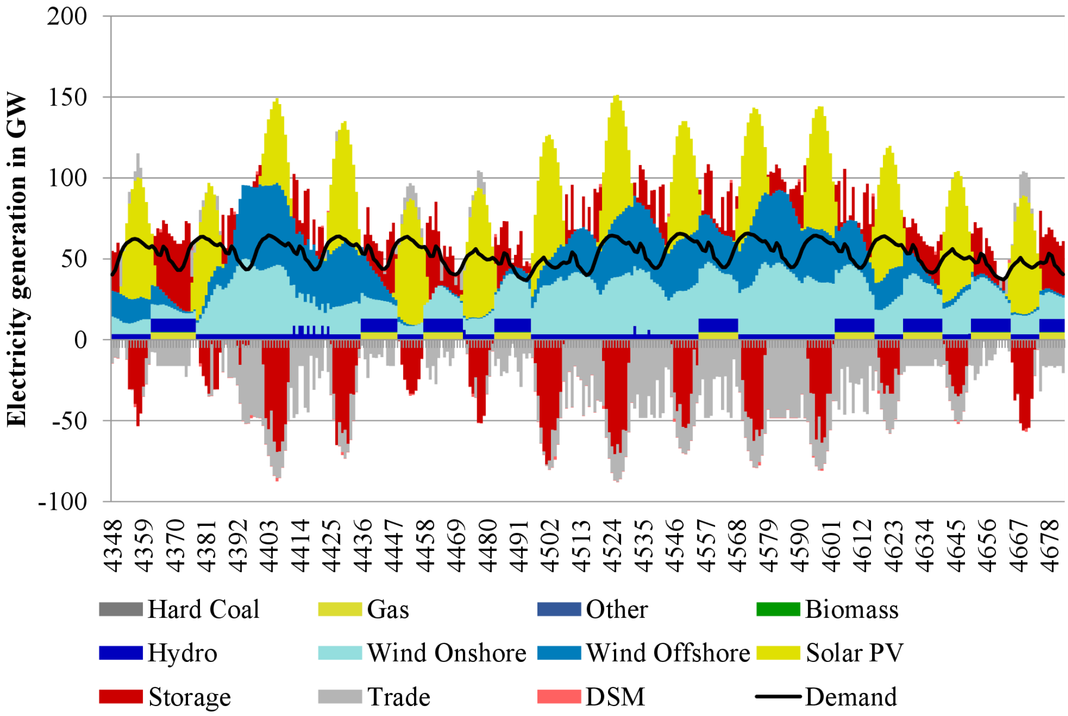


(b) Dispatch in Germany summer 2050

Figure 2.18.: Dispatch in Germany in the year 2050



(a) Dispatch in France winter 2050



(b) Dispatch in France summer 2050

Figure 2.19.: Dispatch in France in the year 2050

In Figure 2.18 we observe that Germany imports for most of the time in the selected winter and summer weeks. Exports occur only when there is high wind feed-in. In the summer an interesting storage charging pattern occurs, where electricitiy is imported while electricity is stored at the same time. Here, excess electricity from other countries is used to charge the storage technology power to gas, which is characterized by long seasonal cycles. This allows for more storage discharging than charging in the winter weeks and vice versa in the summer. Power to gas is mainly discharging during winter time and charging during summer time. Thus, during the winter weeks only batteries and DSM contribute to storage demand, to balance out daily fluctuations, while during the summer weeks storage discharge comes only coming from batteries and DSM. During the combination of low wind and low solar radiation the German system will be supported by conventional backup capacities.

Comparing the German dispatch to the dispatch in France (Figure 2.19) shows that France is exporting most of the time. Especially in the summer when there is high wind and solar feed-in up to 50 GW are exported in peak hours. Furthermore, the storage charging and discharging is much more balanced within the two weeks. Hence we see less usage of seasonal but mainly daily storage activities.

Large scale weather phenomena are particularly important for the dispatch, as they can affect wide regions, with simultaneous very low or high availability of renewables. The system needs to be adequately prepared for either high in-feed (by means of curtailing in-feed) or low in-feed by means of providing sufficient backup capacity or large enough storage capacities. One example of a wind front moving between countries can be seen in the winter weeks. When we compare the wind feed-in in Germany and France we can observe that while the shape seems similar the timing and peaks of the feed-in is shifted by several hours. The wind front in the beginning of the first winter week lasts about a day longer in France than in Germany.

In both model runs, during the investment step as well as the dispatch step with 8,760 hours, the infeasibility variables are not used by the model. The run with 8,760 hours shows that during the investment phase an adequate electricity system configuration has been obtained.

2.6.4. Varying the inputs and calculation options

CCTS availability

In the results shown previously, the availability of CCTS was restricted, as we intended to do the calculations with technologies that are available for large scale applications today. Assuming commercial availability of CCTS, as well as solutions for the issues around storing and transporting the resulting CO_2, we include this technology in

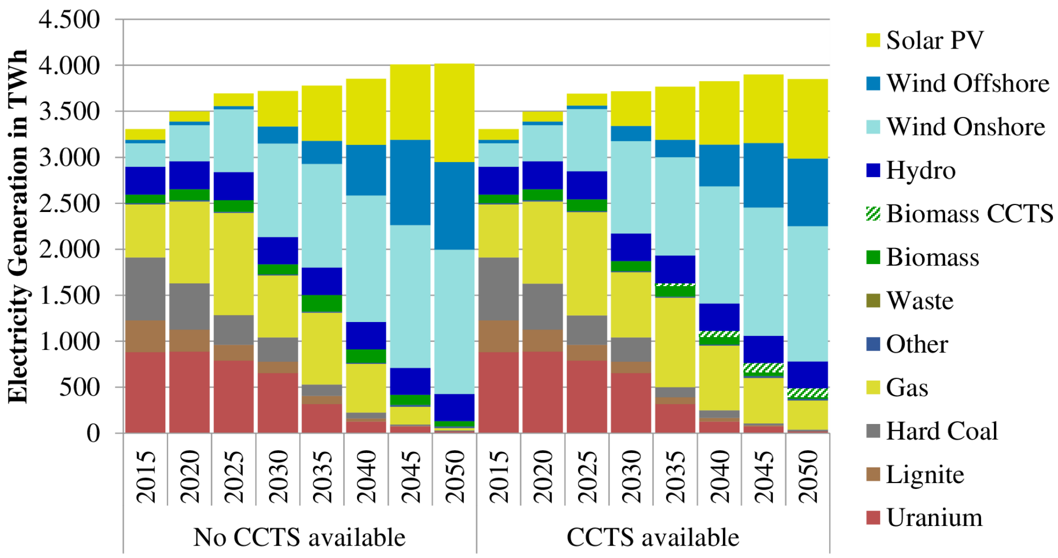


Figure 2.20.: Generation depending on CCTS availability

dynELMOD as a sensitivity. Thus, we allow for several technologies with CCTS to be built. This includes Lignite CCTS, Coal CCTS, two gas-fired CCTS technologies and Biomass CCTS. With availability of these technologies, the investment decision will vary especially when high GHG mitigation pathways are implemented.

Figure 2.20 shows the development of electricity generation in Europe with the availability of CCTS. We see that no additional gas-fired CCTS generation is built. Starting in 2035 when the emission constraint tightens additional Biomass CCTS and gas-fired electricity generation is observed, as Biomass CCTS capacities are built, which in turn enable higher generation from gas. Compared to the standard scenario, this reduces the generation of mostly renewable capacities such as Wind Onshore and Offshore, and Solar PV. As the CCTS capacities are dispatchable and have a higher average availability than renewables, the need for storage capacities is also decreased. The total amount of capacities that are fueled by Biomass increases slightly. Biomass CCTS capacities provide a way to achieve negative emissions, giving the other fossil conventional capacities some leeway to reduce their output in later time steps. The overall electricity generation is lower than in the case without CCTS, as storages see less use, and fewer storage losses occur.

In Figure 2.21 the development of electricity generation with CCTS over time is depicted. Most of the additional generation is based on biomass, accompanied by increased gas fired generation in 2045 and 2050. The additional gas-fired generation roughly corresponds to three times the additional biomass fueled generation, as these lead to an assumed emission reduction.

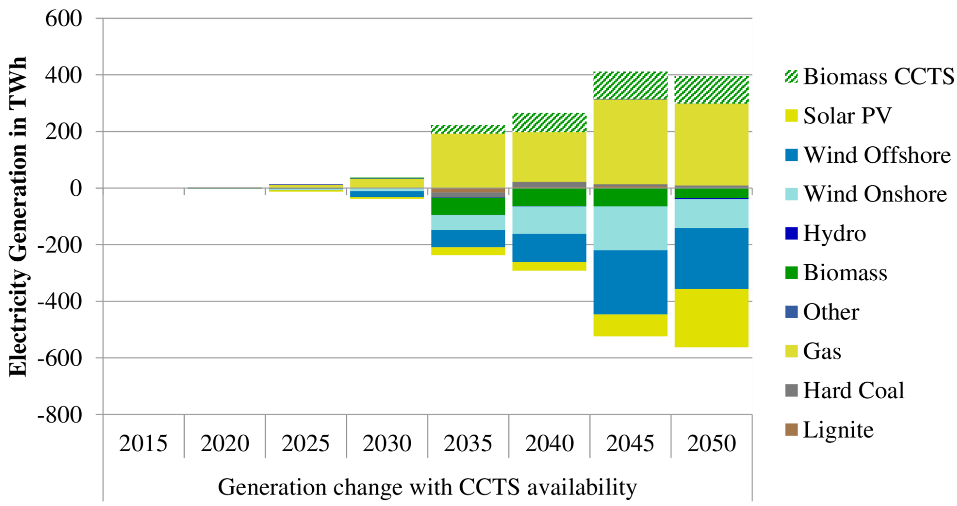


Figure 2.21.: Difference in electricity generation with CCTS available

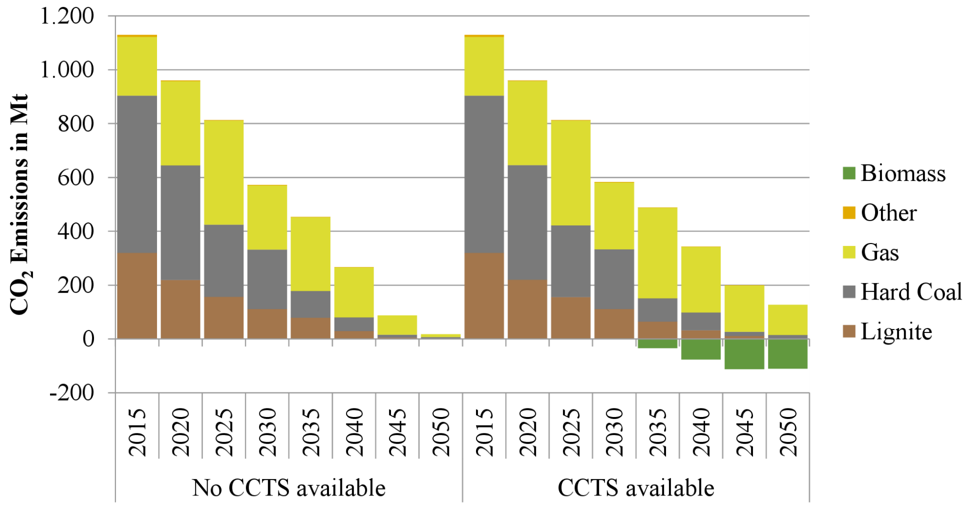


Figure 2.22.: Emissions depending on CCTS availability

In the Figure 2.22 the emissions by fuel are shown. The adoption of biomass fueled CCTS starts in 2035, and reaches its maximum in 2045. This development enables conventional gas-fired power plants without CCTS to run while not violating the total yearly emission constraint.

Emission constraint implication

One of the main constraints driving the results is the decarbonization target. A goal of reaching a nearly emissions free electricity system implies major changes to the underlying electricity generation portfolio as well as other infrastructure providing flexibility such as storage and grid. In this subsection a sensitivity analysis tests the effect of altering the decarbonization target to gain insights what outcomes could arise when decarbonization takes place earlier or is not implemented until 2050. Starting from 2015, linear CO_2 emission pathways have been implemented (see Figure 2.8), which range from only reaching 50% decarbonization of the electricity sector until 2050 to zero emission already in 2040.

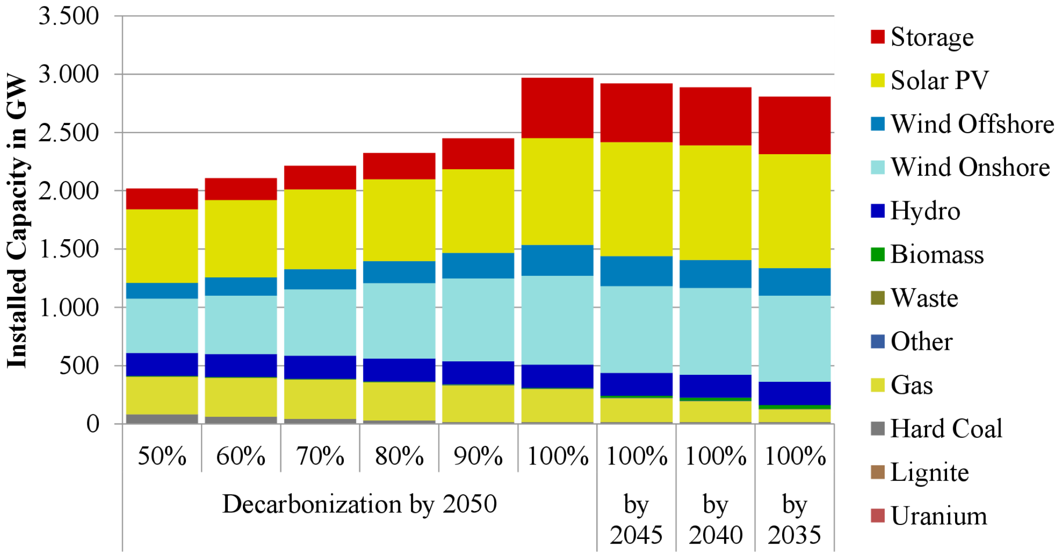


Figure 2.23.: Installed capacity 2050 subject to the decarbonization target

Figure 2.23 shows the installed electricity generation capacities in 2050 depending on which CO_2 emission pathway has been implemented. In the cases where only 50% decarbonization is reached until 2050, the capacity needed is lower than in the standard case, as a higher amount of electricity generated comes from fossil fuels (mainly gas, only 78 GW of hard-coal capacities). Renewable power sources play a significant role even in the 50% decarbonization pathways, as the future cost development leads to widespread implementations regardless of scenario. In the case of 90% decarbonization, the installed capacities are highest, as here both gas-fired capacities for the transition years as well as sufficient renewable capacities to reach 90% decarbonization in 2050 are built. With stronger targets for 2050 or earlier decarbonization, the amount of renewable plants installed in 2050 are similar, but fewer gas-fired plants exist, as these are not needed during the transition years.

Grid representation approach

In addition to the flow-based cross border grid representation approach, the option exists to using a simplified grid representation, which implements the cross-border flows as a transport model. The so-called "NTC approach" has the advantage of substantially faster calculation times as well as lower data requirements. This section presents the grid expansion results of the NTC approach.

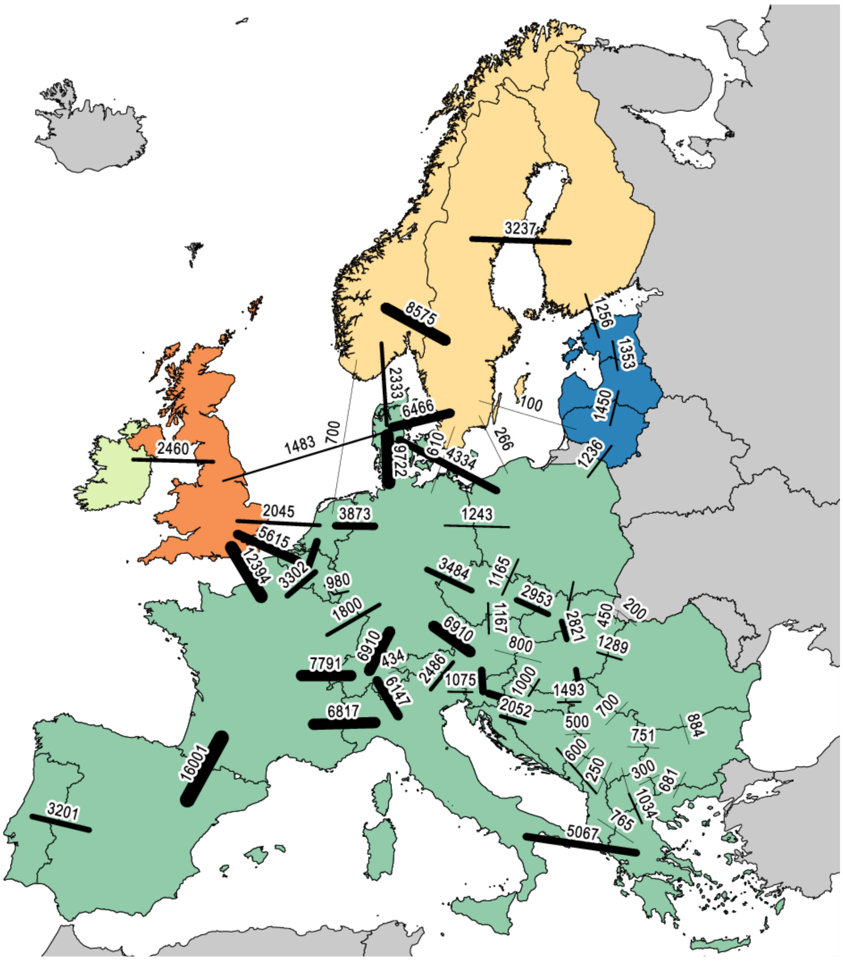


Figure 2.24.: NTC values in the year 2050 in MW, calculated with NTC approach

Figure 2.24 depicts the NTC values of the year 2050. Overall cross-border capacity expansion is similar to the flow-based approach. As expected, the cross border investments in continental are more evenly distributed in the flow-based approach, as all cross-border investments also influence the need for cross-border grid expansion on neighboring borders. This is not the case in the NTC approach. This can be seen at the Germany-France border, where no expansion takes place in the NTC approach and the transfer capacity through Switzerland is used, but in the flow-based approach the same line shows a capacity of 4,500 MW in 2050. The interconnector between Sweden and Lithuania is built in 2045, but only at a capacity of 100 MW.

The investment in electricity generation and storage capacities also changes slightly but not substantially by using the NTC approach. The largest shift between countries occurs also between Germany and France. Here Solar PV capacities and storage capacities of about 10 GW are shifted from Germany to France when the NTC approach is used. As the overall change is small, the shifts in installed capacity are

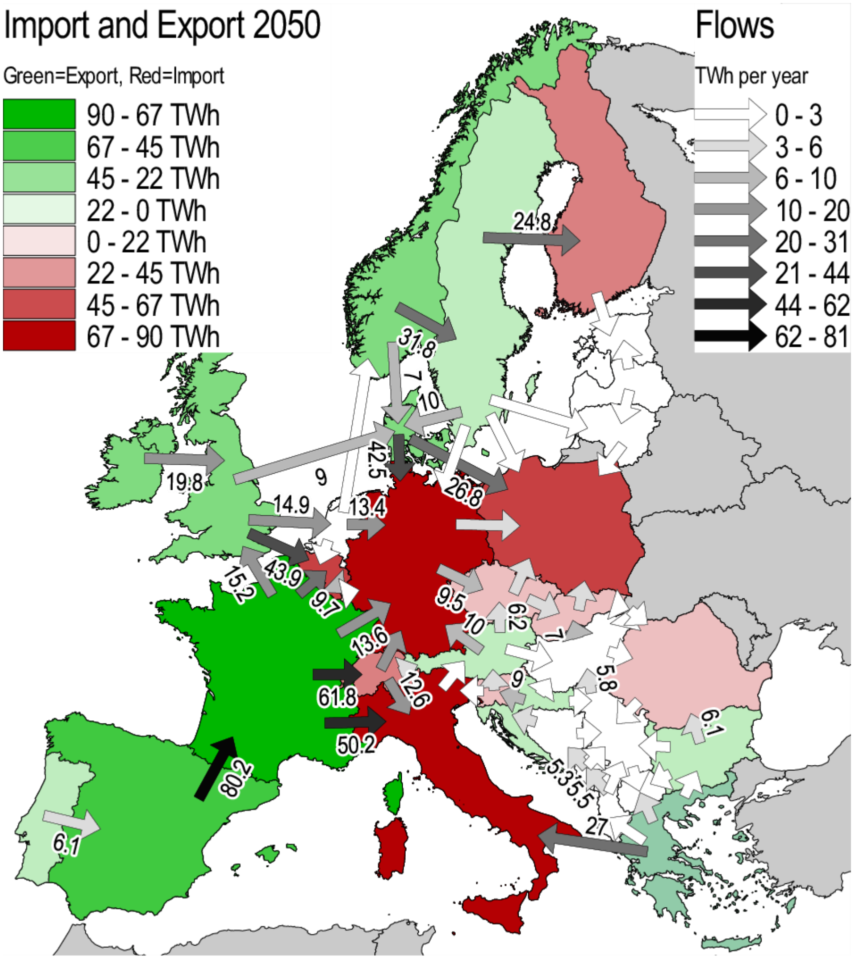


Figure 2.25.: Import and export in TWh in the year 2050, calculated with NTC approach

not depicted here. The imports and exports in 2050 resulting from the new NTC values are shown in Figure 2.25. The distribution of electricity transfers is also less evenly distributed when the NTC approach is in place, as implied by the methodology.

2.6.5. Discussion of limitations

dynELMOD can be used to answer a variety of questions about the future of the European electricity system. As it is a large scale model of the European electricity system, it has to abstract from many aspects which could influence the outcome.

One the one hand this is caused by the model formulation itself, which is a LP and thus neglects any non-linear relationships between parts of the system, on the other hand many other factors influence the results. The variability of the countries' regional characteristics is certainly greater than represented in dynELMOD. E.g. regionally different cost of capital might influence the results. In addition to the points listed below, the model assumes no stochastic or other implementations of uncertainty regarding the development of relevant boundary conditions.

NTC and flow-based approach dynELMOD uses a country-sharp representation of the electricity system. This is due to practical reasons, but neglects the market design in certain parts of Europe, where one country contains multiple price zones, or price zones span multiple countries. Between the country zones, line expansion is approximated by increasing the NTC capacity. The cost for this kind of expansion is mainly dependent on the distance between the country centers (see Section 2.4.3). Therefore the true costs of increasing the interconnection capacity might be over- or underestimated. This is subject to further investigation in the future. Also separating price zones within countries is a possible extension of dynELMOD.

Time series In the previous sections the importance of temporal and spatial variation of the time series was highlighted, as the dynamics of the time series contribute largely to the model outcome. During the time series preparation step, the time series is smoothed. The smoothing of the reduced time-series leads to a loss of short-term variation between countries. This is expected, but overall temporal and seasonal characteristics are preserved adequately.

The goals of finding a cost-effective investment in future electricity system is not only driven by the GHG constraint, but also other aspects should be taken into account. Ensuring an adequate electricity system that provides sufficient generation or storage capacity while only using a small subset of all possible temporal variations during the investment determination step requires a robust time series reduction algorithm. Testing the outcome of the investment step is done in the dispatch step. This provides a good approximation, that the overall model outcome provides an adequate system, but includes only a single year of validation. Here, more extreme events that exceed the variation of the provided time series might not be represented adequately.

Sector coupling and other boundary conditions As discussed in Section 2.4.2, dynELMOD focuses on the development in the electricity sector. The interactions with other sectors is limited, and reflected by the demand development assumptions as well as flexibility approximations such as DSM. The future adoption of energy efficiency measures will also substantially affect the future demand of electricity, and not only change the total amount but also the daily and seasonal distribution of demand. Especially the interactions between the electricity and heat demands are currently subject to improvement, as CHP is not taken into account for new built power plants. Also a more detailed representation of the transportation sector and corresponding BEV use is anticipated. As dynELMOD is also a partial equilibrium model, input assumptions such as the prices for coal and natural gas are fixed and do not vary when the electricity sector's demand changes.

Availability of generating units In dynELMOD a simple approximation of the availability of conventional power plants is implemented. Here average availability numbers over the course of the year are implemented.

Availability of CCTS and negative emissions The availability and possible cost to install CCTS as well as negative emissions to achieve a carbon-neutral electricity system is still unknown. We implement simple CCTS technology approximation, and allow biomass CCTS technology as a sensitivity.

Regional policies While dynELMOD can be used to determine the relationship of several influencing factors and boundary conditions, the effect of single policies that might drive the development is hard to measure, as the real-world implications of policy restrictions far exceed the complexity of such models. Especially as not only centrally administered policies are in place (such as the EU ETS) but also local policy development on a country level will shape the development of the future European energy supply. For example, the early adoption of renewable generation technologies in Germany is driven by the EEG, which in turn contributed to the current cost development of these technologies. The rate of transformation that can be undergone in single countries is not part of any constraint and might also be overestimated. Furthermore, by implementing constraints to reproduce policy measures, the correct functioning of the respective constraint is assumed.

2.7. Conclusion

This chapter describes the open-source model dynELMOD which determines the cost-minimal investment in and dispatch of generation and transmission infrastructure in the European electricity sector until 2050. The model combines several novel approaches to be able to approximate the underlying electricity grid infrastructure adequately, and to reduce the time frame of the investment calculation to keep the model size and computation requirement tractable. It provides a tool set to determine the effect of several boundary conditions that can be analyzed.

dynELMOD is applied to a dataset of the European electricity system, with assumptions on the future development of fuel prices, electrical demand, the development of future investment cost pathways. One of the major constraints is the

CO_2 emission constraint, which decreases almost linearly from 2020 to 2050 to reach almost complete decarbonization of the European electricity sector.

The model results show that no new nuclear, lignite, or hard coal capacities are built, but renewable energy sources provide the majority of the electricity generation in the future. Electricity production from nuclear, lignite and coal is phasing out gradually and not longer significant on a European scale after 2040. Until 2035 electricity production from gas is constant but from then on steep declining and will only be used as backup capacity in 2050. Due to the lower FLH of renewables energy sources compared to conventional energy sources this leads to an increase of installed capacity. Furthermore as renewable energy sources have a lower firm capacity, storage investments increase when high shares of renewable energy are reached. To balance out those possible fluctuations the interconnector capacity between countries will be increased. This allows to profit from the spatially different feed-in characteristics of renewable, especially wind. Furthermore fortified interconnections allows to transport electricity from locations with the highest wind speeds or solar radiation and therefore lowest production cost to the load centers of Europe. The results show mayor electricity flows from the south and the west towards central (east) Europe. This leads to changes compared to current import and export patterns, especially for Germany.

Discussion of model insights need to be done while being aware of the limitations that such a model contains. Therefore it is necessary to allow for full transparency and accessibility to the model formulation and the input data assumptions. In line with current trends, dynELMOD is published under an open source license, including the model formulation and all required input data.

Chapter 3

Scenarios for decarbonizing the European electricity sector

Previous versions were presented at the 10^{th} Annual Trans-Atlantic Infraday (TAI 2016) in Washington, USA, and the 10. Internationale Energiewirtschaftstagung (IEWT 2017) in Vienna, Austria.

3.1. Introduction

Reducing the carbon emissions from the electricity sector is an essential element of any low-carbon energy transformation strategy, essentially because mitigating emissions in other sectors is more challenging and costly. Europe has set out particularly stringent targets for the low-carbon energy transformation: it has set a binding target of 40% greenhouse gas emission reductions until 2030 (basis: 1990), and a (non-binding) target of 80-95% reduction by 2050. Already the European Union (EU) "Reference Scenario," of 2011 the long-term energy projection carried out EU-wide every three years, did foresee an almost complete decarbonization of the electricity sector, with only 2% of the 1990 carbon dioxide (CO_2)-emissions remaining by 2050 (EC, 2011b). In doing so, it relies on a combination of fossil fuels, some of which is equipped with carbon capture, and some renewable energy sources. The chapter analyzes different scenarios of decarbonizing the electricity sector in Europe at the horizon 2050. In particular, we sketch out several scenarios of the transformation of the European electricity sector and discuss the implication of different assumptions on the foresight of the actors, such as perfect foresight, myopic foresight, and a budgetary approach (allocation of CO_2-emissions over the entire period from 2020 to 2050). We are also interested in the future role of nuclear power in the cost-minimal decarbonization pathway.

This chapter is structured in the following way: the next section describes the dynamic investment model of the European electricity market, called dynELMOD, which is a result of a decade of modeling work on electricity markets. Section 3.2 also describes the main data used in the model, including a survey of cost estimates for low-carbon technologies. Section 3.3 contains the definition of the scenarios, Section 3.4 the main results of the model calculations; in addition to the main scenarios we distinguish between a world with perfect foresight, one with myopic foresight, and one with an overall CO_2 budget available to the decision makers. Section 3.5 provides a discussion of the results, and Section 3.6 concludes.

3.2. Model and Data

3.2.1. dynELMOD: a detailed model of the European electricity sector

We apply the dynELMOD framework from Chapter 2, which is a dynamic investment and dispatch model for Europe formulated as a linear problem in GAMS. The objective is to minimize total system costs in Europe until 2050. To do so, the model can decide endogenously upon investments into conventional and renewable

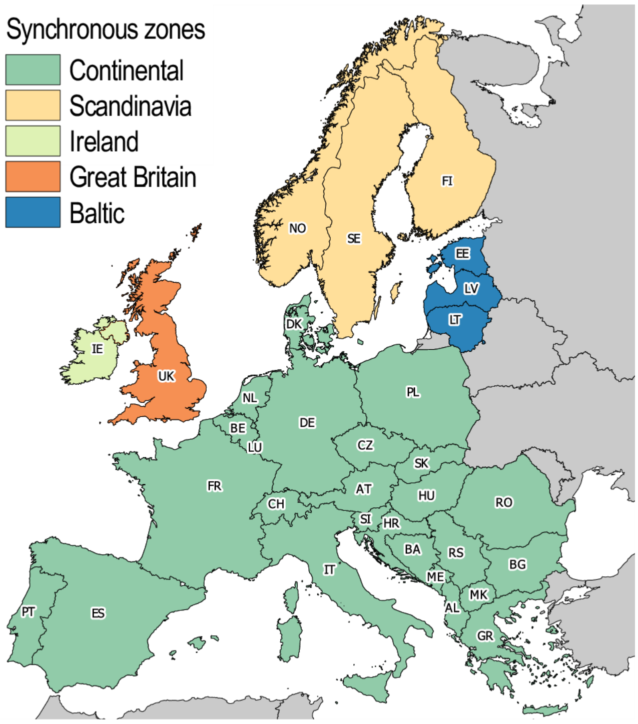


Figure 3.1.: dynELMOD geographical coverage

power plants, different storages including demand side management (DSM), and the high-voltage electricity transmission grid. This determines the solution space for the resulting power plant dispatch and electricity flows between countries. While for the investment decisions a reduced time frame is considered, the dispatch calculations are done in a subsequent step with a full year and checked for system adequacy. The time frame reduction technique allows to represent the general and seasonal characteristics of an entire year but also to achieve a continuous time series for renewables feed-in and electricity demand including times with low solar radiation and little wind in-feed. dynELMOD determines investments into electricity generation capacities in 5-years steps with a variable foresight length. The underlying electricity grid and cross-border interaction between countries is approximated using a flow-based market coupling approach based on a power transfer distribution factor (PTDF) matrix. It is derived from a full-fledged node- and line-sharp representation of the European high-voltage electricity system. Relevant boundary conditions are the CO_2-budget, decommissioning of existing plants after the ending of their lifetime and the electricity demand development. A detailed model description and the mathematical formulation can be found in Chapter 2.

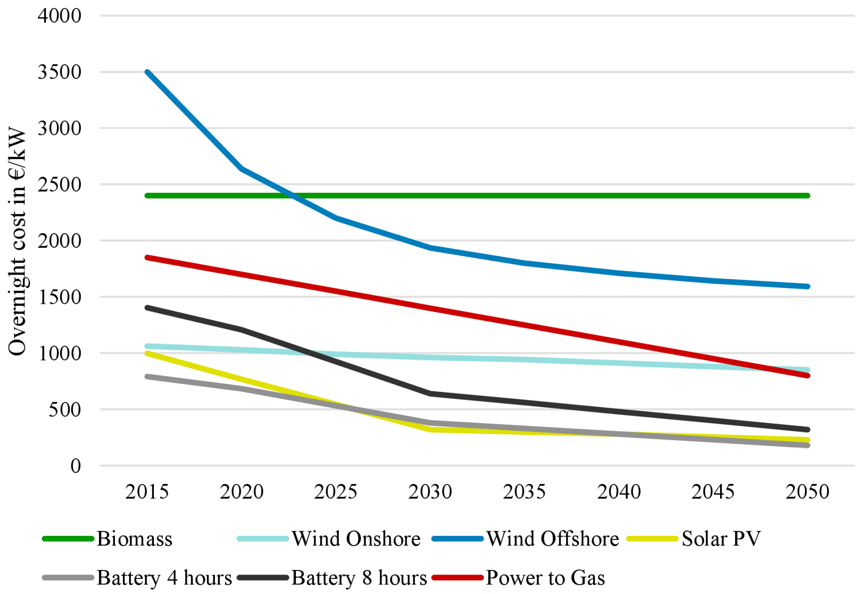


Figure 3.2.: Investment cost assumptions for selected technologies

3.2.2. Data

The data used describes the essential characteristics of the European electricity sector, including demand, electricity transmission, and generation and storage technologies. We use input data and assumptions provided in Chapter 2 that are published under an open source license. This dataset includes 33 countries, each represented with one node and located within five different synchronous areas (Figure 3.1). The anticipated development of the existing power plant portfolio serves as the baseline upon which investments into new generation capacity can be built. Potentials and different resource grades for renewable energy sources (RES) are included on a country resolution

An essential element of any dataset is the assumption about future investment costs. dynELMOD relies on an extensive survey of the literature carried out over the last years and documented in the DIW Berlin Data Documentation 68, published by Schröder et al. (2013) and updated over time using newest studies and expert estimates. Figure 3.2 summarizes the main assumptions of how investments costs are likely to evolve.

Nuclear power invest costs have gone up systematically over the last decades, as observed by Grubler (2010), Joskow and Parsons (2012), and Rangel and Lévêque (2015). Consequently, the EU Reference Scenario 2016 has increased its estimates from 4,500 €/kW to 6,000 €/kW (EC, 2016).[11] We decided to take the average

[11]"Compared to the previous Reference Scenario costs of nuclear investments have been increased by over a third and the costs for nuclear refurbishments have also been revised upwards" (EC, 2016).

expected costs of the ongoing new build projects in Europe (Olkiluoto, Finland; Flamanville, France; and Hinkley Point, UK), and the US (Vogtle, Summers), and to discount them by 15% due to potential "first-of-a-kind" cost inflation.[12] Following the literature, we do not foresee economics of scale from potential "n^{th}-of-a-kind" plants, but we do not foresee any overnight cost increases neither. We add 900 €/kW in provisions for plant decommissioning and long-term storage, arriving at constant overnight costs of 6,000 €/kW – which is in line with the estimates of the European Commission (EC, 2016).

Cost estimates for renewables rely on a large number of figures provided by industry and independent experts. We expect the cost degression of solar photovoltaic (PV) to continue, though at a slower pace over time; onshore wind also has a positive, but significantly less steep learning curve. The estimates for offshore wind are subject to a much higher uncertainty. Biomass is expected to remain by far the most expensive renewable source.

Cost development estimates for storage and DSM technologies are based on Pape et al. (2014) and Zerrahn and Schill (2015a). For assumptions about costs for carbon capture, transport and storage (CCTS) technologies, which can be implemented as a sensitivity but are not included in the default model runs, we follow the optimistic forecast by the industry to propose a technology that is not yet available at commercial scale (Oei and Mendelevitch, 2016; Schröder et al., 2013).

3.3. Scenarios

We apply dynELMOD to three main scenarios with different degrees of planning foresight regarding the decarbonization pathway until 2050. Our objective is to analyze the development of the European electricity sector under different boundary conditions. dynELMOD can present different scenarios of how decision makers deal with information: The knowledge (or lack thereof) how the electricity sector's future boundary conditions will evolve can have a substantial impact on the investment decisions done over time. Therefore we test different assumptions regarding the planner's foresight:

- The *Default Scenario* anticipates an overall moderate electricity demand increase as well as an almost complete decarbonization of the electricity sector in Europe until 2050. It serves as a reference for the next scenarios. It assumes perfect foresight over the entire horizon (2015–2050). The central decision maker faces a yearly CO_2 constraint, which reduces carbon dioxide emissions by 2050 to only 2% of the current level.

[12]See the detailed methodological approaches set out by D'haeseleer (2013) and Rothwell (2015).

- By contrast, a *Reduced Foresight* scenario considers that the decisions makers are only aware of the CO_2 target of the upcoming five-year period, and thus behave “myopically.” The interest of this scenario is to model possible short-sightedness of politicians due to election cycles as well as investors’ limited trust in long-germ (environmental and) political targets. The results should therefore identify the danger of stranded investments resulting from such a short-term vision.
- An alternative scenario to reflect a different CO_2 allocation mechanism is implemented in the *Budget Approach*: decision makers receive an aggregate emission budget covering the entire period from 2015 up to 2050 ($\approx$ 22.5 bn. t of CO_2), and then can use this budget at their discretion over the period. An additional constraint is that the annual emissions in 2050 are not allowed to exceed 2% of 2015 CO_2 emission levels. The budget approach has become popular among climate policymakers and academic researchers recently. It allows decision makers a higher degree of decision resulting in lower overall costs. In general, abatement decisions are taken earlier to “save” emission rights for the final years where abatement is expected to become more expensive.

3.4. Results

3.4.1. European electricity under emission constraints

The model results give insights into a possibility for the generation capacity development in the European electricity sector until 2050. Figure 3.3 shows the development of electricity generation in Europe between 2020 and 2050, in five-year steps, under the given linear CO_2-reduction path to 2% in 2050. Due to high investment costs, no new nuclear power plants are built, and therefore nuclear power generation is reduced over time as older plants reach the end of their technical lifetime. Renewables become the dominant electricity source in Europe. In the absence of carbon capture technology due to high costs, lignite and coal are phased out as no new coal capacities emerge. Gas electrification, on the other hand, is expanded until 2035. Although 215 GW of gas-fired capacities are built, their usage declines significantly after 2035, to become a backup technology. Electricity generation from biomass and other sources such as waste and geothermal energy remains nearly constant.

The largest share of the abatement is carried by renewable sources, wind (onshore and offshore) and solar PV. In the competition between the renewables, wind dominates, obtaining a share of over 60% in 2050. This share consists of onshore wind generating 1,570 TWh, and offshore wind adding additional 951 TWh. Despite benefiting from the strongest cost degression, solar PV produces “only” 1,070 TWh

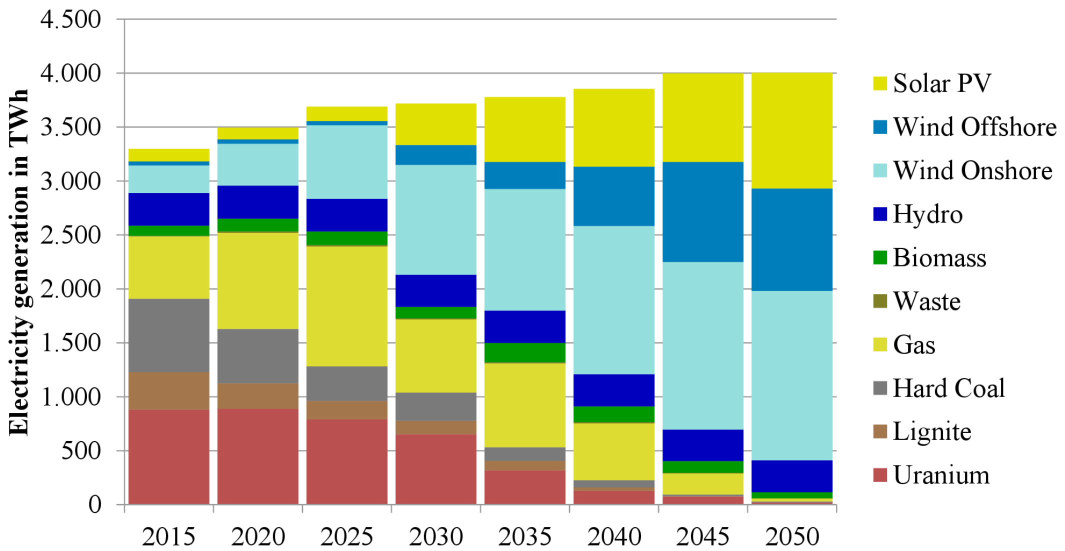


Figure 3.3.: European electricity generation in the *Default Scenario* 2015–2050

in 2050; even though not less than 880 GW of solar PV capacities are installed in 2050. The installations of wind are lower with capacities of 740 GW Onshore and 270 GW Offshore.

To accommodate the fluctuation of renewables, a total of 465 GW of storage capacities are built, mainly towards the latter half of the period. New pumped storage capacities are negligible due to limited new potential. Therefore lithium-ion battery storage obtains almost all investments. DSM, although implemented in the model, only plays a marginal role, providing only 3% of the flexibility needed in the system.

Figure 3.4 shows the accumulated investments in power generation capacities in the default scenario in France, Spain, the United Kingdom (UK), Germany, Italy, Poland, Greece, and the Netherlands from 2020 until 2050. Aging conventional power plant fleets especially in France, Spain and the UK call for a refurbishment of the electricity system. Investments in France are highest overall, with 47 GW of new gas power plants, 147 GW onshore and 75 GW offshore wind installations. Investments in solar PV are also above 100 GW, investments in concentrated solar power (CSP) plants appear only in minor quantities and are aggregated under the solar PV category. In Spain, no new investments in conventional power plants are observed, but onshore wind and solar PV dominate the future electricity generation. This leads to investments into storage technologies of 92 GW. In Germany, onshore and offshore wind power obtain the largest share of investments with 74 GW and 65 GW respectively, whereas the model builds 100 GW of solar PV. Italy shows a different profile, where almost only solar PV capacities are built until 2040, followed

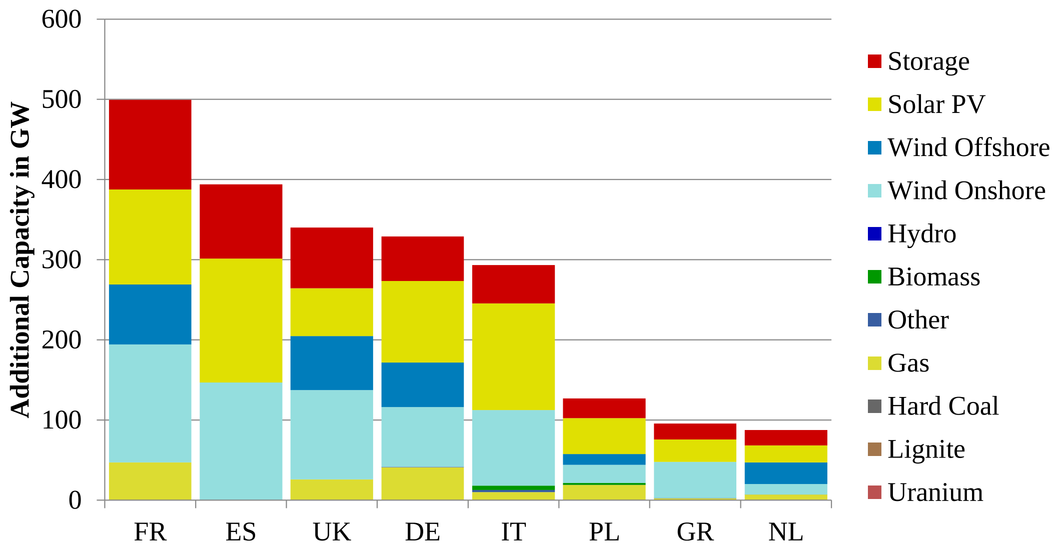


Figure 3.4.: Accumulated investments in generation capacities in the *Default Scenario* in selected countries from 2020-2050

by some wind, and a little bit of biomass investments. In both countries, the need for storage increases over time.

3.4.2. Reduced foresight leads to stranded investments

We now compare differences that emerge from different assumptions about the foresight of the decision makers. In the scenario *Reduced Foresight* the myopic foresight, e.g. a reduced vision of future CO_2 abatement needs, leads to a different investment strategy as the future decarbonization targets are not taken into account. This provides insights into possible developments of the power plant portfolio in case the overall investment decision making is not driven by a belief in further decarbonization in the future. This leads to significantly higher investments in carbon fuel capacities. Figure 3.5 shows the differences in investments between the *Reduced Foresight* scenario, compared to the *Default Scenario*. Clearly, large quantities of "stranded" investments into gas fired capacities would occur, e.g. in the UK 15 GW, France 14 GW, Spain 7 GW, and Germany 6 GW. In the years 2020 and 2025, the investments in gas capacities are similar to the default scenario. But in 2030 and 2035 additional 56 GW and 59 GW are added to the system, which is 22 GW respective 53 GW higher than in the default scenario. Afterwards no investments take place. No investments into coal-fired power plants occur even in the *Reduced Foresight* scenario.

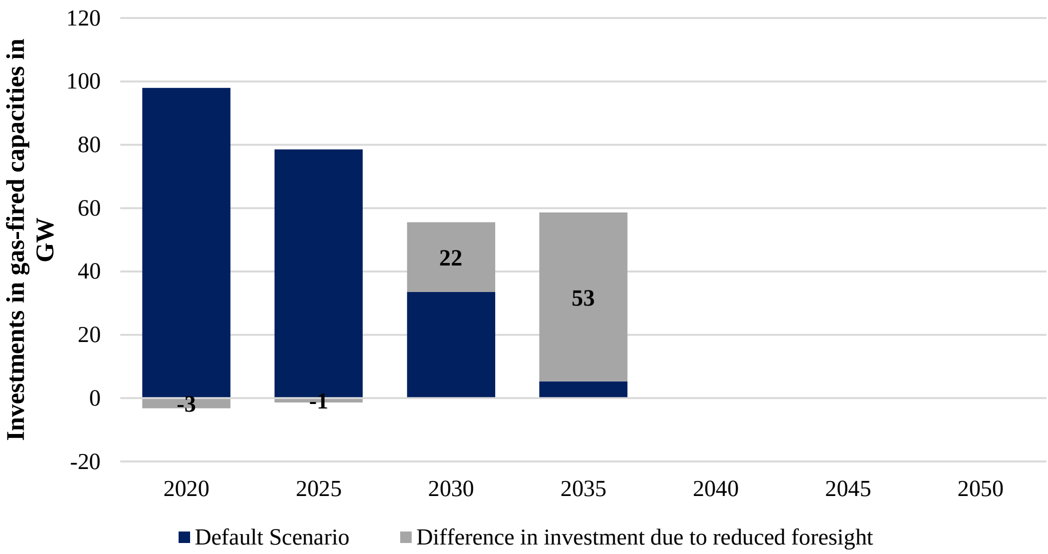


Figure 3.5.: Investment differences for gas power plants in *Reduced Foresight* scenario vs. *Default Scenario* from 2020 – 2050 in Europe

3.4.3. Emissions comparison

In Figure 3.6 the CO_2-emissions over time by fuel are depicted for the default and the reduced foresight scenarios, as well as the difference in emissions induced by the reduced model foresight. In the default setting, emissions from hard coal and lignite decrease faster than emissions from gas, where until 2025 an increase in emissions follows. From 2035 onward, emissions from coal are overtaken by gas, which is from then onwards the largest source of CO_2-emissions. In 2050, the remaining 19 Mt of CO_2 almost exclusively originate from gas.

In the case of reduced model foresight, the timing and structure of investments is different. In the *Reduced Foresight* scenario, investments in gas capacities are similar initially, but starting in 2030, are significantly higher than in the default scenario. At this point, the investment structure of the *Default Scenario* has shifted to a mostly storage and renewables-based one, whereas investments into gas capacities remain stable until 2035 in the *Reduced Foresight* scenario. These capacities of additional 22 GW in 2030 and 53 GW in 2035 lead to additional stranded fossil capacities as the emission constraint remains the same. Especially run times of carbon-intensive coal power plants are substituted by these additional gas power units. The average full load hours of coal-fired power plants are decreased by more than 1.000 hours in between 2030 and 2040, the decrease of lignite's full load hours is accelerated compared to the default scenario, where full load hours above 6,000 are observed until 2035. The additional gas capacities decrease the full load hours to less than 4,000 in 2035.

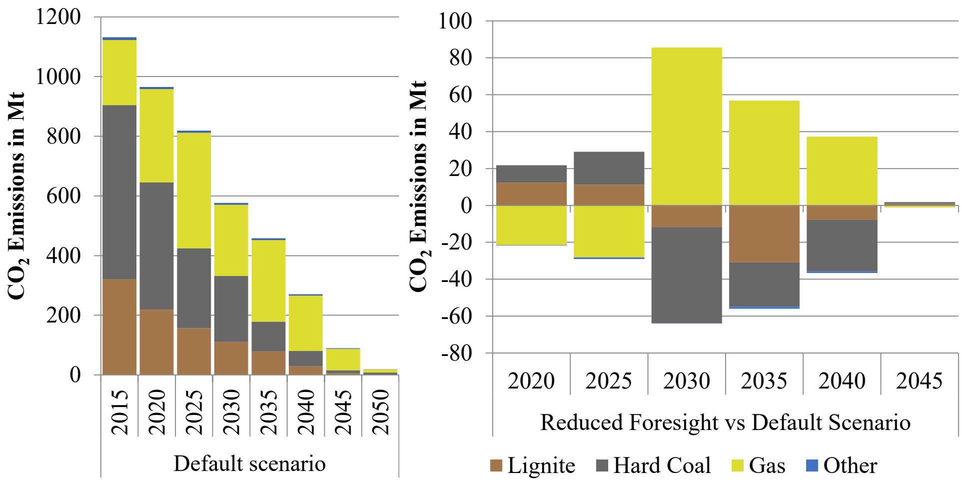


Figure 3.6.: CO_2 emissions by fuel and scenario

3.4.4. Emissions in the Emission Budget scenario

We now compare the results of the *Default Scenario* with those of the *Emission Budget* scenario, where the decision maker is free to allocate the total emission budget (here: about 22.5 bn. t CO_2) over the entire period. Figure 3.7 shows the difference between the CO_2 emissions in the default scenario with those occurring under an emission budget. Clearly, the control of the full budget leads to a reduction of emissions in the early period (2020 – 2030), where emissions are about 170 Mt lower than in the default scenario. On the contrary, in 2040 and 2045, emissions under the budget approach increase beyond the default scenario: they are highest in 2045. Overall system costs over the entire period can be reduced by about 1% due to this shift which amounts to about 1.2 bn € per year for the entire model region. One interpretation of this result is that the new degrees of freedom invite the decision maker to use "low hanging fruits" of abatement earlier, mainly by reducing existing overcapacities of coal and lignite electrification. This strategy allows for additional emissions, primarily used by gas plants, towards the end of the modeled period.

3.5. Discussion

3.5.1. Operating a low-carbon electricity system in 2050

Can a largely renewables-based electricity system, that dynELMOD foresees as the lowest-cost solution for decarbonization, deliver secure electricity? Previously, it was considered that intermittent renewables needed to be balanced by conventional capacities, mainly gas. With the cost degression of both renewable energy and storage capacities, and under a strict carbon constraint, the renewables-gas combination is

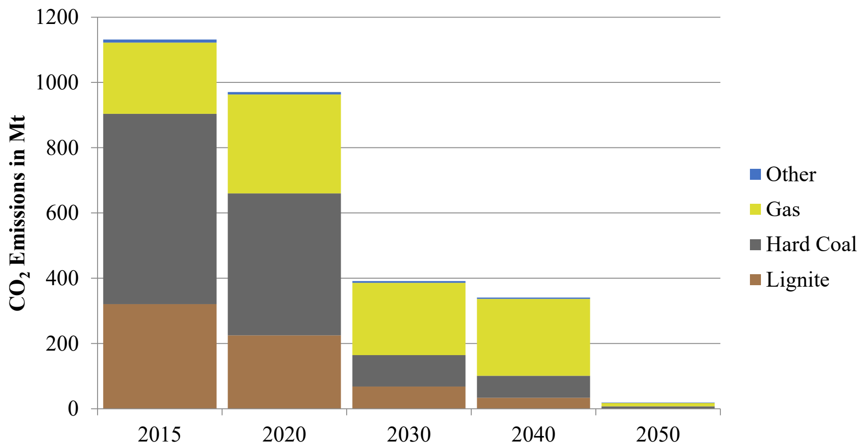


Figure 3.7.: CO_2 emissions in the “Emission Budget” scenario (2020 – 2050) in ten-year steps

much less attractive. This section looks at the concrete hour-to-hour functioning of the electricity system and specifically addresses the operation in different European countries using Germany and Italy as examples. Aside from pure electricity generation aspects, also stability of the system and the use of ancillary services with rising shares of renewables becomes important. Lorenz (2017) estimates that balancing services can be provided in decarbonized electricity systems at current cost levels if technical and regulatory boundary conditions enable participation of renewables.

Figure 3.8 shows the hour-to-hour functioning of the German electricity system in the default scenario. The two depicted weeks in early February 2050 are the most critical period in the year regarding demand peaks as well as low solar PV availability and intermittent periods of low wind in-feed as well. Given the investment program sketched out above, wind is clearly the dominant source of supply and delivers 47% of total electricity in that two-week period. Both wind and solar PV are intermittent and have moments where little of it is available, such as around the model-hour 953, that – in addition to electricity trade, i.e. imports – significant amounts of storage are necessary. Points at which the system is in an inadequate configuration do not occur in any model hour. These storages are charged at times of high renewable availability or low demand. Between 2020 and 2050, 56 GW of storage capacity have been built. Figure 3.8 also shows how the combination of storage and trade assures a secure supply of electricity even in the most critical hours of the year. The imports come in decreasing order from Denmark, Switzerland, the Netherlands, France, and Austria. The balance with Sweden and Poland is roughly zero. At the same time on average 960 MWh are exported to the Czech Republic. As dynELMOD is a model with an hourly resolution, ramping constraints can only apply to a subset of technologies such as lignite power plants. Gas capacities can ramp to their full capacity within a

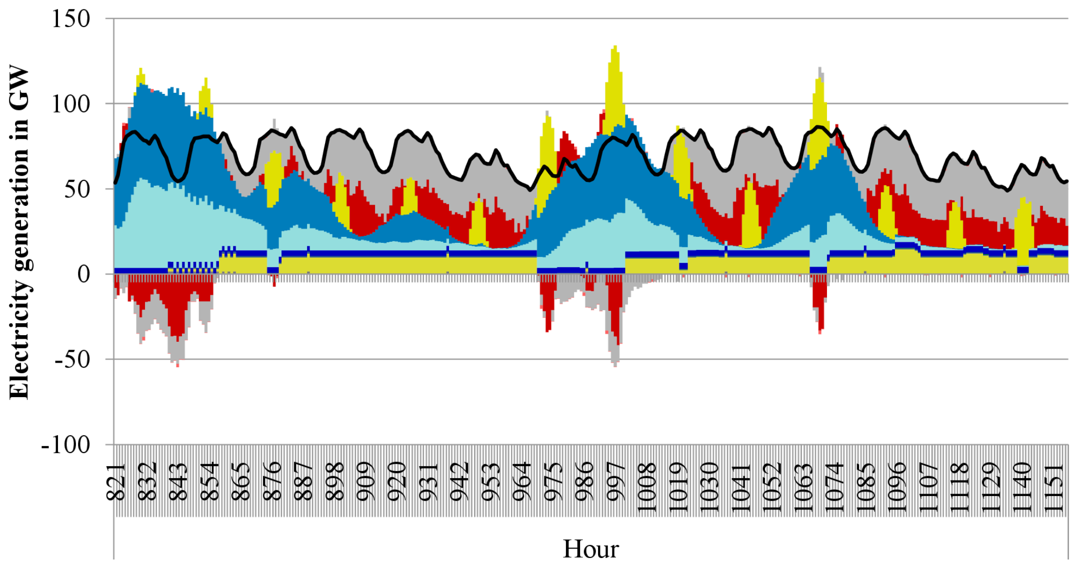


Figure 3.8.: Hour-to-hour operation of the German electricity system in 2050 (first two weeks of February) for the default scenario

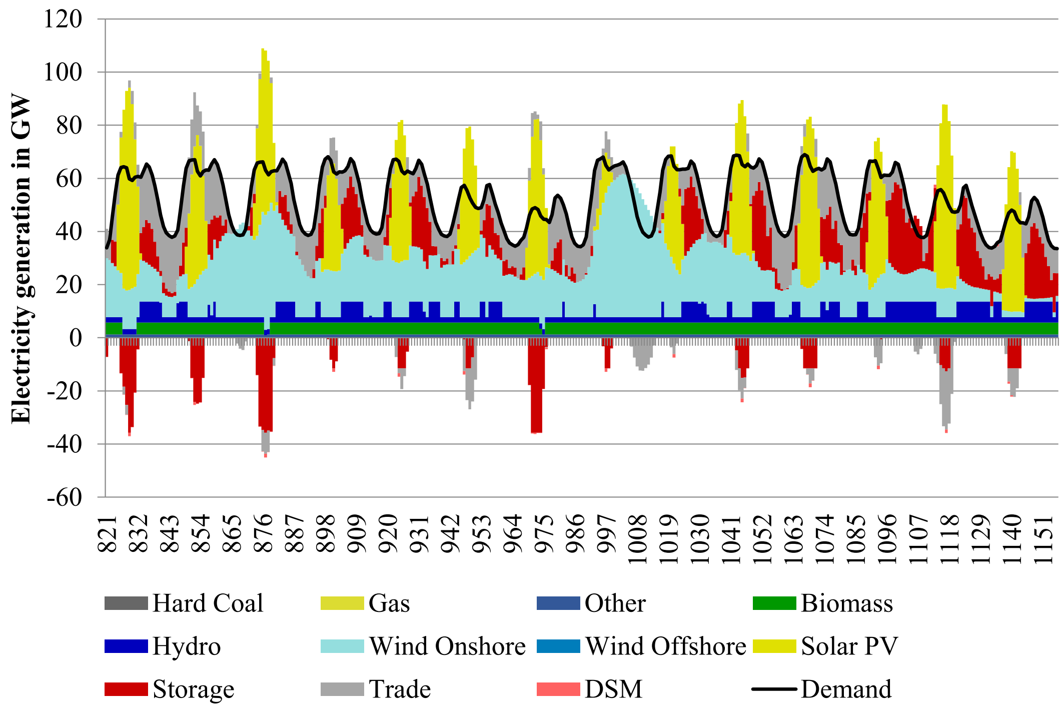


Figure 3.9.: Hour-to-hour operation of the Italian electricity system in 2050 (first two weeks of February) for the default scenario

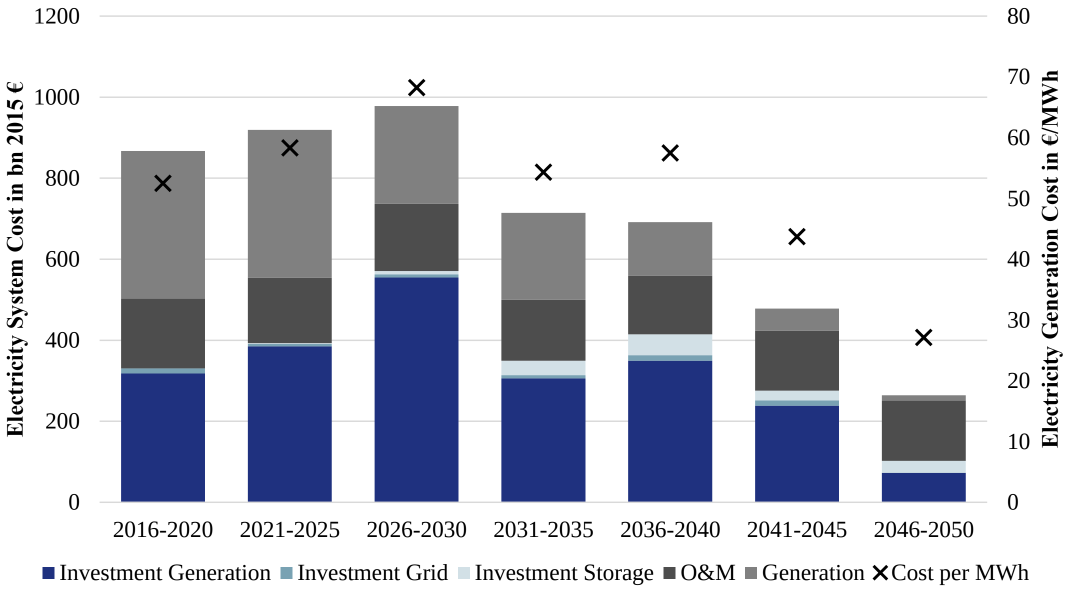


Figure 3.10.: Overall electricity system costs (2020 – 2050), by segment

single hour. This is visible in Figure 3.8, where gas capacities show high ramping rates. As the electricity system is almost fully decarbonized in 2050, the electricity supply of gas capacities is limited throughout the year.

Figure 3.9 presents a similar exercise for Italy, also in the time-frame of the first two weeks of February for the default scenario. The dispatch of generation technologies in Italy is shaped by wind in-feed as well as solar PV availability which during the day often exceeds the demand. During these hours, storage capacities are charged to release the power during the evening hours. Italy also intermittently relies on imports mainly from France, Switzerland, and Greece.

3.5.2. Costs and prices to 2050

The rapid sector transformation leads to substantial investments into a different power generation and storage portfolio compared to today's outset. The costs associated with this transformation and the resulting average electricity generation costs are discussed in this section. Figure 3.10 shows the composition of total system costs for the default scenario, about €$_{2015}$ 4,900 bn., composed of initially approximately equal shares for variable costs, investment costs, and operation & maintenance costs. Over time variable generation costs decrease as the system shifts to a more renewables based dispatch. Even though it constitutes a crucial element in the generation mix, the costs for storage make up only about 3% of total system costs. Also, investments in the electricity grid infrastructure only contribute to 1.3% of the total costs.

Dividing the system costs by electricity generation provides an aggregate average cost of supplying Europe with electricity. Figure 3.10 also shows the development of average costs for the period 2020 – 2050, which shows a decreasing trend: from 52 €/MWh in 2020, mainly based on fossil fuels, until 2050, where an average cost of 27 €/MWh is reached.

Last but still not least we take a look at the implicit CO_2-prices that the model renders as the shadow price on the carbon constraint. Not surprisingly, the reduction of the available CO_2 emissions in the *Default Scenario* leads to an increase in the implicit CO_2 price (which is not explicitly paid by the emitting firm): from 32 €/t (2020) to 177 €/t (2050). The price development of the *Reduced Foresight* is comparable to the default scenario, here the price increase occurs at a later stage between 2045 and 2050. For the emission budget, no yearly values, but a price spanning the entire model period is available. At about 34 €/t it reflects the shadow price of an additional ton of CO_2 at any point during the period from 2015 to 2050.

3.6. Conclusion

Enabling a decarbonization of the electricity sector is crucial for keeping global temperature rise under 2 °C, as mitigating emissions in other sectors is more difficult and costly. No investment in new hard coal or lignite fueled power plants are observed in any scenario. Incorporating the climate targets makes the investment into any additional conventional capacity uneconomic from 2025 onwards, resulting in a coal and gas phase-out in the 2040s.

However, international consensus on how to achieve a decarbonization of the sector is lacking. Electricity generation will undergo substantial structural change over the next three decades, and developments in Europe, where strict carbon restrictions are likely to be imposed, are a particularly interesting case. This chapter presents different scenarios for the decarbonization of the European electricity sector in 2050 relying on a very detailed model of electricity generation, transmission, and consumption, called dynELMOD.

The model is run using different foresight assumptions. These results quantify the advantage of a structured energy transition pathway instead of potentially short-sighted decisions. Limited foresight results in stranded investments of fossil 75 GW gas-capacities in the 2030s. The amount of stranded investments is small compared to the overall installed capacities, but a robust result across sensitivities. Using a CO_2 budgetary approach, on the other hand, leads to an even sharper emission reduction in the early periods before 2030, reducing overall overall costs by 1%. A more rapid decarbonization of the European electricity system due to the COP21

Paris agreement does also not lead to an adoption of nuclear power plant but relies on further expansion of renewables and storage capacities.

We find that in the default scenario, renewables carry the major burden of decarbonization, other technologies such as nuclear power (3^{rd} or 4^{th} generation) and carbon capture appear to be unable to compete.

Transforming the electricity system towards 98% decarbonization changes the overall generation structure substantially. The accompanying total electricity generation cost shows a downward trend after reaching its highest point in 2025, to arrive at a minimum of 27€/MWh in 2050 in the default scenario. Across all scenarios costs in 2050 range between 27€/MW and 32€/MW and therefore below levels of 2017.

Further research should address the diffusion process of new technologies, mainly renewables and storage: we have assumed the emerging technologies to be available globally, and at identical, rather low costs. However, these assumption may not be provided in practice. Another important aspect is the future use of nuclear energy. While electricity from nuclear energy is clearly not economic, some countries are likely to pursue the nuclear route, for other reasons, and this should be reflected in the specific scenario runs. Last but not least, the role of electricity transmission infrastructure needs to be critically reviewed: in our scenarios, transmission constraints seem to play a minor role, whereas this might look quite different in the real world.

Part II

Balancing reserves within a decarbonized electricity sector

Chapter 4

Wind providing balancing reserves – Model development and application to the German electricity system of 2025

This chapter is based on DIW Berlin Discussion Paper No. 1655 (Lorenz and Gerbaulet, 2017) and submitted to Applied Energy.

4.1. Introduction

The degree of reliability of every electricity system depends on the functioning of all components and market segments. One of these markets is the balancing market and effective operation of balancing reserves to control short-term deviations of demand and supply is paramount. In this chapter we analyze possible price and dispatch developments in the German balancing market until 2025. The application to Germany proves to be an interesting study topic, as the current market structure might change significantly in the future. The range of changes is manifold and includes adjustments to auction design, increased market harmonization with neighboring countries, transformation of the power plant portfolio and entrance of new market participants. We want to analyze the effects of the latter two.

In the context of the low carbon transformation of the electricity system, the share of renewables is expected to increase. The rising share of renewable energy sources (RES) could lead to a change in balancing reserve demand (see Section 4.3) but could also enable participation of renewables in the provision of balancing reserves, where (among other actors) fluctuating renewables will be able to offer a percentage of their output on the market.

The reasons for deviations from the alternating current (AC) system's nominal frequency of 50 Hz can be numerous: i) load fluctuates constantly and cannot be forecast perfectly, ii) schedule leaps occur between each auctioned (quarter) hour, iii) power plant or grid outages take place unexpectedly, and iv) the in-feed of RES deviates from its forecast. All these deviations alter the system's frequency, balancing reserves restore and stabilize the frequency by activating upward or downward reserves. The balancing market in Germany is organized in three products, distinguished by their response time and length of activation. In Germany these products are primary balancing power (PRL, Primärregelleistung), secondary balancing power (SRL, Sekundärregelleistung), and tertiary balancing power (TRL, Tertiärregelleistung), corresponding to the nomenclature primary control (PC), secondary control (SC), and tertiary control (TC) of this chapter.[13]

[13]These products are auctioned by the four German transmission system operators (TSOs) on a joint platform, where some pre-qualified units from outside of Germany are able to participate. The German TSOs are also part of the International Grid Control Cooperation (IGCC), which fosters cross-border balancing exchanges. Together with seven neighboring TSOs, imbalance netting of SC capacities is applied to reduce total activation volumes. Throughout the literature different terms like balancing reserves, balancing capacity, control power, control energy are used. We will use the terms balancing reserves, balancing power and balancing energy that are used by ENTSO-E (2013a). The differentiation of the balancing power products used in this chapter corresponds to the German variant. Thus, short-time load frequency control products such as frequency containment reserve (FCR) are PC, while automatic frequency restoration reserve (aFRR) is denoted as SC and manual frequency restoration reserve (mFRR) is denoted as TC in this chapter. Furthermore, replacement reserve (RR) are used to restore the required level

The current state and development of the German balancing markets is discussed in general in Hirth and Ziegenhagen (2015), Koliou et al. (2014), Mauritzen (2015), and Müsgens et al. (2011). The majority of the literature focuses research questions ranging from technical balancing frameworks and the integration of renewables, the market design, or pricing policies. Methods of analysis are manifold, starting with numerical fundamental models (Chao and Wilson, 2002; Müsgens et al., 2014; Ortner and Graf, 2013; Swider, 2007). These models are often mixed integer linear programs (MILPs) with a detailed representation of power plant characteristics in the dispatch. Stochastic approaches are applied by Just (2011) and Lindsjørn (2012). The evaluation of statistical (panel-)data such as realized market outcomes and company behavior is conducted by Growitsch et al. (2010), Haucap et al. (2014), and Heim and Goetz (2013).

The auction design of balancing capacity reservation is often discussed: Abbasy et al. (2010), Bucksteeg et al. (2014), Knaut et al. (2017), Müsgens et al. (2012, 2014), Niesen and Weber (2014), and Swider (2007) discuss lead times in the balancing market and conclude that shorter lead times and increased flexibility of auctions in the balancing market also positively affect the efficiency of the spot market. Böttger and Bruckner (2015), Just and Weber (2008), and Just (2011) show that shorter contract duration lead to efficiency increases and less capacity effectively withheld from the spot market.

Furthermore, the effect of allowing new market participants other than conventional or renewable power plants such as renewables, battery storage, electrical boilers or managed refrigerated warehouses into the market is discussed. As discussed in Hirth and Ziegenhagen (2015) and Sorknæs et al. (2013), fluctuating renewables will most likely supply negative balancing in the next years. However, with increased hours of excess electricity production, it starts to makes sense for RES also to provide positive reserves. During these times, withholding generation from RES for balancing reserves leads to no system cost, as they would be curtailed in any case. The model used in Böttger and Bruckner (2015) is also used in Böttger et al. (2015) to analyze the participation of 1,000 MW of electric boilers on negative SC and show cost savings of about 52-158 million € in Germany in 2025. The effect of participation of wind and solar photovoltaic (PV) on the German balancing market of 2035 is analyzed by Spieker et al. (2016) using a detailed fundamental unit-commitment model. Similar to the results obtained in this chapter, the authors show that with participation of renewables, the total balancing reservation cost are decreased, but remain above 2014 values.

of other reserves (FCR, aFRR, and mFRR) to be prepared for a further system imbalance. No comparable balancing product exists in Germany.

Increased cooperation between neighboring balancing markets regarding reservation and activation of SC and TC reserves between Austria, Germany and Switzerland is carried out in Chapter 5 with the result, that regional cooperation can significantly reduce total reserve provision costs. Similarly, Farahmand and Doorman (2012), Gebrekiros et al. (2013, 2015a,b), and Jaehnert and Doorman (2010) conclude that joint reserve provision in northern Europe is beneficial.

Possibly grouping bids into portfolios also affects the market outcome. Niesen and Weber (2014) formulate an analytical equilibrium model of the balancing market and show that capacity prices are lower with shorter contract durations using a detailed unit commitment model applied to the European electricity market of 2012. If large power plant portfolios are introduced into the market, this effect is reduced. These results are confirmed by Lorenz et al. (2014), who apply a unit-commitment model of the German balancing market that allows for portfolio bidding by large generation companies.

Several of the changes to the current market setup suggested in the literature have been adopted by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Commission (EC). In the current draft of the EC's regulation of establishing a guideline on electricity balancing (EC, 2017), measures such as the harmonization of the balancing products and changes to the gate closure times and pricing structures are addressed, which could further improve the efficiency of the market and enable more flexibility in providing balancing services by wind turbines and other market participants.

This chapter contributes to the existing literature by introducing the fundamental unit commitment model ELMOD-MIP, which features a novel approach of modeling balancing reserve provision by considering possible activation costs during the reservation phase. The anticipation of reserve activation probabilities, should lead to a more realistic balancing reserve dispatch. We use this model to give an outlook on the developments of the German balancing market until 2025 and analyze the influence of wind turbines participating in the provisioning of balancing reserves. The chapter is structured as follows: Section 4.2 describes the characteristics and motivation of ELMOD-MIP, as well as the applied novel approach of our methodology and fundamental price formations in the balancing market. The mathematical formulation of the model is presented in Section 4.2.1. In Section 4.3 the data and scenarios applied to ELMOD-MIP are described. The results are analyzed in Section 4.4 and followed by a conclusion in Section 4.5.

4.2. Methodology

In order to be able to analyze possible changes in the balancing reserve markets, the basis is an accurate representation of the power plant dispatch in the respective market area, as the balancing reserve market is a comparatively small part of the entire electricity sector. The goal is to find an approximation of the prices, quantities and cost that the balancing market could have under the assumption of a perfectly competitive market setup without any inefficiencies and strategic behavior. We focus on secondary and tertiary control reserves and neglect primary control reserves due to comparable small market volumes and complex technical prerequisites for its provision.

In fundamental optimization models, the procurement of balancing reserves is often represented using one or more market clearing equations, that represent the balancing reservation demand and is fulfilled by the market participants by reserving a part of their upward or downward generation potential. This influences the dispatch decision, as the flexibility to operate on the "main" market is restricted by the balancing reservation. Further, the model's selection of what type of generation capacity or power plant is used to provide balancing services is largely influenced by the models' level of detail. This approach can be applied in linear models (Jaehnert and Doorman, 2010; Zerrahn and Schill, 2015a) on a technological or block-sharp level, as well as unit commitment models. These models implement more complex power plant dispatch restrictions such as start-up cost, minimum load, or minimum offline or online durations (van den Bergh et al., 2016; Böttger et al., 2015; Brouwer et al., 2014; Farahmand et al., 2012). The impact of power plants' part-load behavior further influences the model outcome, as especially to be able to provide positive balancing reserves, some upward potential needs to be kept available, leading to a dispatch below the optimum efficiency point. In Bucksteeg et al. (2014) and Knaut et al. (2017) this characteristic is also reflected in the balancing reserves procurement. To further improve the model's selection of capacities for balancing reserves during the balancing reservation phase Gebrekiros et al. (2015b) and Müsgens et al. (2012) include an approximation of opportunity cost between the balancing and spot markets commitment.

Most approaches presented do not anticipate the activation of balancing reserves during the reservation phase, or use static approaches to weigh the decision what capacities should provide balancing services. The approach used this chapter contributes to the literature by presenting an endogenous anticipation of the balancing reserves' activation probability. To represent the market participant's assumptions over the different stages of the balancing market (capacity reservation and energy activation) ELMOD-MIP has the possibility to anticipate the probability of balancing

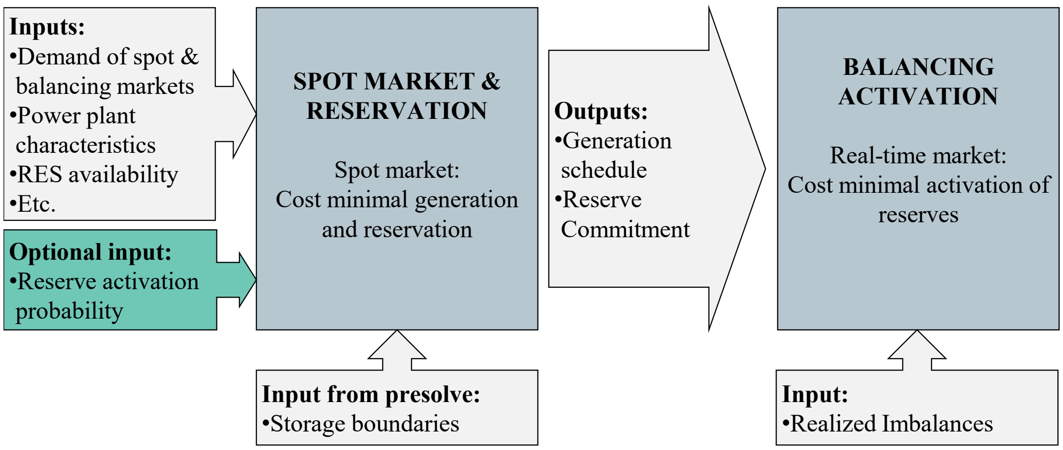


Figure 4.1.: ELMOD-MIP Model Steps

reserve activations during the reservation phase. This anticipation of the activation probability has several advantages: It resembles the behavior that is expected from real market participants, that are likely to include the revenue from the activations in their market participation. In ELMOD-MIP, this leads a more realistic and slightly higher balancing reserve cost estimation than a negligence of the activation probabilities.

ELMOD-MIP is a bottom-up electricity sector model, formulated as a MILP which allows us to include unit-commitment constraints as minimum load, part-load efficiency, time-dependent start-up and shutdown restrictions, complex combined heat and power (CHP) constraints and minimum bid sizes for balancing capacity reservation. These detailed representations of the power plants' flexibility are crucial to accurately represent the power plant dispatch as well as capacity reservation when modeling balancing markets. If these constraints were not part of the model, the power plants' flexibility would be significantly overestimated and distort the balancing market outcome.

4.2.1. The model ELMOD-MIP

We formulate ELMOD-MIP as a multi-step approach (Figure 4.1), where for all steps the same model is used, but some equations are deactivated and some variables and parameters are fixed or set to zero based on each step's goal.

In the first step, the spot and balancing reserve markets are optimized simultaneously, minimizing total system cost. Thus, the balancing capacity reservation as well as the power plant dispatch in the spot market are determined. The actual balancing reserve activations are not part of the optimization, as they are approximated using the anticipated reserve activation probability, or neglected depending on the scenario (see Section 4.3).

In the second step, the activation of balancing reserve is optimized. Necessary activated balancing reserve is determined based on historical time series. Here, the variables determining the reservation of balancing capacity are fixed in the model. Only power plants with reserved capacity can be dispatched for balancing reserve activations by the model.

To generate storage levels and associated limitations for the starting and end period of each individual week, we solve a limited version of the model ("presolve") for the entire model year prior to the actual calculations using the same input data. The limited version is a linear reformulation with technology sharp aggregation for non-hydro generation and linear balancing requirements.

In this chapter we focus on the cost induced by the balancing reserves' influence on the electricity system as generation technologies reserve capacity to provide them. Hence, the cost for activating these reserves is not fully analyzed in this chapter. Still, balancing reserve activation is fully implemented in the model and the calculations. This is necessary as the activation results in additional technical constraints for the reservation phase. Furthermore, this allows us to study possible impacts on activation cost in subsequent analyses. The cost for balancing activation will therefore only be evaluated briefly.

4.2.2. Determining the cost of balancing reserves

Determining cost and prices for balancing reserve provision in fundamental electricity system models can be a challenge. In contrast to the spot market, balancing reserve cost comprise of different components. Furthermore, the total balancing reserve cost can not be quantified directly, as it is influenced by the spot market situation.

Balancing cost components

In ELMOD-MIP, three factors can induce costs when reserving balancing capacity: Opportunity costs, part-load costs when reserving positive balancing capacity, and the cost of anticipated balancing reserve activation.

First, opportunity costs occur in the spot market due to balancing restrictions on the available generation capacity. Capacity is either reserved in a power plant in case of positive capacity reservation, or a must-run condition is introduced in case of negative capacity reservation. Depending on the difference between current market price and the marginal cost of the power plant opportunity cost are described in (4.1) and (4.2).

$$cost_p^{resv,pos} = \begin{cases} (p^{spot} - mc_p) \cdot G_{p,t}^{resv,pos} & \text{if } p^{spot} \geq mc_p \\ (mc_p - p^{spot}) \cdot g_p^{min} \cdot g_p^{max} & \text{if } p^{spot} \leq mc_p \end{cases} \tag{4.1}$$

$$cost_p^{resv,neg} = \begin{cases} 0 & \text{if } p^{spot} \geq mc_p \\ (mc_p - p^{spot}) \cdot g_p^{min} \cdot g_p^{max} + G_{p,t}^{resv,neg} & \text{if } p^{spot} \leq mc_p \end{cases} \tag{4.2}$$

The opportunity cost for positive reservation are zero if the marginal cost of the power plant equal the current market price. Hence, the price setting power plant can theoretically provide reserves without opportunity cost. Power plants without minimum load constraints, such as pumped hydro or run-of-river power plants (RoR) are able to provide positive reserves at no cost, as long as their water value is above the spot market price. If the water value is lower than the spot market price, opportunity costs occur. Inflexible CHP plants without a heat storage (or other means to provide heat output) also have no opportunity cost for capacity reservation, at times when their marginal costs are above the spot market price but they have to produce heat and therefore need to run at least at minimum load. In this situation they do not face any losses from not offering their spare capacity at the spot market and therefore can provide reserves at no opportunity cost.

Opportunity cost are zero for negative reserves, if the power plants' marginal cost are below the market price and the power plant is producing for the spot market. Hence, as long as a power plants is "in the money," it can provide negative reserves at zero cost. A detailed explanation and more examples can be found in Müsgens et al. (2014) and Brandstätt (2014).

Second, in the case of positive reserve provision, power plants have to produce below their rated capacity and thus are not able to operate at their optimal output point. This results in higher relative fuel cost for electricity production as the power plant's efficiency is reduced. These part-load cost are the biggest cost component when power plants marginal cost are close or equal to the spot price.

The third cost component is the anticipated balancing reserve activation. As the activation probability distribution can be anticipated in ELMOD-MIP (see Section 4.2.3 below), the activation probability of balancing reserves takes into account the cost for additional fuel or startup costs that occur when activated. This also includes anticipated part-load situations when deviations from the optimal power plant dispatch are anticipated.

Balancing cost calculation

In this chapter the cost of balancing reservation is calculated as the difference in system cost, with and without balancing reserve restrictions. Van den Bergh et al. (2016), Gebrekiros et al. (2015b), and Knaut et al. (2017) use a two-step approach that is also used in this chapter. In a first calculation, the amount of balancing capacity reserved is set to zero, and all power plant capacities can operate fully on the spot market. This is compared to the actual calculations with balancing reservation. The increase in cost contains all alterations occurring in the spot market, such as a selection of more costly power plants in the dispatch, as well as part-load costs of power plants that provide positive balancing reserves.

Brandstätt (2014) and Müsgens et al. (2012) estimate the opportunity cost of providing balancing reserves for each power plant in a first step. Based on these cost, they determine which power plants are the cheapest to provide reserves. The product of these cost with the actually reserved capacity gives the total cost of balancing reservation. This approach allows for a plant-sharp estimation of balancing reservation cost, but has the disadvantage of neglecting some aspects of interaction between the spot and balancing markets. Especially the effect of part-load efficiency decrease of the power plants induced by the reservation is neglected, which is a main cost-driver of balancing reserve provision (see above). Thus not all system cost components that arise from balancing reservation are reflected.

4.2.3. Anticipating balancing reserve activations

To be able to incorporate the uncertainty of how much balancing power is actually activated, we separate the balancing reserves into multiple products with different sizes and activation probabilities. This methodology approximates the actual activation distribution, where a small amount of balancing reserves is almost always activated, but the maximum reserved capacity is activated only in a few hours per year. The model uses this information to determine which power plants are likely to be used for the activation of balancing reserves by taking into account the activation cost multiplied by the activation probability. This becomes part of the optimization. Thus, power plants are not just committed to provide balancing capacity, but are committed to a small block of balancing capacity with a certain activation probability. Assigning multiple blocks and splitting each block's capacity to multiple power plants is possible. The effect of this improvement is analyzed in the *2013 Anticipation* scenario (see Section 4.3).

Historical frequencies for SC are shown in Figure 4.2. We derive the distribution of these blocks using historical time series data that are part of the model input described in section 4.3. The sum of each block's size in megawatt (MW) multiplied

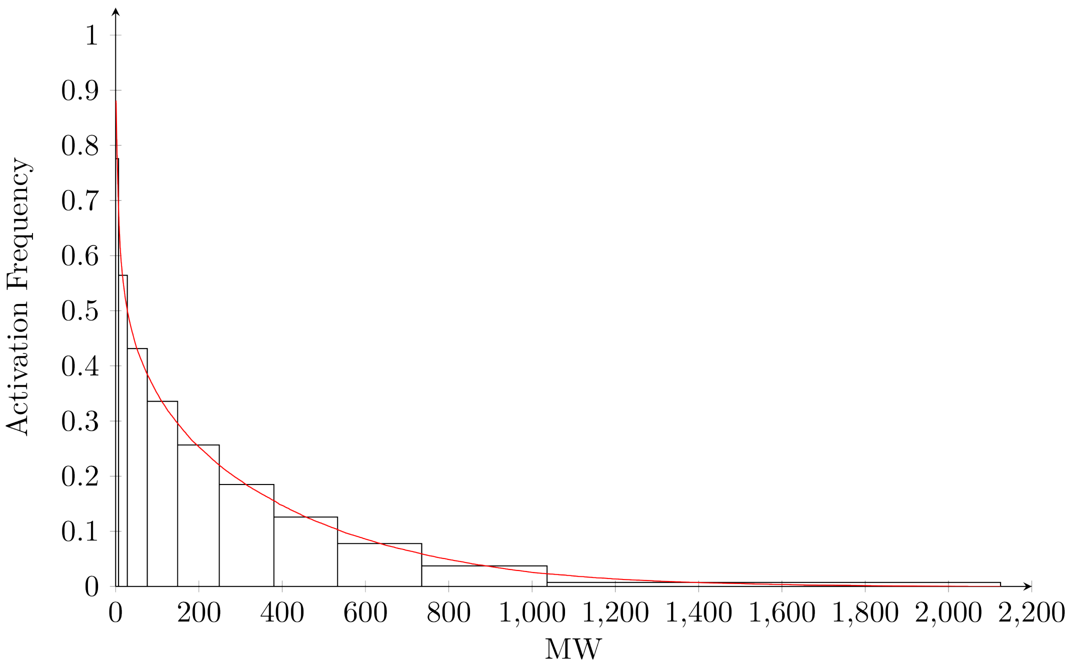


Figure 4.2.: Activation frequency for positive SC in Germany 2013 and calculated blocks.

by the frequency equals the average activation values in MW. This ensures that the model's anticipation of the average balancing reserve activations is correct.

In the current market design, balancing capacity is reserved regularly for time periods between four hours and one week, depending on the product and region. This reservation is allocated to the bidding firm's power plant portfolio and not to individual plants. Therefore, the firms can optimize their power plant portfolio at the time of delivery of the balancing energy, hence at least hourly. In ELMOD-MIP we approximate this setting by allowing for balancing capacity reservation for each power plant and hour separately. This results in a situation similar to various big firms participating in a cost minimizing behavior on the balancing market.

We do not apply price markups for balancing capacity because they might distort the model results significantly in case of changing market situations (induced by increased cooperation or a changed future power plant portfolio), as the markups are usually not endogenous to the model and based on historical data. This approach gives us the possibility to determine a lower bound of the anticipated balancing cost for the future electricity system.

4.2.4. Computational complexity

The problem is solved in 52 weekly blocks with two days overlap[14] to cover a whole year. This allows us to parallelize the calculations and reduce the computation time for an entire year significantly. It is solved with the help of a unix cluster. Up to 50 nodes were used in parallel, each equipped with at least 16 GB of RAM and AMD or Intel processors of at least 2.6 GHz. For the scenarios without anticipation, each calculation period needs up to 20 hours. Thanks to parallelization each scenario can be calculated in less than two days. However, the scenarios with anticipation need up to one week of wall-clock time as each calculation period can take up to 100 hours.

4.2.5. Mathematical formulation

The objective of ELMOD-MIP is to minimize total system costs, while clearing the spot market as well as the balancing market for the two balancing power products SC and TC. The model is solved using the General Algebraic Modeling System (GAMS) with the commercial solver CPLEX.

The mathematical formulation can be found in equations (4.3) to (4.53). The overall objective is to minimize the sum of generation, start-up, shut-down, and balancing cost (4.3 – 4.10). For the scenarios where no anticipation of activations is included, the parameter $frq_{bl,b}$ is set to zero and equations are simplified.

$$\begin{aligned} \min Cost^{total} = \; & Cost^{gen} + Cost^{start} + Cost^{down} + Cost^{ramp} \\ & + Cost^{partload} + Cost^{resv} + Cost^{call} \end{aligned} \tag{4.3}$$

s.t.

$$Cost^{gen} = \sum_{c,t} mc_c \cdot G_{c,t} \tag{4.4}$$

$$Cost^{start} = \sum_{c,t} UP_{c,t} \cdot c_c^{start} + \sum_{u,t} Frq_{u,t}^{max} \cdot c_u^{start} \tag{4.5}$$

$$Cost^{down} = \sum_{c,t} DN_{c,t} \cdot c_c^{down} + \sum_{u,t} Frq_{u,t}^{max} \cdot c_u^{down} \tag{4.6}$$

$$Cost^{ramp} = \sum_{p,t} G_{p,t}^{rampup} \cdot c_c^{rampup} + G_{p,t}^{rampdown} \cdot c_c^{rampdown} \tag{4.7}$$

[14] See Barrows et al. (2014) for an analysis of time series partitioning and overlap times. The authors suggest the setting used in this chapter to achieve adequate solutions while achieving fast solution times.

$$
\begin{aligned}
Cost^{partload} &= \sum_{c,t} ON_{c,t} \cdot c_c^{partload} - \frac{c_c^{partload}}{g_c^{max} \cdot ava_{c,t} - g_c^{min} \cdot g_c^{max}} \cdot \Bigg(G_{c,t} \\
&\quad - g_c^{min} \cdot g_c^{max} + \sum_b \Bigg(G_{b,c,t}^{call,pos} - G_{b,c,t}^{call,neg} + \sum_{bl} \Big((G_{u \in c,t,bl,b}^{resv,pos} \\
&\quad - G_{u \in c,t,bl,b}^{resv,neg}) \cdot frq_{bl,b} \Big) \Bigg) \Bigg)
\end{aligned} \tag{4.8}
$$

$$
Cost^{resv} = \sum_{b,bl,c,t} mc_c \cdot \left(G_{c,t,bl,b}^{resv,pos} - G_{c,t,bl,b}^{resv,neg} \right) \cdot frq_{bl,b} \tag{4.9}
$$

$$
Cost^{call} = \sum_{b,c,t} mc_c \cdot \left(G_{b,c,t}^{call,pos} - G_{b,c,t}^{call,neg} \right) \tag{4.10}
$$

The total system costs (4.3) include variable costs of generation (4.4), start-up (4.5) and shut-down (4.6) costs, ramping cost (4.7), part-load cost (4.8) and the costs for providing balancing power (4.9) and (4.10). The variable cost of generation is defined as the generation $G_{c,t}$ of all conventional power plants c and time steps t multiplied by the plants' marginal production cost mc_c. Start-up cost c_c^{start} occur when a plant assumes production and was in a shut-down state in the previous time step. Then, the binary variable $UP_{c,t}$ has the value 1.

During the reservation phase the expected start up probability of fast-starting power plants u, which is a subset of all conventional power plants c, is also taken into account. Shut-down cost occur analogously. For fast-starting power plants that do not participate in the spot market at the time of activation, we assume that these plants provide balancing power for a short time period and shut down afterward. Therefore not only the startup cost c_u^{start} but also the shut-down cost c_u^{down} are taken into account as well during the reservation phase.

The reservation of positive or negative balancing capacity $G_{c,t,bl,b}^{resv,pos}$ and $G_{c,t,bl,b}^{resv,neg}$ for the balancing power products b and blocks bl incurs opportunity cost mc_c multiplied with the block's specific activation frequency $frq_{bl,b}$ in the model, as the capacity reservation reduces the available capacity in the spot markets. The balancing reserve activations $G_{b,c,t}^{call,pos}$ and $G_{b,c,t}^{call,neg}$ are accounted for by the power plants' marginal cost mc_c. The part-load cost represent the non-linear link between fuel cost per produced MWh depending on current output level. At minimum generation level, part load cost in the magnitude of $c_c^{partload}$ would occur. When a power plant is operating above minimum generation level, these costs are reduced depending on current output level $G_{c,t}$ as expressed in the fraction.[15]

[15] The combination of equations (4.4) and (4.8) replicates the part-load decrease of a power plant's efficiency η using the formula $\eta(G) = \frac{G}{aG+b}$ where $G \in [g^{min}, g^{max}]$. a and b are power plant specific parameters, g^{min} and g^{max} are minimum and full power plant output.

Market clearing

The spot market is cleared by leveling load $q^{spot}_{r,t}$, dispatchable generation $G_{c,t}$, storage activity $G^{up}_{s,t}$, $G^{down}_{s,t}$, non-dispatchable renewable and conventional feed-in $g^{res}_{r,t}$, $g^{conv}_{r,t}$, and exogenous exchange flows g^{cb} for all time steps t and regions r, as stated in (4.11). Markets for positive and negative balancing capacity are cleared separately for each product b and block bl, by leveling demand $q^{resv,pos}_{b,bl,r,t}$, $q^{resv,neg}_{b,bl,r,t}$ and reserves $G^{resv,pos}_{p,t,bl,b}$, $G^{resv,neg}_{p,t,bl,b}$. This is shown in (4.12) and (4.13) for the reservation and in (4.14) and (4.15) for the activation of balancing reserve.

$$
\begin{aligned}
0 = {} & q^{spot}_{r,t} - \sum_{c\in r} G_{c,t} + \sum_{s} \left(G^{up}_{s,t} - G^{down}_{s,t}\right) \\
& - g^{res}_{r,t} - g^{conv}_{r,t} - g^{cb}_{r,t} && \forall r,t \qquad (4.11)
\end{aligned}
$$

$$q^{resv,pos}_{b,bl,r,t} = \sum_{p\in r} G^{resv,pos}_{p,t,bl,b} \qquad \forall t,r,bl,b \qquad (4.12)$$

$$q^{resv,neg}_{b,bl,r,t} = \sum_{p\in r} G^{resv,neg}_{p,t,bl,b} \qquad \forall t,r,bl,b \qquad (4.13)$$

$$q^{call,pos}_{b,r,t} = \sum_{p\in r} G^{call,pos}_{b,p,t} \qquad \forall b,r,t \qquad (4.14)$$

$$q^{call,neg}_{b,r,t} = \sum_{p\in r} G^{call,neg}_{b,p,t} \qquad \forall b,r,t \qquad (4.15)$$

Generation restrictions

$$G_{c,t} \leq g^{max}_{c} \cdot ava_{c,t} - \sum_{bl,b} G^{resv,pos}_{c,t,bl,b} \qquad \forall c,t \qquad (4.16)$$

$$G_{c,t} \geq g^{min}_{c} \cdot g^{max}_{c} \cdot ON_{c,t} + \sum_{bl,b} G^{resv,neg}_{c,t,bl,b} \qquad \forall c,t \qquad (4.17)$$

$$G_{o,t} \leq ON_{o,t} \cdot g^{max}_{o} \cdot ava_{o,t} - \sum_{bl,b} G^{resv,pos}_{o,t,bl,b} \qquad \forall o,t \qquad (4.18)$$

$$G_{u,t} \leq ON_{u,t} \cdot g^{max}_{u} \cdot ava_{u,t} - \sum_{bl} G^{resv,pos}_{u,t,bl,sc} \qquad \forall u,t \qquad (4.19)$$

$$DN_{c,t} + ON_{c,t} = UP_{c,t} + ON_{c,t-1} \qquad \forall c,t \qquad (4.20)$$

$$UP_{c,t} + DN_{c,t} \leq 1 \qquad \forall c,t \qquad (4.21)$$

$$1 - UP_{c,t-t^{minup}_c} \geq \sum_{tt=t-t^{minup}_c}^{t} DN_{c,tt} \qquad \forall c,t \qquad (4.22)$$

$$1 - DN_{c,t-t^{mindn}_c} \geq \sum_{tt=t-t^{mindn}_c}^{t} UP_{c,tt} \qquad \forall c,t \qquad (4.23)$$

$$G_{c,t} \geq \sum_{b,bl} G^{resv,neg}_{b,bl,c,t} \qquad \forall c,t \qquad (4.24)$$

$$G^{resv,pos}_{tc,bl,u,t} \leq (SB_{b,bl,u,t} + ON_{u,t}) \cdot g^{max}_{u} \qquad \forall tc,bl,u,t \qquad (4.25)$$

$$G^{resv,pos}_{tc,bl,u,t} \geq SB_{b,bl,u,t} \cdot g^{max}_{u} \cdot g^{min}_{u} \qquad \forall tc,bl,u,t \qquad (4.26)$$

$$Frq^{max}_{u,t} \geq SB_{b,bl,u,t} \cdot frq_{b,bl} \qquad \forall b,bl,u,t \qquad (4.27)$$

$$1 \geq SB_{b,bl,u,t} + ON_{u,t} \qquad \forall b,bl,u,t \qquad (4.28)$$

A power plant's generation $G_{c,t}$ and balancing reservation $G^{resv,pos}_{c,t,bl,b}$, $G^{resv,neg}_{c,t,bl,b}$ are constrained by its minimal and maximal generation capacity (4.16), (4.17). Slow starting power plants o have to be online to provide balancing power (4.18) while fast starting power plants u must only be online when providing energy for the spot market (4.19) and can be on stand-by to provide reserves (4.25). In case of activation of reserve energy we assume that these power plants can reach the desired output levels within time from a shutdown state. Equation (4.20) tracks the plant's status for start-up and shut-down costs and enforces the plant to start up when providing balancing power. Power plants are further restricted by minimum online and offline times. If a plant was started up it cannot be shut down within the interval $t^{minup}_{c,t}$ and vice versa for start ups after a shut down as shown in (4.22) and (4.23). The amount of negative reserved balancing power must always be smaller that the spot market generation of the power plant (4.24). This enforces power plants to be online and to participate in the spot market in order to provide negative balancing power. Slow starting power plants o must be online to provide positive balancing power as well (4.18), whereas fast starting power plants u can be in standby mode (4.25). Fast starting power plants must bid at least their g^{min} when they are bidding out of a standby status (4.26). Fast starting plants that are not generating but provide balancing power will incur their start-up and shut-down costs according to their expected activation frequency (4.27). Equation (4.28) ensures that plants can only either be online or in standby mode.

Combined heat and power

Power plants that additionally deliver heat to industrial or residential customers are further restricted in their operation by the equations (4.29) to (4.33). We separate the CHP plants into plants with a heat storage *chps* and plants without the possibility to store heat *chpn*. The heat storage level $Chp^{storagelevel}_{chps,t}$ is defined in equation (4.30) as the level from the previous hour times an heat loss factor plus heat generation by the power plant $Chp^{output}_{chps,t}$ and minus the heat that is consumed by industry or households. The heat generation is limited in (4.29) not to be higher than the current generation level. The heat level and output are measured in MWh electrical energy but not thermal energy, as the heat demand is also specified as a minimum electricity generation.

$$
\begin{aligned}
Chp^{output}_{chps,t} &\leq G_{chps,t} && \forall chps, t && (4.29)\\
Chp^{storagelevel}_{chps,t} &= Chp^{storagelevel}_{chps,t-1} \cdot eta^{chp} \\
&\quad + Chp^{output}_{chps,t} - g^{min,chps}_{chps,t} \cdot g^{max}_{chps,t} && \forall chps, t && (4.30)\\
Chp^{storagelevel}_{chps,t} &\leq chp^{storagemax}_{chp} && \forall chps, t && (4.31)\\
G_{chpn,t} + \sum_{bl,b} G^{resv,pos}_{chpn,t,bl,b} &\leq g^{max,chp}_{chp,t} \cdot g^{max}_{chpn,t} && \forall chpn, t && (4.32)\\
G_{chpn,t} - \sum_{bl,b} G^{resv,neg}_{chpn,t,bl,b} &\geq g^{min,chp}_{chp,t} \cdot g^{max}_{chpn,t} && \forall chpn, t && (4.33)
\end{aligned}
$$

Power plants without heat storage are constraint by equations (4.32) and (4.33). In contrast they have to produce the heat at the specific hour it is needed. The parameters $g^{max,chp}_{chp,t}$ and $g^{min,chp}_{chp,t}$ are determined based on power plant characteristics and an exemplary heat demand curves dependent on outside temperature and hour of the day.

Ramping

$$
\begin{aligned}
G^{rampup}_{c,t} &\leq r^{up}_c \cdot g^{max}_c + \sum_{bl,b} G^{resv,neg}_{c,t-1,bl,b} - \sum_{bl,b} G^{resv,pos}_{c,t,bl,b} && \forall c, t && (4.34)\\
G^{rampdown}_{c,t} &\leq r^{down}_c \cdot g^{max}_c + \sum_{bl,b} G^{resv,neg}_{c,t,bl,b} - \sum_{bl,b} G^{resv,pos}_{c,t-1,bl,b} && \forall c, t && (4.35)
\end{aligned}
$$

$$
\begin{aligned}
G_{c,t} - G_{c,t-1} &+ \sum_{bl,b} (G^{resv,pos}_{c,t,bl,b} - G^{resv,pos}_{c,t-1,bl,b}) \cdot frq_{bl,b} \\
&- \sum_{bl,b} (G^{resv,neg}_{c,t,bl,b} - G^{resv,neg}_{c,t-1,bl,b}) \cdot frq_{bl,b} \\
&+ \sum_{b} (G^{call,pos}_{b,c,t} - G^{call,pos}_{b,c,t-1}) - (G^{call,neg}_{b,c,t} - G^{call,neg}_{b,c,t-1}) && \forall c, t && (4.36)\\
&= G^{rampup}_{c,t} - G^{rampdown}_{c,t}
\end{aligned}
$$

The power plants' ramping restrictions are included in (4.34) and (4.35). These equations limit the change of a power plant's production levels between time steps. For ramping, only the limiting balancing reservations are included, as otherwise the model would be able to weaken the ramping restrictions by reserving balancing capacity in the reverse direction.

Reserve restrictions

$$\sum_{bl} G^{resv,pos}_{b,bl,p,t} \geq resv^{min}_{b} \cdot BAL^{pos}_{b,p,t} \qquad \forall b,p,t \qquad (4.37)$$

$$\sum_{bl} G^{resv,neg}_{b,bl,p,t} \geq resv^{min}_{b} \cdot BAL^{neg}_{b,p,t} \qquad \forall b,p,t \qquad (4.38)$$

$$\sum_{bl} G^{resv,pos}_{b,bl,s,t} \leq v^{max}_{s} \cdot BAL^{pos}_{b,s,t} \qquad \forall b,c,t \qquad (4.39)$$

$$\sum_{bl} G^{resv,neg}_{b,bl,s,t} \leq w^{max}_{s} \cdot BAL^{neg}_{b,s,t} \qquad \forall b,c,t \qquad (4.40)$$

$$\sum_{bl} G^{resv,pos}_{sc,bl,c,t} \leq g^{max}_{c} \cdot r^{up}_{c} \cdot BAL^{pos}_{sc,c,t} \cdot 5 \qquad \forall c,t \qquad (4.41)$$

$$\sum_{bl} G^{resv,pos}_{tc,bl,c,t} \leq g^{max}_{c} \cdot r^{up}_{c} \cdot BAL^{pos}_{tc,c,t} \cdot 15 - \sum_{b,bl} G^{resv,pos}_{sc,bl,c,t} \qquad \forall c,t \qquad (4.42)$$

$$\sum_{bl} G^{resv,neg}_{sc,bl,c,t} \leq g^{max}_{c} \cdot r^{down}_{c} \cdot BAL^{neg}_{sc,c,t} \cdot 5 \qquad \forall c,t \qquad (4.43)$$

$$\sum_{bl} G^{resv,neg}_{tc,bl,c,t} \leq g^{max}_{c} \cdot r^{down}_{c} \cdot BAL^{neg}_{tc,c,t} \cdot 15 - \sum_{b,bl} G^{resv,neg}_{sc,bl,c,t} \qquad \forall c,t \qquad (4.44)$$

Equations (4.37) to (4.44) describe the restrictions that determine how much of a plant's capacity can be reserved for balancing. The combination of (4.37) and (4.38) enforces power plants or storages to bid at least the minimum bid specified by $resv^{min}_{b}$ when bidding into the balancing market. Storage plants can (besides other restrictions) only reserve as much capacity as limited by their pumping and generating abilities as seen in (4.39) to (4.40). Equations (4.41) and (4.44) limit the maximal bid size dependent on the maximum up and down ramping abilities of each power plant.

Activation restrictions

$$G^{call,pos}_{b,p,t} \leq \sum_{bl} G^{resv,pos}_{b,bl,p,t} \qquad \forall b,p,t \qquad (4.45)$$

$$G^{call,neg}_{b,p,t} \leq \sum_{bl} G^{resv,neg}_{b,bl,p,t} \qquad \forall b,p,t \qquad (4.46)$$

$$\sum_{b} G^{call,pos}_{b,u,t} \leq g^{max}_{u} \cdot ON_{u,t} \qquad \forall u,t \qquad (4.47)$$

When reserve energy is activated, the positive and negative activation must always be smaller than the reserved amount for each power plant, hour and product as shown in (4.45) and (4.46). Equation (4.47) ensures that fast starting plants must start up to provide balancing energy. Note that the status of the power plants is not transferred between the stages of the multi-stage model but redetermined each stage, transferring the amount of reserved capacity is sufficient to determine the power plant status. A fast-starting power plant that is in “Standby” in the reservation stage with reserved capacity might be set to “Online” during the activation stage. This way the actual startup cost of fast starting power plants can be accounted for in the model when the activations take place.

Storage restrictions

$$STOR^L_{s,t} - STOR^L_{s,t-1} = G^{up}_{s,t} \cdot \eta_s - G^{down}_{s,t} + g^{nat}_{s,t} - G^{discard}_{s,t} - \sum_b G^{call,pos}_{b,s,t} + \sum_b G^{Call,Neg}_{b,s,t} \cdot \eta_s \qquad \forall s,t \quad (4.48)$$

$$v^{max}_s \geq G^{down}_{s,t} + \sum_{bl,b} G^{resv,pos}_{s,t,bl,b} \qquad \forall s,t \quad (4.49)$$

$$w^{max}_s \geq G^{up}_{s,t} + \sum_{bl,b} G^{resv,neg}_{s,t,bl,b} \cdot \eta_s \qquad \forall s,t \quad (4.50)$$

$$STOR^L_{s,t} - \sum_{bl,b,tt=t-12}^{tt=t+12} G^{resv,pos}_{s,tt,bl,b} \cdot \eta_s \geq l^{min}_s \qquad \forall s,t \quad (4.51)$$

$$STOR^L_{s,t} + \sum_{bl,b,tt=t-12}^{tt=t+12} G^{resv,neg}_{s,tt,bl,b} \leq l^{max}_s \qquad \forall s,t \quad (4.52)$$

In our model pumped hydro storage plants s take part in the balancing market. Equation (4.48) describes the storage level $STOR^L_{s,t}$ for every storage plant s that is dependent on the historic storage level $STOR^L_{s,t-1}$, pumping $G^{up}_{s,t}$ and generation activities $G^{down}_{s,t}$. Equations (4.49) to (4.52) limit the pumping, generation, and storage level as well as reserved balancing power. The restrictions on minimum and maximum storage level include the reserved positive and negative balancing reserves twelve hours prior and post the actual time step. This should represent the constraint that, within a time interval of 24 hours, the storage contains a sufficient amount of water to be able to deliver the balancing energy for both extreme cases of no or full activations of balancing reserves in all 24 hours.

Further restrictions

$$\begin{aligned} G_{p,t}, G^{rampup}_{p,t}, G^{rampdown}_{p,t}, G^{up}_{s,t}, G^{down}_{s,t}, STOR^L_{s,t} &\geq 0 \\ G^{ResvPos}_{b,bl,c,t}, G^{ResvNeg}_{b,bl,c,t}, G^{Call,Pos}_{b,p,t}, G^{Call,Neg}_{b,p,t}, Frq^{max}_{u,t} &\geq 0 \qquad \forall b, bl, p, t \qquad (4.53) \\ Chp^{storagelevel}_{chps,t}, Chp^{output}_{chps,t} &\geq 0 \end{aligned}$$

The constraints in (4.53) ensure positive values for some variables in the model.

4.3. Scenarios and data

We apply ELMOD-MIP to scenarios that represent the spot and balancing markets of Germany in 2013 and 2025. We use the year 2013 to estimate the effect of a potentially improved anticipation of the balancing energy reservation. Therefore, the scenarios for 2013 differ in the anticipation of balancing reserve activations. In contrast to assessing model improvements with historical data of 2013, we use the future year of 2025 to analyze the effect of a changing power plant portfolio and the possible participation of RES in the provisioning of balancing reserves. Therefore, in the 2025 scenarios we vary the participation of renewable energy sources in the balancing market.

As this modeling exercise uses a cost-minimization approach, the model results report a lower bound on the costs that can be anticipated in the balancing reserve market, not taking into account inefficiencies originating from the market design or strategic behavior.

In total we analyze seven scenarios:

- *2013*: power plant and renewable portfolio of 2013;
- *2013 Anticipation*: power plant and renewable portfolio of 2013 with anticipation of possible activation costs;
- *2025*: power plant and renewable portfolio of 2025;
- *2025 Wind5*: power plant and renewable portfolio of 2025 and wind turbines participating with 5 % of their capacity in providing negative reserves;
- *2025 Wind10*: power plant and renewable portfolio of 2025 and wind turbines participating with 10 % of their capacity in providing negative reserves;
- *2025 Wind5+*: in addition to the *2025 Wind5* scenario, wind turbines can offer 5 % of their capacity to provide positive and negative reserves;
- *2025 Wind10+*: in addition to the *2025 Wind10* scenario, wind turbines can offer 10 % of their capacity to provide positive and negative reserves.

4.3.1. Boundary conditions

Where possible, we use data available to the public. Load, balancing reserve requirements, cross-border exchange flows, and balancing reserve activations are based on historical time series from 2013. Renewable feed-in time series are based on TSO data from 50Hertz (2013), Amprion (2013), TenneT (2013), and TransnetBW (2013). Load time series are taken from ENTSO-E (2013-2016).

The power plant data for Germany is based on the DIW Data Documentation 72 by Egerer et al. (2014). Data from the Federal Network Agency (BNetzA, Bundesnetzagentur) has been used to augment the data further (BNetzA, 2014b; Umweltbundesamt, 2015). Cost assumptions for fuels and the CO_2 price are based on Egerer et al. (2014). Power plant characteristics are derived from the DIW Data Documentation 68 by Schröder et al. (2013). Only power plants belonging to a portfolio that is pre-qualified are allowed to provide balancing reserves.[16]

In the application for 2025, most of the model's boundary conditions change. Prices for fuels and CO_2, the power demand, the power plant portfolio, and the renewable capacities are taken from scenario B of BNetzA (2014a). The 2013 application uses given historical data with exogenous exchange flows for the surrounding countries. In the 2025 application the cross-border flows are also exogenously given. These time series have been derived from a calculation using the model dynELMOD described in Gerbaulet et al. (2014a) using the same 2025 input data plus additional information from the 2014 version of the Scenario Outlook and Adequacy Forecast (SOAF) by ENTSO-E (2014b) for all other European Countries.

The time-series of wind power feed-in has not only been scaled to adjust to the capacity anticipated in 2025, but has also been transformed to meet 2,000 full load hours (FLH), as technological advancements especially in the field of low-wind turbines are assumed in accordance with BNetzA (2014a, p. 111).

Data for reserved balancing power and activated balancing energy is taken from the official platform of the four German TSOs Regelleistung.net (2013). For positive secondary and tertiary reserves, 2.2 GW and 2.5 GW were contracted on average, respectively. For negative secondary and tertiary reserves these values differ, here 2.2 GW and 2.7 GW were contracted on average. As discussed in the introduction of this chapter, the influence of renewables on balancing demand is highly debated and uncertain.

4.3.2. Potentials and challenges for wind turbines providing balancing reserves

When considering the provision of balancing reserves from wind turbines, technical, regulatory and market-based challenges must be taken into account. The technical challenges of sufficiently fast response times and forecast accuracy have been addressed by most market participants: In 2015, the four German TSOs published a guideline for a two-year long pilot-test to pre-qualify wind turbines for minute reserve with

[16]The list of pre-qualified firms is derived from from `https://www.regelleistung.net/`. In technical terms, portfolios cannot be qualified but only single power plants. As this information is not provided on a power plant sharp basis, we abstract from this and use the portfolio sharp pre-qualification data.

the aim to determine how much of a wind turbine's capacity can be pre-qualified for balancing services (50Hertz et al., 2015). Pre-qualification of wind turbines to provide balancing reserves is the prerequisite of the participation. Technical and regulatory implementation hurdles have been taken (EWEA, 2014; Gesino, 2010; de Vos and Driesen, 2015), and in Germany two wind farms (86 MW) have been pre-qualified to provide up to 70 % of their installed capacity for negative TC (50Hertz, 2016). Götz and Baumgart (2014) assume that, for a security level of 99.994 %, up to 30 % of the entire German wind power can be used for balancing services when all turbines are pooled. Similar assumptions by Fraunhofer IWES (2014) assume a share of 10 % of wind capacity would be available for balancing services in a day-ahead regime. Depending on the scenario we assume a participation of wind power for positive and negative balancing reserves. For both SC and TC they can offer a total of 5 % or 10 % of their forecast feed-in in the 2025 application. We do not include the possibility of PV to provide (positive or negative) balancing reserves, as we assume that until 2025 a large share of PV installations are still decentral and not remotely controllable. Moreover, new battery storages could provide balancing reserves, still we do not assume new battery storages in our analysis for three reasons: First, prices in the SC and TC market are much lower than in the PC market, hence the provision of solely PC is the most likely option, where currently pilot projects exist. Second, the therefore required arbitrage profits from the spot market are not expected in the next ten years. Third, in line with reason two and forecasts for 2025 (compare 50Hertz et al., 2016a), not enough investments into battery storages are expected before 2040 in current long-term electricity investment models to play a substantial role for SC and TC balancing products.

4.3.3. Future balancing reserve demand

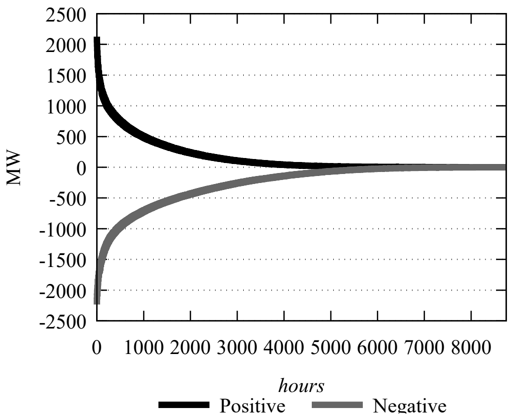
In the literature, the future balancing demand increase due to RES is thoroughly discussed. Most studies assume that due to the fluctuating nature of wind and solar power, the demand for balancing capacity reservation increases in order to compensate for forecast errors. Hirth and Ziegenhagen (2015) give an overview over the estimates in the literature: Here a reserve increase by 2 % to 9 % of additional wind power is expected in Brouwer et al. (2014), dena (2010), DLR (2012), Holttinen et al. (2011), and Lew et al. (2013). Ziegenhagen (2013) estimates an increase of 6 % of additional wind capacity; with additional solar installation this value decreases to about 4 %. Contrary to the literature results, the absolute value of reserved balancing capacity has decreased in the years 2010–2015, although renewable capacity has increased significantly in Germany.

This contradiction can be explained by a restructuring of the German intraday and balancing market which have lead to efficiency gains. Morbee et al. (2013) and Ortega-Vazquez and Kirschen (2009) present a further explanation and show show that until a high share of RES is reached, no significant effect on the demand for balancing reserves need to be expected.

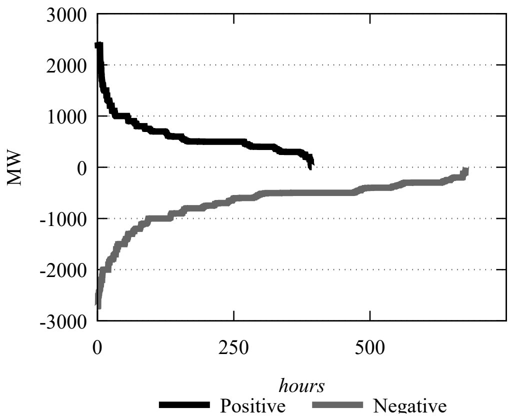
While it can be assumed that the power plant portfolio of 2025 is significantly different from the 2013 portfolio, the uncertainty regarding the future balancing reserve demand can be allocated to different developments: On the one hand, improvements in quality and precision of renewable in-feed forecast could decrease balancing demand. On the other hand the reserve sizing mechanism influences the amount reserved substantially. With a static reserves sizing horizon, the amount of reserves is determined on a regular (e.g. quarterly) basis, whereas a dynamic reserves sizing horizon takes short term influences on the system such as renewable availability into account, possibly leading to a decreased reserves size. Breuer et al. (2013), Bucksteeg et al. (2016), and dena (2014) compare static and dynamic reserves sizing methods for future German balancing reserves and anticipate higher shares of renewable in-feed. The authors show that in case of dynamic reserves sizing the amount of required reserves only increases slightly compared to today's values. If static sizing was continued until 2030, where the amount of renewables is substantially higher than today, stronger increases up to a doubling of required reserves is estimated. Van den Bergh et al. (2016) develop a reserves sizing method in the context of cooperation between market zones, but conclude that the cost minimal approach is uncoordinated sizing, with joined activation across zones. Since most studies assume that until high shares of RES are reached, no significant influence on the balancing demand will be seen if dynamic reserves sizing is in place, and not to distort the results, we assume the same level of reserve demand for 2025 as for 2013.

The reserved balancing capacity is interlinked to the activated balancing capacity. Hence, the changing power plant portfolio does not only change the demand for reserved balancing capacity but could also change the probabilities of the activation of those capacities. On one hand, the magnitude of activation could increase due overlapping forecast errors for large RES capacities or decrease due to smaller power plant sizes. On the other hand, the relative volume of activation (FLH of balancing capacity) could increase due to an inevitable remaining forecast error of large RES capacities or could decrease due to new possibilities to trade closer to real time and even out previous forecast errors on intraday markets. Therefore the future magnitude and relative volume of activated reserve capacities is highly uncertain. In order not to distort the results, we assume no change for the probabilities of activation.

Figure 4.3 shows the duration curves of balancing reserve activations from 2013. Values above zero represent positive activations, whereas negative values represent



(a) Secondary Capacity



(b) Tertiary Capacity

Figure 4.3.: Balancing reserve activation duration curves of 2013. Source: own depiction.

negative balancing reserve activations. The figures show that the secondary balancing energy demand can reach above 2 GW and below −2 GW in Germany.

While activations for secondary balancing energy occur throughout the year, tertiary capacity is used less frequently. At the same time, the peak activations for tertiary balancing energy are higher. Comparing these numbers to the peak load of about 83 GW and an overall energy demand of about 535 TWh in Germany shows that the energy activated on the balancing reserve markets is – by its nature – relatively small.

Data published by the TSOs shows the average values for balancing reserve activation within 15 minutes. These quarter hourly values are used to generate blocks with specific activation frequencies for each country, product, and direction. In this application we use ten different blocks for each balancing product. These activation frequencies are used to estimate the activation cost when reserving balancing power. See Section 4.2 for an explanation of activation frequencies and blocks. The quarter hourly values are also used to model the activation of balancing reserve during the call. This could result in an underestimation of possibly high ramping gradients as these activation could occur within seconds in practice.

4.4. Results and discussion

The application of ELMOD-MIP yields interesting insights into a possible development of the German balancing reserve market of 2025 and confirms an overall good

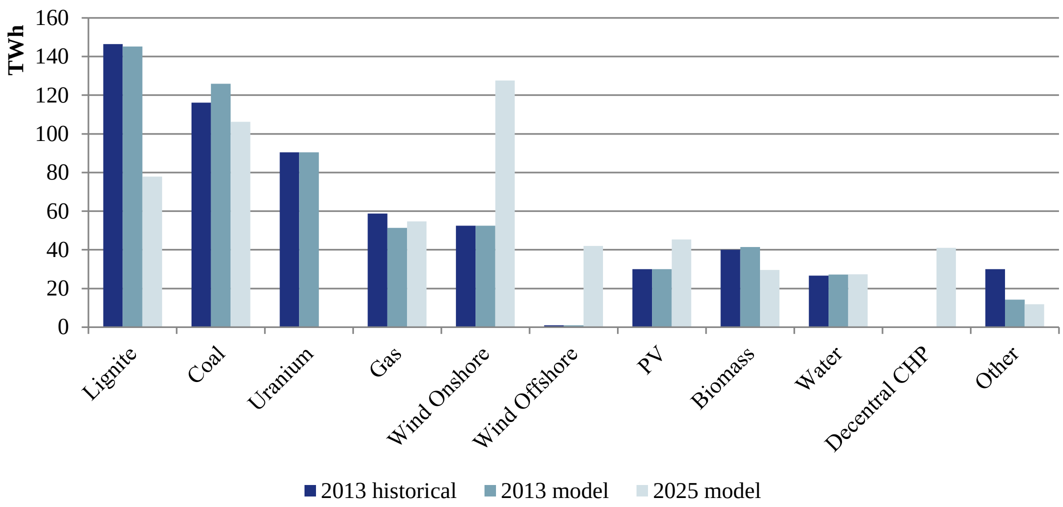


Figure 4.4.: Spot market generation by fuel for 2013 and 2025. This figure does not differentiate between the balancing reserve scenarios, as the effect on the spot market is minimal. Source: own depiction.

representation of the German electricity market of 2013, as the realized electricity generation levels of 2013 are met by the model values (Figure 4.4).[17]

In 2013, lignite and hard coal produced nearly half of the German electricity demand, followed by nuclear power and natural gas. RES accounted for around a quarter of the electricity demand. The generation levels of 2025 show strongly increased production by renewable energy sources compared to 2013, corresponding to the increase in installed capacity and improved FLH. Consequentially, also following the anticipated decrease in installed capacity of lignite and coal power plants, the production of lignite and coal-fired power plants is reduced significantly. No more nuclear electricity generation capacities are present in 2025. The gas-fired electricity generation level increases, as not only gas-fired power plants are used, but also "decentral CHP" generation is partly based on gas.

The model's spot price calculations also match the observed spot price values. The 2013 spot market price duration curve (Figure 4.5) as well as the average market price are nearly met by the model results with 36.5 €/MWh model average price compared to 37.8 €/MWh realized electricity price.

In 2025, the new power plant portfolio and increased generation from renewables lead to a different price duration curve with a slightly higher average price of 38 €/MWh, which corresponds to current forecasts for 2025 (cf. Oei et al., 2015b). Furthermore, we observe over 1,300 hours where the spot price is close to 0 €/MWh,

[17]Small deviations of the realized values to the model results are present, which are caused by different technology assignments for some power plants, especially regarding the categorization between "Coal" and "Miscellaneous." Furthermore, the production of gas-fired power plants is slightly underestimated.

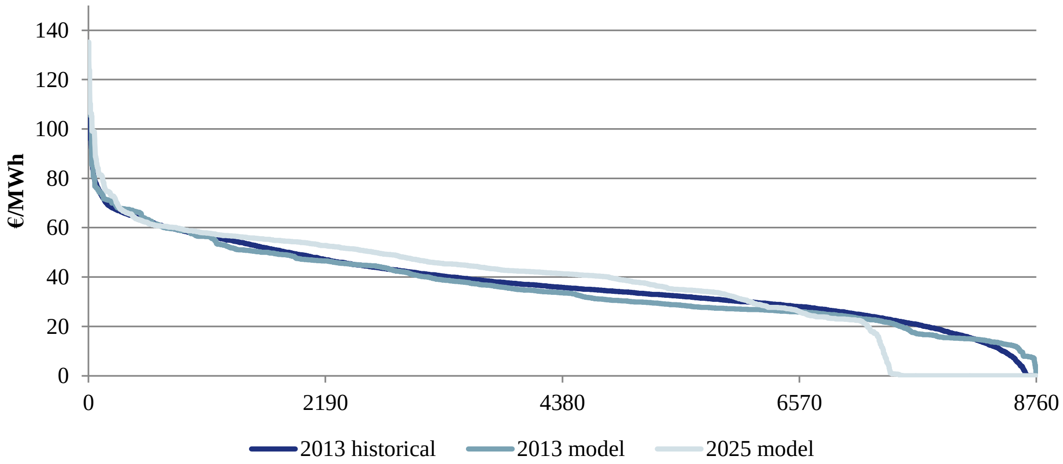


Figure 4.5.: Spot Price duration curves for 2013 and 2025. This figure does not differentiate between the balancing reserve scenarios as the effect on the spot market is minimal. Source: own depiction.

which is on the one hand caused by the uptake in renewable feed-in and on the other hand result of the model formulation, as the interaction with the neighboring countries is determined in a preparatory model run using the model dynELMOD described in Chapter 2.

4.4.1. Balancing reserve provision

Positive reserves are mainly provided by coal (40 %) and gas (40 %) in 2013. Lignite and pumped hydro storage capacities provide the remaining part of the reserves (Figure 4.6). Nuclear capacities do not participate in providing positive reserves. Similar technology shares for reservation of SC and TC are observable. For TC, more fast starting gas turbines are reserved that can be offline during the spot market dispatch. The inclusion of activation anticipation has a small but noticeable effect on the reservation by the different fuel types. Reservation of gas and oil fueled power plants is slightly reduced and replaced by water and coal fueled power plants, as their marginal costs, and therefore possible activation costs, are lower.

For the 2025 scenario, the reservation shifts towards lignite and pumped storage plant (PSP) reservation and fewer gas capacities. In comparison to 2013, lignite power plants are more often below full capacity in the spot market due to an increased variation of the residual load. Therefore they are able to provide more positive capacity without opportunity costs. In contrast, CHP power plants show higher FLH due to two factors: first, fewer CHP plants are in the market to provide heat. Second, more CHP plants are equipped with heat storage that allows for complete shutdowns

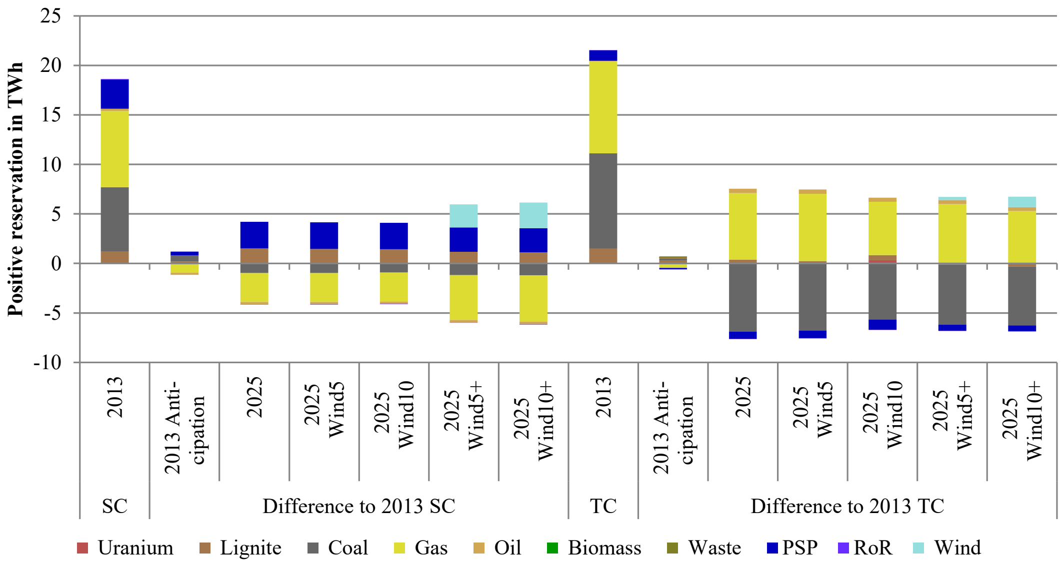


Figure 4.6.: Positive balancing capacity reservation by product, scenario and fuel for 2013 and 2025

when demand is low. These two factors lead to higher utilization, which in return leads to less options for reserve provision with low opportunity cost.

For TC the usage of gas-fired power plants increases in *2025* with the results of an almost exclusive provision of positive TC reservation by gas. This is caused by the high flexibility of gas-fired power plants compared to coal, allowing them to be offline and use their fast-starting gas turbines to start when needed. The possibility to use fast starting power plants is not given for SC, which explains the interesting contrary developments in SC and TC. However, in times with high spot market prices, gas fired power plants are used in both markets as their marginal cost are now close to the market price, which allows for cheap reserve provision. The PSP capacities are mostly used for SC reservation. The effect of the scenarios *2025 Wind5* and *2025 Wind10* on positive reservation is small as they only include participation of wind in the negative balancing market. Clearly a much larger effect can be observed in *2025 Wind5+* and *2025 Wind10+*. It is slightly different for SC and TC. For SC, wind replaces a significant share of gas reserves. The volumes are similar for the 5 % and 10 % wind participation. For TC, wind replaces less capacities as most of them are already provided by cheap offline gas turbines. The difference between 5 % and 10 % is bigger than for SC, indicating that first, costly SC is provided by wind and only when excess wind capacity is available the already cheap TC is replaced.

The reservation of negative balancing capacity (Figure 4.7) in the *2013* scenario is distributed between coal (30 %), lignite (29 %), run-of-river (18 %), natural gas (10 %) and PSP (7 %). Taking into account possible activation probabilities in the scenario *2013 Anticipation* alters the reservation towards more fossil based capacities,

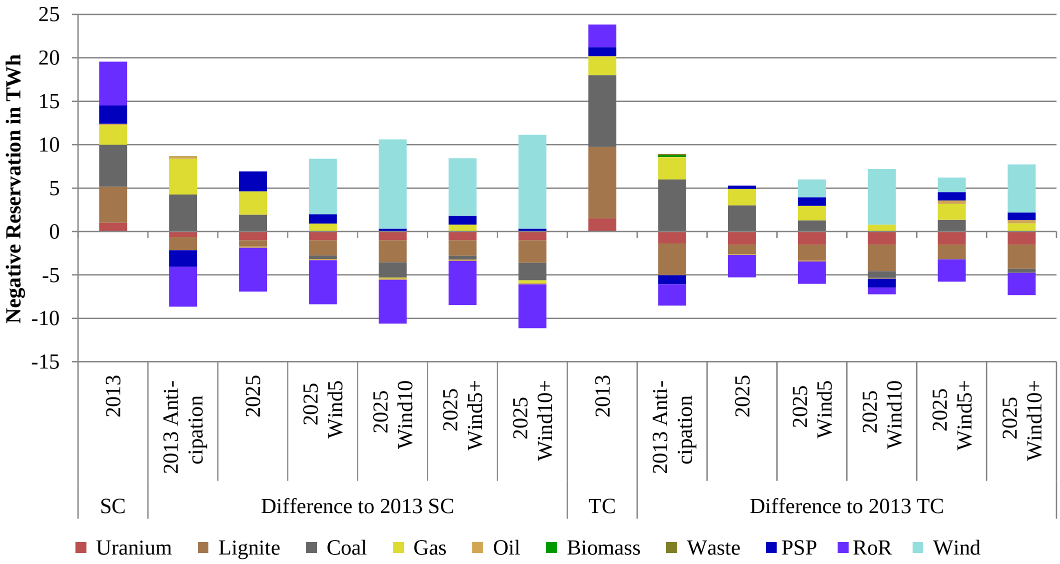


Figure 4.7.: Negative balancing capacity reservation by product, scenario and fuel for 2013 and 2025

as potential fuel savings in the case of activation are anticipated, which would not occur with run-of-river capacities.

In the *2025* case without wind, the reserved capacity also shifts to coal, gas, and PSP, reducing lignite and run-of-river reservation. The reduced FLH of lignite lead to less possibilities to provide negative reserves without additional costs. In contrast, one can see an increased provision by gas fired power plants, as these power plants are now producing due to a spot price above their marginal costs and hence above their minimum load. Therefore, they have the potential to ramp down and provide negative reserves.

With increased wind participation for negative reserves in the scenarios *2025 Wind5* and *2025 Wind10* wind is used increasingly and provides 53 % of the SC capacity and about 33 % of the TC capacity in the scenario *2025 Wind10*. The participation of wind turbines in providing negative reserves reduces mainly the provision of coal but for high shares also of PSP and gas. As expected, the provision of positive reserves by wind in the *2025 Wind5+* and *2025 Wind10+* scenarios does not have an significant influence on the provision of negative reserves.

4.4.2. The system cost of balancing reserves

Comparing the computed costs for reservation with the observed costs and between the scenarios provides insights whether the model is able to replicate the current market setting sufficiently well, and what the effect of the novel model formulation with activation anticipation is. Also, the cost estimate for 2025 can be analyzed.

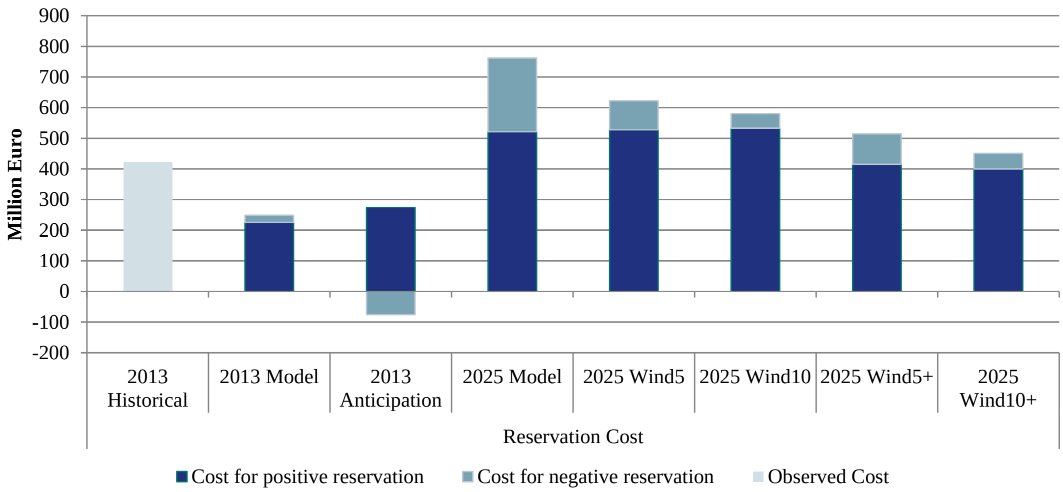


Figure 4.8.: Total cost for reserves provision by scenario for 2013 and 2025. Source: BNetzA (2015) and own calculations.

Independent of the scenario, the calculated cost for reserving SC and TC balancing capacities in 2013 are lower than the 423 million € costs observed (Figure 4.8). This is mainly a result of the assumption of hourly reserve capacity reservation as well as underestimated costs for negative balancing capacity. In the current market setting, prices for negative reserves are not mainly driven by market fundamentals but also by market participant behavior and price expectations. Especially in a setting with many plants running at or near full capacity, the cost of providing negative balancing capacity should be close to zero. Thus, replicating the historical results in a fundamental electricity model is challenging.

While the cost for positive balancing capacity reservation in the scenario *2013* do not fully meet the values observed, the comparison with included anticipation in the scenario *2013 Anticipation* shows a slightly better approximation of the positive balancing reservation cost with 273 million €. Here, generation capacities with higher opportunity cost on the spot market but potentially lower anticipation cost are reserved. The overall calculated cost are still lower than observed, especially as the price for negative reserves is underestimated by the model.

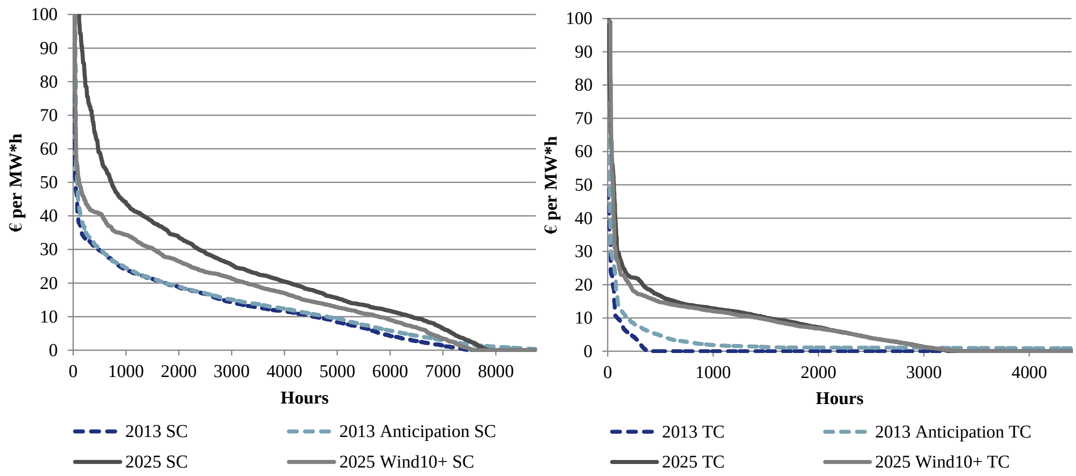
The cost estimate for negative reservation is not improved by the inclusion of anticipation. Here overall negative costs are observed, because hourly prices are often negative. This is caused by the anticipation of potentially saved fuel costs in the model, leading to a negative price in this fundamental model setting. Thus, while the overall reservation structure and prices for positive reserves are improved in the scenario *2013 Anticipation*, the representation of prices for negative balancing cannot be improved.

In 2025 we see an overall reservation cost increase throughout the scenarios. The reservation cost range between 761 million € in the *2025* scenario to 450 million € in the scenario *2025 Wind10+*. The overall cost increase can be explained by a lower supply for balancing capacity as a consequence of the changes in the German power plant portfolio. During times of very low residual load, power plants must now just be online to provide reserves, inducing high costs due to minimum load constraints. Additionally, the shift towards gas-fueled power plants increases the part load costs. Within the scenarios for the year 2025 the overall costs decrease with ascending wind participation as expected. Wind capacities mostly replace fossil capacities during times when residual demand is very low. During this time these capacities would not run normally (above minimum load) due to the low market price, except for providing reserves. Hence, this "unnecessary" generation cost can be avoided. The additional benefit of 10 % instead of 5 % percent of wind turbines participating is different for positive and negative reserves. While negative reserve cost are further reduced when increasing the number of participating turbines, the cost for positive reservation do not decrease substantially. Furthermore, the relative cost savings stemming from wind participation in negative reserves are higher than from participation in positive reserves, as for negative reserve provision, no ex-ante curtailment of wind feed-in is necessary. For positive reserve provision, wind feed-in must be curtailed to enable upward potential. Thus, the opportunity cost for providing positive reserves are much higher than for negative reserves. Therefore, only in situations with a very residual load close to or below zero (which are still rare in 2025) it is beneficial to provide positive balancing reserves with wind turbines. Hence, the resulting cost savings by wind providing positive reserves, are lower. In systems with a higher share of fluctuating RES and more hours with low residual load, the use of positive reserves by wind turbines become a sensible option.

In line with the reservation cost, the activation cost differ depending on scenario. The results show that in the *2013 Anticipation* scenario activation cost for positive and negative balancing energy can be reduced in comparison to the *2013* scenario by up to 10 %. For the *2025* scenario activation cost for positive and negative balancing energy are increasing by 15 %. These cost for negative balancing energy are significantly reduced with the participation of wind in the *2013 Wind5* scenario and *2013 Wind10* scenario. Similarly, the cost for positive balancing activation are significantly reduced in the *2013 Wind5+* scenario and *2013 Wind10+* scenario.

4.4.3. Prices on balancing reserve markets

We now analyze the price duration curves as well as the average reservation price for the balancing products. This allows further insights into the effect of the scenario



(a) Price of positive reservation SC (b) Price of positive reservation TC

Figure 4.9.: Price duration curves for positive reservation by product and scenario for 2013 and 2025. The scenario *2025 Wind5* is not depicted for clarity. The duration curve of *2025 Wind5* is directly between *2025* and *2025 Wind10*. Source: own calculations.

Table 4.1.: Average marginal prices for balancing capacity reservation by scenario

€/MW·h	Product	*2013*	*2013 Anticipation*	*2025*	*2025 Wind5*	*2025 Wind10*	*2025 Wind5+*	*2025 Wind10+*
Positive reservation	SC	11.66	12.87	23.30	23.49	24.32	17.68	17.13
	TC	0.40	1.59	4.14	4.21	4.72	4.06	3.82
Negative reservation	SC	1.03	-3.61	7.63	2.39	1.14	2.55	1.20
	TC	0.14	-0.39	3.84	2.03	1.06	2.08	1.14

Source: own calculation.

variations regarding the price distribution. Table 4.1 gives an overview of the observed average marginal prices for balancing capacity reservation. Looking at the market results for positive balancing capacity of *2013*, we observe an average marginal price for positive SC reservation of 11.66 €/MW·h. This comes close to the historical average of 12 €/MW·h (Figure 4.9a). The average marginal price for positive TC reservation is much lower with 0.4 €/MW·h (Figure 4.9b). Also the historical market results for positive TC reservation shows a much lower price than than SC, still the model price is significantly lower than the historical results.[18] In the scenario *2013 Anticipation* the average price for positive SC reserves increases as expected by 1 €/MW·h to 12.87 €/MW·h. On the right hand side the low prices increase

[18] In the current German balancing market pay-as-bid is used in contrast to the marginal prices reported in our model. According to Kahn et al. (2001) all pay-as-bid bids in such a market setting will converge towards the market clearing price in the long term, not taking into account risk-aversive behavior. Therefore, the marginal pay-as-bid price and our marginal price can be compared.

slightly. This is a result of the call anticipation, the peak prices remain unaffected, as other influencing factors are relevant here. The price duration curve for TC in *2013 Anticipation* shows higher prices overall, showing an improved representation of the historical results with 1.59 €/MW·h, almost matching the observed average of 1.51 €/MW·h of 2013.

In 2025, the average marginal price for SC increases to 23.3 €/MW·h, while prices for TC increase to 4.1 €/MW·h. With the participation of wind in the positive reserve provision the average marginal price for SC decreases to 17.7 €/MW·h for *2025 Wind5+* and 17.1 €/MW·h for *2025 Wind10+*. Therefore, only the load duration curve for the *2025 Wind10+* is shown. Especially the high prices for SC can be reduced with wind participation. Prices for TC decrease less heavily to 4 €/MW·h for *2025 Wind5+* and 3.8 €/MW·h for *2025 Wind10+*. As expected, the provision of negative reserves by wind turbines in the *2025 Wind5* and *2025 Wind10* scenarios does not have a significant impact on prices for positive reserves.

In 2025 the general price level is higher, and higher price peaks are observed. This price increase stems from different factors: First, the German power plant portfolio is characterized by higher average marginal cost than in 2013, which mainly applies to gas-fired power plants. Furthermore, the gas-fired power plants' relative part-load efficiency decrease is higher than for other plant types, leading to higher part load cost.[19] Second, more situations with very low residual load occur, in which no or very few dispatchable thermal power plants are online or have spare generation capacity. Thus, additional plants need to be started up and operating in minimum load just to provide available capacity for possible reserve energy activation.

Third, the increased flexibility of CHP plants in 2025 (e.g., due to additional heat storage) results in reduced online times and higher load factors during electricity production. Hence, CHP plants produce less often when their marginal costs are above the market price. Thus, the amount of must-run capacity is reduced in 2025, which would allow for an reserve provision without opportunity cost.[20]

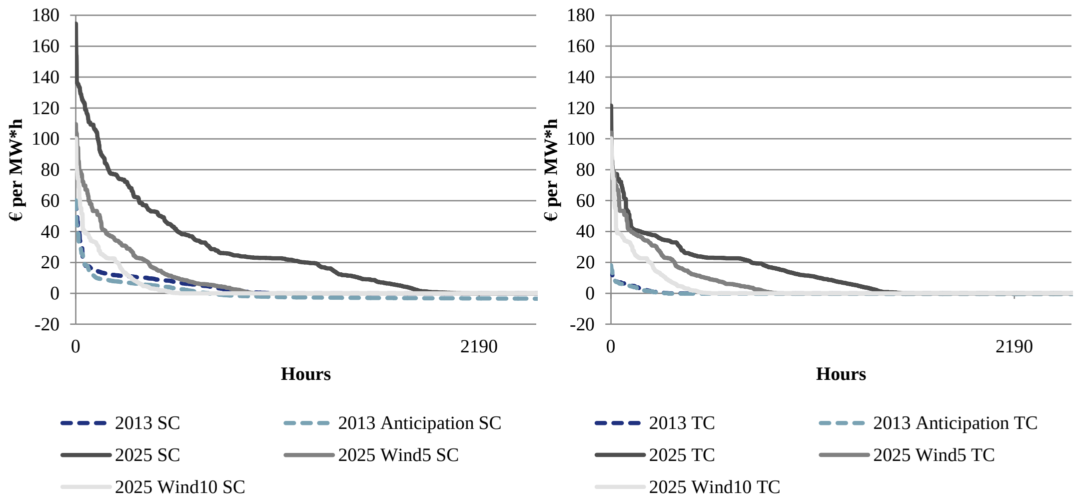
Analyzing the negative prices (Figure 4.10) for reserve capacity shows a different picture: In 2013 we observe an average marginal price for negative SC of 1.03 €/MW·h, which is significantly lower than the actually observed market outcome of 40 €/MW·h.[21] Hence, we find that prices for negative reserves are not fully replicable using a fundamental model, which is inline with current literature.[22]

[19] See Section 4.2 for an explanation on cost components driving the price of reserve capacity.

[20] See footnote 19.

[21] In the actual market outcome for 2013, the average marginal price for negative reserves of 40 €/MW·h is much higher than the average bid price of 8 €/MW·h. In the market for positive reserves the average marginal price and average price are much closer.

[22] This is confirmed by Bucksteeg et al. (2014) who compute prices for negative reserves close to zero in a fundamental model approach and thus only analyze the prices for positive balancing capacity.



(a) Price of negative reservation SC (b) Price of negative reservation TC

Figure 4.10.: Price duration curves for negative reservation by product and scenario for 2013 and 2025. Source: own calculations.

Looking at the results for negative reserves in the *2013 Anticipation* scenario we observe negative prices for a large percentage of hours. This is a result of the model formulation, as the potential fuel savings are included in the reservation price. In this case, the novel model formulation does not lead to more realistic price results.

In *2025* the average prices for negative SC increase to 7.63 €/MW·h; peak prices increase from 60 €/MW·h (*2013*) to 174 €/MW·h. Prices are still low in general, as prices above zero are observed in less than 2,000 hours. The inclusion of wind participation in the *2013 Wind5* and *2013 Wind10* scenarios influences the prices visibly, as the price averages are much lower with an average price of 2.39 €/MW·h and 1.14 €/MW·h, respectively. In contrast to positive reserves, additional wind turbines in the *2013 Wind10* scenario can further reduce the prices compared to *2013 Wind5* scenario.

For negative TC, average marginal prices close to zero are observable in *2013* that increase to 3.84 €/MW·h in the *2025* scenario. The *2025 Wind5* and *2025 Wind10* scenarios reduce the price for negative TC reservation again, to 2.03 €/MW·h and 1.06 €/MW·h, respectively. In line with the results for SC, additional wind turbines further reduce the prices. As expected, the provision of positive reserves by wind turbines in the *2025 Wind5+* and *2025 Wind10+* scenarios does not have a significant impact on prices for positive reserves.

The price increase for negative reserves in the *2025* scenarios stems from the fact that conventional generation is running at minimum load (or is even offline) in more hours. Thus, some plants must produce electricity only to provide negative reserves, even if their marginal cost are above the spot price. The provision of negative balancing reserves by wind reduces these cost significantly, as in situations with low residual demand wind feed-in is often very high. This allows for large quantities of negative balancing reserves being provided by wind turbines, which in return allows for reducing the amount of conventional power plants that have to be online merely to provide negative reserves.

4.4.4. Discussion of limitations

This chapter's findings need to be discussed in the context of the model's limitations as well as assumptions regarding the regulatory and technical boundary conditions.

We abstract from any strategic behavior that the market participants might apply, which might lead to higher prices on the spot and balancing markets and could increase costs. Furthermore, we abstracts from some characteristics of the actual balancing market design, that includes product durations of more than an hour as well as portfolio bids, where an actor controlling multiple power plants can bid into the balancing market without revealing in advance which power plant will provide the balancing reserves. However, for power plants within large portfolios this approximation leads to no changes, only for power plants in small portfolios these approximation could lead to an overestimation on their flexibility. Together with the neglection of uncertainty of RES infeed and load realization, a perfect adjustment of the reserved capacities neglecting any market inefficiencies is possible. Thus, the true cost of the balancing reserve system is likely underestimated. The increasing market volume would also increase the absolute cost savings. Hence, the absolute cost savings observed in the model are a lower bound, as the relative cost savings are not changing, because the different scenarios are based on the same assumptions.

Apart from strategic behavior, most technical constraints can only be approximated in a large-scale unit-commitment model. This includes also limitations on wind turbine output when withholding capacity to provide balancing reserves. As the future output of a wind turbine always includes some level of uncertainty, it can be complicated to determine the capacity that must be withheld to provide balancing reserves with a sufficient high level of security. Thus, real opportunity cost of wind turbines providing balancing reserves, could be slightly higher, although the general picture will not change.

4.5. Conclusions

This chapter presents the fundamental market model ELMOD-MIP which includes a detailed approach to model balancing provision for 2013, and analyzes a future scenario for the German balancing market of 2025. ELMOD-MIP includes the probability of reserve activation during the calculation of reserve capacity allocation. This allows us to closer approximate the behavior of market participants. In the future scenario of 2025, the influence of a changed power plant portfolio on prices and allocation of reserves is analyzed. Furthermore, the influence of wind power as a new market participant for the provision of positive and negative reserves is analyzed. The model shows a good representation of the spot and balancing markets. The novel approach leads to an improved representation of the historical market results for positive reserves, especially for TC. For negative reserves the representation cannot be improved substantially. Here, besides market fundamentals, strategic behavior and price expectations are important price drivers, which are hard to replicate in a fundamental electricity model.

The application of ELMOD-MIP to scenarios of the year 2025 shows an increase of prices for positive and negative reserves, when no entrance of new market participants is anticipated. With the participation of wind turbines the cost for balancing provision is reduced by 40 %, but remains above 2013 values. The relative cost savings stemming from wind participation are higher for negative reserves, as no previous curtailment of feed-in is required for reservation in contrast to positive reserve provision by wind turbines. The participation of wind turbines especially reduces the occurrence of peak prices for positive and negative reserves in 2025. This reduction effect occurs even with a relatively low share where wind turbines participate with only five percent of their capacity.

Further fostering the process of allowing wind turbines to participate in the German reserve market favorable. Although participation of wind turbines in balancing reserves is already reality, the current motions to adapt the current market setup to improve timing and flexibility of the auction process by decreasing lead times between bid and delivery, shorter product lengths, or an adapted bidding procedure to include marginal cost pricing could improve the market environment to enable the findings discussed in this chapter.

Chapter 5

Options for cross-border balancing reserve provision – A model analysis of electricity balancing cooperation arrangements in the Alpine region

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This chapter is based on Economics of Energy & Environmental Policy 3(2), 45–60 (Gerbaulet et al., 2014b); DIW Berlin Discussion Paper No. 1400 (Lorenz and Gerbaulet, 2014). Previous versions were presented at the 14th IAEE European Energy Conference 2014 in Rome, Italy, 9th Internationale Energiewirtschaftstagung 2015 in Vienna, Austria, and the 10th Conference on Energy Economics and Technology (ENERDAY 2015), in Dresden, Germany.

5.1. Introduction

One of the European Commission's goals is to establish an internal energy market for Europe. This includes a restructuring of the electricity market, laid out to a large extent in Directive 2009/72/EC and Regulation EC No. 714/2009. This exposes the European electricity system to significant changes, not only with respect to developments in generation and grid, but also to arrangements for the operation of the electricity system. In 2017, the European Network of Transmission System Operators for Electricity (ENTSO-E) published the final draft of the Network Code on Electricity Balancing (NC EB) which foresees arrangements to foster cross-border exchange of balancing services with the objective of lowering overall costs and increasing social welfare (EC, 2017). In line with the suggestions of the NC EB, in this chapter we analyze different forms of cross-border exchanges of balancing reserves with an application to the region of Austria, Germany, and Switzerland.

Increasing cross-border cooperation regarding balancing reserves is important because in the long term a high share of renewables will be reached, which could lead to higher balancing needs and lower balancing supply if the current balancing markets design remains unchanged. Borggrefe and Neuhoff (2011) see the upcoming importance of balancing markets with rising shares of wind penetration and propose a joint provision and adjustment of balancing services. While balancing markets have a much lower volume than the spot market, changes on balancing markets can also influence the spot market price. Wieschhaus and Weigt (2008) analyze these influences and show that an increasingly competitive balancing market also leads to lower prices on the spot market.

Balancing costs in Germany have been relatively constant to decreasing, although the renewable share is rising (Hirth and Ziegenhagen, 2015). This can partly be explained by the reorganization of the market design in Germany. Nevertheless dena (2014) and Holttinen et al. (2011) project rising balancing reserve requirements and specific costs for higher renewables shares if the market circumstances do not change. This phenomenon has not materialized in the market, although the share of renewables has increased substantially in recent years in Germany.

Balancing reserves stabilize the system's frequency of 50 Hz in the European electricity grid. In general, deviations from the nominal frequency can occur due to unexpected fluctuations in demand or generation. Three different types of reserve can be distinguished by their response time and length of activation: primary control (PC), secondary control (SC), and tertiary control (TC).[23]

[23]Throughout the literature different terms like balancing reserves, balancing capacity, control power, control energy are used. We will use the terms balancing reserves, balancing power and balancing energy that are used by ENTSO-E (2013a). The differentiation of the balancing power

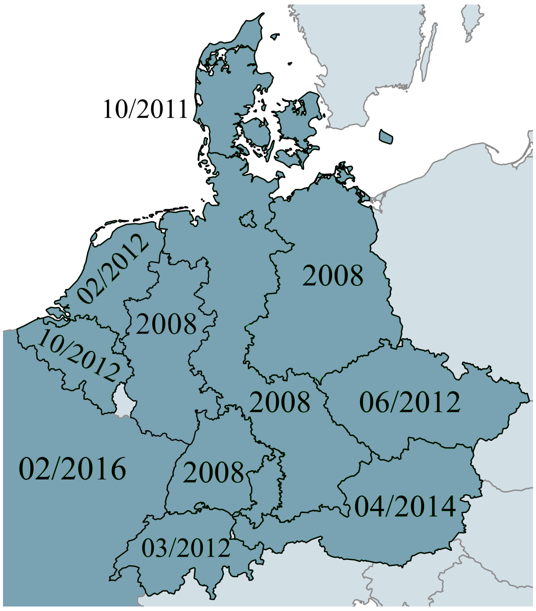


Figure 5.1.: TSOs' participation in the IGCC over time. The dates reflect the start of cooperation in the IGCC.

5.1.1. Cooperation efforts for balancing reserve procision in Europe

Currently, these products are auctioned on predominantly national markets with partly different procurement mechanisms. In Germany a joint balancing control area with joint coordinated procurement of secondary reserve capacity including all four German transmission system operators (TSOs) was established in 2010. This cooperation was extended in 2012 to the International Grid Control Cooperation (IGCC), see Figure 5.1. It is limited to the avoidance of counteractivation between two countries, called imbalance netting. Hence no joint procurement or activation of SC or TC takes place, as this could require the alteration of national framework conditions. Additional participants since 2012 are Energinet.dk (Denmark), Swissgrid (Switzerland), ČEPS (Czech Republic), Elia (Belgium), and TenneT TSO B.V. (the Netherlands). In April 2014 the cooperation was expanded to APG (Austria), and RTE (France) joined the cooperation in February 2016.

The IGCC is one of the most promising of ENTSO-E's cross-border electricity balancing pilot projects. Another leading balancing pilot project is the Trans European

products used in this chapter corresponds to the German variant. Thus, short-time load frequency control products such as frequency containment reserve (FCR) are PC, while automatic frequency restoration reserve (aFRR) is denoted as SC and manual frequency restoration reserve (mFRR) is denoted as TC in this chapter. Furthermore, replacement reserve (RR) are used to restore the required level of other reserves (FCR, aFRR, and mFRR) to be prepared for a further system imbalance. No comparable balancing product exists in Austria, Germany or Switzerland.

Replacement Reserves Exchange (TERRE) project, whose objectives is to establish a platform for all replacement reserve (RR) offers and to optimize the allocation of RR across the systems of various TSOs. It consists of TSOs in Great Britain, France, Spain, Portugal, Italy, Switzerland, and Greece (ENTSO-E, 2015b). A further advanced pilot project started in 2013 with the aim to establish one common market for the procurement of FCR based on a TSO–TSO model. Participants are currently Austria (APG), Denmark (Energienet.dk), the Netherlands (TenneT NL), Germany (50Hertz, Amprion, TenneT DE and TransnetBW) and Switzerland (Swissgrid). It is planned that Belgium (Elia) and France (RTE) will join the project in the future (ENTSO-E, 2015a).

Currently, several pilot projects tackle different balancing products (FCR, aFRR, mFRR, and RR), involving many TSOs and pursue diverse objectives (ENTSO-E, 2014a). These pilot projects have been established because in contrast to other European energy markets, where a rather clear target model exists, different forms for the provision and exchange of balancing services are still in discussion. This diversity highlights the challenge for harmonization (cf. ENTSO-E, 2012).

To overcome this diversity the NC EB tries to set a framework for future balancing harmonization. It addresses the topics of i) imbalance settlement, ii) procurement of balancing services, and iii) reservation and use of cross-zonal capacity for balancing. It is binding for each TSO, distribution system operator (DSO), balancing service provider (BSP) and balancing responsible party (BRP) and should frame their settlement processes. To harmonize the process of balancing service exchange between two or more TSOs the concept of Coordinated Balancing Areas (CoBAs) is developed. Every TSO must cooperate with two or more TSOs in a CoBA by exchanging at least one standard product or through implementation of an Imbalance Netting Process. However there is a transition period of two years after the entry into force of the NC EB before this rule applies. After various consultations by the Agency for the Cooperation of Energy Regulators (ACER) the final draft of the NC EB was sent to the electricity cross-border committee of the European Commission (EC) before it entered the comitology process, through which it should become European law. (EC, 2017)

The TSOs from Austria, Belgium, Germany and the Netherlands form the "European X-border Project for Long term Real-time balancing Electricity market design" (EXPLORE) that aim at creating a consistent cross-border balancing market design for aFRR and mFRR in line with the definition of CoBAs described in the NC EB. Furthermore, it takes a special position, as this cooperation focuses not only on balancing markets, but also on interlinks with the spot markets. (50Hertz et al., 2016b)

5.1.2. Literature on cross-border cooperation for balancing reserve provision

In the literature several studies treat the issue of cross-border balancing cooperation. The major part of the studies apply numerical models, focusing on the Nordic electricity markets. In contrast to most of the literature we analyze the region of Austria, Germany and Switzerland. One the one hand, they share a long history of cooperation between their electricity systems and are working closely together in different balancing pilot projects (ENTSO-E, 2014a). On the other hand, their generation portfolios are divers regarding technologies and potentials for renewable energy sources (RES), which prospects significant efficiency gains when forming a cooperation.

Van der Veen et al. (2010) give an overview on cross-border balancing agreements and perform a qualitative analysis on different arrangements. They conclude that cross-border balancing agreements are generally beneficial but uncertainties exist regarding their impact depending on the resulting detailed balancing market design.

Neuhoff and Richstein (2016) confirm that notion but highlight the need to avoid lock-in effects arising from an evolutionary market design process. Instead, first a consistent blue-print for a future balancing market market should be created, that could in a second step be the basis to assess individual market designs.

A study for the EC analyzes the impacts of a European balancing market (Mott MacDonald, 2013). It studies different approaches to handle cross-border exchange of balancing services by applying empirical methods as well as quantitative simulations. The results show a gain in social welfare and additional advantages for the integration of RES. To reach this goal the study recommends a TSO-to-TSO platform with a Common Merit Order List (CMOL), harmonization of key elements, and “appropriate” bidding blocks.

Van den Bergh et al. (2016) analyze the coordinating the sizing, allocation and activation of reserves among market zones. The reserve coordination among zones is mainly limited by network constraints. Their model is formulated as a three-step approach: i) a reserve sizing module, ii) a day-ahead module which determines the optimal energy scheduling and reserve allocation and iii) a real-time reserve activation module. They apply the model to the Central Western Europe (CWE) electricity system. The highest benefits occur when reserves are jointly activated but not jointly sized and allocated. This counter-intuitive result is caused by simplified transmission constraints during sizing and allocating reserves. Therefore reserves are not guaranteed to be deliverable in the model.

A further approach to analyze the reserve procurement and transmission capacity reservation in the northern European power market is Gebrekiros et al. (2015b). The authors also implement a three-step approach however with different objectives. In the first step the frequency restoration reserve (FRR) bidding price is determined on the power plant's opportunity cost. In the second step the TSO selects the cheapest FRR bids including cross-border capacities when transmission capacity is reserved. In the third step optimal dispatch is determined, taking into account the reserve and transmission capacity allocations. In a case study on the northern European power system balancing provision cost can be reduced when transmission capacity is reserved. With a transmission capacity reservation level of around 20%, total system cost tend to be the lowest.

Abbasy et al. (2009) analyze the effect of integrating balancing markets of Northern Europe. They show that balancing costs can be decreased by 100 million € in the region by increased integration. While overall cost are reduced, balancing power prices remain stable on average. A similar question is analyzed by Jaehnert and Doorman (2010). The authors show that increased integration of the Nordic and German balancing markets shows positive effects, but these are dependent on assumptions regarding the cost of regulation services. Farahmand and Doorman (2012) estimate cost savings of up to 400 million € per year resulting from an integration of the Nordic balancing market with the German balancing market.

Furthermore, van der Veen et al. (2011) show the positive effects of cross-border cooperation in providing balancing services, by an agent-based analysis for different agreements for integrating the Dutch, German, and Nordic balancing markets. Results indicate a 50% reduction of balancing cost resulting from the implementation of a common merit order list. Furthermore, Abbasy et al. (2011) analyze the effects of trading among BSPs and TSOs (i.e. foreign bidding) between Norway and the Netherlands. To simulate the change in market prices an agent-based model is used. They conclude that there is no general answer to whether a BSP-TSO model would result in too much shifted capacity (therefore increasing prices in the cheaper market) because this is dependent on the current situation of the spot market. The usage of an agent-based model allows to introduce strategic behavior and different players. However, it requires assumptions on the behavior of players, which can influence results to a great extent. Farahmand et al. (2012) compare the effects of a non-integrated and a fully-integrated balancing market in the Nordic region for a 2030 scenario. They apply a two-stage approach to model the spot and balancing market, which is similar to the approach applied in this chapter. Results show that possible cost saving opportunities due to balancing market integration that allow for less activation and cheaper reservation of balancing capacity exist.

Regional cooperation in the procurement of tertiary balancing capacity in the alpine region has been analyzed by Gerbaulet et al. (2012) with the result, that common procurement leads to cost decreases in the region. Bilateral cooperations can also lead to a decrease in total cost. The authors note that optimal allocation of interconnector (IC) capacity for the spot market and balancing services might gain significance in the future.

Besides the benefits of cooperation described above, pursuing cross-border balancing agreements might be a challenging task. A comprehensive study by Tractebel (2009) analyzes a pathway towards cross-border balancing agreements in Europe and demonstrates possible obstacles. Main prerequisites of cross-border harmonization are identified as common technical characteristics of balancing services and gate closure times, a common remuneration mechanism for balancing services, and a harmonization of imbalance settlement mechanisms. Possible inefficiencies and distortions due to insufficient harmonization of national market designs are analyzed by Vandezande et al. (2008). They recommend an implementation of cross-border balancing agreements with very low prerequisites to allow for a fast and functioning realization. Intensified harmonization should be done at a later stage.

Building upon the prevailing literature we analyze possible effects of the proposed NC EB for SC and TC, taking into account the cross-border lines and potential competing allocation objectives of the different energy markets of Austria, Germany, and Switzerland.

The remainder of this chapter is structured as follows: Section 5.2 describes the methodology applied in this chapter and underlying assumptions. The mathematical formulation of the modeling approach is explained in section 5.3. Section 5.4 describes the scenarios applied in the model. The data and application are presented in Section 5.5. In Section 5.6 the quantitative results are discussed, and Section 5.7 draws conclusions.

5.2. Methodology

We analyze the benefits stemming from regional cooperation between Austria, Germany, and Switzerland in the procurement of balancing services taking into account the suggestions of the NC EB. We only take into account the effects on SC and TC and neglect PC as its provision is already done jointly. Furthermore, the activation of PC is also done on a pro-rata basis within the entire synchronized grid as it is activated based on the grid's frequency.

We apply an extended variant of the model ELMOD-MIP that determines the cost-minimal power plant dispatch in the spot market under the assumption of perfect competition.

In our model two factors induce costs when reserving balancing capacity: On the one hand opportunity costs occur due to balancing restrictions on the available generation capacity, as capacity is either reserved in a power plant in case of positive capacity reservation, or a must-run condition is introduced in case of negative capacity reservation. On the other hand activation of balancing reserves leads to costs, because additional fuel is required or deviations from the optimal power plant dispatch occur. Pumped storage and hydro reservoirs can also participate in the balancing reserve market. Although no actual fuel cost occur in these plants, the connected nature of the electricity system leads to opportunity costs that are taken into account as well.

This chapter neglects price markups for balancing capacity as it focuses on the inefficiencies that exist in the balancing markets devoid of strategic behavior. Historical price markups, that are used in the majority of the existing literature, might distort the model results significantly in case of market integration, as the markups are usually not endogenous to the model. This could lead to an overestimation of the cost saving potential. Therefore our results will show lower cooperation benefits, as the model setting is different in comparison to the existing literature.

The extension of ELMOD-MIP (a mixed integer linear program (MILP)) is also a multi-step model. The steps involved are shown in Table 5.1. For all steps the same model is used, but relevant variables and parameters are fixed or set to zero based on each step's goal.

Table 5.1.: Model steps

Step	Description
1. Reservation	Spot market dispatch is calculated given balancing capacity requirements. Cross-border capacities are reserved depending on the scenario.
2. Activation	balancing reserves is activated given the reservation done in the previous step. This is either conducted for each region or the whole balancing area depending on the scenario.

1. Reservation Step 1 optimizes the power plant dispatch for all countries, given the balancing capacity requirements. The cross-border transfer capacities are optimized depending on the scenario for electricity exchanges only, or for electricity and reserve exchanges jointly. The model does not consider the cost for possible activation at this stage.

2. Activation In step 2, the dispatch including the activation of balancing reserves is optimized. Here, the variables determining the reservation of balancing capacity are fixed in the model. Only power plants with reserved capacity can be dispatched for balancing reserve activations by the model. No uncertainty about future spot market outcomes is integrated at this point, hence load and RES feed-in are certain for all hours of the model.

In the current market design balancing capacity is reserved regularly for time periods between four hours and one week, depending on the product and region. Furthermore this reservation is allocated to the bidding firms. The firms can optimize the dispatch of their power plant portfolio at the time of delivery of the balancing energy. In our model we abstract from this setting, thus balancing capacity can be reserved for each power plant and hour separately. This results in a situation similar to a single big firm participating in a cost-minimizing behavior on the balancing markets.

Computational complexity

The problem is not solved for an entire year at once, but each week is solved separately with a two-day overlap[24] to cover a whole year. To generate storage levels and associated limitations for the starting and the end period of each period, we solve a limited version of the model for the entire model year prior to the actual calculations. This is necessary because large-scale reservoirs not only optimize their dispatch on a day-to-day basis but the reservoir level and inflows into these reservoirs are very different over the course of a year. This allows to parallelize the calculations and reduce the computation time for an entire year significantly. It is solved with the help of a unix cluster. Up to 50 nodes were used in parallel, each equipped with at least 16 GB of RAM and AMD or Intel processors of at least 2.6 GHz. Each calculation needs up to 20 hours. Thanks to parallelization each scenario can be calculated in less than 2 days.

5.3. Model implementation

We extend the model ELMOD-MIP to be able to represent cross-border interaction and reservation and activation of balancing reserves within a multi-market environment. This sections only shows the additions and alterations to the model.

The model's objective is to minimize total system costs, while clearing the spot market as well as the balancing market for the two balancing power products SC and TC. The model is solved in the General Algebraic Modeling System (GAMS) using the commercial solver CPLEX.

[24]See Barrows et al. (2014) for an analysis of time series partitioning and overlap times. The authors suggest the setting used in this chapter to achieve adequate solutions while achieving fast solution times.

Market clearing

$$
\begin{aligned}
0 = q^{spot}_{r,t} - \sum_{c \in r} G_{c,t} + \sum_{s} (G^{up}_{s,t} - G^{down}_{s,t}) & \\
- g^{wind}_{r,t} - g^{pv}_{r,t} - g^{bio}_{r,t} - g^{water}_{r,t} - g^{waste}_{r,t} & \qquad \forall r,t \qquad (5.1)\\
- g^{sewage}_{r,t} - g^{deposite}_{r,t} - g^{cb}_{r,t} + \sum_{rr} F^{spot}_{r,rr,t} &
\end{aligned}
$$

$$q^{resv,pos}_{b,bl,r,t} = \sum_{p \in r} G^{resv,pos}_{p,t,bl,b} - \sum_{rr} F^{resv,pos}_{b,bl,r,rr,t} \qquad \forall t,r,bl,b \qquad (5.2)$$

$$q^{resv,neg}_{b,bl,r,t} = \sum_{p \in r} G^{resv,neg}_{p,t,bl,b} - \sum_{rr} F^{resv,neg}_{b,bl,r,rr,t} \qquad \forall t,r,bl,b \qquad (5.3)$$

$$q^{call,pos}_{b,r,t} = \sum_{p \in r} G^{call,pos}_{b,p,t} - \sum_{rr} F^{call,pos}_{b,r,rr,t} \qquad \forall b,r,t \qquad (5.4)$$

$$q^{call,neg}_{b,r,t} = \sum_{p \in r} G^{call,neg}_{b,p,t} - \sum_{rr} F^{call,neg}_{b,r,rr,t} \qquad \forall b,r,t \qquad (5.5)$$

The spot market is cleared by leveling load $q^{spot}_{r,t}$, generation $G_{c,t}$, storage $G^{up}_{s,t}$, $G^{down}_{s,t}$, renewable feed-in $g^{wind}_{r,t}$, $g^{sol}_{r,t}$, $g^{bio}_{r,t}$ and exchange flows $F^{spot}_{r,rr,t}$ for all time steps t and regions r, as stated in (5.1). Markets for positive and negative balancing capacity are cleared separately for each product b and activation probability block bl, by leveling demand $q^{resv,pos}_{b,bl,r,t}$, $q^{resv,neg}_{b,bl,r,t}$, reserves $G^{resv,pos}_{p,t,bl,b}$, $G^{resv,neg}_{p,t,bl,b}$, and cross-border flows to or from other regions $F^{bal,pos}_{b,bl,r,rr,t}$, $F^{bal,neg}_{b,bl,r,rr,t}$. This is shown in (5.2) and (5.3) for the reservation and (5.4) and (5.5) for the activation of balancing reserves.

Flow restrictions

$$f^{max}_{r,rr} \geq F^{spot}_{r,rr,t} + \sum_{b,bl} F^{resv,pos,ge0}_{b,bl,r,rr,t} - \sum_{b,bl} F^{resv,neg,le0}_{b,bl,r,rr,t} \qquad \forall r,rr,t \qquad (5.6)$$

$$-f^{max}_{r,rr} \leq F^{Spot}_{r,rr,t} + \sum_{b,bl} F^{resv,pos,le0}_{b,bl,r,rr,t} - \sum_{b,bl} F^{resv,neg,ge0}_{b,bl,r,rr,t} \qquad \forall r,rr,t \qquad (5.7)$$

$$F^{spot}_{r,rr,t} = -F^{Spot}_{rr,r,t} \qquad \forall r,rr,t \qquad (5.8)$$

$$F^{resv,pos}_{b,bl,r,rr,t} = -F^{resv,pos}_{b,bl,rr,r,t} \qquad \forall b,bl,r,rr,t \qquad (5.9)$$

$$F^{resv,neg}_{b,bl,r,rr,t} = -F^{resv,neg}_{b,bl,rr,r,t} \qquad \forall b,bl,r,rr,t \qquad (5.10)$$

$$F^{call,pos}_{b,r,rr,t} = -F^{call,pos}_{b,rr,r,t} \qquad \forall b,r,rr,t \qquad (5.11)$$

$$F^{call,neg}_{b,r,rr,t} = -F^{call,neg}_{b,rr,r,t} \qquad \forall b,r,rr,t \qquad (5.12)$$

$$F^{resv,pos,ge0}_{b,bl,r,rr,t} \geq F^{resv,pos}_{b,bl,r,rr,t} \qquad \forall b,bl,r,rr,t \qquad (5.13)$$

$$F^{resv,neg,ge0}_{b,bl,r,rr,t} \geq F^{resv,neg}_{b,bl,r,rr,t} \qquad \forall b,bl,r,rr,t \qquad (5.14)$$

$$F^{resv,pos,le0}_{b,bl,r,rr,t} \leq F^{resv,pos}_{b,bl,r,rr,t} \qquad \forall b,bl,r,rr,t \qquad (5.15)$$

$$F^{resv,neg,le0}_{b,bl,r,rr,t} \leq F^{resv,neg}_{b,bl,r,rr,t} \qquad \forall b, bl, r, rr, t \quad (5.16)$$

$$\sum_{bl} F^{Resv,Pos,ge0}_{b,bl,r,rr,t} \geq F^{call,pos}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (5.17)$$

$$\sum_{bl} F^{resv,pos,le0}_{b,bl,r,rr,t} \leq F^{call,pos}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (5.18)$$

$$\sum_{bl} F^{resv,neg,ge0}_{b,bl,r,rr,t} \geq F^{call,neg}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (5.19)$$

$$\sum_{bl} F^{resv,neg,le0}_{b,bl,r,rr,t} \leq F^{call,neg}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (5.20)$$

We distinguish three types of flows: Spot market flows $F^{spot}_{r,rr,t}$, flow reservation of balancing capacity $F^{resv}_{b,bl,r,rr,t}$, and flows induced by the activations of balancing reserves $F^{call}_{b,r,rr,t}$. The maximum flows between regions are limited in the positive (5.6) and in the negative direction (5.7). These flows consist of spot market flows as well as reserved capacity for balancing purposes if available in the scenario. Equations (5.8) to (5.12) ensure model symmetry. In order to avoid model-induced counteracting for the possible balancing flows only the positive or the negative part is included in these equations. Hence counter-balancing-flows can not increase the flow limit. The flows induced by the activation of balancing reserves must always be lower than the reserved capacity as show in (5.17) to (5.20).

Further restrictions

$$F^{Resv,Pos,ge0}_{b,bl,r,rr,t}, F^{Resv,Neg,ge0}_{b,bl,r,rr,t} \geq 0 \quad (5.21)$$

$$F^{Resv,Pos,le0}_{b,bl,r,rr,t}, F^{Resv,Neg,le0}_{b,bl,r,rr,t} \leq 0 \quad (5.22)$$

Equations (5.21) and (5.22) ensure positive or negative values for some variables in the model.

5.4. Scenarios

We study different levels of balancing market integration as suggested in the current version of the NC EB: i. *No Cooperation* as a base case, ii. *Imbalance Netting* only, iii. *Joint Activation* across borders, and iv. *Full Cooperation*. We assume perfect competition and the objective is to minimize total system cost while taking into account generation restrictions, reserve restrictions and flow limitations between different countries.

i. In the scenario *No Cooperation* every country procures and activates balancing services on its own. Cross-border flows on the spot market exist but the balancing markets are separated.

ii. The scenario *Imbalance Netting* adds limited cooperation between countries during the activation phase of balancing reserves. Procurement of balancing capacity takes place nationally like in scenario i., but imbalances are netted between countries when activations for balancing reserves occur and remaining free transmission capacity can handle the induced power flow of imbalance netting. This avoids unnecessary counteracting between countries.

iii. In the *Joint Activation* scenario this cooperation is further extended and the activation of balancing reserves is coordinated between countries. If cross-border capacity is available, balancing reserves can be activated within the country with the lowest cost. The procurement remains separate for each country.

iv. In the *Full Cooperation* scenario the coordination extends to the procurement of balancing capacity, building on the setup of scenario *Joint Activation*. The capacity reservation is conducted for the entire region given cross-border capacity restrictions. Hence the reservation of capacity for cross-border balancing flows competes with the spot market flows. This allows for interesting insights into the value of each kind of cross-border capacity, as the model determines the cost-minimal balance between spot market and balancing flow reservation.

The overall model structure is identical for all scenarios. The scenarios are differentiated by the available transfer capacity for balancing purposes and the netting of imbalances between countries. Spot market flows are only limited by the available net transfer capacities (NTCs) in all stages.

5.5. Data and application to model region

We apply the model to our region of interest consisting of Switzerland[25], Austria and Germany as shown in Figure 5.2. We use exogenous exchange flows for the surrounding countries. Changes to these exchange flows due to the inclusion and change of the balancing cooperation scheme are not taken into account.

Where possible, we use publicly available data. Load, balancing power reserve requirements, and balancing reserves activations are based on historical time series from 2013. Renewable feed-in time series are based on TSO data for Germany from 50Hertz (2013), Amprion (2013), TenneT (2013), and TransnetBW (2013). For

[25] Liechtenstein is incorporated into Switzerland for our analysis.

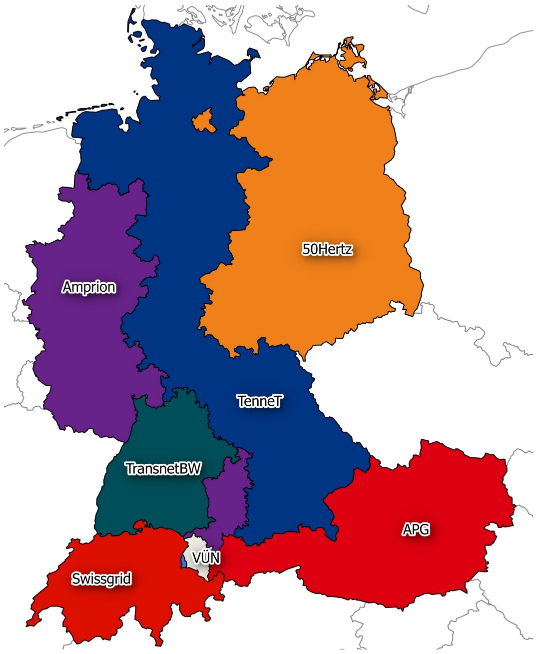


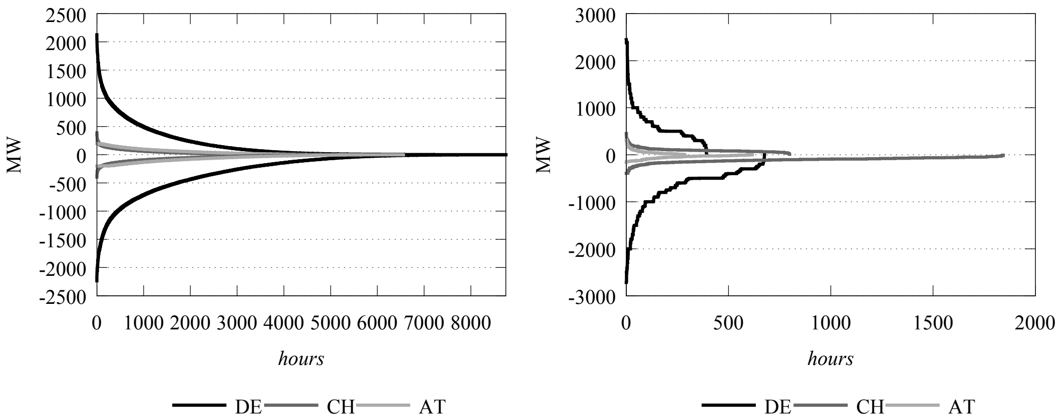
Figure 5.2.: TSOs in the model region

Austria and Switzerland the feed-in time series are approximated based on installed capacities and weather data. Hydro inflows for Austria are based on E-Control (2013) and for Switzerland on Bundesamt für Energie BFE (2013). Load time series for all regions are taken from ENTSO-E (2013-2016). The NTC between the countries is based on ENTSO-E (2016).

The power plant data for Germany is based on Egerer et al. (2014), and for Austria and Switzerland based on PLATTS (2011) as well as additional data from BFE (2014), BNetzA (2014b), and Verbund (2014). The transfer capacities between regions are based on NTC values from ENTSO-E (2013c). Cost assumptions for fuels and the CO_2 price are based on Egerer et al. (2014). Power plant characteristics are derived from Schröder et al. (2013).

Data for necessary reserved balancing power and activated balancing reserves is taken from the official platform of the four German TSOs Regelleistung.net (2013) for Germany and from Swissgrid (2013) for Switzerland and E-Control (2013) for Austria. Figure 5.3 shows the duration curves of balancing reserves activations from 2013: Values above zero represent positive activations, whereas negative values represent negative balancing reserves activations.

The figures show that the balancing energy demand for SC can reach above 2,000 MW and below −2,000 MW in Germany. The balancing energy need in Austria and Switzerland is smaller, here the SC balancing reserves activations do not exceed ±400 MW for Switzerland and ±200 MW for Austria. While activations for secondary



(a) Secondary Capacity (b) Tertiary Capacity

Figure 5.3.: Balancing reserve activation duration curves of 2013.

balancing reserves occur throughout the year, tertiary capacity is used less frequently. At the same time the countries' peak activations for tertiary balancing reserves are higher. Comparing these numbers to the peak load of about 84 GW and an overall energy demand of about 535 TWh in Germany shows that the energy activated on the balancing reserve markets is – by its nature – relatively small. The same holds true for Austria with a peak demand of about 10.2 GW and a yearly consumption of 66 TWh as well as for Switzerland with a peak demand of 9.8 GW and a yearly consumption of 62 TWh.

In the calculations the balancing time series is aggregated from quarter hours to full hours, as the model's time resolution is one hour. This is achieved by taking the maximum activation of each hour and ensures that the necessary ramps that occur when balancing reserves are activated are also realized in our model. This slightly overestimates the total amount of activated balancing reserves.

5.6. Results and discussion

5.6.1. Cost for balancing reserve provision

The costs for balancing reserve provision are determined as the difference between the total system cost with and without inclusion of balancing reservation and activation. Our results indicate that increased cooperation in the provision of balancing reserves leads to a reduction in total cost, as depicted in Figure 5.4. The most beneficial scenario *Full Cooperation* leads to savings of up to 104 million € per year for the entire region. *Imbalance Netting* only has a minor cost effect, and *Joint Activation* leads to improvements in activation costs of about 30 million € savings per year.

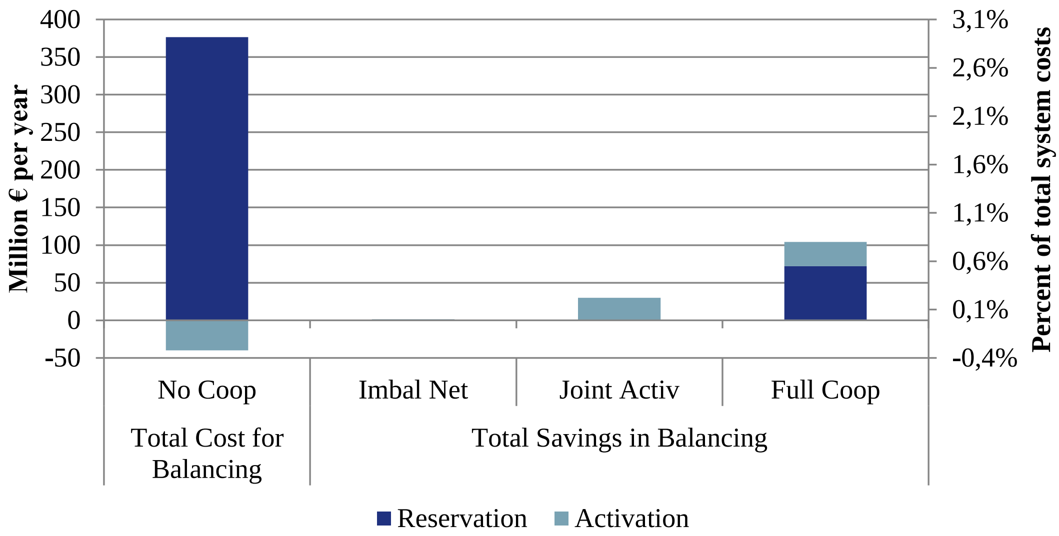


Figure 5.4.: Costs and savings

Only the scenarios *No Cooperation* and *Full Cooperation* are compared regarding the reservation outcome, as the reservation in the other scenarios is identical with the scenario *No Cooperation*. Here we see a cost improvement of 74 million € by coordinating the balancing procurement.

The difference in activation cost can be analyzed for all four scenarios. The total cost for activation of balancing capacities are negative in our application. This is caused by the fact that the total demand for negative balancing capacity is larger than positive balancing both for SC and TC in 2013. In case of negative balancing demand the model has the option to decrease the output of more expensive generation capacities, compared to the case of positive balancing demand. This causes the total cost of activation to be negative. This also reflected in historical prices of 2013, where the imbalance price during time of control zone shortage was also negative on average, fitting the results of our fundamental model.

Imbalance netting does not lead to significant activation cost improvements compared to existing projects. This deviation is partly caused by the fact, that the quarter-hours provided by the TSOs are already aggregated and hence less imbalance netting is possible. Further, the structure might be changed slightly. *Joint activation* shows cost improvements, as here the distribution of activated power plants can be optimized more with a higher degree of freedom. In the case of *Full Cooperation* the activation also leads to a further improvement in cost. In the *Full Cooperation* scenario not only the reservation but also the spot market as well as cross-border transmission capacity is optimized simultaneously. Despite the competition of the spot and balancing market for cross-border transmission capacity the overall cost in the *Full Cooperation* scenario, with partly reserved interconnectors are still lowest.

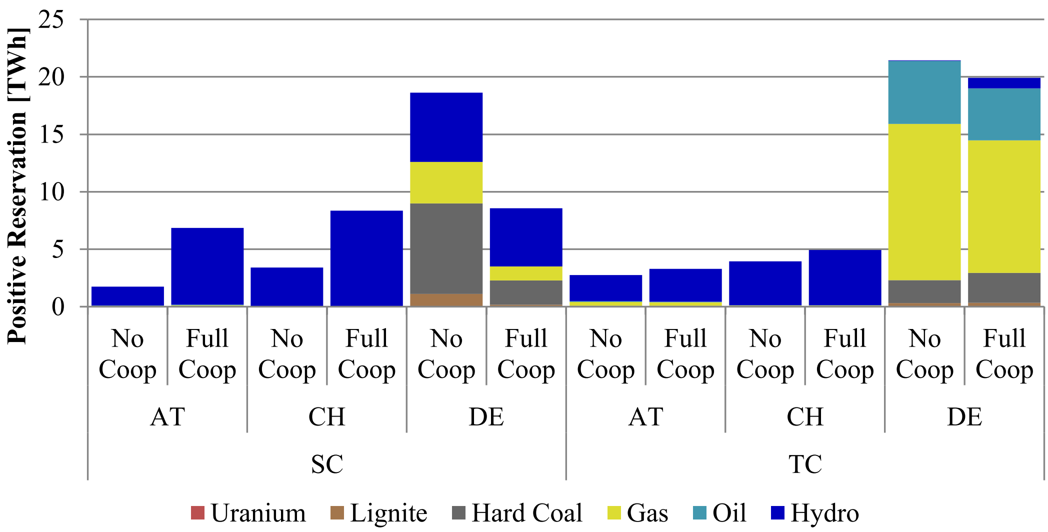


Figure 5.5.: Positive reservation

The much higher savings in the *Full Cooperation* justify the high complexity of the process. Therefore it would be beneficial to apply it to specific regions separately, as this requires a less complicated adaption and harmonization process.

The relatively small savings in comparison to the total cost are mainly caused by the small volumes of reserved balancing capacity in comparison to the spot market load. Furthermore only a small fraction of the reserved capacities is activated and causes direct generation costs.

Reservation of generation capacity for balancing power

When regional cooperation is in place a great impact on the amounts of reserved and activated balancing capacities can be observed. The scenario *Full Cooperation* – the only one that allows for inter-regional reservation – shows drastic changes of reserved capacities within the regions. Comparing the reservation of positive balancing capacity (Figure 5.5) between the *No Cooperation* and *Full Cooperation* scenarios shows a general trend towards generation both of SC and TC capacity from Germany towards Austria and Switzerland. We only analyze these two scenarios in this section, as the reservation result for the scenarios *Imbalance Netting* and *Joint Activation* is identical to the *No Cooperation* scenario. It is not only the amount of reserved capacity that allows for insights into a theoretically cost-optimal allocation of reserve capacity, but also the technologies that are used for capacity reservation.

In the case without cooperation, the demand for positive balancing capacity in Germany is met by hard coal, natural gas, and hydro capacities. For TC, oil and gas turbines capacities are also reserved, as these remain often unused and are not part of the least cost dispatch. They can be started sufficiently fast within the time

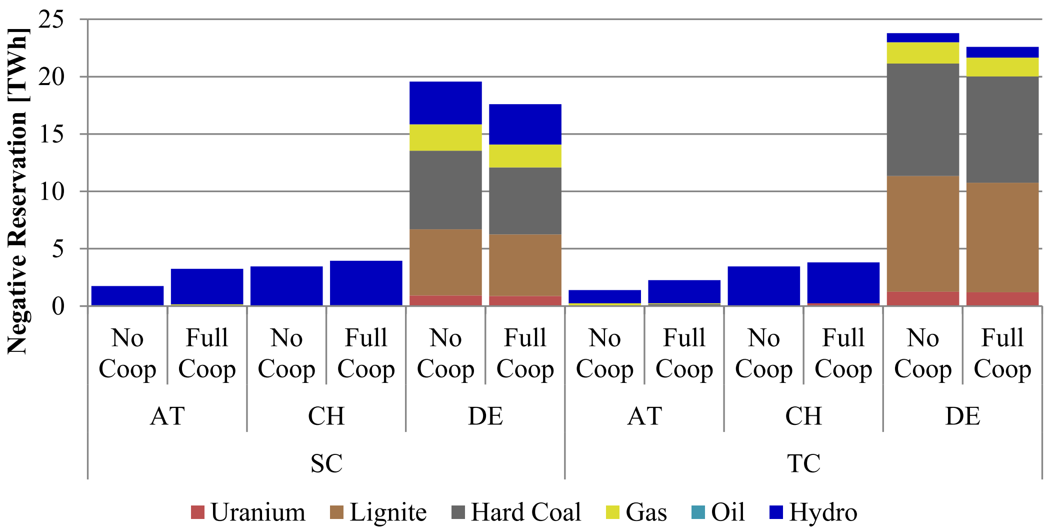


Figure 5.6.: Negative reservation

required to provide capacity for the TC product. Both in Austria and Switzerland, the demand for positive balancing capacity is almost entirely met by hydro based electricity generation technologies.

Reasons for the discrepancy can be explained by the difference in the generation portfolios between Germany and Austria/Switzerland. Germany's generation portfolio contains more fossil fueled generation capacities to serve its base load than its neighbors. Austria and Switzerland mainly rely on hydro power with theoretical zero marginal cost. Withheld generation capacity from run-of-river power plants (RoR) power plants is lost in our model as it can not be stored. Therefore it is not beneficial to provide positive reserve capacity with this technology. However it is beneficial to provide negative reserve capacity as these plants have no assumed minimum generation level. Due to their marginal cost close to zero, RoR are nearly always in the market. It is the other way around with pumped storage plants (PSPs), where unused water is not lost. Hence it is especially beneficial to use storage for positive reserve capacities. Furthermore, these plants also do not have minimum generation constraints and can can be started very quickly in our model. However, during hours with high spot prices, positive reserve is provided by power plants with marginal cost. During these times it is more efficient to reserve these plants and to use the storage plants in the spot market.

When the positive balancing capacity is reserved across the entire region, the reservation shifts toward more hydro capacity in Austria and Switzerland. About 50% of German SC capacity and 8% of German TC capacity are shifted towards Austria and Switzerland. This leads to significant transmission capacity reservation, analyzed in Section 5.6.1. This shift of SC is significantly higher than for TC as the provision of TC is relatively cheap in Germany due to fast starting power plants. Hence the cost advantage of hydro power from Austria and Switzerland is less prevalent. This results in lignite in Germany not providing positive balancing capacity anymore, and the share of hard coal is also significantly reduced.

In the *No Cooperation* scenario hydro sources also provide negative reserves (Figure 5.6) for Austria and Switzerland. In Germany, hard coal and lignite power plants provide negative capacity, as those power plants are often part of the dispatch solution, and have the option to decrease the output of electricity without opportunity costs. This is often not the case for natural gas fired power plants, as these are further to the right in the merit order and also are often restricted by heat demand requirements.

The changes of coordinated reservation of negative balancing capacity are less distinct than in the case of positive balancing capacity. Only 10% of German SC capacity and 5% of German TC capacity is shifted towards Austria and Switzerland. The composition remains similar.

Activation of generation capacities to provide balancing energy

The activation of balancing reserves can be analyzed for all four scenarios. As balancing reserves activations are not constant but occur dispersed over time the values shown are significantly smaller than in Figures 5.5 and 5.6.

In the *No Cooperation* scenario, positive reserves in Austria and Switzerland are mainly provided by PSPs. In Germany, lignite and coal and PSP are the main provider for SC. For TC, fast starting natural gas plants are the main provider. In the *Imbalance Netting* scenario the SC and TC activations decrease by about 20% and 2% respectively (Figure 5.7). In all scenarios the amount of activated positive balancing reserves is decreased by imbalance netting as the effect remains also for the *Joint Activation* and *Full Cooperation* scenarios. The high cost decrease in the *Joint Activation* scenario (shown in Figure 5.4) stems from the shift away form gas fired activation in Germany for TC towards activations of hydro energy sources in Austria and Switzerland. In the *Full Cooperation* scenario in less coal and lignite is activated in Germany and shifted towards activations of hydro energy sources in Austria and Switzerland. This further shift in comparison to the *Joint Activation* scenario is due to the changes already occurring during reserving balancing capacities.

In the *No Cooperation* scenario, negative reserves in Austria and Switzerland are mainly provided by RoR. In Germany, hard coal, natural gas and RoR are the main provider. The development of negative activations throughout the scenarios show a similar overall picture as shown in Figure 5.8. Imbalance netting leads to an overall decrease in activations. These reduced activations are the base of the *Joint Activation* and *Full Cooperation* scenario. In the *Joint Activation* scenario, a shift from Austria

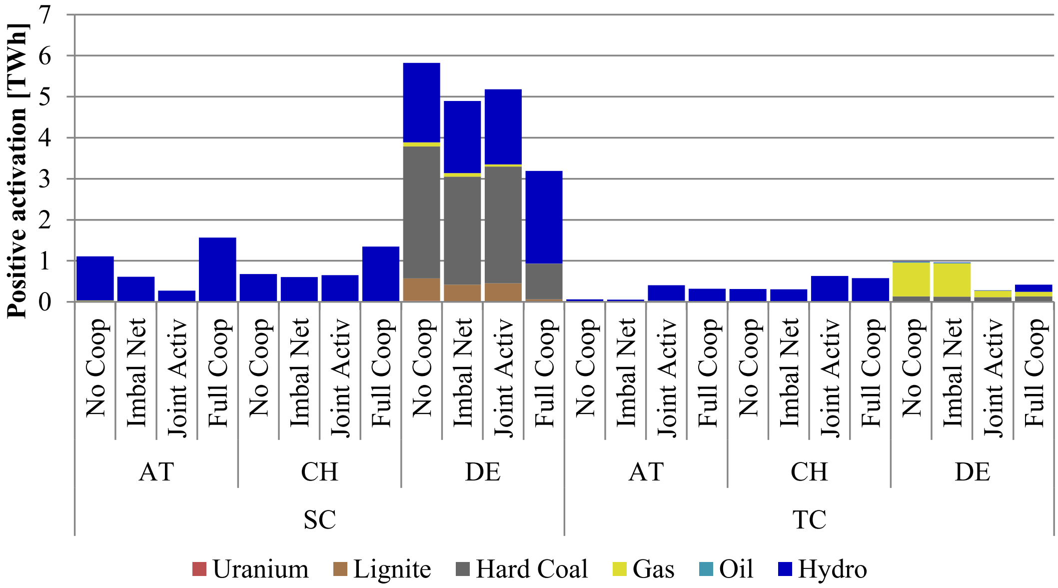


Figure 5.7.: Positive balancing reserve activations by scenario

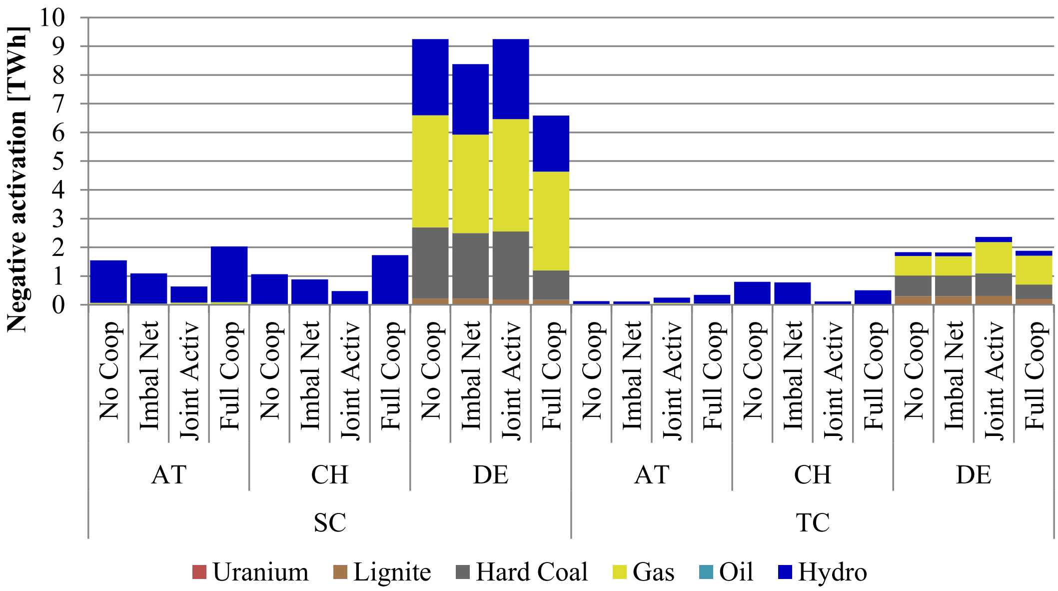


Figure 5.8.: Negative balancing reserve activations by scenario

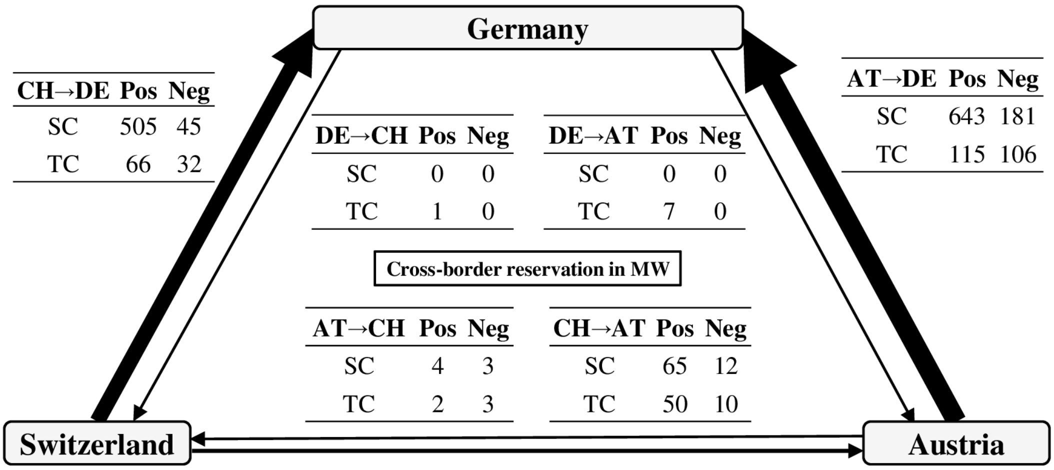


Figure 5.9.: Cross-border reservation of balancing capacity in the *Full Cooperation* scenario in MW

and Switzerland to Germany occurs. This initially counter-intuitive result stems from cost reduction of negative activation when applied to fossil generation technologies. Hence, increased activation of fossil generation capacities in Germany leads to an overall cost decrease. In the *Full Cooperation* scenario, the activations of SC also decrease and the lowest for Germany, as here the shift to Austria and Switzerland had already occurred during the reservation phase.

Cross-border analysis

In the *Full Cooperation* scenario, not only balancing capacities in neighboring zones are reserved, but also the cross-border grid must anticipate potential full activation of these capacities. Thus, cross-border transmission capacity is also reserved simultaneously.

Figure 5.9 shows the cross-border reservation of balancing capacity in the scenario *Full Cooperation*. We observe high reservation of IC capacity from Austria and Switzerland to Germany for positive reserves. While most of the capacity is reserved for positive SC. The IC capacity reservation from Germany to Austria and Switzerland is negligible, similarly for the capacity between Austria and Switzerland. The reserved IC capacity between Switzerland and Austria in contrast is small but significant and even between SC and TC.

The IC reservation for positive reserves between Austria and Germany accounts for up to 70% of the total IC capacity. The IC reservation for positive reserves between Switzerland and Germany accounts for up to 80% of the total IC capacity. At first, this seems quite high as the volumes in the balancing market are usually low compared to the spot market. However the IC reservation occurs in the opposite direction of the normal prevalent spot market flows, as Germany regularly exports to Austria and Switzerland. Therefore the IC reservation for positive balancing services does not compete with spot market flows and hence does not increase total spot market costs.

For negative reserves we observe a very similar pattern of IC capacity reservation as just shown for positive reserves. However the level of IC capacity reservation is much lower. A reservation of IC capacity for negative reserves leads blocks the IC in the opposite direction. Hence, the negative reserves that are “flowing” from Austria and Switzerland towards Germany reduce the IC capacity from Germany to Austria and Switzerland. Therefore the IC capacity reservation occurs parallel to the direction of normally prevalent spot market flows. Hence, the reservation for negative balancing services competes with spot market flows and therefore potentially increases spot market cost. Therefore the IC capacity is only reserved during times of very high reservation prices or untypical spot market flow directions. As these situations occur less often, the average reservation of IC capacity is lower than for the positive reserves.

Results show, that often spot and reserve market see flows going in different directions. Electricity is exported from Germany while at the same time reserves are imported to Germany. During these times, spot market prices in Austria and Switzerland are higher than in Germany, leading to these spot market flows. But why does it then makes sense to withhold generation capacity in these countries to provide reserves for Germany? The type of generation capacity reserved in Austria and Switzerland induces this result: In Austria and Switzerland, mostly storage capacities are reserved for balancing. These capacities do not generate electricity during these time, as their water value is above the current spot market price. Therefore, they do not face opportunity cost when providing balancing reserves. Those reserve capacities will then be procured in Germany.

In the *Full Cooperation* scenario described above, the reservation of the activation of balancing reserves is always within the limit of the NTC, as activation must always be lower than the reservation. In contrast, the *Joint Activation* scenario allows for activation of balancing reserves across borders without prior IC capacity reservation. Therefore, only capacity that is not used in the spot market is used for balancing purposes.

5.6.2. Model limitations

Our model allows capacity reservation on an hourly basis. Together with the neglection of uncertainty of renewable energies in-feed and load realization, a perfect adjustment of the reserved capacities is possible. Thus, the true cost of the electricity system are likely underestimated. Furthermore the benefits shown by our results are generated under the assumption of a social planner. We abstract from any strategic behavior that the market participants might want to apply, which would lead to higher prices on the spot and balancing markets and would increase costs. Network constraints are approximated using a transport model, hence loop flows and line specific limitation are not analyzed.

5.6.3. Implementation issues

When analyzing possible benefits of market reforms the cost and effects of implementation must also be addressed. *Imbalance Netting* requires the least technical and regulatory interventions. Furthermore is is already implemented in various balancing exchange cooperations like the IGCC. *Joint Activation* has similar technical prerequisites, and the implementation is therefore not critical from a technical perspective. In line with *Imbalance Netting*, *Joint Activation* is also already applied in different balancing pilot projects. In contrast, the implementation of *Full Cooperation* with joint procurement is more complex, both from technical but also from regulatory aspects. It requires the harmonization of balancing products and regulations. These challenges are partly addressed in the NC EB. Furthermore these requirements can be reduced when using a TSO–TSO model. The technical complexity regarding the adequate sizing of reserves across zones remains. The change of capacity reservation also shifts BSP rents and possibly influences the spot markets.

5.7. Conclusion

In this chapter we analyze regional cooperation scenarios on the balancing reserve market. The motivation for our analysis stems from "Network Code Electricity Balancing" by ENTSO-E which is close to implementation as of early 2017. It introduces various regulations to increase cross-border exchange of balancing reserves and should lead to lower overall balancing cost.

We estimate the efficiency increases for different levels of regional cooperation on the secondary and tertiary control markets of Austria, Germany, and Switzerland. We apply a fundamental electricity sector model with unit-commitment constraints and endogenous flows.

The model results confirm the expectations that increased cooperation in balancing markets is highly beneficial. The degree of cost savings depends on the depth of cooperation. The *Imbalance Netting* scenario show only minor cost savings, which can be largely increased by *Joint Activation*. The largest benefits can be gained in the *Full Cooperation* scenario. However, this requires the reservation of IC capacity for balancing purposes, which could influence spot market cost. Therefore the IC capacity reservation is mostly done against the direction of regularly spot market flows, hence no competition rises. Only occasionally, when high reserve prices occur, IC capacity is reserved in the same direction as spot market flows. This coordinated procurement and cross-border capacity reservation mostly shifts capacity reservation from Germany towards Austria and Switzerland. These shifts are largely driven by the countries' different power plant portfolios. Coordinated procurement and cross-border activation also cause transfers of producers' rents. Thus, the resulting distributional effects need to be analyzed carefully.

Chapter 6

Balancing reserves within a decarbonized European electricity system in 2050 - From market developments to model fundamentals

This chapter is based on DIW Berlin Discussion Paper No. 1656 (Lorenz, 2017) and submitted to Renewable Energy. Previous versions were presented at the 15$^{\text{th}}$ IAEE European Energy Conference 2014 in Bergen, Norway, the 11$^{\text{th}}$ Conference on Energy Economics and Technology (ENERDAY 2016), in Dresden, Germany, and the 10$^{\text{th}}$ Internationale Energiewirtschaftstagung 2017 in Vienna, Austria.

6.1. Introduction

To be able to adhere to the target of the Paris Agreement (UNFCCC, 2015) the European electricity sector must be decarbonized, implying a transformation of the generation portfolio. Depending on assumptions regarding the cost and availability of nuclear electricity generation and carbon capture, transport and storage (CCTS) technologies, different pathways for this transformation are suggested by science and politics. Most pathways include very high shares of fluctuating renewable energy sources (RES) until 2050. These shares can be a challenge for generation capacity adequacy because of their daily and seasonal variability of the feed-in. This medium and long-term variability is not the only challenge: fluctuating RES are regularly deviate from their planned production schedules. These short-term deviations must be balanced out by the activation of balancing reserves. Hence, an increasing RES share will, most probably, lead to an increasing balancing reserve demand (despite forecast quality improvements, see section 6.2.1 for a detailed discussion). Furthermore, a large share of balancing reserves are still provided by fossil-fueled generation, which will be phased-out by 2050 under a decarbonization target. These challenges resulting from balancing provision are neglected in most investment models and will therefore be analyzed in detail in this chapter.

To reduce the cost of balancing reserve provision, multi-national cooperations have been formed, new technologies participate in balancing reserve provision, and a large part of the regulatory framework has changed. Falling prices in spot and forward markets have motivated more and more generators to participate in the relatively, profitable balancing markets. Nevertheless the provision of balancing reserves and the balancing markets are a technically and regulatory highly complex field which still offers large room for developments and harmonization of the framework across Europe.

In the first part of this chapter, these developments of the framework for balancing reserve provision are analyzed with a focus on: i) dynamic dimensioning of the demand for balancing reserves, ii) provision of balancing reserves by fluctuating renewable electricity sources, iii) the role of new (battery) storage technologies, and iv) possible exchanges of balancing reserves between balancing zones and joint procurement of balancing reserves. See Section 6.2 for a detailed review on the possible developments and their transformation into scenarios. These scenarios are applied to an enhanced version of dynELMOD (**dyn**amic **El**ectricity **Mod**el), an investment model of the European electricity system (see Chapter 2), that is extended to include balancing reserve provision. The model is capable of evaluating the effects of possible developments in balancing reserve provision and high shares of fluctuating RES jointly. Hence, it allows me to analyze the future cost of balancing reserve provision in a decarbonized electricity system while evaluating the influence of different developments within the technical and regulatory framework of balancing.

There are several options to analyze balancing markets based on electricity system models. In general, electricity system models can be categorized either as long-term planning models or short-term operation models. Large-scale and long-term planning models are mainly used to determine cost-efficient investments pathways for generation and transmission capacities. To allow for this large scope they abstract from some technical details and neglect some operational issues (Hagspiel et al., 2014; Ludig et al., 2011; Mantzos and Wiesenthal, 2016). Most studies analyze the effect of different policies or technologies on the spot and balancing markets in a unit-commitment model which does not allow for endogenous capacity investments (Farahmand and Doorman, 2012; Gebrekiros et al., 2015b; Spieker et al., 2016).

Only very few studies analyze the future balancing provision in dynamic large scale electricity system models that includes endogenous capacity investments. Zerrahn and Schill (2015a) develop a greenfield model that includes balancing reservation. It is a single node application and roughly calibrated with German input data and cost assumptions for 2050. Similarly, Belderbos and Delarue (2015) present a model that allows for endogenous investment planning with operational constraints. However, in both papers, the implications of the balancing constraints have not been analyzed systematically and no large-scale brown field application is done due to computational limits.

Most similar to the analysis presented in this chapter, van Stiphout et al. (2017) analyze the impact of balancing reserves on investment planning within electricity systems with a high RES target. Their hypothesis is that in the existing literature the technical barriers and integration cost of large shares of RES are underestimated as in most long-term electricity models balancing reserves are not included. To test their hypothesis, they develop an endogenous greenfield investment model that includes detailed constraints for system operation. The model is applied to a conceptual test system that is roughly calibrated to the Belgian power system. Their results confirm their assumption, that the necessary balancing reserve requirements will lead to substantial additional cost for the integration of large shares of RES. Even a rather unambitious RES generation share of 50% would lead to a dramatic total system cost increase of up to 30%. This is due to necessary reserves, assuming no change of the currently existing balancing framework conditions. Even with possible improvements in the balancing market (RES participation and dynamic reserve sizing) the total system cost would still go up by 20%. These high costs can possibly be explained by the following simplifications of van Stiphout et al. (2017) in comparison to this chapter: i) only three generic generation technologies, ii) no other countries, iii) no electricity grid, iv) no upward reserve provision from RES, v) no storage or demand side management (DSM), and vi) no biomass or hydro generation capacities.

The reminder of the chapter is structured as follows: Section 6.2 analyzes future developments within the technological and regulatory framework of balancing reserve provision and transforms them into quantitative scenarios. These scenarios are applied to the electricity system model dynELMOD that is presented in Section 6.3. The model includes a large-scale data set of the European electricity system, described in Section 6.4. In Section 6.5 the model results for the scenarios and sensitivities of the different developments are analyzed and Section 6.6 concludes.

6.2. Balancing market developments

The balancing market is influenced by the following developments: i) steady technical progress in weather forecasts for fluctuating RES, reducing their balancing reserve demand, ii) fluctuating RES increase their potential to participate in the balancing reserve provision (Hirth and Ziegenhagen, 2015), iii) prices for battery storages decrease rapidly and allow for further applications in balancing markets (Nykvist and Nilsson, 2015), and iv) the regulatory framework changes to enhance cross-border exchange and foster harmonization between markets (EC, 2017). In the following, these developments of the framework for balancing reserve provision will be analyzed in detail. With this analysis, factors that could influence the model outcome regarding balancing reserve provision will be identified. These factors will be summarized in assumptions that will be varied in the different scenarios and sensitivities described in Sections 6.2.1 to 6.2.4.

6.2.1. Balancing reserve dimensioning and sizing horizon

When determining the size of the necessary balancing reserve, the aim is to dimension the reserves as small as possible to reduce the cost for reserving capacity, but as big as necessary to reduce the risk of insufficient reserves to balance the electricity system. Reserve sizing methodologies can be characterized by their sizing approach and sizing horizon. The sizing approach can be either deterministic (e.g. based on the possible failure of the largest power plant in the synchronous system), heuristic (e.g. using a formula accounting for system characteristics and empiric coefficients) or probabilistic (based on a probability distribution of system imbalances). The heuristic and deterministic sizing approach is usually combined with a static sizing horizon. The static sizing horizon determines the necessary reserves for relatively long time periods ranging between days and a full year. The probabilistic approach can be used with a static and a dynamic sizing horizon. The dynamic sizing horizon includes much shorter time period than the static horizon. The reserves can be resized (e.g. every day for each of the next 24 hours), based on the latest forecast of RES in-feed. Therefore not the full theoretical generation capacity is included, hence, only the probability of forecast deviation of a much lower capacity must be included. Especially for systems with high shares of RES, the reserves can be reduced significantly with a dynamic horizon. (Holttinen et al., 2012)

The impact of increasing shares of RES on balancing reserve provision is still in discussion: most studies assume that, due to the fluctuating nature of wind and solar power, the demand for balancing reserve capacity increases in order to compensate for forecast errors (Papavasiliou et al., 2011). The estimates in the literature for the additional reserve demand caused by additional wind capacity are in the range of 2 % to 9 % (Brouwer et al., 2014; dena, 2010; DLR, 2012; Holttinen et al., 2011; Lew et al., 2013). Ziegenhagen (2013) estimates an additional reserve demand of 6 % of the installed wind capacity which can be decreased to about 4 % with additional solar installation. To account for the uncertainty within the literature I vary the additional balancing demand per GW of fluctuating RES (referred in the following as "RES demand factor") in our different scenarios and sensitivities (see Section 6.2.4).

For the German balancing market, a continuation with a static sizing horizon and a high RES share, as it is projected for 2030, would lead to a balancing reserve demand increase between 25% and 75% dependent on assumptions regarding forecast quality improvements for RES (Bucksteeg et al., 2016; Kays et al., 2010). With a dynamic sizing horizon the balancing reserve demand increase would be limited to 5%-15% (Bucksteeg et al., 2016).

Contrary to the literature, the absolute value of reserved balancing capacity decreased in Germany in the years 2010-2015, although renewable capacity increased significantly. At the same time, restructuring of the market and regulations lead to efficiency gains. Morbee et al. (2013) and Ortega-Vazquez and Kirschen (2009) present a further explanation and show show that until a high share of RES is reached, no significant effect on the demand for balancing reserves need to be expected.

The implementation of such reserve sizing calculations in a large-scale investment model leads to difficulties: the probabilistic calculation of balancing reserves is non-convex due to the convolution of probability distribution functions. For this calculation the installed capacities of the technologies (in this case wind onshore, wind offshore and photovoltaic (PV)) must be know. These capacities are endogenous in an investment model and hence not known beforehand. Because of the non-convexity of the sizing approach, it can not be included in an investment model due to computational limits. Therefore a possible reduction of balancing reserve demand due to stochastic independent deviations by different technologies is underestimated.

6.2.2. Renewables and storage as new market participants

Regularly only dispatchable power plants were allowed by the transmission system operator (TSO) to provide balancing reserves. However, this changed and also non-dispatchable technologies are allowed as new possible providers of balancing reserves. This includes electrode boilers, large customers, battery storages, virtual power plants and also fluctuating RES. The potential for battery storage and fluctuating RES will be analyzed in detail.

The provision of balancing reserves by RES is not longer a technical problem (EWEA, 2014; Gesino, 2010). Wind (on and offshore) have successfully passed the pre-qualification procedure, which certifies their sufficiently fast response time and controllability, to participate in German balancing markets (50Hertz, 2016). Similarly PV is able to provide part of its capacity in the balancing market (Jansen and Speckmann, 2013). As discussed in Hirth and Ziegenhagen (2015) and Sorknæs et al. (2013) fluctuating RES will most likely supply negative balancing reserves in the next years. However, for hours of excess electricity production, it makes sense for RES also to provide positive reserves. During these times, withholding generation from RES for balancing reserves leads to no opportunity cost, as they would be curtailed anyhow (EWEA, 2014). If the hours of excess electricity production will continue to increase in the upcoming years, an increasing share of positive balancing reserves could be provided by fluctuating RES.

Fluctuating RES include a special challenge as their final production always includes risk. Due to this risk, not the full forecasted generation can be reserved for balancing provision. To reach the same security level of dispatchable power plants, the share that can be used for balancing reserve is dependent on the forecast quality of the feed-in. As a result, long before delivery very few capacity can be reserved, as the forecast has a high deviation probability.

As time of delivery approaches, forecast quality is higher and more capacity can be used for balancing provision. Therefore currently common lead times of a week and product lengths of days, as in Germany, are too long. As a result, single units must currently be in a pool with sufficient dispatchable generation to be able to participate.

Götz and Baumgart (2014) conclude, that for an security level of 99.994 % up to 30 % of the entire German wind power feed-in is firm, when all turbines are pooled. A similar analysis by Fraunhofer IWES (2014) estimates a share of 10 % of the feed-in that would be available for balancing services in a day-ahead regime. This share is referred to the “firm capacity forecast” and varied in the different scenarios and sensitivities (see section 6.4).

Besides fluctuating RES, battery storage entered the balancing reserve market in 2015. Large-scale batteries are already used for the provision of frequency containment reserve (FCR), and a market share of 27% is expected by the end of 2017 (Fleer et al., 2016). Due to rapidly falling battery prices, it could become economic, that storage will also provide frequency restoration reserve (FRR). Brijs et al. (2016) show that considering battery storage for balancing services is beneficial and reduces the total system cost (TSC). For the profitability of storages in balancing market, it is decisive for how many subsequent hours the battery storage must be able to provide its reserves. This implies how often it will be possible to activate the balancing reserves in a row without unplanned recharges. The duration a balancing reservation is influencing the storage level constraints is referred as the "storage reservation window".

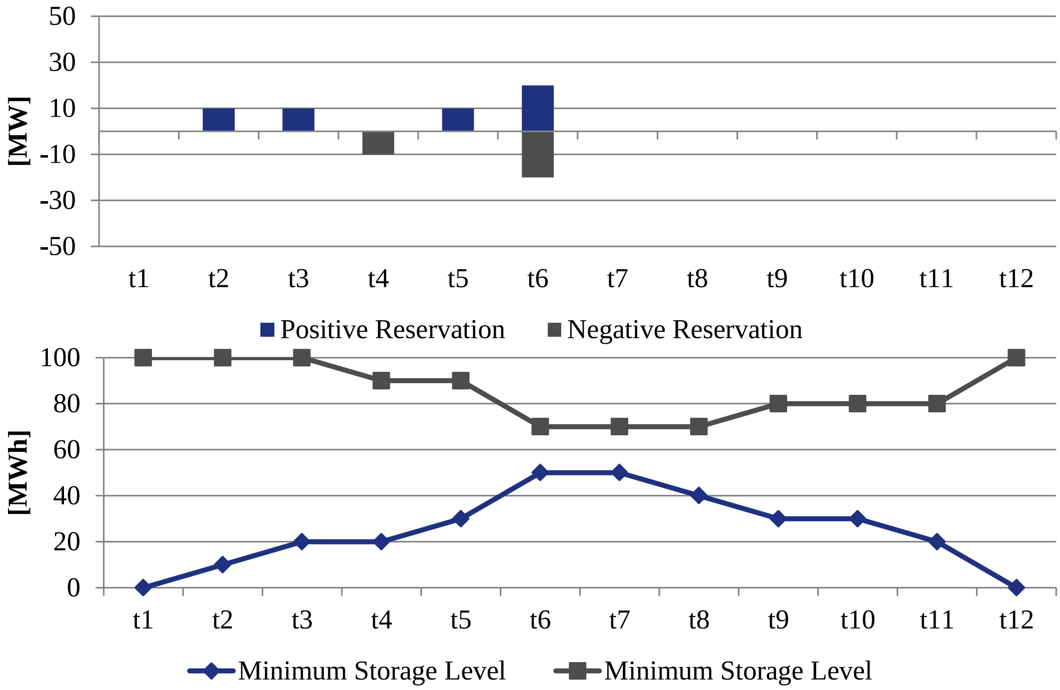


Figure 6.1.: Influence of positive and negative balancing reservation on the storage level constraints

The storage reservation window describes the length for which balancing reservation is influencing the storage level constraints (see Section 6.3.2 for the mathematical formulation). In Figure 6.1, the influence of this constraint is demonstrated for a storage reservation window of six hours with an exemplary storage consisting of 100MW charge and recharge capacity and a storage volume of 100MWh. In the upper graph a fictional positive and negative reservation is depicted. Every reservation narrows the gap between the minimum and maximum storage level, as depicted in the lower graph. The solution space for the storage level is defined as the area between the gray and blue line. From hour eight on the minimum storage level decreases, as the positive reservation in hours one (and following) falls out of the storage reservation window. I vary the storage reservation window in the different scenarios and sensitivities (see Section 6.4).

6.2.3. Cross-border cooperation

When the electricity grids within Europe have been interconnected and synchronized one reason was to increase the system stability and security. Another reason was the possibility to trade electricity over these interconnectors (ICs). The trade of electricity normally reduces the TSC as it allows to use generation portfolio more efficiently. Besides the trade of electricity, the ICs allow for cross-border cooperation between the TSOs for the provision and activation of balancing reserves.

Different degrees of cross-border cooperation are possible between the TSOs. The options are characterized by different regulatory and technical complexity but also resulting levels of benefits. The first option refers to imbalance netting. Imbalance netting describes the process of netting positive and negative imbalances in the cooperating control zones. Thereby the imbalance of both zones can be reduced if the imbalances in at least two zones have a different sign. Imbalance netting is performed at the point in time when the imbalance occurrs and transmission capacity is available. Hence, neither the balancing reservation nor the balancing activation merit-order is influenced. Therefore this option requires the least technical and regulatory interventions.

The second option is a joint activation of reserves, that normally comes after imbalance netting. This option allows to use a common merit-order list for two or more cooperating balancing zones. Therefore the power plant that is activated must not be in the same zone where the imbalance occurs, if sufficient transmission capacity is available. Due to the common merit-order it is more complex than imbalance netting; still the allocation of the reserved capacities is not influenced. The third option is the joint procurement of balancing reserves, that only makes sense if the two other options are already implemented. This option results in a common market which is only limited by cross-border transmission capacity. In contrast to the other options, this transmission capacity must be known before. This could make the reservation of IC capacity necessary, which is then not longer available for the spot market. Hence, a joint optimization of balancing and spot market IC capacity usage is important to set the cost-efficient share between the two.

The benefits and implications of cross-border exchange of balancing reserves have been studied in various papers: Van der Veen et al. (2010) give an overview on main cross-border balancing agreements and conclude that cross-border balancing agreements are generally positive, but the impact depends on the detailed balancing market design. Farahmand and Doorman (2012) estimate cost savings of up to 400 million € per year resulting from an integration of the Nordic balancing market with the German balancing market. A further approach to analyze the reserve procurement and transmission capacity reservation in the northern European power market is shown by Gebrekiros et al. (2015b). They confirm that balancing provision cost can be reduced when transmission capacity is reserved. With a transmission capacity reservation level of around 20%, total system cost tend to be the lowest. Chapter 5 analyzes different degrees of balancing cooperation between Austria, Germany and Switzerland. They show that joint procurement of balancing reserves allows for much larger cost savings than imbalance netting or joint activation only. In the optimal setting, balancing power cost can be reduced by up to 40%. They conclude, that currently existing imbalance netting should be expanded towards the joint procurement of balancing reserves.

European Network of Transmission System Operators for Electricity (ENTSO-E) also acknowledges the need to foster and regulate cross-border exchange of balancing services (ENTSO-E, 2012). To regulate possible cross-border cooperations, ENTSO-E formulated the Network Code on Electricity Balancing (NC EB), which foresees arrangements to promote cross-border exchange of balancing services with the objective of lowering overall costs and increasing social welfare. Therefore, it address the topics of i) imbalance settlement, ii) joint procurement of balancing services, and iii) reservation and use of cross-zonal capacity for balancing (EC, 2017). In 2017, eight pilot projects tackle these problems for the different balancing products (FCR, FRR and replacement reserve (RR)) (ENTSO-E, 2014a). The International Grid Control Cooperation (IGCC) is one of them and consists of eleven TSOs from central and west Europe and allows for imbalance netting. Another balancing pilot project is the Trans European Replacement Reserves Exchange (TERRE) project, whose objectives is to establish a platform for all RR offers and to optimize the allocation of RR across the systems of various TSOs (ENTSO-E, 2015b). Furthermore, the EXPLORE project aims at creating a consistent cross-border balancing market design for automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR) while taking into account possible interlinking between spot and balancing market (50Hertz et al., 2016b).

The question remains, whether there is a limit on balancing exchanges. The secure supply of balancing reserves is crucial for system stability. Hence, it must be guaranteed that the reserved balancing capacities can also be delivered. Therefore the unplanned reduction of IC capacity can put the whole electricity system at risk. However, this can also happen within a control zone. Therefore, the reserves must be allocated in such a way, that enough redundant transmission pathways are possible (in line with the n-1 criteria). I vary the maximum amount of reserves that can be exchanged, which in the following is referred to as "maximum exchanges".

6.2.4. Scenarios and sensitivities

The future technical and regulatory framework for balancing reserve provision is uncertain, as shown in the previous analysis in Section 6.2. The analysis identified the following factors as most critical:

1. Static or dynamic sizing horizon for balancing reserves;
2. Reserve demand in percent of each additionally installed GW of fluctuating RES;
3. Firm capacity forecast in percent of RES feed-in forecast;
4. Storage reservation window in hours;
5. Maximum cross border balancing reserve exchange in percent of total reserve demand;

The factors are combined in three scenarios *pessimistic*, *conservative* and *optimistic*. Additionally, each factor will be analyzed in a separate sensitivity analysis based on the *conservative* scenario. Table 6.1 gives an overview on scenarios and sensitivities. *Max* and *min* are not tested in joint scenarios but are only used as worst case and optimal case for the sensitivity analysis.

Table 6.1.: Scenarios and sensitivities

	Max	Pessimistic	Conservative	Optimistic	Min
Dynamic sizing horizon		yes/no	yes/no	yes/no	
RES demand factor	10%	8%	6%	4%	2%
Firm capacity forecast	5%	10%	20%	35%	50%
Storage reservation window	24	12	8	4	1
Maximum exchange	10%	20%	30%	40%	50%

6.3. Methodology

6.3.1. dynELMOD

dynELMOD (**dyn**amic **El**ectricity **Mod**el) is a dynamic partial equilibrium model of the European electricity sector which determines cost-effective development pathways for the entire system. It endogenously decides upon investment in conventional and renewable generation, storage, DSM, and network capacities that influence the resulting dispatch. Electricity flows can be approximated using a flow-based market coupling approach, that accounts for loop-flows, or with a transport model. Due to computational complexity of balancing reservation, the transport model is used in this chapter. The model dynamically optimizes the investments into generation and networks over the entire time horizon, but includes options to limit the planner's foresight to represent myopic investment behavior. A Carbon dioxide (CO_2) emission limit can be set for each year. Chapter **??** provides a detailed description of the model.

The starting point for new investments is the currently available power plant portfolio, which decreases over time as the end of the lifetime of power plants are reached, and the existing electricity grid infrastructure. Further developments in the upcoming years are characterized by assumptions regarding the change of i) investment and operational cost, ii) fuel cost, iii) full load hours (FLH) of RES, iv) load and the CO_2 emission limit. These developments form the boundary conditions, together with regional CCTS storage availability, overall and yearly investment limits and regional fuel availability.

In order to reduce complexity and proof generation adequacy the calculation is separated into two steps: in the first step, the investments are determined using a reduced time set for the dispatch calculations. To determine these hours, a time frame reduction technique that covers the characteristics of seasonal and time-of-day variations in the input parameters is included. In the second step, the investment decisions are fixed and evaluated based on a dispatch calculation with a full time set. This calculates the final generation and determines whether a reliable generation portfolio has been found that is adequate for the entire year.

6.3.2. Extension of dynELMOD

So far dynELMOD was focused on the electricity generation to cover the demand. This chapter extends the model so that also the demand for reserves to balance short-term deviations will be included. The demand for balancing reserves is partly dependent on the installed capacities of fluctuating RES and hence endogenous within the model. The models does not only have to meet the electricity demand with the generation capacities but also the endogenous balancing reserve demand by partly withholding the same generation capacity.

The determination of the cost for balancing reserve provision will be done through a comparison of different calculation. The basis is always a calculation without balancing reserve provision, that is compared to calculations with balancing reserve provision within different technological and regulatory frameworks. The difference between the cost of the calculations thereby defines the cost for the provision of balancing reserves. Furthermore the cost increase due to balancing reserve provision can be differentiated into the different components like variable generation cost or investment cost.

Apart from the cost, a country specific reserve price can be determined. Still, power plant sharp prices can only be calculated ex-post. A further challenge in long-term investment models is a detailed approximation of flexibility constraints. Poncelet et al. (2014b, 2016) analyze the problem of including short-term flexibility and balancing constraints into a long-term model. On the one hand, the reduced time-set, long-term investment models use, does often not represent the full variability of weather phenomena influencing the feed-in from RES. Increasing the time set would increase computation time intensively and is hence, only possible in simple models. Therefore large-scale models apply time reduction techniques (Green et al., 2014; Nahmmacher et al., 2016). On the other hand, some flexibility constraints like power plant status require binary variables. Introducing binary or integer variables in linear long-term investment models would significantly increase optimization time. A possible solution is to implement linear flexibility constraints (e.g. ramping restrictions) by linearization of the binary or integer constraints, which is also done in this approach.

In the following, the changes in the mathematical formulation to represent balancing provision are presented. Only the formulas that are new or changed in comparison to the basic dynELMOD will be shown here for simplicity. For the full mathematical formulation see Chapter 2.

Market clearing: I introduce two new market clearing conditions, one for positive reserves (6.1) and one for negative reserves (6.2). In every hour the necessary balancing reserves must be provided by generation capacities within the country or by reserve imports or exports to cover the surplus or deficits. The balancing reserve demand consists of an exogenous and an endogenous part: first, an exogenous part for load noise, schedule leaps and power plant failure that is based on historical reserve requirements. Second, an endogenous part, that depends on the scenario and is calculated based on either i) the installed capacity of non-dispatcheable RES (static sizing) or ii) the forecasted feed-in of non-dispatchable RES (dynamic sizing).

$$\begin{aligned}
\sum_i g^{resv,pos}_{co,i,t,y} = {} & Q^{resv,pos}_{co,t,y} + \sum_{cco} flow^{resv,pos}_{cco,co,t,y} \\
& + \textstyle\sum_{yy \le y, ndisp} inv^{cap}_{co,ndisp,yy} * BalDem^{static}_{co,ndisp} \qquad \Big\} \text{Static Sizing} \qquad \forall y, co, t \\
& + \textstyle\sum_{yy \le y, ndisp} inv^{cap}_{co,ndisp,yy} * BalDem^{dynamic}_{co,t,ndisp} \qquad \Big\} \text{Dynamic Sizing}
\end{aligned} \tag{6.1}$$

$$
\begin{aligned}
\sum_{i} g^{resv,neg}_{co,i,t,y} = \;& Q^{resv,neg}_{co,t,y} + \sum_{cco} flow^{resv,neg}_{cco,co,t,y} \\
&+ \textstyle\sum_{yy\leq y,ndisp} inv^{cap}_{co,ndisp,yy} * BalDem^{static}_{co,ndisp} && \Big\}\text{ Static Sizing} \qquad \forall y, co, t \\
&+ \textstyle\sum_{yy\leq y,ndisp} inv^{cap}_{co,ndisp,yy} * BalDem^{dynamic}_{co,t,ndisp} && \Big\}\text{ Dynamic Sizing}
\end{aligned}
\tag{6.2}
$$

Generation restrictions: Equations (6.3) and (6.4) define the reservation from dispatchable technologies. For these, the positive reservation is limited by the available generation capacity and current spot market production (Equations (6.5) and (6.6)). Furthermore dispatchable technologies (exept storage) must produce above minimum generation to provide positive reserves (6.7) and in addition at least the amount of negative reserves (6.8).

$$
g^{resv,pos}_{co,disp,t,y} = \sum_{p} g^{resv,pos,existing}_{p,co,disp,t,y} + \sum_{yy\leq y} g^{resv,pos,newbuilt}_{co,disp,t,y,yy} \qquad \forall co, disp, t, y \tag{6.3}
$$

$$
g^{resv,neg}_{co,disp,t,y} = \sum_{p} g^{resv,neg,existing}_{p,co,disp,t,y} + \sum_{yy\leq y} g^{resv,neg,newbuilt}_{co,disp,t,y,yy} \qquad \forall co, disp, t, y \tag{6.4}
$$

$$
Ava_{co,disp,y} * G^{max}_{p,co,disp,y} \geq g^{existing}_{p,co,disp,t,y} + g^{resv,pos,existing}_{p,co,disp,t,y} \qquad \forall p, co, disp, t, y \tag{6.5}
$$

$$
Ava_{co,disp,y} * inv^{cap}_{co,disp,yy} \geq g^{newbuilt}_{co,disp,t,y,yy} + g^{resv,pos,newbuilt}_{co,disp,t,y,yy} \qquad \forall co, disp, t, y, yy \tag{6.6}
$$

$$
g_{co,i,t,y} * \frac{G^{max}_{p,co,disp,y} - G^{min}_{c,y}}{G^{min}_{c,y}} \geq g^{resv,pos}_{co,disp,t,y} \qquad \forall co, t, y, yy, disp \notin s \tag{6.7}
$$

$$
g_{co,i,t,y} - G^{min}_{c,y} \geq g^{resv,neg}_{co,disp,t,y} \qquad \forall co, t, y, yy, disp \notin s \tag{6.8}
$$

The positive reserve provision by non-dispatchable RES is limited by their feed-in in equation (6.9). Furthermore the positive and negative reserve provision is limited to their firm capacity forecast of the feed-in (Equations (6.10) and (6.11)).

$$
\begin{aligned}
g_{co,ndisp,t,y} + g^{resv,pos}_{co,ndisp,t,y} \leq \;& \\
& \sum_{yy\leq y} ResAva^{newbuilt}_{co,t,ndisp,yy} * inv^{cap}_{co,ndisp,yy} \qquad \forall co, ndisp, t, y \\
& + \sum_{p} ResAva^{existing}_{co,t,ndisp} * G^{max}_{p,co,ndisp,y}
\end{aligned}
\tag{6.9}
$$

$$
g^{resv,pos}_{co,ndisp,t,y} \leq g_{co,ndisp,t,y} * G^{safeshare}_{ndisp,y} \qquad \forall co, ndisp, t, y, yy \tag{6.10}
$$

$$
g^{resv,neg}_{co,ndisp,t,y} \leq g_{co,ndisp,t,y} * G^{safeshare}_{ndisp,y} \qquad \forall co, ndisp, t, y, yy \tag{6.11}
$$

Ramping: Equations (6.12) and (6.13) define the maximum possible up and downward ramping taking into account the activation of reserves. Equation (6.14) and (6.15) enforce, that enough ramping capability is reserved so that reserves can be activated sufficiently fast.

$$g^{resv,up}_{co,i,t,y} = g^{resv,pos}_{co,i,t,y} + g^{resv,neg}_{co,i,t-1,y} \qquad \forall co,i,t,y \quad (6.12)$$

$$g^{resv,down}_{co,i,t,y} = g^{resv,neg}_{co,i,t,y} + g^{resv,pos}_{co,i,t-1,y} \qquad \forall co,i,t,y \quad (6.13)$$

$$g^{up}_{co,c,t,y} + g^{resv,up}_{co,i,t,y} \leq R^{up}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{up}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co,i,t,y \quad (6.14)$$

$$g^{down}_{co,i,t,y} + g^{resv,down}_{co,i,t,y} \leq R^{down}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{down}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co,i,t,y \quad (6.15)$$

Storage: The provision of positive and negative reserves by storages limit their maximum release and loading (Equations (6.16) and (6.17)). Still, their storage level does not change by balancing reservation, as the activation is still unknown (Equation (6.18)). However, it must be guaranteed, that the prevailing storage level is sufficiently high (low) to be able to provide positive (negative) reserves. These reserves must be provided for the consecutive hours comprised in the storage reservation window (T^{window}) without violating maximum (6.19) or minimum (6.21) storage level constraints.

$$\begin{aligned} stor^{release}_{co,s,t,y} + g^{resv,pos}_{co,s,t,y} \leq\ & Ava_{co,s,y} * Storage^{maxrelease}_{co,s,y} \\ & + Ava_{co,s,y} * Storage^{maxrelease}_{co,s,y} \\ & + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \end{aligned} \qquad \forall co,s,t,y \quad (6.16)$$

$$\begin{aligned} stor^{loading}_{co,s,t,y} + g^{resv,neg}_{co,s,t,y} \leq\ & Ava_{co,s,y} * Storage^{maxloading}_{co,s,y} \\ & + Ava_{co,s,y} * Storage^{maxloading}_{co,s,y} \\ & + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \end{aligned} \qquad \forall co,s,t,y \quad (6.17)$$

$$\begin{aligned} stor^{level}_{co,s,t,y} =\ & stor^{level}_{co,s,t-1,y} - stor^{Release}_{co,s,t,y} \\ & + \eta^{storage}_{co,s,y} * stor^{loading}_{co,s,t,y} \\ & + Inflow_{co,s,y,t} \end{aligned} \qquad \forall co,s,t,y \quad (6.18)$$

$$stor^{level}_{co,s,t,y} + \sum_{t \geq tt \geq t-T^{window}} g^{resv,neg}_{co,s,t,y} \leq Storage^{maxlevel}_{co,s,y} + \sum_{yy \leq y} inv^{stor}_{co,i,yy} \qquad \forall co,s,t,y \quad (6.19)$$

$$(6.20)$$

$$stor^{level}_{co,s,t,y} - \sum_{t \geq tt \geq t - T^{window}} g^{resv,pos}_{co,s,t,y} \geq Storage^{minlevel}_{co,s,y} \qquad \forall co, s, t, y \qquad (6.21)$$

Network restrictions: The reservation of transmission capacity is always defined for both flow directions (Equation (6.22) and (6.23)). It should only lead to reductions of net transfer capacity (NTC) between countries, never to increased NTC for the spot market. This is realized by only taking the NTC-decreasing part of the reservation into account (Equation (6.24) and (6.25)). Therefore the model can not increase the NTC between countries by counter trading balancing reserves. Equations (6.26) to (6.29) therefore derive the positive and negative parts of the reserved capacities.

$$flow^{resv,pos}_{co,cco,t,y} = -flow^{resv,pos}_{cco,co,t,y} \qquad \forall co, cco, t, y \qquad (6.22)$$

$$flow^{resv,neg}_{co,cco,t,y} = -flow^{resv,neg}_{cco,co,t,y} \qquad \forall co, cco, t, y \qquad (6.23)$$

$$NTC_{co,cco} + inv^{line}_{y,co,cco} \geq flow_{co,cco,t,y} + flow^{resv,pos,ge0}_{co,cco,t,y} - flow^{resv,neg,le0}_{co,cco,t,y} \qquad \forall co, cco, t, y \qquad (6.24)$$

$$-NTC_{co,cco} - inv^{line}_{y,co,cco} \leq flow_{co,cco,t,y} + flow^{resv,pos,le0}_{co,cco,t,y} - flow^{resv,neg,ge0}_{co,cco,t,y} \qquad \forall co, cco, t, y \qquad (6.25)$$

$$flow^{resv,pos,ge0}_{co,cco,t,y} \geq flow^{resv,pos}_{co,cco,t,y} \qquad \forall co, cco, t, y \qquad (6.26)$$

$$flow^{resv,neg,ge0}_{co,cco,t,y} \geq flow^{resv,neg}_{co,cco,t,y} \qquad \forall co, cco, t, y \qquad (6.27)$$

$$flow^{resv,pos,le0}_{co,cco,t,y} \leq flow^{resv,pos}_{co,cco,t,y} \qquad \forall co, cco, t, y \qquad (6.28)$$

$$flow^{resv,neg,le0}_{co,cco,t,y} \leq flow^{resv,neg}_{co,cco,t,y} \qquad \forall co, cco, t, y \qquad (6.29)$$

Model Limitations: When interpreting the results one has to bear in mind the model structure. On the one hand, not the all flexibility constraints can be included in a linear model with a country-sharp resolution. On the other hand, no strategic behavior can be included, which can be an important price driver in the market setting. Therefore, the costs of balancing provision may be underestimated. However relative cost changes between different scenarios remain valid.

This model abstracts from different types of balancing reserves. It does not differentiate between FCR, aFRR and mFRR nor between spinning and non-spinning reserves. On the one hand, this would significantly increase computational time. On the other hand it is not clear, how the additional balancing reserve demand from fluctuating RES demand will be allocated to the different types of balancing reserves. Therefore, using different reserve types could distort results and pertinence a false precision. Furthermore the influence of different reserve types is reduced, as two main sources for future balancing reserve provision are anyhow either spinning (fluctuating RES) or very flexible and able to provide FCR (storages).

The amount of balancing reserves that will be activated is not known beforehand. Hence, this model only includes the cost for the reservation and neglects the cost for the activation of reserves. Still the model formulation assures, that for all hours, sufficient capacity is available to allow for positive or negative reservation. Dependent on the volumes of positive and negative activation, the TSC could be increased or lowered.

6.4. Data and application

I apply the extended version of dynELMOD to an European data set described in Chapter 2. As long as not stated otherwise all data used for this application based on this dataset, is published under open-source license together with the model.[26] Therefore, in the following, only a short summary of the data will be given.

The data-set is defined for the periode from 2015 to 2050 in five-year steps. It includes 33 different countries in five synchronous areas, each country represented by one node. It represents 31 different generation technologies: ten conventional, nine renewable, five CCTS and seven storage (including four DSM) technologies as well as their future development regarding cost and efficiencies. For existing capacities, a decommissioning path is calculated based on assumptions for lifetimes and each power plant block's commissioning date. Potentials for CCTS are included on a country resolution. The data set includes demand and renewable feed-in time series spanning 8,760 hours from the year 2013 for each country. These are scaled individually to meet the different FLH for each country of the upcoming years.

The CO_2 emission pathway is based on based on the scenario "Diversified supply technologies" from the European Commission's *Energy Roadmap 2050 – Impact Assessment and scenario analysis* (EC, 2011c). As dynELMOD only covers the electricity sector, the CO_2 pathway that sets a limit on yearly CO_2 emissions allocated to the electricity sector is used. The usage of such a strict CO_2 emission pathway is a main driver of the resulting transformation of the generation portfolio. Furthermore no banking of CO_2 emissions is allowed between the periods.

Prices for coal, gas and oil and their development until 2050 are based on the "EU Reference Scenario 2016" by EC (2016).

[26] http://diw.de/elmod#dynELMOD

6.5. Results

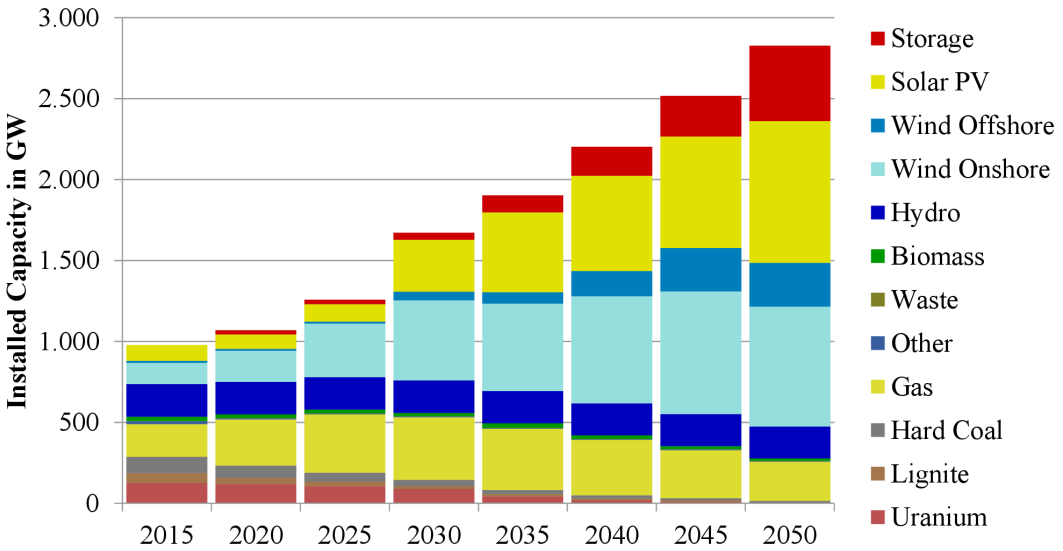


Figure 6.2.: Installed electricity generation and storage capacities in Europe until 2050

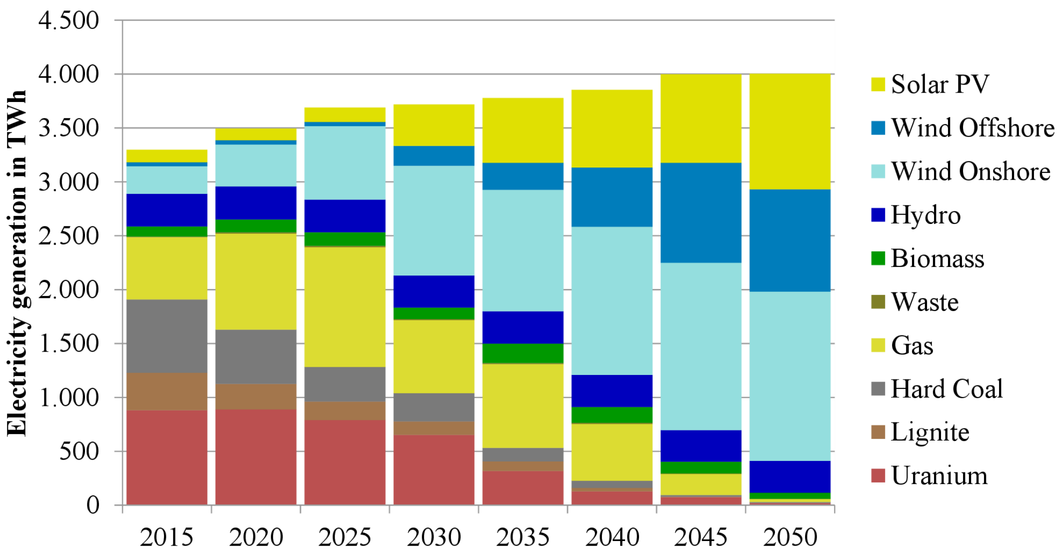


Figure 6.3.: Electricity generation in Europe until 2050

The transformation pathway for the electricity sector, provided by the model results of dynELMOD, will be looked at first, as it sets the stage for the balancing reserve provision. I analyze the installed capacities and resulting electricity generation before taking a closer look at the cost and technology structure of the balancing reserve provision.

Figure 6.2 shows the development of the installed capacities from 2020 to 2050 in Europe. The total installed capacity increases from 1,100 GW in 2020 to 2,900 GW in 2050. This steep increase can be explained by the, on average, lower FLH of RES compared to fossil fired power plants. In 2050, 870 GW of solar PV, 740 GW wind onshore and 270 GW of wind offshore make up for the major share of the generation portfolio. No new nuclear, lignite, or hard coal fired capacities are constructed, which results in a nearly complete phase-out for those technologies until 2050. The fluctuating generation from RES is evened out with 465 GW of storage capacity which includes batteries, power to gas and DSM. During extreme hours, natural gas fired power plant capacities, with 215 GW, serve as backup capacities.

Resulting from the developments of the generation portfolio, the electricity mix changes from 2020 to 2050 as shown in Figure 6.3. In 2050 more than 95 % of the electricity generation is renewable. Onshore wind is the biggest producer with a share of more than one third while the share of offshore wind and solar PV reach one quarter. An additional source of flexibility is transmission capacity that allows to use the spatial variability of demand and RES supply. As this is not the focus of this chapter, the resulting transmission expansion will not by analyzed. A detailed analysis can be found in Chapter 2.

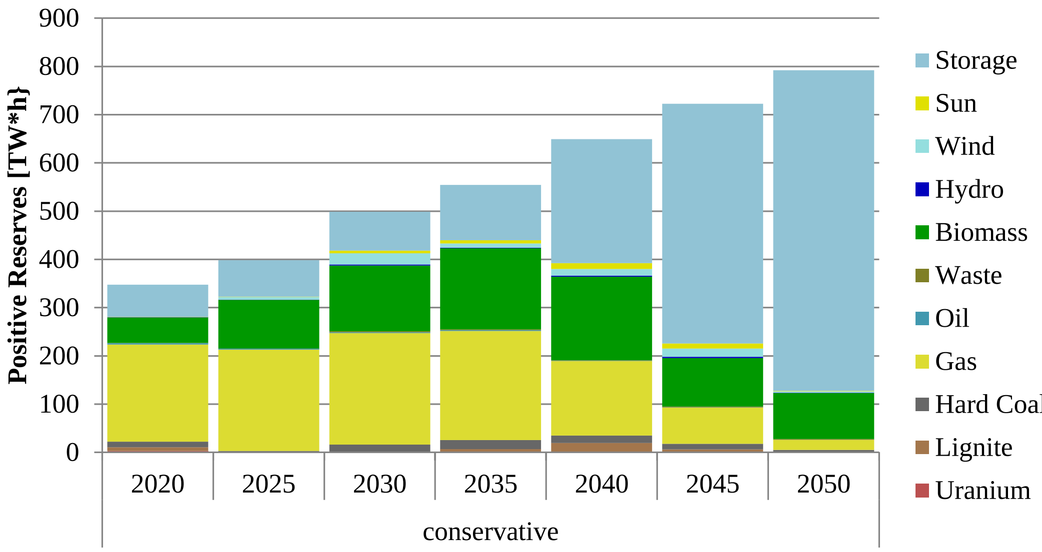


Figure 6.4.: Positive balancing provision in Europe from 2020 to 2050

Figure 6.4 shows the provision of positive reserves by different technologies in the different years. Despite a dynamic sizing horizon, the total volume of positive balancing reserves more than doubles until 2050, still the electricity demand increases by less then 20%. This can be traced back to the balancing reserve demand caused by increased generation capacities from fluctuating RES. The provision by storages is increases rapidly from 2035 onwards and accounts for the largest share in 2040.

In contrast, the provision by fluctuating RES is very low. It is most of the time not beneficial to curtail fluctuating RES just to provide positive reserves as there is sufficient storage and demand flexibility in the fully interconnected European electricity system to store or use it. The provision by biomass peaks in 2035, when the provision by gas fired capacities starts to decrease rapidly. Biomass retains a much higher share than gas in 2050, as the minimum generation restrictions during balancing provision reduces the possibility for gas largely due to the CO_2 constraint.

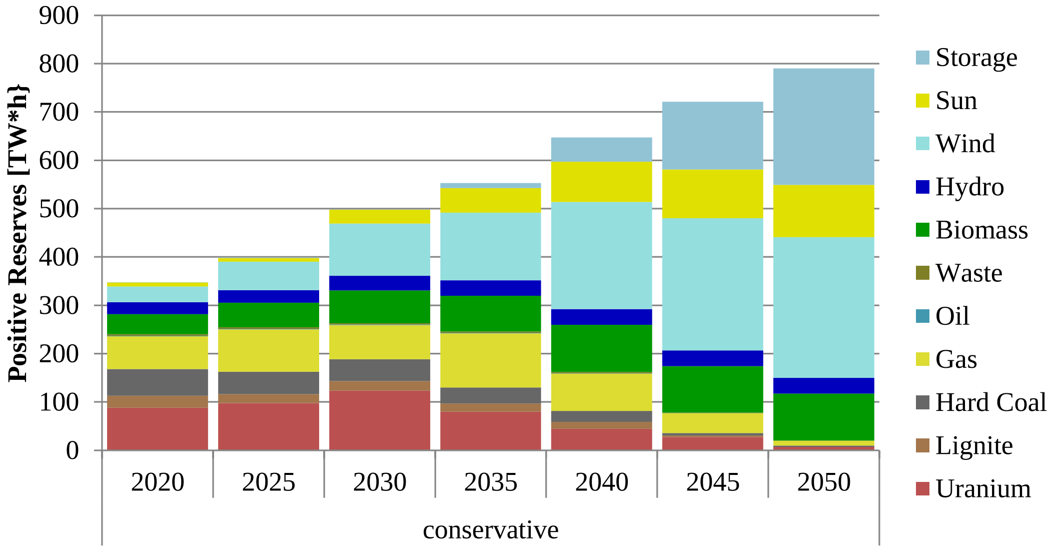


Figure 6.5.: Negative balancing provision in Europe from 2020 to 2050

The total volume of negative balancing reserves more than doubles until 2050, due to the same reasons as the positive balancing reserves. However, in contrast to positive balancing reserves, the negative balancing reserves are mainly provided by fluctuating RES from 2040 onwards (Figure 6.5). From 2035 on, wind (on- and offshore) has the largest share, while PV also participates but to a lesser extent. The dominance of fluctuating RES can be explained by their very low opportunity cost to provide negative reserves, as they have no marginal generation cost and are therefore dispatched first. Also storages, which increase their share from 2040 on, have very low opportunity cost as they can use their recharge capability to provide negative reserves. The provision by nuclear, coal and gas is gradually reduced, in line with their diminishing share in the spot market (compare Figure 6.3).

The results show that balancing reserve cost (shown in figure 6.6) does not have to increase due to a fully renewable electricity system. When comparing the calculated balancing cost to the observed balancing cost range in Europe in 2015 (ACER and CEER, 2016), no increase can be identified. As most important factor, the choice between a static or a dynamic sizing horizon determines the cost. With a static horizon, cost are up to five times higher than for a dynamic sizing horizon. Even

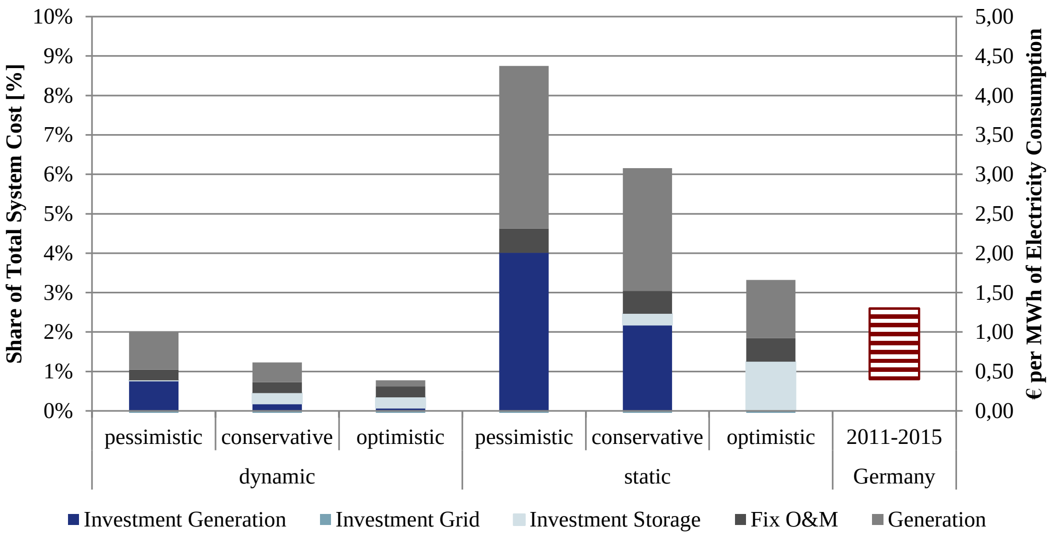


Figure 6.6.: Electricity balancing cost in Europe until 2050

within an optimistic technical and regulatory framework the statical sizing horizon would result in 70% higher cost compared to the dynamic sizing horizon within a pessimistic framework. Both, additional generation and investment cost would be much lower in the dynamic sizing horizon. This is due to the very high share of RES in 2050, for which in the static case also during hours with low RES feed-in, reserves for the entire installed capacity must be reserved. During these times of low RES feed-in, reserve provision is costly, as dispatchable generation capacities are necessary for electricity production and hence have high opportunity cost when providing balancing reserves. Therefore a static balancing reserve demand would cause additional investments and higher generation capacity in the static sizing horizon. With a dynamic sizing horizon balancing reserve provision cost are ranging from 0.7% and 2% of the TSC (0.5 €/MWh to 1.5 €/MWh of electricity generation) depending on the assumptions for the technical and regulatory framework. Despite the large importance of the sizing horizon on the cost, the remaining technical and regulatory developments are crucial to keep cost down. With ambitious technical and regulatory developments in the *optimistic* scenario cost savings of up to 60% compared to the *pessimistic* scenario can be realized. However, even with *pessimistic* assumptions regarding the framework development, the cost for balancing reserve provision does not rise above the cost observed between 2011 and 2015 in Germany. [27] When comparing the cost components of the balancing reserve provision cost, variable generation cost are the biggest component for all scenario combinations. Furthermore the relative shares of the components are similar between the static and dynamic sizing horizon.

[27]The model abstracts from strategic behavior and therefore the cost are likely to be a lower bound.

When comparing the large share of positive balancing reserves that are provided by storages, to the low additional investments into storages caused by balancing reserve provision, it becomes clear, that there are large flexible capacities left in the system. These capacities are mainly storages, required to even out daily and seasonal variations of RES availability. As these storage capacities are not fully used during most of the time, they can provide balancing reserves at very low opportunity cost. Hence, only for very few occasions additional storage or other dispatchable capacities are necessary for balancing reserve provision.

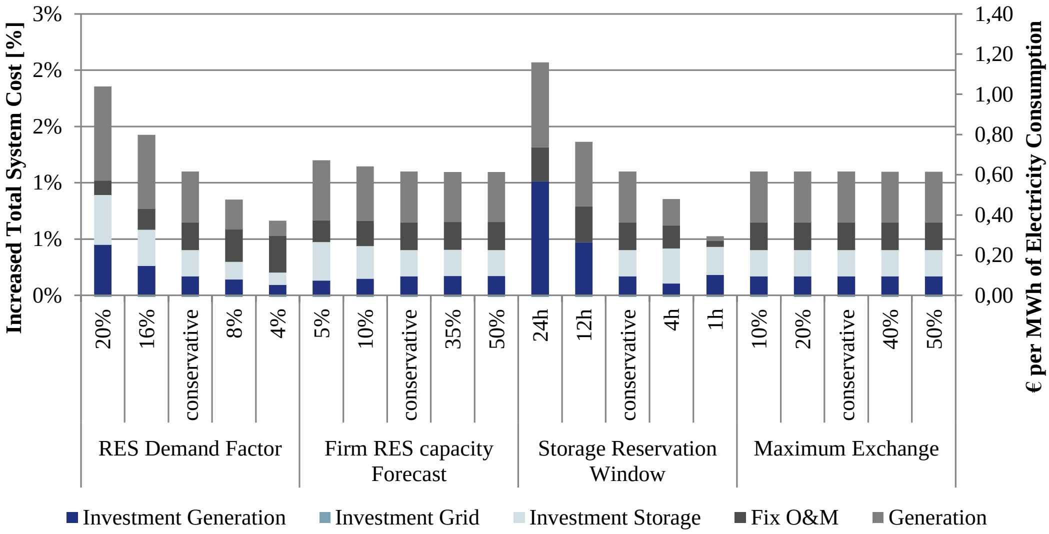


Figure 6.7.: Sensitivities of electricity balancing cost in Europe until 2050

The costs for balancing reserve provision show different sensitivities with respect to the developments of the technical and regulatory framework. All sensitivities shown in Figure 6.7 are assessed against the development that is assumed in the *conservative* scenario. The assumptions regarding the length of the storage reservation window have the biggest influence on balancing cost. With long durations, less reserves can be provided by storages and hence additional generation capacity becomes necessary. When the additional generation capacity is used to provide reserves their minimum run constraints cause additional variable generations. When looking at the cost components it becomes clear, that below a storage reservation window of eight hours no additional storage capacity will be built for balancing reserve provision in comparison to a neglection of those reserves. In sum, a very long storage reservation window can nearly double the cost for balancing reserve provision.

When the RES demand factor is increased up to 20%, the balancing reserve demand increases in comparison to the *conservative* scenario. A higher balancing reserve demand in turn leads to higher overall cost. In total, cost can increase by nearly 60%, while the shares of the cost components remain constant.

In comparison to the RES demand factor, the influence of the firm RES capacity forecast is much lower. A firm capacity of only five percent, in comparison to the *conservative* scenario with 20% firm capacity, causes only minor balancing reserve cost increase of less then 10%. A firm forecast of only 10% of the RES capacity is already sufficient for balancing reserve provision. This can be explained by the high share of storage used for positive reserves provision and RES providing mainly negative reserves.

A limitation on the exchange of balancing reserves (the share of the balancing demand that is covered by imports) has the lowest impact on the balancing reserve provision cost. This unintuitive result can be explained by a rather even distribution of storage capacities over Europe until 2050. These storage capacities allow for positive balancing reserve provision independent from the generation portfolio of the country. Nevertheless before a large deployment of storages the exchange of balancing reserves can lead to large efficiency gains.

6.6. Conclusion

The decarbonization of the electricity sector also influences the future of balancing reserve provision. Therefore, the balancing provision is analyzed in a long-term perspective of a fully renewable electricity system. The developments of the technical and regulatory framework of future balancing reserve provision are subject to large uncertainties. This chapter applies a dynamic investment model of the European electricity sector to analyze the cost and effects of the future balancing reserve provision.

The results show that balancing reserve cost can be kept at current levels for a renewable electricity system until 2050. This requires no optimistic developments of the technical and regulatory framework, however a dynamic reserve sizing horizon is of importance to keep costs down. Apart from the sizing horizon, storage capacity withholding duration, and additional balancing demand from RES are the main drivers of balancing costs. RES participation in balancing provision is mainly important for negative reserves, while storages play an important role for the provision of positive reserves. However, only for very few occasions, additional storage investments are required for balancing reserve provision, as most of the time sufficient storage capacities are available in the electricity system.

Appendix A

Appendix to Chapter 4 and 5

A.1. Nomenclature

The following tables give an overview of all sets, parameters, and variables used in ELMOD-MIP.

Table A.1.: Sets in ELMOD-MIP

Sets	
t, tt	Time
r	Region
p	Power plants
c	Subset of conventional power plants
u	Subset of fast starting power plants
o	Subset of must-run power plants
s	Subset of PSP powerplants
bl	Blocks of balancing power
b	Balancing power product

Table A.2.: Parameters in ELMOD-MIP

Parameters	
c_p^{start}	Cost per start-up
c_p^{down}	Cost per shut-down
mc_c	Marginal generation costs
g_p^{max}	Maximum generation
g_p^{min}	Minimum generation if online
g_t^{sol}	Solar energy feed-in
g_t^{wind}	Wind energy feed-in
g_t^{bio}	Biomass energy feed-in
r_p^{down}	Maximum ramping down speed [% per hour]
r_p^{up}	Maximum ramping up speed [% per hour]
q_t^{spot}	Electricity load
$q_{b,bl,r,t}^{resv,neg}$	Total amount of negative balancing power needed
$q_{b,bl,r,t}^{resv,pos}$	Total amount of positive balancing power
$q_{b,r,t}^{call,neg}$	Total Negative activation in per region, time, and product
$q_{b,r,t}^{call,pos}$	Total Positive activation in per region, time, and product
$f_{r,rr}^{max}$	Max flow
$frq_{bl,b}$	Activation frequency of balancing reserve in a specific block
l_s^{max}	Maximum storage level
l_s^{min}	Minimum storage level
v_s^{max}	Maximum storage release
w_s^{max}	Maximum storage loading
η_s	Storage efficiency
$g_{s,t}^{nat}$	Natural inflow into storage

Table A.3.: Binary Variables in ELMOD-MIP

Binary Variables	
$ON_{c,t}$	Plant status
$UP_{c,t}$	Plant startup variable
$DN_{c,t}$	Plant shutdown variable
$SB_{b,bl,u,t}$	Activation from standby per product and block for fast starting plants

Table A.4.: Variables in ELMOD-MIP

Variables	
$Cost$	Objective value: total cost
$Cost^{gen}$	Generation cost
$Cost^{resv}$	Total balancing reservation cost
$Cost^{call}$	Total balancing activation cost
$Cost^{start}$	Total start up cost
$Cost^{down}$	Total shut down cost
$G_{c,t}$	Conventional generation in MW
$G^{resv,pos}_{p,t,bl,b}$	Positive reserved balancing power assigned to a plant
$G^{resv,neg}_{p,t,bl,b}$	Negative reserved balancing power assigned to a plant
$G^{resv,pos,A}_{s,t,bl,b}$	Positive reserved balancing power of a PSP (active = more generation)
$G^{resv,pos,P}_{s,t,bl,b}$	Positive reserved balancing power of a PSP (passive = less pumping)
$G^{resv,neg,A}_{s,t,bl,b}$	Negative reserved balancing power of a PSP (active = more pumping)
$G^{resv,neg,P}_{s,t,bl,b}$	Negative reserved balancing power of a PSP (passive = less generation)
$G^{call,pos}_{b,p,t}$	Positive activated balancing energy
$G^{call,neg}_{b,p,t}$	Negative activated balancing energy
$F^{spot}_{r,rr,t}$	Spot market flow
$F^{resv,pos}_{b,bl,r,rr,t}$	Reservation of positive balancing flow
$F^{resv,neg}_{b,bl,r,rr,t}$	Reservation of negative balancing flow
$F^{call,pos}_{b,r,rr,t}$	Positive balancing flow
$F^{call,neg}_{b,r,rr,t}$	Negative balancing flow
$F^{resv,pos,ge0}_{b,bl,r,rr,t}$	Positive part of the reservation of positive balancing flow
$F^{resv,pos,le0}_{b,bl,r,rr,t}$	Negative part of the reservation of positive balancing flow
$F^{resv,neg,ge0}_{b,bl,r,rr,t}$	Positive part of the reservation of negative balancing flow
$F^{resv,neg,le0}_{b,bl,r,rr,t}$	Negative part of the reservation of negative balancing flow
$Frq^{max}_{u,t}$	Highest possible Activation Frequency in specific hour
$PSP^{discard}_{s,t}$	Discard of excess water
$PSP^{D}_{s,t}$	Storage loading (pumping)
$PSP^{G}_{s,t}$	Storage release (generation)
$PSP^{L}_{s,t}$	Storage level

Appendix B

Appendix to Chapter 2: A dynamic investment and dispatch Model (dynELMOD)

B.1. Nomenclature

Table B.1.: Sets in dynELMOD

Sets	
p	Power plant
f	Fuel
i	Generation technology
$c(i)$	Conventional technology
$disp(i)$	Dispatchable technology
$ndisp(i)$	Non-dispatchable technology
$s(i)$	Storage technology
$dsm(i)$	DSM technology
t, tt	Hour
y	Calculation Year
yy	Investment Year
$co, cco, ccco$	Country

Table B.2.: Variables in dynELMOD

Variables	
$cost$	Objective value: total cost
$cost^{gen}$	Variable generation cost
$cost^{inv}$	Investment in generation capacity
$cost^{cap}$	Fixed generation capacity cost
$cost^{line}$	Line expansion cost
$g_{co,i,t,y}$	Sum of existing and newbuilt electricity generation
$g^{existing}_{co,i,t,y}$	Generation of existing technology
$g^{newbuilt}_{co,i,t,y,yy}$	Generation of new built technology
$g^{up}_{co,i,t,y}$	Upward generation
$g^{down}_{co,i,t,y}$	Downward generation
$g^{instcap}_{co,i,y}$	Installed generation capacity
$inv^{cap}_{co,i,yy}$	New generation capacity
$inv^{stor}_{co,i,yy}$	New storage capacity
$inv^{line}_{y,co,cco}$	Grid expansion
$ni_{co,t,y}$	Net input from or to network in country
$dcflow_{co,cco,t,y}$	HVDC flow between countries
$flow_{co,cco,t,y}$	Flow between countries in NTC aproach
$stor^{level}_{co,i,t,y}$	Storage level
$stor^{loading}_{co,i,t,y}$	Storage loading
$stor^{release}_{co,i,t,y}$	Storage release

Table B.3.: Parameters in dynELMOD

Parameters	
$Ava_{co,i,y}$	Average annual availability [%]
$CarbonRatio^{emission,new}_{co,i,yy}$	Carbon emission ratio of newbuilt capacities
$CarbonRatio^{emission}_{p,co,i,y}$	Carbon emission ratio of existing capacities
$CarbonRatio^{sequestration,new}_{co,i,yy}$	Carbon sequestration ratio of newbuilt capacities
$CarbonRatio^{sequestration}_{p,co,i,y}$	Carbon sequestration ratio of existing capacities
$CCTSStor^{Capacity}_{co}$	CO_2 storage capacity
$Cfix_{co,i,y}$	Fix generation cost [EUR per MW]
$Cinv^{stor}_{i,y}$	Annuity of storage investment [EUR per MWh]
$Cinv_{i,y}$	Annuity of investment [EUR per MW]
$Cline_{y,co,cco}$	Line expansion cost [EUR per (km and MW)]
$Cload_{co,i,y}$	Load change cost [EUR per MWh]
$Cvar^{newbuilt}_{co,i,y,yy}$	Variable cost of new built technology [EUR per MWh]
$Cvar_{co,i,y}$	Variable cost of existing technology [EUR per MWh]
DF_y	Discount factor for each year
$Emissionlimit_y$	Yearly CO_2 emission limit
$\eta^{existing}_{p,co,i,y}$	Thermal efficiency of existing technology [%]
$\eta^{newbuilt}_{p,co,i,y}$	Thermal efficiency of newbuilt technology [%]
$\eta^{storage}_{co,i,y}$	Storage efficiency [%]
$G^{max\_installed}_{co,i,y}$	Maximum installable capacity [MW]
$G^{max\_inv}_{co,i,y}$	Maximum investment per time period [MW]
$G^{max}_{p,co,i,y}$	Maximum generation of existing capacities [MW]
$G^{min\_CHP}_{p,co,t,i}$	Minimum generation induced by CHP constraint [MW]
$Gen^{max}_{co,f,y}$	Availability of fuel f [MWh_{th}]
$HVDC^{max}_{co,cco}$	Maximum existing HVDC transmission capacity [MW]
$Inflow_{co,s,y,t}$	Inflow into reservoirs or other storages [MW] $NTC_{co,cco}$
NTC between countries	
$P^{max}_{co,cco}$	Maximum existing AC transmission capacity [MW]
$PTDF_{co,cco,ccco}$	Country-sharp power transfer distribution matrix
$Q_{co,t,y}$	Electricity demand [MWh]
$R^{down}_{i,y}$	Ramping down [% per hour]
$R^{up}_{i,y}$	Ramping up [% per hour]
$ResAva^{existing}_{co,t,i}$	Renewable vailability of existing capacities [%]
$ResAva^{newbuilt}_{co,t,i,y}$	Renewable vailability of newbuilt capacities [%]
$Storage^{maxlevel}_{co,i,y}$	Maximum storage level of existing capacities [MWh]
$Storage^{maxloading}_{co,i,y}$	Maximum storage loading of existing capacities [MW]
$Storage^{maxrelease}_{co,i,y}$	Maximum storage release of existing capacities [MW]
$Storage^{minlevel}_{co,i,y}$	Minimum storage level of existing capacities [MWh]

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