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Abstract

This Data Documentation presents a dynamic investment and dispatch model for Europe named dynELMOD. The model endogenously determines investments into conventional and renewable power plants, different storage technologies including demand side management measures, and the electricity grid in five-year steps in Europe until 2050 under full or myopic foresight. The underlying electricity grid and cross-border interaction between countries is approximated using a flow-based market coupling approach using a PTDF matrix. Carbon emission restictions can be modeled using an emission path, an emission budget, or an emission price. For the investment decisions a time frame reduction technique is applied, which is also presented in this document. The code and the dataset are made publicly available under an open source license on the website of DIW Berlin.

The model results show that under almost complete decarbonization renewable energy sources in conjunction with storage capacities will provide the majority of the electricity generation in Europe. At the same time with a rising renewables share, especially after 2040, the need for storage capacities increases. No additional capacity from nuclear energy or fossil fuels is installed, due to high costs and in order to meet the greenhouse gas emission target.

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Acronyms

AC . . . . Alternating Current
BEV . . . . Battery-Electric Vehicle
CCTS . . . . . . Carbon Capture, Transport, and Storage
CHP . . . . . . Combined Heat and Power
CO_2 . . . . Carbon Dioxide
CWE . . . . . . Central Western Europe
DCLF . . . . . . Direct-Current Load Flow
DNLP . . . . . . Discontinuous Non-Linear Program
DSM . . . . . . Demand Side Management
E/P-Ratio . . . . Energy to Power Ratio
EC . . . . European Commission
EEG . . . . . . German Renewable Energy Sources Act
EU ETS . . . . . European Union Emission Trading Scheme
FLH . . . . Full Load Hours
GAMS . . . . . General Algebraic Modeling System
GHG . . . . . . Greenhouse Gas
HVAC . . . . . . High Voltage Alternating Current
HVDC . . . . . High Voltage Direct Current
kW . . . . Kilowatt
LIMES . . . . . Long-term Investment Model for the Electricity Sector
LP . . . . Linear Program
MILP . . . . . . Mixed Integer Linear Program
MW . . . . Megawatt
NTC . . . . . . Net Transfer Capacity
O&M . . . . . . Operation and Maintenance
PRIMES . . . . Price-Induced Market Equilibrium System
PTDF . . . . . . Power Transfer Distribution Factor
PV . . . . Photovoltaic
RES . . . . Renewable energy sources
RoR . . . . Run-of-River Power Plants
SOAF . . . . . . Scenario Outlook and Adequacy Forecast
TWh . . . . . . Terawatt-hours
UCM . . . . . . Unit Commitment Model

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 1).

This paper 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 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

Table 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)

Act (EEG, Erneuerbare-Energien-Gesetz). Furthermore, the cost for renewable integration can be reduced due to spatial and technological diversification.

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.

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 paper is as follows. Section 2 gives an overview of the existing model landscape, Section 3 discusses the model dynELMOD, methodological considerations of the model implementation and provides the model formulation. In Section 4 the data used in this application is described. Section 5 provides the methodology of the time-series reduction technique developed for dynELMOD. The Results are provided in Section 6. A critical discussion of model limitations is given in Section 6.5. Section 7 concludes.

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, 2011b,c,d, 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.

2.1. 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.

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 paper 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.

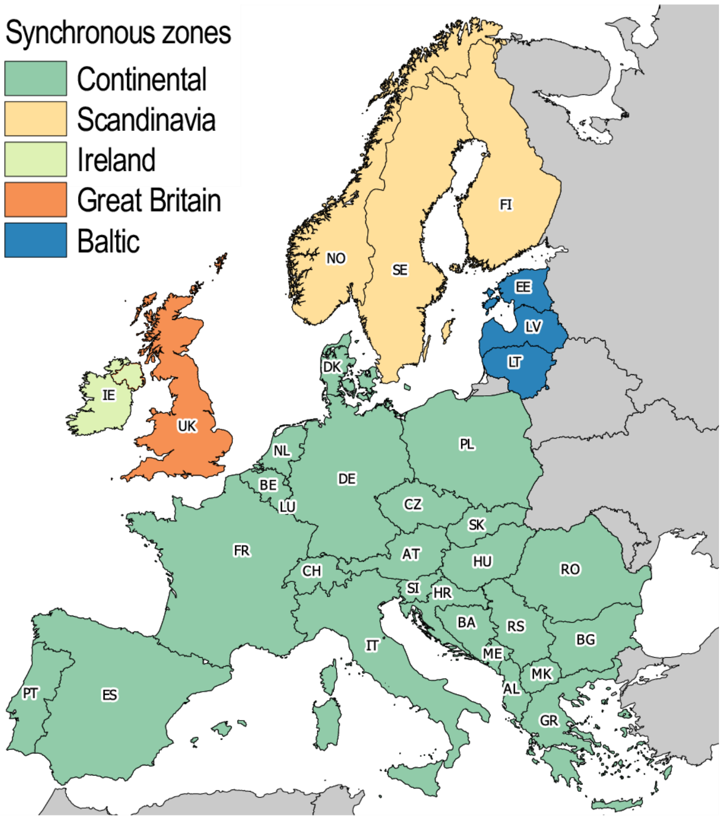


Figure 1: dynELMOD geographical coverage

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 1.[1] In this application, possible points of interconnection with Northern parts of Africa are not taken into account.

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

[1] 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 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 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 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.

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 (1) to (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* (1) include variable cost for generation $cost^{gen}$ (2), investment cost for new built generation $cost^{inv}$ (3), fixed operation and

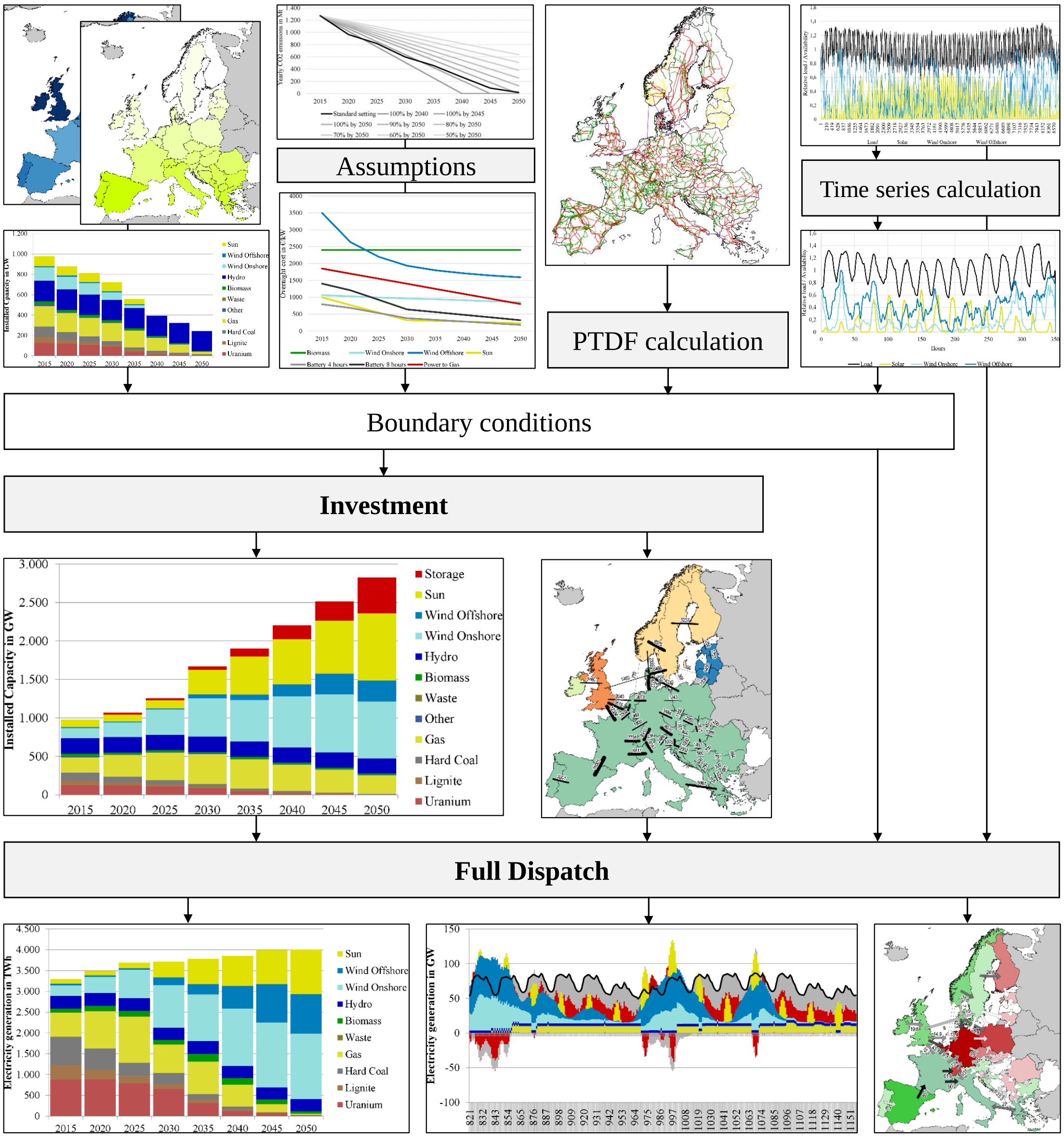


Figure 2: dynELMOD calculation procedure

maintenance cost for existing and new built generation capacity $cost^{cap}$ (4), and investment cost for network expansion $cost^{line}$ (5). The nomenclature for all sets, variables and parameters can be found in Section 7. 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.

$$
\begin{aligned}
\min cost =& cost^{gen} + cost^{inv} + cost^{cap} + cost^{line} && (1)\\
cost^{gen} =& \sum_{co,i,t,y,p} Cvar_{p,co,i,y} * g^{existing}_{p,co,i,t,y} * DF_y \\
&+ \sum_{co,i,t,y,yy,yy\leq y} Cvar^{newbuilt}_{co,i,y,yy} * g^{newbuilt}_{co,i,t,y,yy} * DF_y && (2)\\
&+ \sum_{co,i,t,y,yy} Cload_{co,i,y} * (g^{up}_{co,i,t,y} + g^{down}_{co,i,t,y}) * DF_y \\
cost^{inv} =& \sum_{co,i,y,yy,yy\leq y} Cinv_{i,yy} * inv^{cap}_{co,i,yy} * DF_y \\
&+ \sum_{co,i,y,yy,yy\leq y} Cinv^{stor}_{i,yy} * inv^{stor}_{co,i,yy} * DF_y && (3)\\
cost^{cap} =& \sum_{co,i,y} Cfix_{co,i,y} * (\sum_{p} G^{max}_{p,co,i,y} + \sum_{yy} inv^{cap}_{co,i,yy} + inv^{stor}_{co,i,yy}) * DF_y && (4)\\
cost^{line} =& \sum_{yy,co,coo} Cline_{co,i,y} * 0.5 * inv^{line}_{yy,co,cco} * DF_{yy} && (5)
\end{aligned}
$$

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) to (5) are scaled with a scaling parameter to ensure similar variable magnitude orders. This helps the solver to achieve fast solution times. In (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 (6). Depending on the grid approach, the equation (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.

$$
\begin{aligned}
0 = Q_{co,t,y} - \sum_{i} g_{co,i,t,y} & \\
\left.\begin{array}{l} + ni_{co,t,y} \\ + \sum_{cco} dcflow_{co,cco,t,y} \\ - \sum_{cco} dcflow_{cco,co,t,y} \end{array}\right\} & \text{Flow-based approach} \qquad \forall y, co, t \qquad (6) \\
+ \sum_{cco} flow_{cco,co,t,y} \qquad \Big\} & \text{NTC approach}
\end{aligned}
$$

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 (8) and (9). For non-dispatchable technologies availability is defined for every hour and is calculated during the time series scaling described in Section 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 (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 (10) 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.

$$
\begin{aligned}
g_{co,disp,t,y} &= \sum_{p} g^{existing}_{p,co,disp,t,y} + \sum_{yy \leq y} g^{newbuilt}_{co,disp,t,y,yy} \\
&\quad + stor^{Release}_{co,i,t,y} - stor^{loading}_{co,i,t,y} && \forall co, disp, t, y \qquad (7) \\
g^{existing}_{p,co,disp,t,y} &\leq Ava_{co,disp,y} * G^{max}_{p,co,disp,y} && \forall p, co, disp, t, y \qquad (8) \\
g^{newbuilt}_{co,disp,t,y,yy} &\leq Ava_{co,disp,y} * inv^{cap}_{co,disp,yy} && \forall co, disp, t, y, yy \qquad (9) \\
g_{co,ndisp,t,y} &\leq \sum_{yy \leq y} ResAva^{newbuilt}_{co,t,ndisp,yy} * inv^{cap}_{co,ndisp,yy} \\
&\quad + \sum_{p} ResAva^{existing}_{co,t,ndisp} * G^{max}_{p,co,ndisp,y} && \forall co, ndisp, t, y \qquad (10)
\end{aligned}
$$

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 (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.

$$
\sum_{p,i,t} \frac{g^{existing}_{p,co,i,t,y}}{\eta^{existing}_{p,co,i,y}} + \sum_{i,t,yy \leq y} \frac{g^{newbuilt}_{co,i,t,y,yy}}{\eta^{newbuilt}_{co,disp,yy}} \leq Gen^{max}_{co,f,y} \qquad \forall co, f, y \qquad (11)
$$

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.

$$g^{existing}_{p,co,i,t,y} \geq G^{min\_chp}_{p,co,i,t} \qquad \forall co, i, t, y \tag{12}$$

Investment restrictions Equations (14) and (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.

$$g^{instcap}_{co,i,y} = \sum_{p} G^{max}_{p,co,i,y} + Storage^{maxrelease}_{co,i,y} + \sum_{yy \leq y} inv^{cap}_{co,i,yy} \qquad \forall co, i, y \tag{13}$$

$$g^{instcap}_{co,i,y} \leq G^{Max\_installed}_{co,i,y} \qquad \forall co, i, y \tag{14}$$

$$\sum_{co,i} inv^{cap}_{co,i,y} \leq G^{max\_inv}_{co,i,y} \qquad \forall co, i, y \tag{15}$$

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 (16) and (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 (18).

$$g^{up}_{co,c,t,y} \leq R^{up}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{up}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co, i, t, y \tag{16}$$

$$g^{down}_{co,i,t,y} \leq R^{down}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{down}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co, i, t, y \tag{17}$$

$$g^{up}_{co,i,t,y} - g^{down}_{co,i,t,y} = g_{co,i,t,y} - g_{co,i,t-1,y} \qquad \forall co, i, t, y \tag{18}$$

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.

$$\begin{aligned} Emissionlimit_y \geq & \sum_{p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{emission}_{p,co,i,y} \\ & + \sum_{co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{emission,new}_{co,i,yy} \end{aligned} \qquad \forall y \tag{19}$$

$$\begin{aligned} \sum_{y} Emissionlimit_y \geq & \sum_{y,p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{emission}_{p,co,i,y} \\ & + \sum_{y,co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{emission,new}_{co,i,yy} \end{aligned} \tag{20}$$

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.

$$\begin{aligned} CCTSStor^{Capacity}_{co} \geq & \sum_{y,p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{sequestration}_{p,co,i,y} \\ & + \sum_{y,co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{sequestration,new}_{co,i,yy} \end{aligned} \qquad \forall co \tag{21}$$

Storage The operation of storages is constrained in equations (22 to 26). On the one hand the storage operation is limited by the installed loading and release capacity which can be increased by the model (22, 23). On the other hand the release and loading is constrained by the current storage level defined in equation (24).[2] 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 (25, 26). Therefore the model can decide upon the optimal energy to power ratio (E/P-Ratio).

$$stor^{release}_{co,s,t,y} \leq Ava_{co,s,y} * Storage^{maxrelease}_{co,s,y} + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \qquad \forall co, s, t, y \tag{22}$$

[2]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.

$$stor^{loading}_{co,s,t,y} \leq Ava_{co,s,y} * Storage^{maxloading}_{co,S,y} + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \qquad \forall co,s,t,y \qquad (23)$$

$$\begin{aligned} stor^{level}_{co,s,t,y} =& stor^{level}_{co,s,t-1,y} - stor^{Release}_{co,s,t,y} \\ &+ \eta^{storage}_{co,s,y} * stor^{loading}_{co,s,t,y} + Inflow_{co,s,y,t} \end{aligned} \qquad \forall co,s,t,y \qquad (24)$$

$$stor^{level}_{co,s,t,y} \leq Storage^{maxlevel}_{co,s,y} + \sum_{yy \leq y} inv^{stor}_{co,i,yy} \qquad \forall co,s,t,y \qquad (25)$$

$$stor^{level}_{co,s,t,y} \geq Storage^{minlevel}_{co,s,y} \qquad \forall co,s,t,y \qquad (26)$$

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 (27 - 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.

$$\begin{aligned} \sum_{tt, tt+dsmratio \geq t, tt \leq t} stor^{Release}_{co,dsm,tt,y} \geq & \; Storage^{maxlevel}_{co,dsm,y} + \sum_{yy \leq y} inv^{stor}_{co,dsm,yy} \\ & - stor^{level}_{co,dsm,t,y} \end{aligned} \qquad \forall co,dsm,t,y \qquad (27)$$

$$\begin{aligned} \sum_{tt, tt \geq t, tt-dsmratio \leq t} stor^{loading}_{co,dsm,tt,y} \geq & \; Storage^{maxlevel}_{co,dsm,y} + \sum_{yy \leq y} inv^{stor}_{co,dsm,yy} \\ & - stor^{level}_{co,dsm,t,y} \end{aligned} \qquad \forall co,dsm,t,y \qquad (28)$$

Network restrictions When using the NTC approach, the flow between countries is defined in equation (29). The flow between two countries is limited by the available NTC, that can be increased by the model in (30) and (31) through investments in network infrastructure.

$$flow_{co,cco,t,y} = -flow_{cco,co,t,y} \qquad \forall co,cco,t,y \qquad (29)$$

$$flow_{co,cco,t,y} \leq NTC_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co,cco,t,y \qquad (30)$$

$$flow_{co,cco,t,y} \geq -NTC_{co,cco} - \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co,cco,t,y \qquad (31)$$

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 (32). DC-interconnectors are incorporated as well (33). Equation (34) enforces symmetrical line expansion between countries.

$$\sum_{ccco} PTDF_{co,cco,ccco} * ni_{ccco,t,y} \leq P^{max}_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \tag{32}$$

$$dcflow_{co,cco,t,y} \leq Hvdc^{max}_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \tag{33}$$

$$inv^{line}_{y,co,cco} = inv^{line}_{y,cco,co} \qquad \forall y, co, cco \tag{34}$$

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.

3.3.1. 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,[3] 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.

3.3.2. 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.

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

3.3.3. 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 paper 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 (35).

$$PTDF_{l,nn} = \sum_{n} H_{l,n} * B^{-1}_{n,nn} \quad \forall l, nn \tag{35}$$

As in dynELMOD zonal data on a country level is needed, we then calculate a zonal PTDF as shown in (36).

$$PTDF_{ic,co} = \sum_{n \in co} \frac{PTDF_{l,n}}{N_{co}} \quad \forall ic, co \tag{36}$$

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 (37) using the line-sharp

PTDF-representation obtained in (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.

$$PTDF_{co,cco,ccco} = \sum_{l1} PTDF_{l,ccco} - \sum_{l2} PTDF_{l,ccco} \quad \forall co, cco, ccco \tag{37}$$

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 6), although some loop flow effects are not accounted for.

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. 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.

4.1. Generation

We include 31 different conventional and renewable generation technologies in dynELMOD. Table 2 shows an overview of the technologies implemented in the model, as well as relevant assumptions regarding costs, efficiencies and lifetimes.[4] 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.

[4] Table 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: 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.

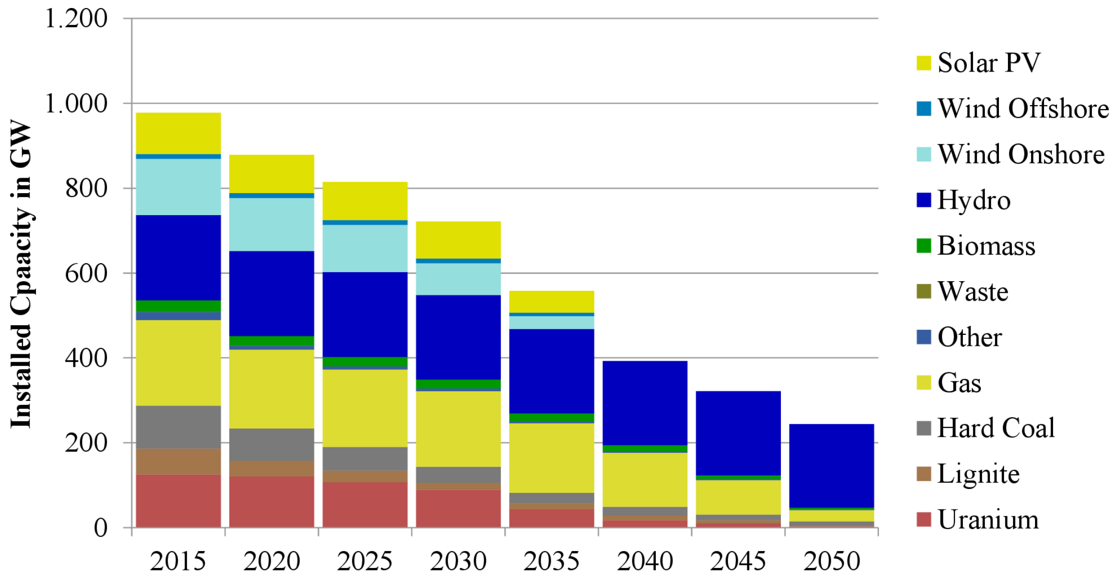


Figure 3: Capacity development of the operational power plant fleet of 2015

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 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 4 shows an overview of the assumed development of overnight costs for selected technologies.

4.1.1. 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, 2015). 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

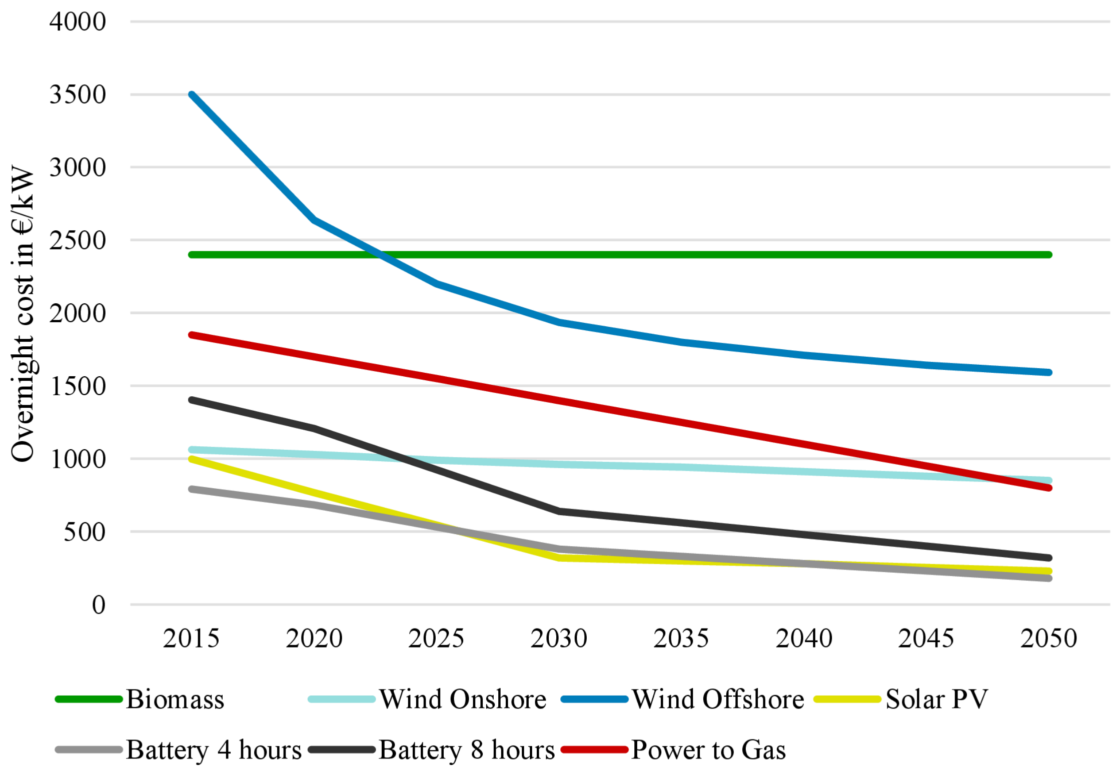


Figure 4: Investment cost pathway for selected technologies

operational power plant fleet can be seen in Figure 3.[5] 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.[6]

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

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

[6] 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.

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 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.

Table 3: CO_2 storage potential per country

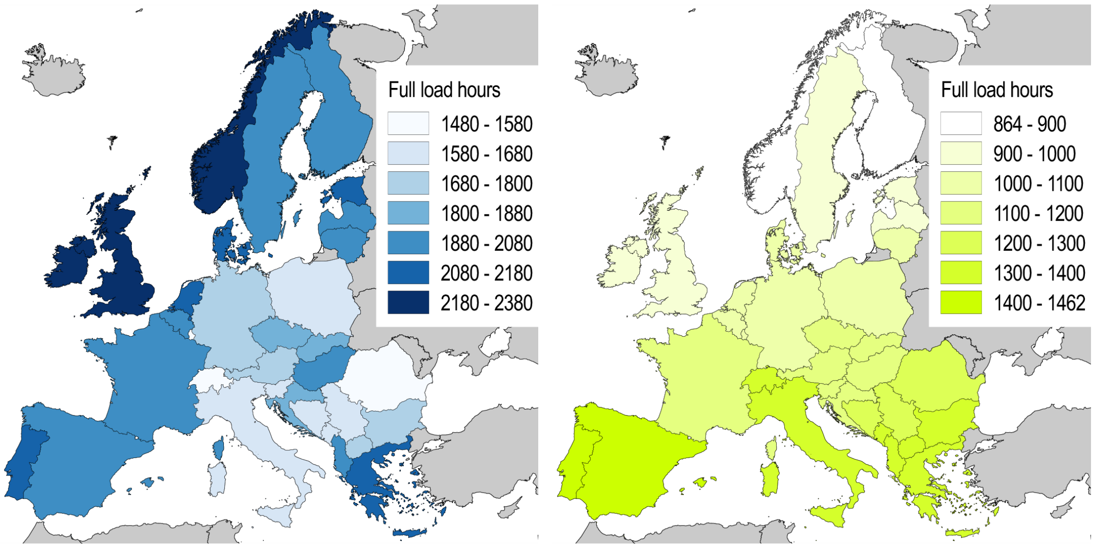
Country	Storage Potential [Mt CO_2]
Germany	1,200
Denmark	2,500
Spain	3,500
Ireland	1,300
Netherlands	500
Norway	13,800
Poland	3,500
United Kingdom	22,000
Lithuania	1,300

Source: Oei et al. (2014)

4.1.2. 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 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 5a and 5b show the geographical distribution of FLH for the first resource



(a) Onshore wind (b) Solar PV

Figure 5: Exemplary full load hours for 2015

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 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.[7] 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

[7]Such reservoirs are implemented in Austria, France, Italy, Norway, Sweden and Switzerland.

pattern.[8] This accounts for the fact that the seasons are much shorter when using a reduced time frame.

4.1.3. 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).

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.

4.1.4. 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.

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

[8]The maximum storage level is reduced by the factor *model-hours*/8,760.

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.

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 (2013) 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 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 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 paper is on a country-level we use relevant aggregates of the data.

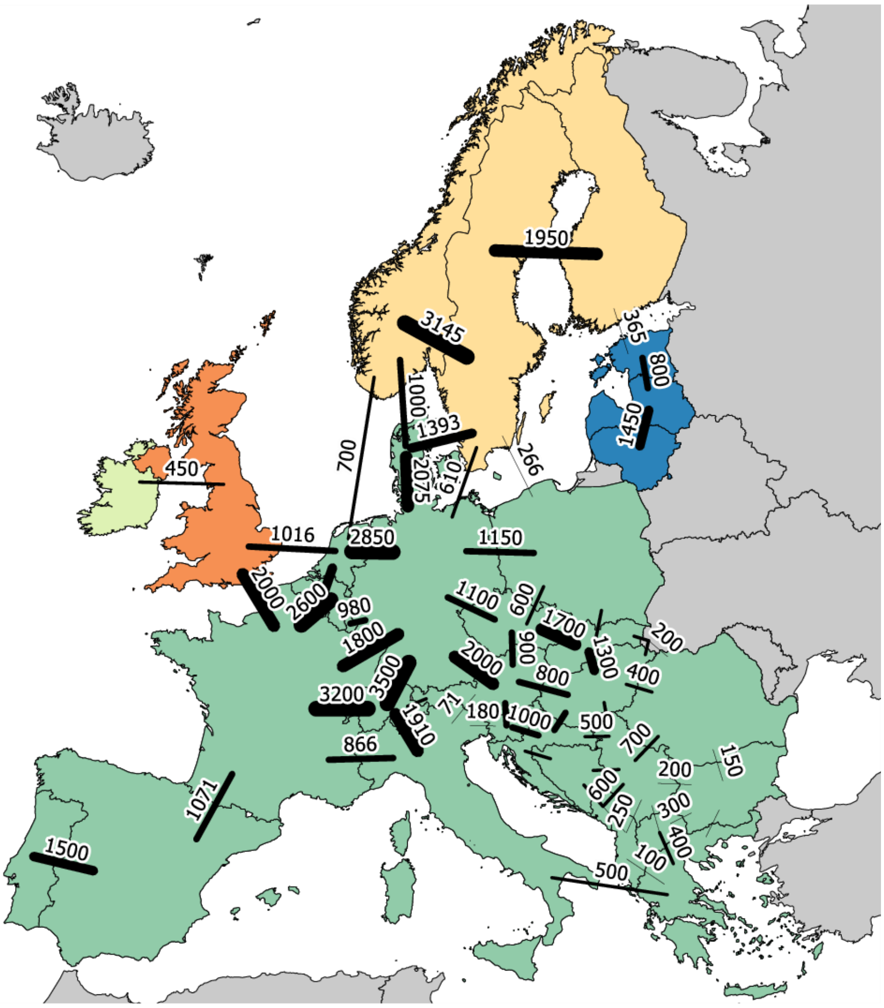


Figure 6: NTC values in 2015 in megawatt.
Source: Own calculations based on ENTSO-E (2013) and ENTSO-E (2016)

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 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.

4.4.1. 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

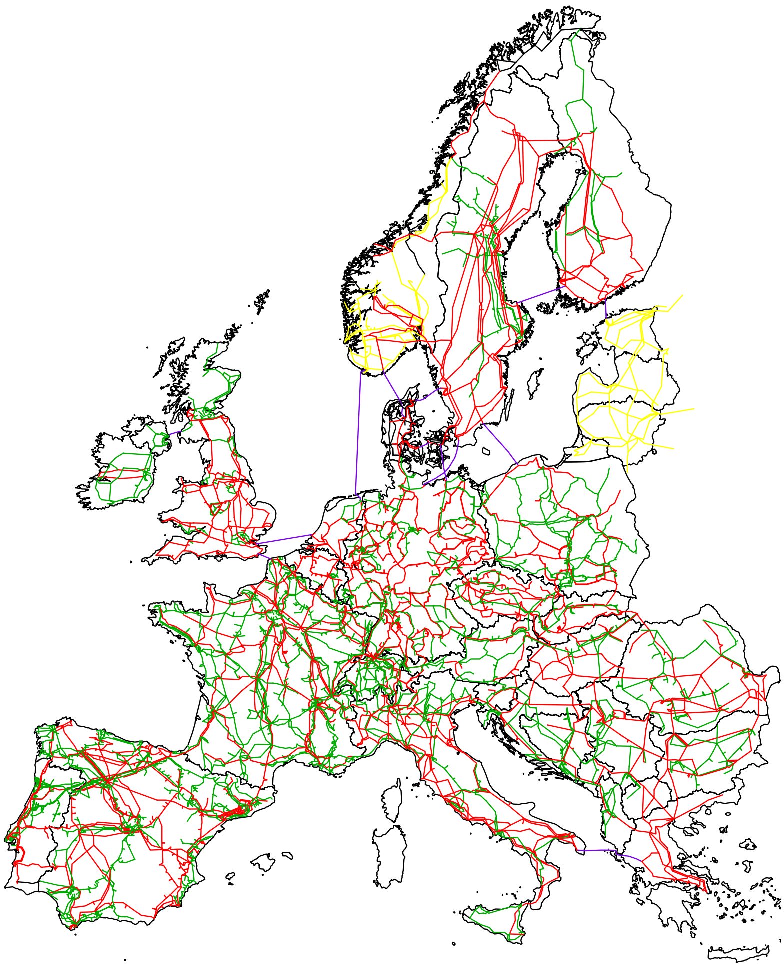


Figure 7: European high voltage electricity grid in 2014
Red: 380 kV, Yellow: 300 kV, Green: 220 kV, Violet: HVDC
Source: Egerer et al. (2014)

Albania no demand time series are available. Here, an interpolation based on the time-series of neighboring countries is used.

4.4.2. 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 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.

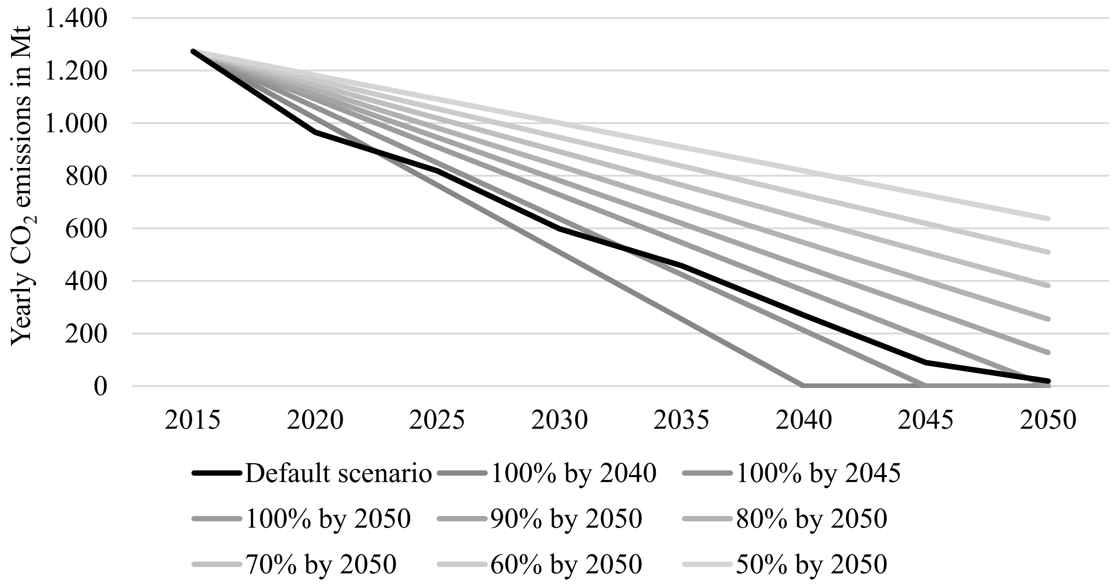


Figure 8: CO_2 emissions constraints

4.5. Other

4.5.1. CO_2 pathway

Figure 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, 2011b). In this scenario and in the EU ETS more than the electricity sector 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 8.

4.5.2. 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 4) are based on the EU Reference Scenario 2016 by EC (2016).

Table 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)

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.

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.

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 (38) to (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 (38) determines the difference between the *target* and reached average sum of the time series. The equations (39) and (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 (39) and (40) is solved first, then the variables B and C are fixed, and the model containing the equations (38) to (40) is solved.

$$\min obj = \left(target * T - \sum_{t \in T} \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \right)^2 \tag{38}$$

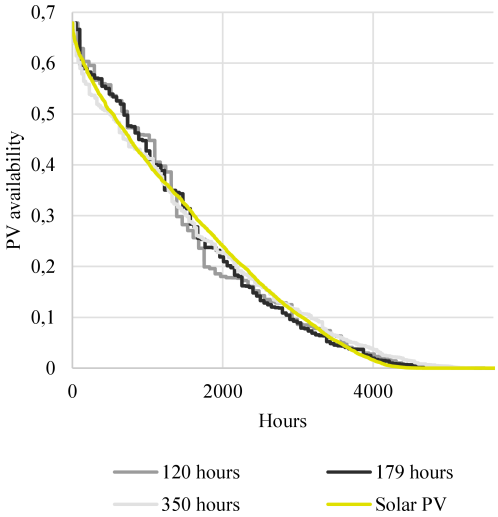
$$mintarget = \min_t \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \tag{39}$$

$$maxtarget = \max_t \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \tag{40}$$

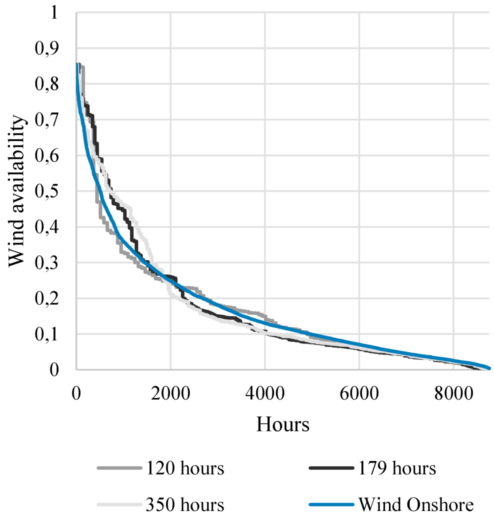
After finishing this step, all relevant time-dependent input parameters can be calculated and put into the model.

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

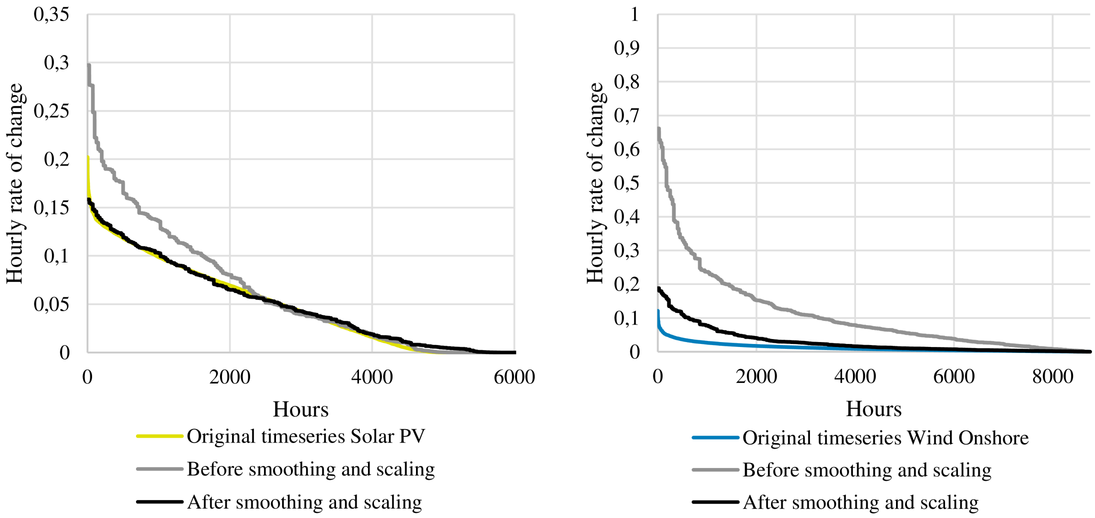


(b) Wind onshore infeed duration curve

Figure 9: Original and processed load and infeed duration curves

Figure 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.

The time series' sorted gradients are displayed in Figure 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.



(a) Solar PV

(b) Wind onshore

Figure 10: Time-series rate of change

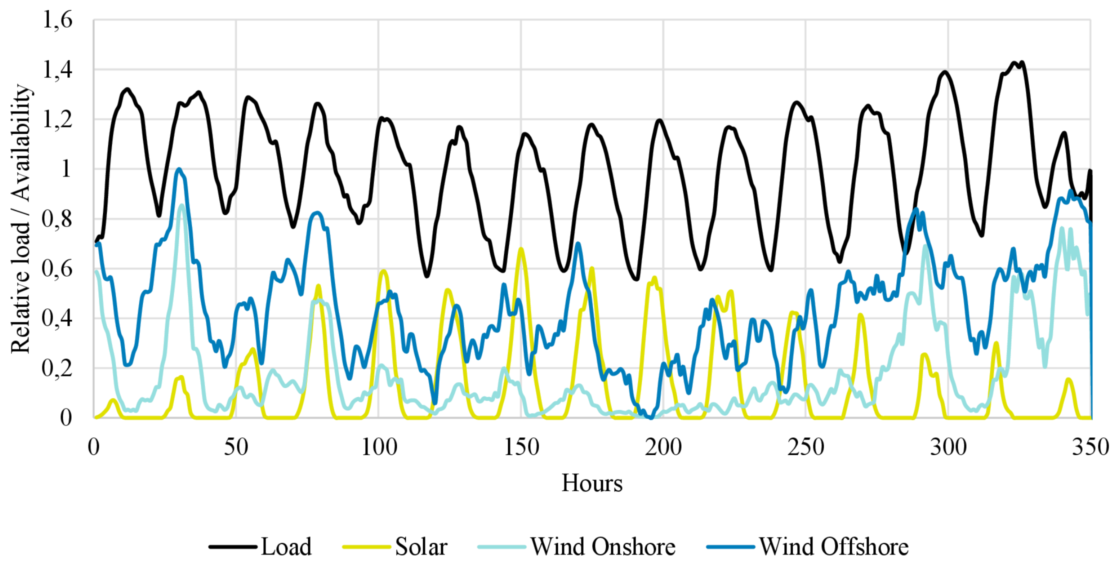


Figure 11: Example time series reduction results

Figure 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 25th 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.

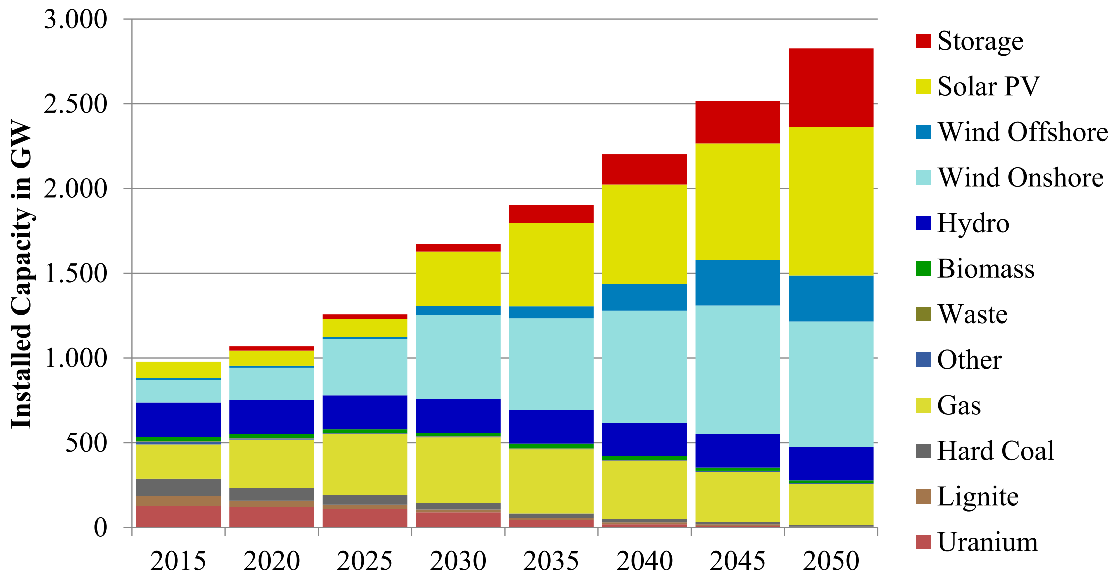


Figure 12: Installed electricity generation and storage capacities in Europe 2015–2050

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.

6.1. Investment and generation results in the standard scenario

Figure 12 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.[9] Investments in natural gas fired power plant capacities take place. Their capacity in 2050 reaches 215 GW. These capacities mainly serve

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

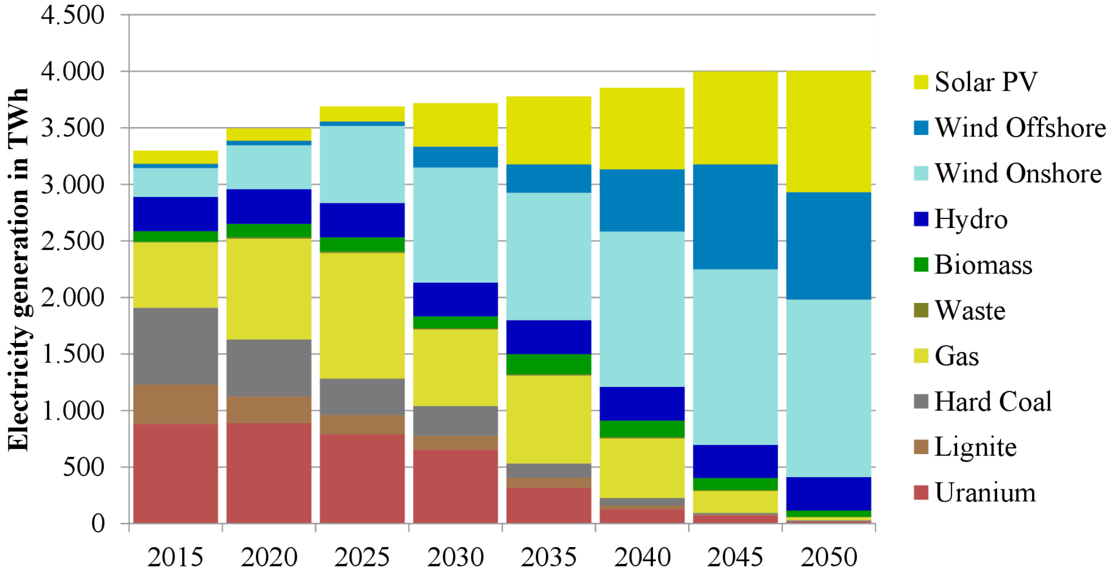


Figure 13: Electricity generation 2015–2050

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 13. 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 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 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

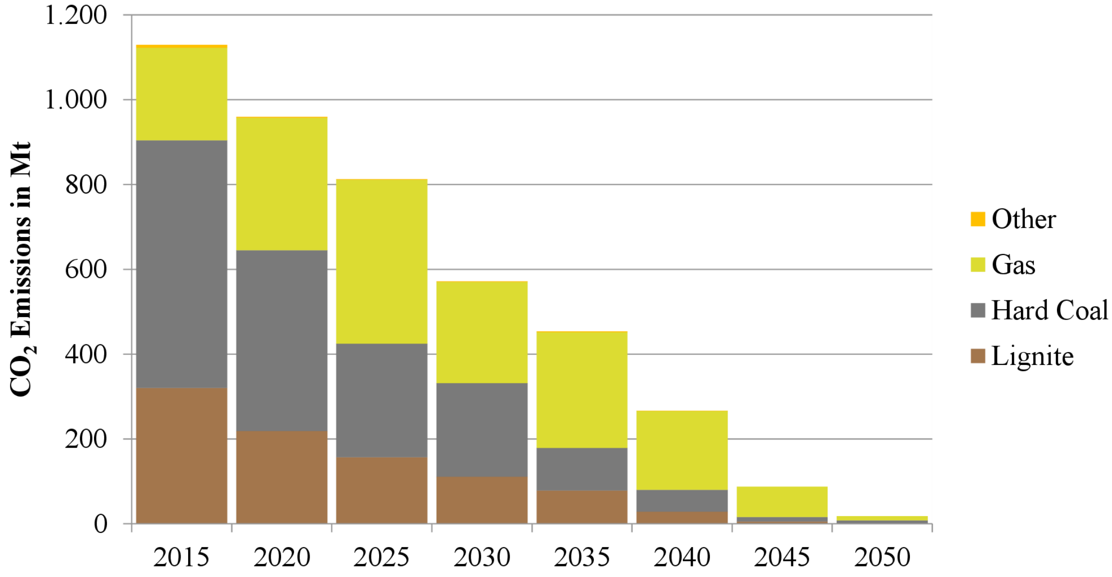


Figure 14: CO_2 emissions by fuel 2015–2050

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.

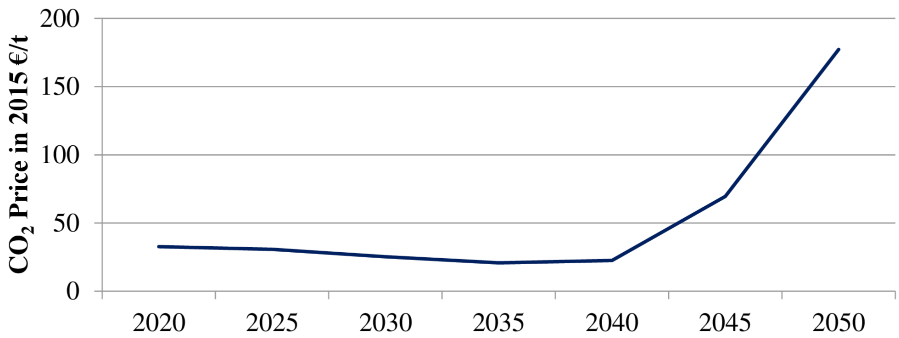


Figure 15: CO_2 Price development 2015–2050

The development of the implicit CO_2 price is shown in Figure 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.

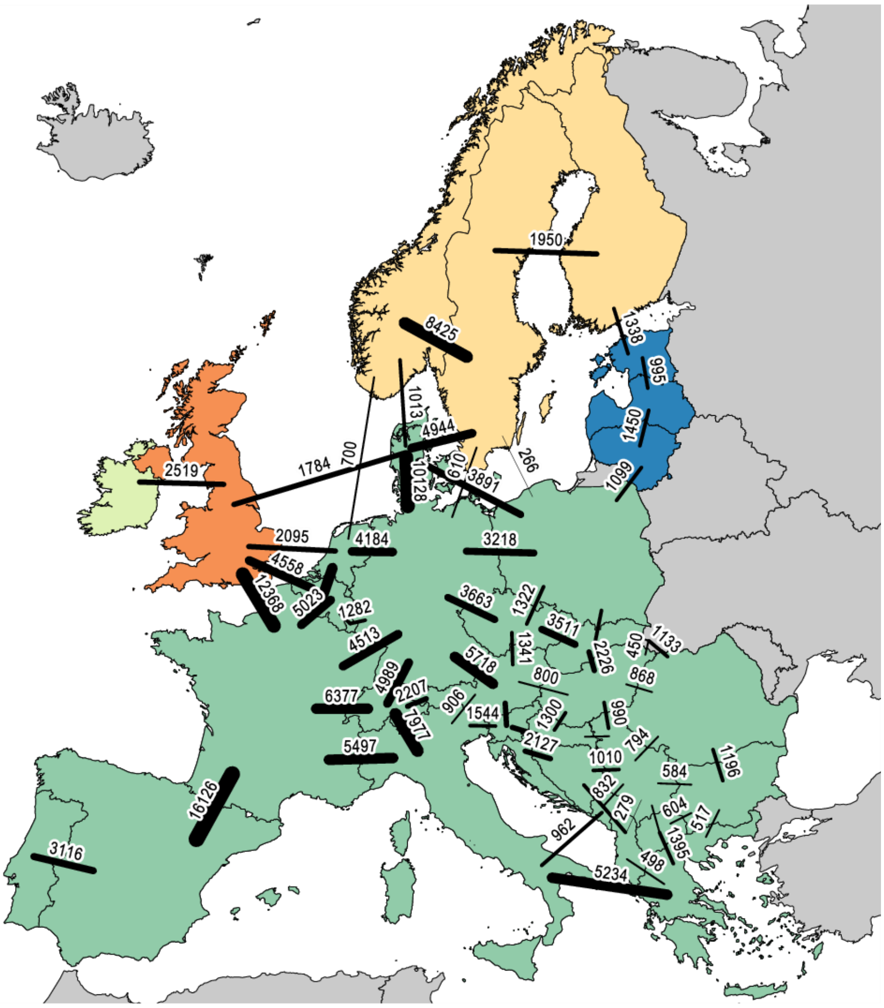


Figure 16: NTC values in the year 2050 in MW

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

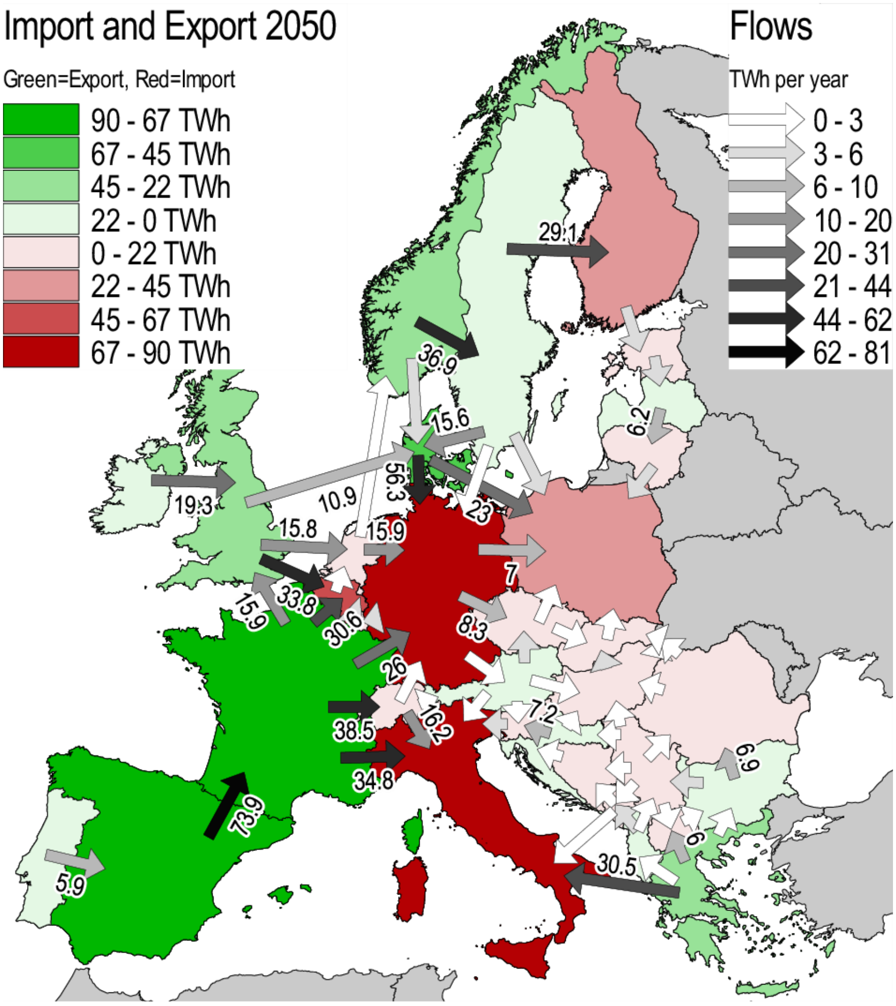


Figure 17: Import and export in TWh in the year 2050

The increased transmission capacities described in the previous paragraph allow for intensified electricity exchange between countries. Figure 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 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 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.

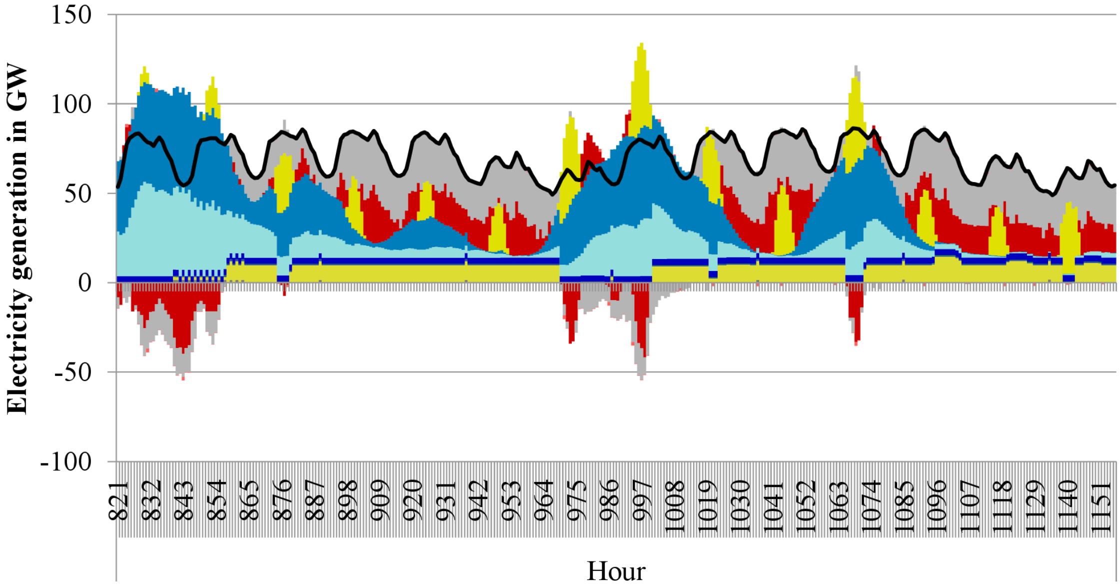
6.3. Detailed dispatch results for selected countries

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.

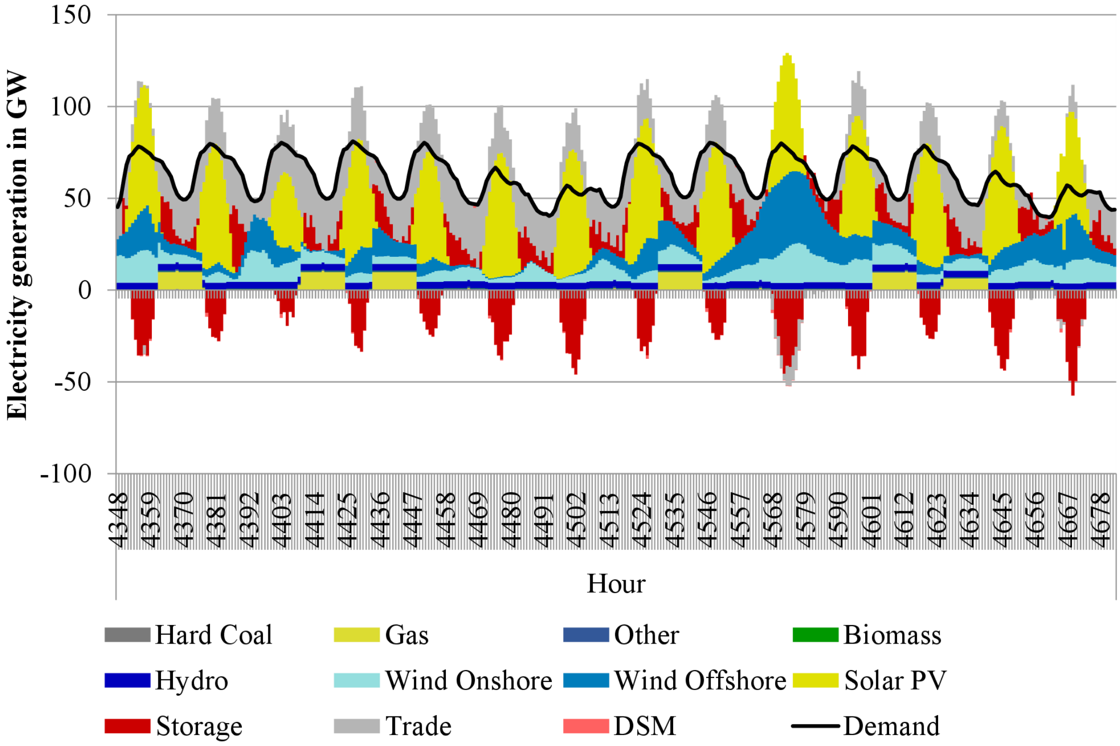
In Figure 18 we observe that Germany imports for most of the time in the selected winter and summer weeks. Exports occur only when there is high wind feed-in. In the summer an interesting storage charging pattern occurs, where electricitiy is imported while electricity is stored at the same time. Here, 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 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

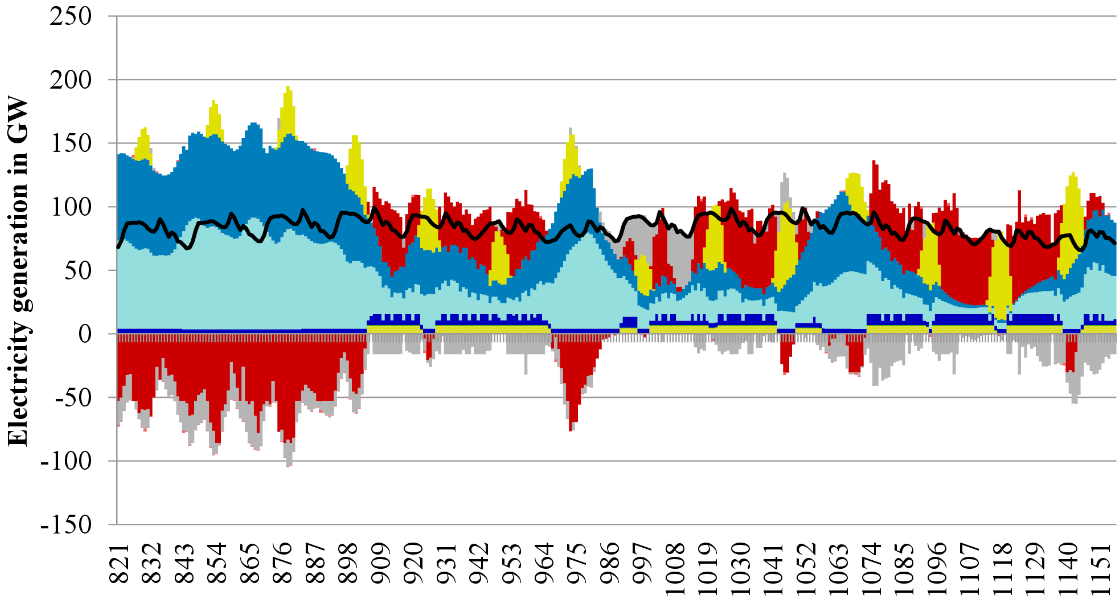


(a) Dispatch in Germany winter 2050

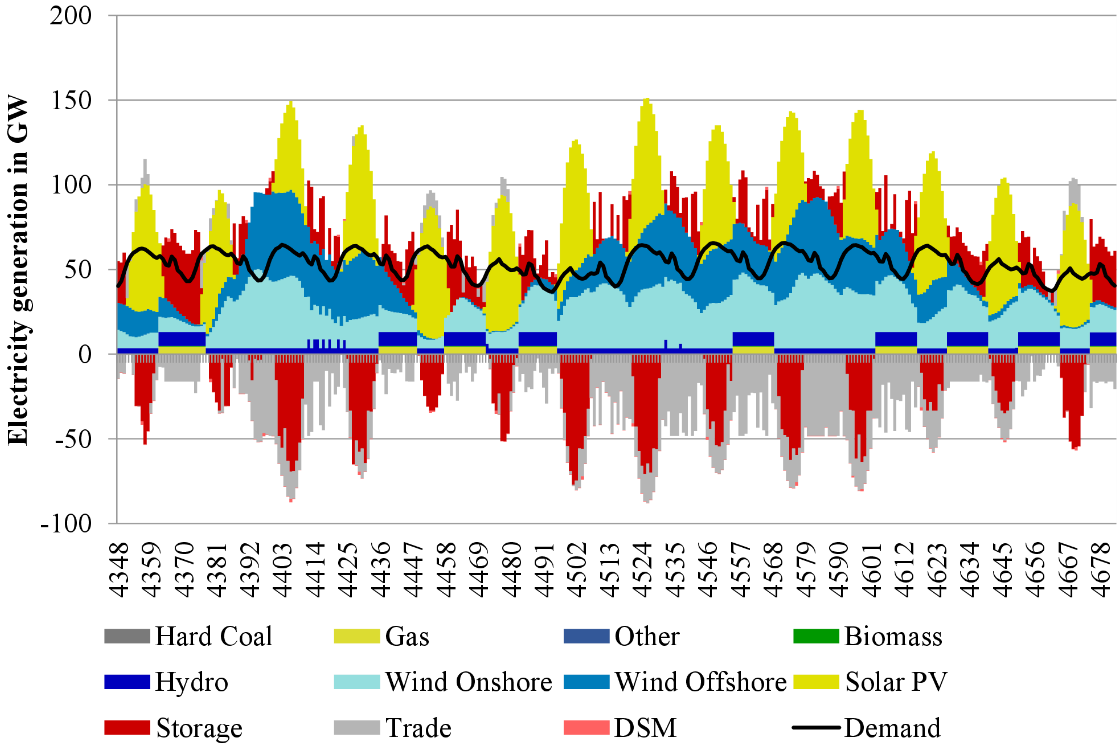


(b) Dispatch in Germany summer 2050

Figure 18: Dispatch in Germany in the year 2050



(a) Dispatch in France winter 2050



(b) Dispatch in France summer 2050

Figure 19: Dispatch in France in the year 2050

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.

6.4. Varying the inputs and calculation options

6.4.1. CCTS availability

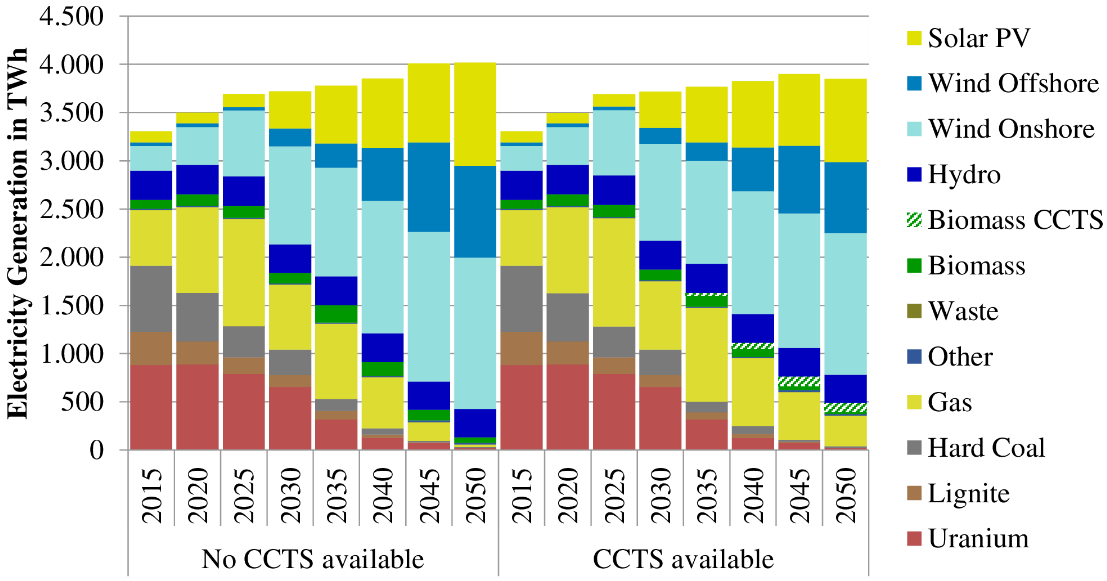


Figure 20: Generation depending on CCTS availability

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 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 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.

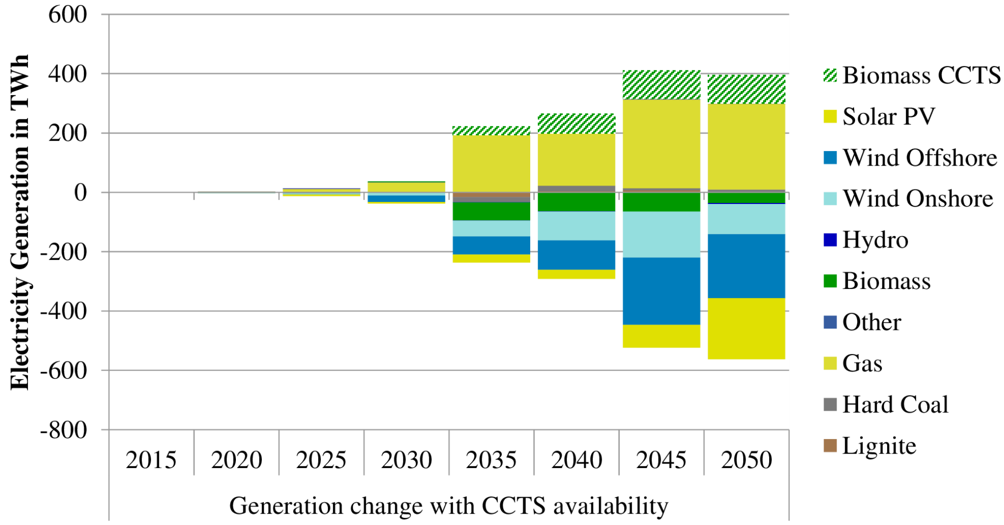


Figure 21: Difference in electricity generation with CCTS available

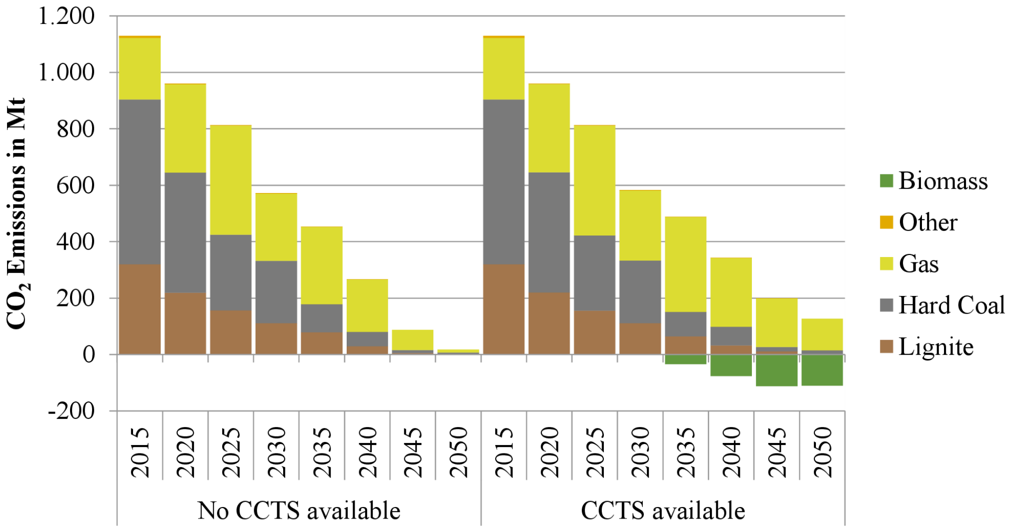


Figure 22: Emissions depending on CCTS availability

In Figure 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.

In the Figure 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.

6.4.2. 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 8), which range from only reaching 50% decarbonization of the electricity sector until 2050 to zero emission already in 2040.

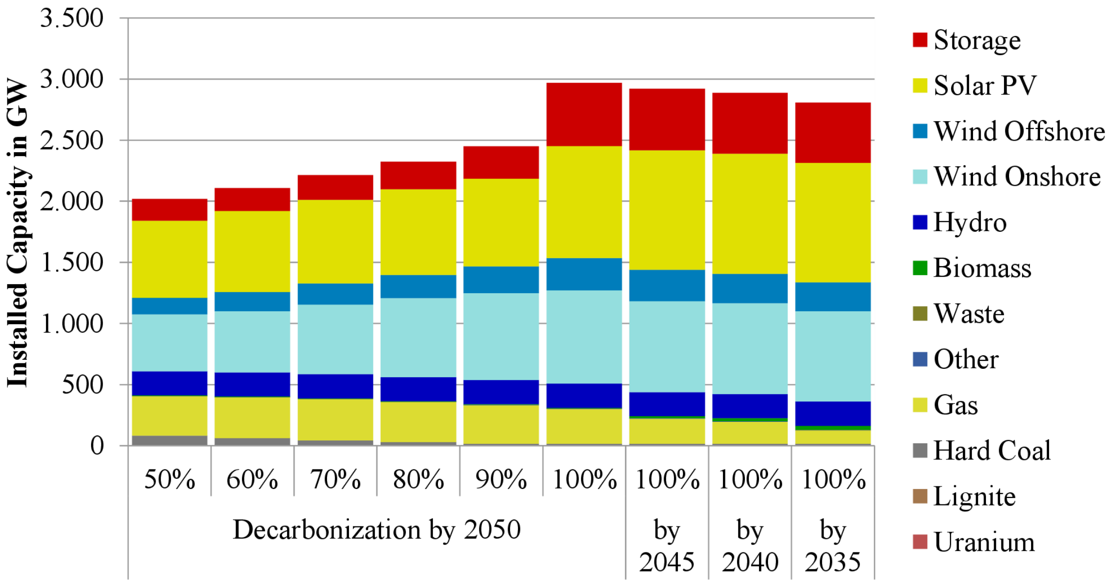


Figure 23: Installed capacity 2050 subject to the decarbonization target

Figure 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

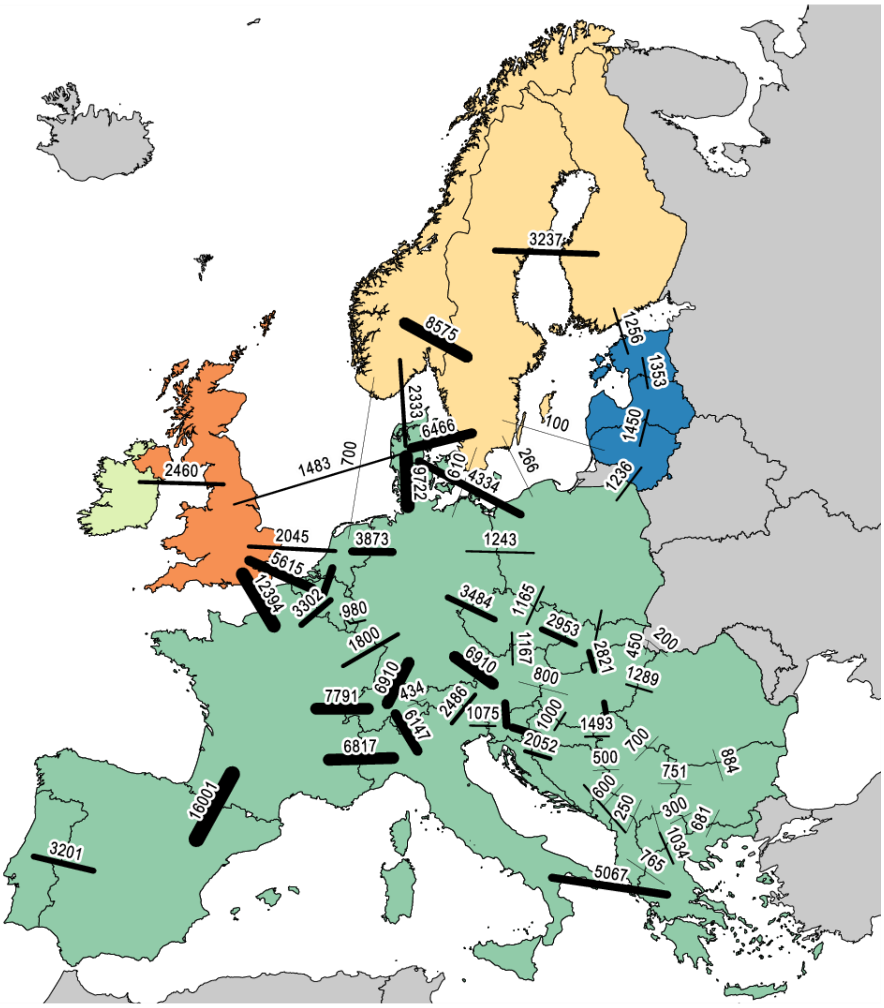


Figure 24: NTC values in the year 2050 in MW, calculated with NTC approach

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.

6.4.3. 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.

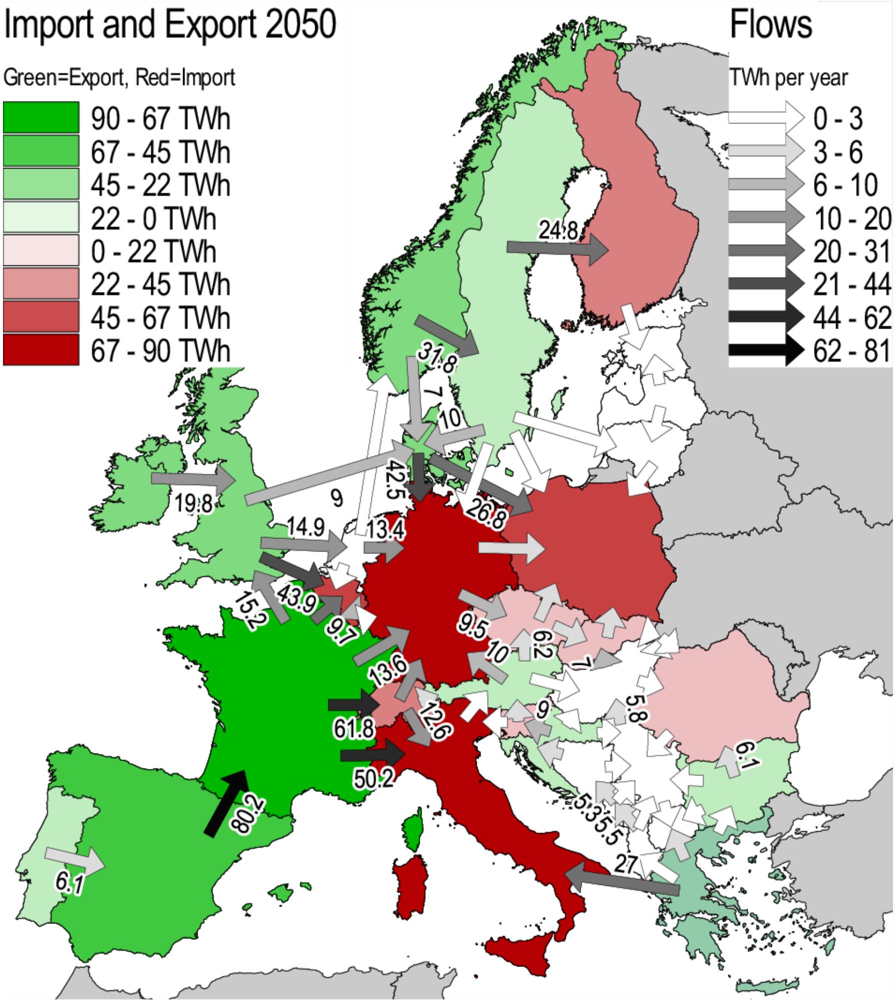


Figure 25: Import and export in TWh in the year 2050, calculated with NTC approach

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 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 not depicted here. The imports and exports in 2050 resulting from the new NTC values are shown in Figure 25. The distribution of electricity transfers is also less evenly distributed when the NTC approach is in place, as implied by the methodology.

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 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 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.

7. Conclusion

This paper 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.

A. Nomenclature

Table 5: 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 6: 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 7: 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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