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Open Source Electricity Model for Germany (ELMOD-DE)

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Abstract

This data documentation introduces to nodal dispatch models and the literature of the ELMOD model framework, which focuses on bottom-up electricity sector models with detailed spatial representation of the transmission system. The paper provides the technical description of ELMOD-DE, a nodal DC load flow model for the German electricity sector. In alignment with this paper, the described model, including its GAMS code and dataset, is made publicly available as open source model on the website of the DIW Berlin. The dataset uses publicly accessible data sources and includes hourly system data for the German electricity sector of the year 2012. The data documentation also illustrates the variety of insights into the German electricity system, ELMOD-DE provides on nodal level, with examples for hourly nodal system states and aggregated results.

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1 Introduction

The decarbonization of electricity systems goes hand in hand with increasing shares of renewable energy sources (RES) and the gradual phase-out of conventional generating units. This development leads to increasing regional imbalance of supply and demand within the mostly national price zones. Transmission system operators (TSOs), responsible for operating the high-voltage transmission network, have to adjust the power plant dispatch of the spot market in an increasing number of hours and volume.

Electricity sector models often abstract from a spatial system representation. They tend to follow the national definition of bidding zones of the European electricity markets. Trade constraints are implemented with aggregated zone-to-zone capacities, so-called net transfer capacities (NTCs). The zonal models are sufficient to represent European spot markets, but their results are sensitive to the choice on NTCs between zones. NTCs do not simply aggregate the capacity of cross-border transmission lines but depend on the situation in the physical transmission system, and are adjusted regularly.

As a result of increasing challenges in the representation of cross-border network capacity in the spot market, TSOs and power exchanges have initiated flow-based market coupling in Central Western Europe (CWE) in 2015. In addition, the national bidding zone configuration is under examination at the European level according to the framework guidelines and the Network Code on Capacity Allocation and Congestion Management. The implementation of a nodal pricing scheme in the European electricity market is not envisaged.

With increasing adjustments of the generation dispatch outside the spot market and uncertainty on future market design, insights in the spatial character of the electricity system are no longer only of concern for TSOs, but also gain importance for other stakeholders. Zonal electricity sector models are not very useful in addressing these challenges. Models with higher spatial granularity are necessary to investigate the regional system effects of decarbonization and their implications on electricity markets. They are also important to identify related infrastructure requirements for the integration of higher RES shares.

The remainder is structured as follows. Section 2 discusses literature on electricity sector models with network representation, focusing on the development of the ELMOD model framework and related publications. The mathematical model formulation for the open source version of ELMOD-DE in Section 3 is followed by an overview on the dataset in Section 4 and an illustration of various nodal and aggregated model results in Section 5. Section 6 discusses the limitations of the model together with possible extensions and the final section draws the conclusions.

2 Literature

2.1 Electricity sector models with network representation

Methodologies for bottom-up electricity sector models with network representation are well-established and applied in nodal dispatch models. Contrary to zonal models, the spatial topology of nodal electricity models follows the high-voltage transmission system and defines individual substations as nodal markets. The nodal market dispatch values the location of generation and demand with nodal marginal prices, which account for constraints of individual transmission lines. Locational marginal pricing results in deviating nodal electricity prices in case of line congestion. Hence, nodal dispatch models are capable of incorporating the physical allocation of power flows within meshed transmission systems.

In the academic literature and even more so in studies, supporting political and business decision making processes, transparency of model approaches and applied datasets is a serious concern. In most cases it is impossible to reproduce results due to missing model insights or private input data. Nodal electricity sector models face the additional challenge of documenting input data for their detailed spatial model resolution. They require hourly nodal system data and technical information for individual transmission lines. Ludig et al. (2013) publish a list with 22 studies on the German electricity sector with their respective (spatial) model approach and transparency indicators. While some of the applied models are considered to be well documented (ELMOD being one of them), transparency is insufficient in many publications. Hutcheon and Bialek (2013) describe a model which publishes data for one snap shot of the nodal input data, i.e., one hour of the European electricity system in 2009. The corresponding mathematical model description is published in Zhou and Bialek (2005). The openmod (2016) project published a list with open models of mostly zonal setting for the electricity sector. Only the SciGrid project focuses on a detailed network by extracting and processing power system data from OpenStreetMap. The output is an open source dataset of the German transmission system which will be extended to Europe (Medjroubi et al., 2015).

This paper follows these examples by providing the technical description of a nodal DC load flow model for the German electricity sector. In alignment with this paper, the described model, including its GAMS code and its dataset, is made publicly available on the website of the DIW Berlin (Department Energy, Transportation, Environment).[1] The dataset relies on publicly accessible data sources and includes hourly system data for the year 2012.

[1] The model website is accessible under the following URL: `http://www.diw.de/elmod`

2.2 Development of the ELMOD model framework

The electricity model (ELMOD), developed at the TU Dresden by Leuthold et al. (2008a), has continuously been extended at the Chair of Energy Economics (TU Dresden), the Department for Energy, Transportation, Environment (DIW Berlin), the Workgroup for Infrastructure Policy (TU Berlin), and the Energy Economics Department (University of Basel). It builds upon the DC load flow approach described in Schweppe et al. (1988), Todem (2004), and Todem and Stigler (2005). Leuthold et al. (2012) provide a detailed overview of the mathematical formulation of ELMOD. The initial model framework applies a welfare optimizing objective function, making it a quadratically constrained problem (QCP). The optimization problem has a convex solution space due to its quadratic objective function and linear model constraints. Later versions of ELMOD mostly apply a linear cost-minimizing objective function with price-inelastic demand. ELMOD is implemented in the General Algebraic Modeling System (GAMS) and can be run with well-known (commercial) solvers, e.g., CPLEX and GUROBI. Additional (optional) bi-linear and binary constraints result in non-convex solution spaces and require more complex solution techniques.

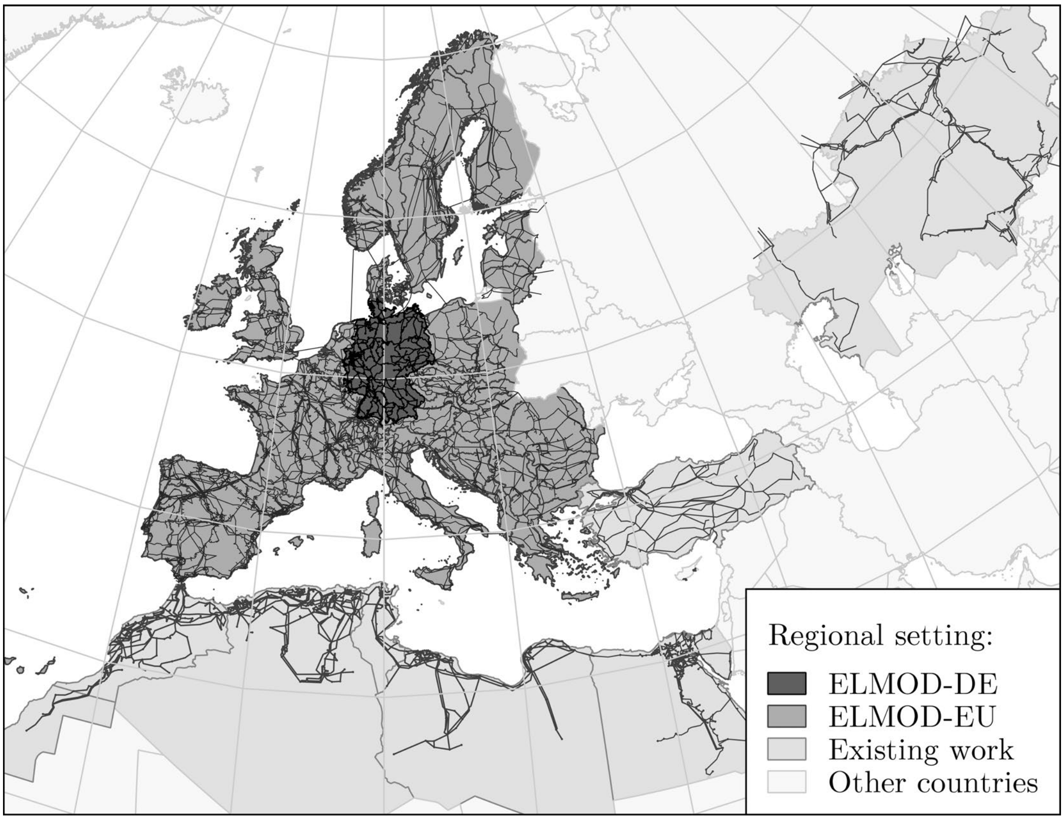


Figure 1: Countries in the ELMOD universe

The spatial model scope has been constantly expanded from Germany to most of Europe and beyond (Figure 1). The two main datasets, Germany (ELMOD-DE) and Europe (ELMOD-EU), have been described in a detailed data documentation by Egerer et al. (2014a). Additional research has been conducted on nodal datasets for North Africa, Turkey, and Kazakhstan.

The original ELMOD model has been adjusted to various research questions and their specific geographic focus. While it is common practice to publish scientific work with detailed mathematical model formulations and a description of input data, this procedure does not include a mandatory digital publication of model source codes and datasets. This paper follows the publication of the detailed data documentation (Egerer et al., 2014a) and is the next step towards more transparency. It includes an overview of ELMOD applications and supplements the publication of ELMOD-DE as an open source model. Sections 3–4 provide a description of the mathematical model formulation and the dataset of 2012.

2.3 Publications on the ELMOD model family

The ongoing development of ELMOD and its application to a large variety of research questions has resulted in an extensive list of publications on the following topics:

- nodal pricing and congestion management;
- uncertainty, balancing, and intraday markets;
- investment in generation, storage, and transmission;
- regulation of the transmission business;
- welfare distribution and strategic (cooperative and non-cooperative) games;
- cross-sectoral models.

2.3.1 Nodal pricing and congestion management

European electricity markets combine (mostly) national bidding zones with implicit auctions of cross-border capacity. While nodal pricing does not reflect the European market design as of 2016, it represents a congestion management scheme which prices transmission capacity for individual lines in the market and results in (theoretically) optimal market results. ELMOD models have been applied to analyze the implications of nodal and zonal pricing for the German and the European electricity market (Leuthold et al., 2008b; Neuhoff et al., 2013). Kunz (2013) examines congestion management and re-dispatch in Germany for increasing renewable shares and analyzes line switching as one possibility of addressing increasing re-dispatch levels for TSOs. The coordination of TSOs to realize efficiency gains in congestion management is analyzed by Kunz and Zerrahn (2015). Egerer et al. (2015b) discuss the increasing regional imbalances in the German electricity system and a possible division of the German single bidding zone.

2.3.2 Uncertainty, balancing, and intraday markets

Most ELMOD publications focus on spot markets and congestion management under certainty of input parameters. Therefore, they neglect uncertainty which marks another aspect of electricity markets. Different types of uncertainty are dealt with by additional sub-markets, e.g., futures, balancing, and intraday markets (Scharff et al., 2014). Abrell and Kunz (2015) develop a stochastic electricity market model with network representation to examine the uncertainty of wind generation.

Lorenz and Gerbaulet (2014), under certainty of input parameters, perform a quantitative analysis of cross-border balancing arrangements for the Alps region, consisting of Switzerland, Austria, and Germany.

2.3.3 Investment in generation, storage, and transmission

Spatial system analyses on nodal level provide valuable insights into investment in generation, storage, and transmission. For Germany, Dietrich et al. (2010) determine power plant placement of coal- and gas-fired generating units, Weigt et al. (2010) discuss wind integration from northern Germany with high-voltage direct current (HVDC) lines to southern Germany, and Kunz and Weigt (2014) evaluate the supply situation after the German nuclear phase-out decision in 2011. Schröder et al. (2013) evaluate renewable integration in the German transmission grid for 2030 scenarios with an aggregated network representation. The process of the German Grid Development Plan (NEP) shows the implications model assumptions have on results. Contrary to the paradigm that transmission investment should follow regional supply and demand scenarios and integrate the lowest-cost generation dispatch in any case, Egerer and Schill (2014) discuss an alternative approach with integrated investment planning for gas-fired power plants, pumped-storage hydroelectric plants, and transmission lines for different scenarios in 2024 and 2034.

At the European level, Leuthold et al. (2009) employ ELMOD-EU with a nodal network representation of continental Europe to determine network investment for increasing wind capacities. Egerer et al. (2013a) apply a later version of ELMOD-EU (including most of Europe) to national results of the PRIMES model. They determine the implications of different mitigation and technology scenarios on transmission investments in the European high-voltage alternating current (HVAC) network and in additional HVDC lines as backbones for the European grid between 2010 and 2050.

Additional research has been conducted on generation dispatch and network investment in Kazakhstan for 2030/50 scenarios (Egerer et al., 2014b) and on electricity sectors in North Africa and Turkey, including an analysis of electricity exports to Europe (Egerer et al., 2009).

2.3.4 Regulation of the transmission business

Research on transmission investment raises the question of incentive regulation for welfare optimal network development. Rosellón and Weigt (2011) apply nodal electricity sector modeling to the HRV mechanism. The HRV mechanism redefines transmission output in terms of incremental financial transmission rights (FTRs) in order to apply a two-part tariff scheme which incentivizes TSOs to conduct welfare-optimal investments in the transmission network. The ELMOD model is extended to a mathematical program with equilibrium constraints (MPEC) which separates the model into an upper level for investment decisions by the TSO and reimbursement with the two-part tariff, and a lower level for market dispatch. Schill et al. (2015) apply the HRV mechanism to a system with increasing wind shares. Egerer et al. (2015a) discuss the implications of dynamic system changes on incentive regulation schemes with two-part tariffs and test the robustness of different weights. Gerbaulet and Weber (2014) discuss the possibility of merchant transmission investment. They extend the ELMOD-EU dataset to the Baltic states to determine possible cases for merchant lines in the Baltic Sea region.

2.3.5 Welfare distribution, cooperative, and non-cooperative games

Egerer et al. (2013b), extending ELMOD-EU to Ireland, the United Kingdom, and Scandinavia, indicate the distributional implications of different topologies for the North and Baltic Seas Grid. While market integration is one of the main objectives of the internal energy market for electricity in the European Union (EU), distribution of national welfare and investment costs could hamper additional physical cross-border integration. Huppmann and Egerer (2015) investigate the impact of zonal planners deciding on network investment strategically. They develop a three-stage equilibrium model and solve the resulting EPEC as non-convex mixed-integer quadratically constrained quadratic problem (MIQCQP) to determine stable solutions for the investment game of zonal planners with national-strategic behavior. Nylund and Egerer (2014) determine a solution space with discrete strategies for cross-border investment with different cost allocation schemes in a stylized model of six European countries. They show that sharing investment cost for cross-border capacity allows stable strategies closer to the overall welfare optimal solution. The potential market power of generating companies is addressed by Gabriel and Leuthold (2010) with an MPEC model, implementing stackelberg competition in a network-constrained energy market by using integer programming.

2.3.6 Cross-sectoral models: hydrology, natural gas, and carbon capture, transport, and storage (CCTS)

The electricity sector has strong interrelations with other sectors. Hydrology and its implications on hydropower play a central role in the electricity system of several European countries. For Switzerland, Lipp and Egerer (2014) implement a detailed representation of cascading hydropower plants to analyze system flexibility. Swissmod, developed by Schlecht and Weigt (2014), includes spatial information on hydrological properties of the Swiss system with an additional network model of the river and water stream system. It captures restrictions of run-of-river, seasonal reservoir storage, and pumped-storage hydroelectric plants. Schlecht and Weigt (2015) apply Swissmod to Swiss-European transmission scenarios until 2050.

Linking sector models for the electricity and the natural gas markets is the research topic of Abrell and Weigt (2012) and Abrell et al. (2013). In a quantitative analysis, they examine the impact of Europe's natural gas network on electricity markets until 2050. Mendelevitch and Oei (2015) combine the electricity sector and CCTS to test different carbon mitigation policies for the United Kingdom.

3 Nodal dispatch model with electricity flows

ELMOD-DE is a nodal dispatch model minimizing generation costs of the network constrained German electricity system for a predefined number of consecutive hours.[2] Generation costs comprise fuel and emission costs of conventional power plants, i.e., short-term variable generation costs. The spatial model scope refers to the topology of the German high-voltage transmission system. Following the nodal pricing scheme, generation, (price-inelastic) demand, and nodal exchange with the electricity grid has to balance at each transformer station (network node) in every hour. ELMOD-DE also applies the DC load flow approximation (Schweppe et al., 1988) for distribution of load flows in meshed networks. Model limitations and possible extensions are described in Section 6 and in Leuthold et al. (2012). Egerer et al. (2015b) and Egerer and Schill (2014) directly build upon ELMOD-DE with

[2]The dataset of the open source model ELMOD-DE includes hourly data for 8784 hours of the year 2012.

adjustments in the model implementation and of scenario specific input data. The full mathematical formulation of ELMOD-DE is provided in the following. Table 1 provides an overview of the mathematical notation of sets, variables, and parameters.

Set	**Description**	**Unit**
Sets and mappings:		
$i \in I$	... (renewable) generation technologies	
$l \in L$	... alternating current (AC) transmission lines in the network	
$n \in N$	... network nodes	
$p \in P$	... generating units of power plant	
$s \in S$	... pumped-storage hydroelectric plants	
$t \in T$	... dispatch time periods (hours)	
$p \in P_n$	... power plant generating units-to-node mapping	
$s \in S_n$	... pumped-storage hydroelectric plants-to-node mapping	
Variables and positive variables:		
c	... objective value: total generation costs	EUR
pf_{lt}	... power flow on line l in hour t	MW
θ_{nt}	... phase angle difference in respect to slack bus	
g_{pt}^{unit}	... generation level: conventional power plant p	MW
ls_{st}	... pumped-storage: hourly energy content level	MWh
$\overrightarrow{ps}_{st}$	... pumped-storage: hourly generation level	MW
$\overleftarrow{ps}_{st}$	... pumped-storage: hourly pumping level	MW
r_{nit}^{tech}	... generation level: renewable technology	MW
Parameters:		
av_{pt}^{unit}	... availability: power plant p in hour t	
av_{nit}^{tech}	... availability: technology i at node n in hour t	
b_{nk}	... network susceptance matrix	$1/\Omega$
$\hat{b}_l$	... series susceptance of line	$1/\Omega$
$\overline{g}_p^{\text{unit}}$	... maximum generation capacity: power plant p	MW
h_{ln}	... network transfer matrix	$1/\Omega$
im_{ln}	... incidence matrix: between line l and nodes n	
$\overline{ls}_s$	... maximum energy storage: pumped-storage plant	MWh
$\overline{pf}_l$	... maximum power flow: transmission line	MW
pf_{nt}^{export}	... cross-border export flow	MW
pf_{nt}^{import}	... cross-border import flow	MW
$\overline{ps}_s$	... maximum turbine capacity of pumped-storage plant	MW
q_{nt}	... electricity load	MW
$\overline{r}_{nit}^{\text{tech}}$	... maximum renewable generation capacity	MW

Table 1: Sets, mappings, (positive) variables, and parameters of ELMOD-DE

3.1 DC load flow approach

The nodal ELMOD models, in most cases, represent network flows with the DC load flow approximation. DC load flow is a linearization of AC power flow. The set of linear constraints can be solved in reasonable computation time and DC load flow provides an acceptable level of accuracy (Overbye et al., 2004). Equation 1 states real power flow on line l between node 1 and node 2.

$$pf_{1,2} = G_l(V_1^2 - V_1 V_2 \cos(\theta_1 - \theta_2)) + \hat{b}_l V_1 V_2 \sin(\theta_1 - \theta_2) \tag{1}$$

The equation can be simplified assuming small values for differences in voltage angles (Equations 2a–2b) and low differences in voltage levels (Equation 2c).

$$\sin(\theta_1 - \theta_2) \approx \theta_1 - \theta_2 \tag{2a}$$

$$\cos(\theta_1 - \theta_2) \approx 1 \tag{2b}$$

$$V_1 \approx V_2 \approx 1 \tag{2c}$$

Following these simplifications (Schweppe et al., 1988, page 313f), line flows between nodes 1 and 2 are calculated using the linear Equation 3. The model constraint 4b implements this formulation with the network transfer matrix h_{ln}.[3]

$$pf_{1,2} = \hat{b}_l(\theta_1 - \theta_2) \tag{3}$$

Network inflows and outflows ni_{nt} in Equation 4c are calculated from the sum of power flows on all adjacent lines.[4] In the slack bus $\hat{n}$, Equation 4d fixes the voltage angle $\theta_{\hat{n}t}$ to zero to define a reference node and enforce unique solutions for the other voltage angles. The constraints of the DC load flow approach span a more restricted solution space than transport models which allow directed flows.

[3] The incidence matrix h_{ln} takes the value +1 for the start node and −1 for the end node of the respective line. The series susceptance of each line $\hat{b}_l = X_l/(R_l^2 + X_l^2)$ calculates from line resistance R_l and line reactance X_l. The expression could be further simplified to $\hat{b}_l = 1/X_l$ assuming $X >> R$. The network transfer matrix $h_{ln} = \hat{b}_l im_{ln}$ aggregates the physical line parameters and the topology.

[4] The network susceptance matrix $b_{nk} = \sum_l im_{ln} h_{lk}$ aggregates all line information to network nodes.

The dataset includes the network topology and technical information on transmission lines.[5] Capacity constraint 4a limits absolute flow levels pf_{lt} on every line l in the transmission network to its thermal line rating $\overline{pf}_l$ which is calculated by the line's voltage level and its number of circuits. Start and end node, defined in the incidence matrix im_{ln}, and thermal line rating of transmission lines would be sufficient to build a model with directed flows.

$$|pf_{lt}| \leq \overline{pf}_l \qquad \forall \quad l,t \tag{4a}$$

$$pf_{lt} = \sum_n \theta_{nt} h_{ln} \qquad \forall \quad l,t \tag{4b}$$

$$ni_{nt} = \sum_k \theta_{kt} b_{nk} \qquad \forall \quad n,t \tag{4c}$$

$$\theta_{\hat{n}t} = 0 \qquad \forall \quad t \tag{4d}$$

3.2 Additional model equations

The objective function in Equation 5 minimizes generation costs of the power plant dispatch. Objective value c comprises hourly output level of conventional generation units g_{pt}^{unit} multiplied by their variable generation costs $\hat{c}_{pt}^{\text{unit}}$. Variable generation costs are composed of fuel prices, regional transportation costs for hard coal, and CO_2 emission costs.[6,7]

$$\min_{g^{\text{unit}}} \mathrm{c} = \sum_{pt} g_{pt}^{\text{unit}} \hat{c}_{pt}^{\text{unit}} \tag{5}$$

The energy balance 6 determines the spatial character of the electricity system. Nodal electricity generation has to be equal to electricity demand at every node n and in every hour t. Therefore, pumped-storage hydroelectricity and input to or withdrawal from the transmission network ni_{nt} can add to the respective node's generation or to its demand. The nodal model topology requires mapping of power

[5] Parallel line circuits, i.e., lines with the same start and end node and of the same voltage level, are aggregated to single network elements.

[6] Other power plants are not considered in the objective function. Variable generation costs for renewable technologies are assumed to be zero. Also, the model data abstracts from load changing costs and operation and maintenance costs.

[7] In the open source model, the 8784 hours of 2012 are solved in weekly blocks of 168 hours. Except for the first week, the first hour of the weekly model runs is Friday to Saturday at midnight.

generation units p and pumped-storage plants s to nodes. The large number of small-scale renewable producers are aggregated by technology i to network nodes. The marginal value of the energy balance reflects the nodal marginal price.

$$\sum_{p \in P_n} g^{\text{unit}}_{pt} + \sum_{i} r^{\text{tech}}_{nit} + \sum_{s \in S_n} \overrightarrow{ps}_{st} + ni_{nt} = q_{nt} + \sum_{s \in S_n} \overleftarrow{ps}_{st} \qquad \forall \quad n,t \tag{6}$$

Nodal hourly electricity load q_{nt} is an exogenous parameter, given the assumption of price-inelastic demand. Equation 7a limits output of conventional power plants to the generating unit's installed capacity $\overline{g}^{\text{unit}}_{pt}$ adjusted with an hourly availability factor av^{unit}_{pt}. Maximum nodal renewable output by technology is set in Equation 7b for every hour by installed capacity at the respective node $\overline{r}^{\text{tech}}_{nit}$ multiplied by an hourly availability factor av^{tech}_{nit}.[8]

$$g^{\text{unit}}_{pt} \leq \overline{g}^{\text{unit}}_{p} av^{\text{unit}}_{pt} \qquad \forall \quad p,t \tag{7a}$$

$$r^{\text{tech}}_{nit} \leq \overline{r}^{\text{tech}}_{nit} av^{\text{tech}}_{nit} \qquad \forall \quad n,i,t \tag{7b}$$

Equations 8a–8c describe pumped-storage hydroelectric plants. Their installed capacity $\overline{ps}_s$ sets the upper bound for the variables of generation and pumping $\overrightarrow{ps}_{st}$ and $\overleftarrow{ps}_{st}$. The energy content ls_{st}, restricted to the individual storage size $\overline{ls}_s$ of each pumped-storage plant, is the only inter-hourly constraint in the model. The storage level of one hour depends on generation and pumping of the storage, its cycle efficiency of 75%, and the level in the previous hour $t-1$.[9]

$$\overrightarrow{ps}_{st} + \overleftarrow{ps}_{st} \leq \overline{ps}_s \qquad \forall \quad s,t \tag{8a}$$

$$ls_{st} \leq \overline{ls}_s \qquad \forall \quad s,t \tag{8b}$$

$$ls_{st} = 0.75\overleftarrow{ps}_{st} - \overrightarrow{ps}_{st} + ls_{s(t-1)} \qquad \forall \quad s,t \tag{8c}$$

[8] In the GAMS implementation the number of variables in the optimization problem is reduced by aggregating all renewable generation technologies at each node.

[9] The storage of every plant is assumed to be empty ($ls = 0$) in the first and last hour to account for consistency between the weekly model runs. An alternative approach is the optimization of model blocks with rolled planning.

4 Input data

The dataset of ELMOD-DE relies entirely on publicly accessible data sources for network topology, supply, demand, and price data. It includes spatial information on infrastructure and hourly time series describing system states of the German electricity sector in 2012. The following section summarizes the main characteristics of the input data. Table 2 provides a thematic overview on the main references. Egerer et al. (2014a) provide a complete description on data sources, their processing, and the final dataset.

Type	**Data description**	**References**[10]
Network	- Topology according to network plans	VDE & TSOs
	- Geo-referenced data for nodes and lines	OpenStreetMap (2013)
	- Technical parameters overhead power lines	Kießling et al. (2001)
Demand	- Load level of Germany (hourly)	ENTSO-E (2013)
	- Adjustment to statistic of annual demand	BDEW (2013)
	- Spatial allocation to network nodes with statistic on population and GDP	Eurostat (EC, 2013) on NUTS 3 level
Generation	- Power plant list for the German system	BNetzA (2013)
	- Renewable data of the EEG support scheme	TSOs
	- Price data for fossil fuels (monthly)	Kohlenwirtschaft e.V.
	- Price data for CO_2 certificates (daily)	EEX (2013)
	- Coal transport cost (dena zones)	Frontier & Consentec
Trade	- Physical cross-border flows (hourly)	TSOs and ENTSO-E
Availability	- Regional time series for wind and PV (hourly)	TSOs

Table 2: Overview on institutions for data sources

4.1 Spatial model scope

The nodal electricity sector model ELMOD-DE builds on line-sharp data for the German high-voltage transmission system of 220 kV and 380 kV. The dataset, illustrated in Figure 2, has 438 network nodes and 697 transmission lines. 393 nodes are substations in Germany—220 kV and 380 kV transformer stations in close proximity are condensed to one node—and 22 nodes are located in neighboring countries. The remaining 23 are auxiliary nodes, i.e., two lines are connected directly without a transformer station. The 938 transmission lines, connecting the network nodes, are

[10] The data documentation Egerer et al. (2014a) provides a complete list of all references on input data. The nomenclature des unités territoriales statistiques (NUTS) is a geocode standard by the European Union for statistical purposes. The NUTS 3 level corresponds to districts in Germany.

aggregated to 697 network elements. Lines with the same start and end node and the same voltage level are treated as single network elements consisting of multiple circuits. The incidence matrix reflects the grid topology and takes the value +1 for the start node and -1 for the end node. Additional technical parameters for every transmission line are reactance, resistance, power flow limit, voltage rating, circuits, and length.

The spatial model scope incorporates the electricity network of Luxembourg, including its generation capacities and demand, and a few generators in Austria. Luxembourg's electricity system is integrated into the German market and there is no historical data on cross-border electricity flows. A different case is Vorarlberg, the most western part of Austria, where some hydropower plants feed into the German transmission system. The two DC offshore cables to Sweden and Denmark are not modeled explicitly. Imports and exports are attached as supply and demand to the respective network node in northern Germany.

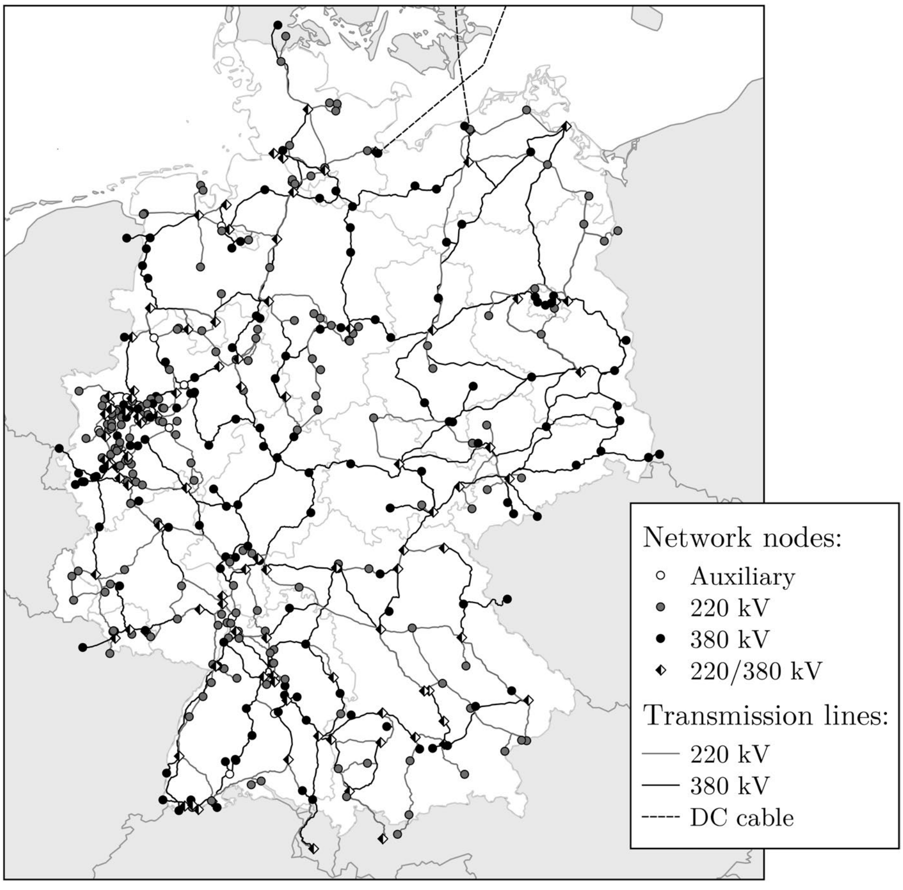


Figure 2: High-voltage transmission network in 2012

4.2 Nodal electricity demand

The regional load distribution in Germany differs between peak and off-peak load. To approximate this circumstance, the dataset has two distribution keys for demand on a state level, one for the highest and one for lowest load level. The load shares of states are approximated with a linear interpolation for national load levels between the two extreme hours, assuming full correlation between national load levels and state load shares. For each NUTS-3 zone within one state a weighted load share is calculated based on information on the zone's gross domestic product (GDP) and population.[11] The main demand centers are in western and southern Germany.

4.3 Generation capacity

4.3.1 Conventional power plants

The dataset has 594 power plants, composed of 558 conventional and 25 pumped-storage hydroelectric plants in Germany, six power plants in Luxembourg, and five in Austria (Table 3). The total capacity of 91.7 GW faces a peak load of about 86 GW (+1 GW in Luxembourg). Off-peak is little less than 36 GW which can be supplied in large shares by renewable capacities (74.3 GW) in hours of high wind and/or PV generation. Storage amounts to 6.2 GW in Germany, 1.1 GW in Luxembourg, and 1.5 GW in Austria, all connected directly to the German system.

Renewable generation and waste plants are implemented with variable costs of zero. Thus, the model will not curtail these technologies unless renewable generation exceeds total demand, or regional demand in case of network constraints. The technology other is fixed to a generation band to meet annual statistics. For the remaining demand, the model optimizes operation of power plants following their variable generation costs, unless network constraints prevail. Variable generation costs do not overlap between nuclear, lignite, hard coal, and CCGT plants, given their efficiency factors and historic fuel and CO_2 price in 2012.

The spatial distribution shows nuclear in the northwest and south, lignite close to one coal mining area in the west and two in the east, and hard coal mostly in the western half of Germany. CCGT plants have been built close to load centers in the south and west, and other generation (mostly gas and oil) is well distributed with emphasis on the Ruhr in the west. Pumped-storage plants are located either in the low mountain range spanning from west to east in the middle of Germany or close to the Alps in the south.

[11] The quality of input data for demand could be improved with a detailed bottom-up dataset on power consumers together with their spatial distribution and hourly load patterns.

Conventional					Renewables	
	Units	Capacity [GW]	Price range [EUR/MWh]			Capacity [GW]
Nuclear	9	12.1	9.1		Run-of-river	3.7
Lignite	61	20.4	14.9–29.0		Biomass	6.4
Hard coal	101	24.7	31.6–54.4		Photovoltaic	32.4
CCGT	26	8.5	55.8–77.0		Wind onshore	31.5
Gas	208	14.3	73.1–138.7		Wind offshore	0.4
Oil	50	4.1	116.0–210.7		Geothermal	0.02
Other	34	2.9			Total	74.3
Waste	73	1.5				
Storage	32	8.8				
Total	594	97.1				

Table 3: Conventional and renewable generation capacities

4.3.2 Renewable energy sources (RES)

Hydropower run-of-river plants, with about 22 TWh annual generation, are mainly located in southern Germany. Biomass generation of 36 TWh is distributed more evenly (Figure 4). Variable renewable energy sources—wind and photovoltaics—are concentrated in specific regions. Wind capacity, with 50 TWh generation in 2012, is mostly located in the northwest and (north)east, regions with comparably low demand. Photovoltaics has 26 TWh annual generation and half of its installed capacity in southern Germany.

4.4 Time series

The dataset includes hourly time series for demand (ENTSO-E, 2013) adjusted to an annual demand of 550.9 TWh (BDEW, 2013). Conventional power plants are implemented with seasonal availability factors separated in six winter and six summer months to approximate revisions and other non-availabilities. The input data has monthly fuel prices for hard coal, gas, and oil and daily prices for carbon certificates. Availability of renewable capacity is calculated to meet historic generation output. Hydropower has monthly availability factors on national levels and biomass is considered with constant availability. German TSOs publish time series for wind generation (onshore and offshore) and generation of photovoltaics. The dataset combines these regional hourly time series with regional installed capacity to calculate regional hourly availability factors, which are matched to dena zones (dena, 2010, page 12).

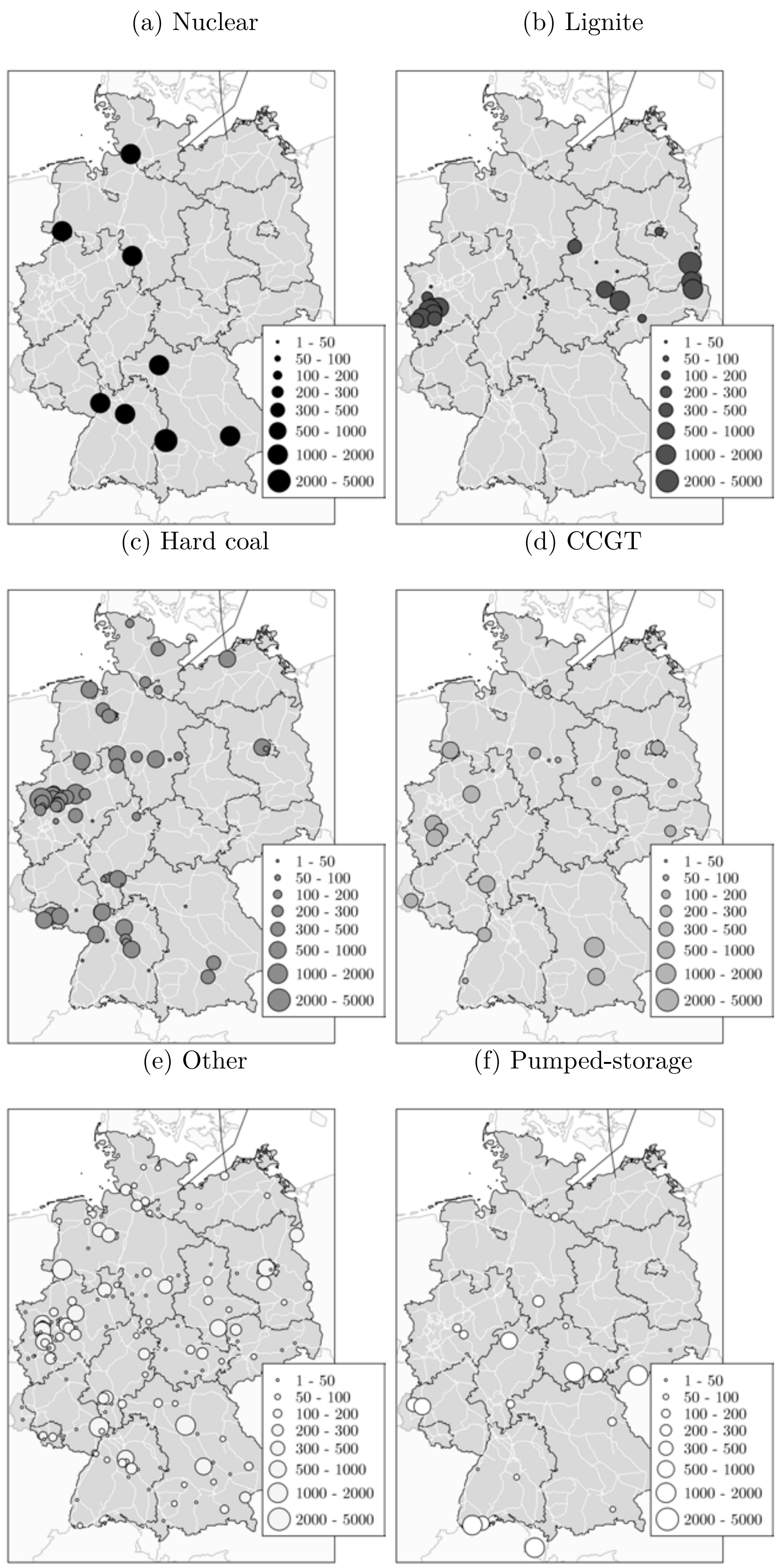
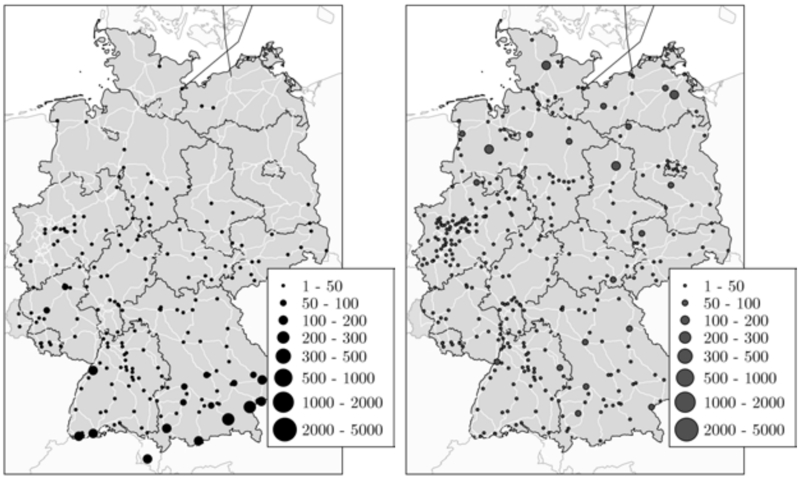


Figure 3: Generation capacities of conventional power plants [MW]

(a) Run-of-river hydro (b) Biomass



(c) Wind (d) Photovoltaics

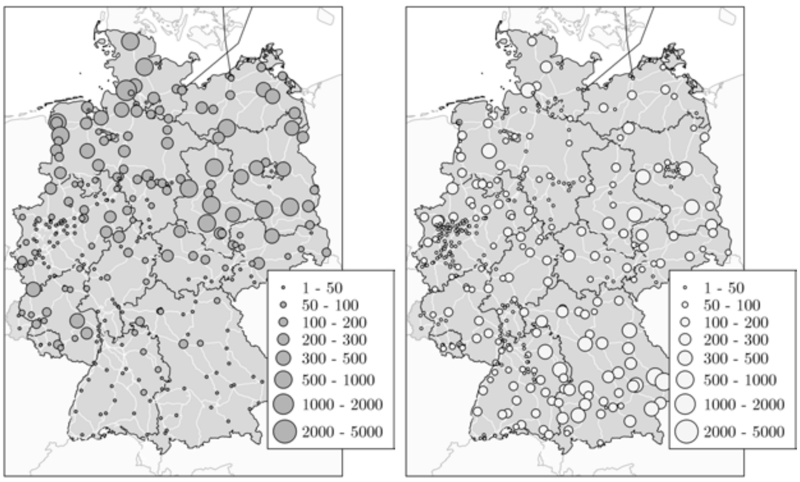


Figure 4: Renewable capacities of conventional power plants [MW]

5 Results

5.1 Hourly model results of the German electricity system

The results of the nodal dispatch model provide an insight into the nodal system state of the German electricity sector for every hour in 2012. Input parameters—nodal electricity demand, nodal available generation capacities with variable generation costs, import and export cross-border flows, and the network topology—provide the hourly solution space for the optimization model which determines the lowest-cost nodal generation dispatch. Results for model variables include generation costs for the weekly model runs, hourly generation levels of all conventional generating units, renewable technologies, storage operation, and hourly line flows in the transmission network. Hourly nodal electricity prices can be derived from the marginal value of the energy balance for every node and hour.

5.1.1 Exemplary hours with specific characteristics

This section presents model results for exemplary hours representing system states with specific characteristics. Figures 5–9 illustrate results, including nodal electricity prices, line utilization, as well as nodal balances of generation and demand. The exemplary hours with specific characteristics are:

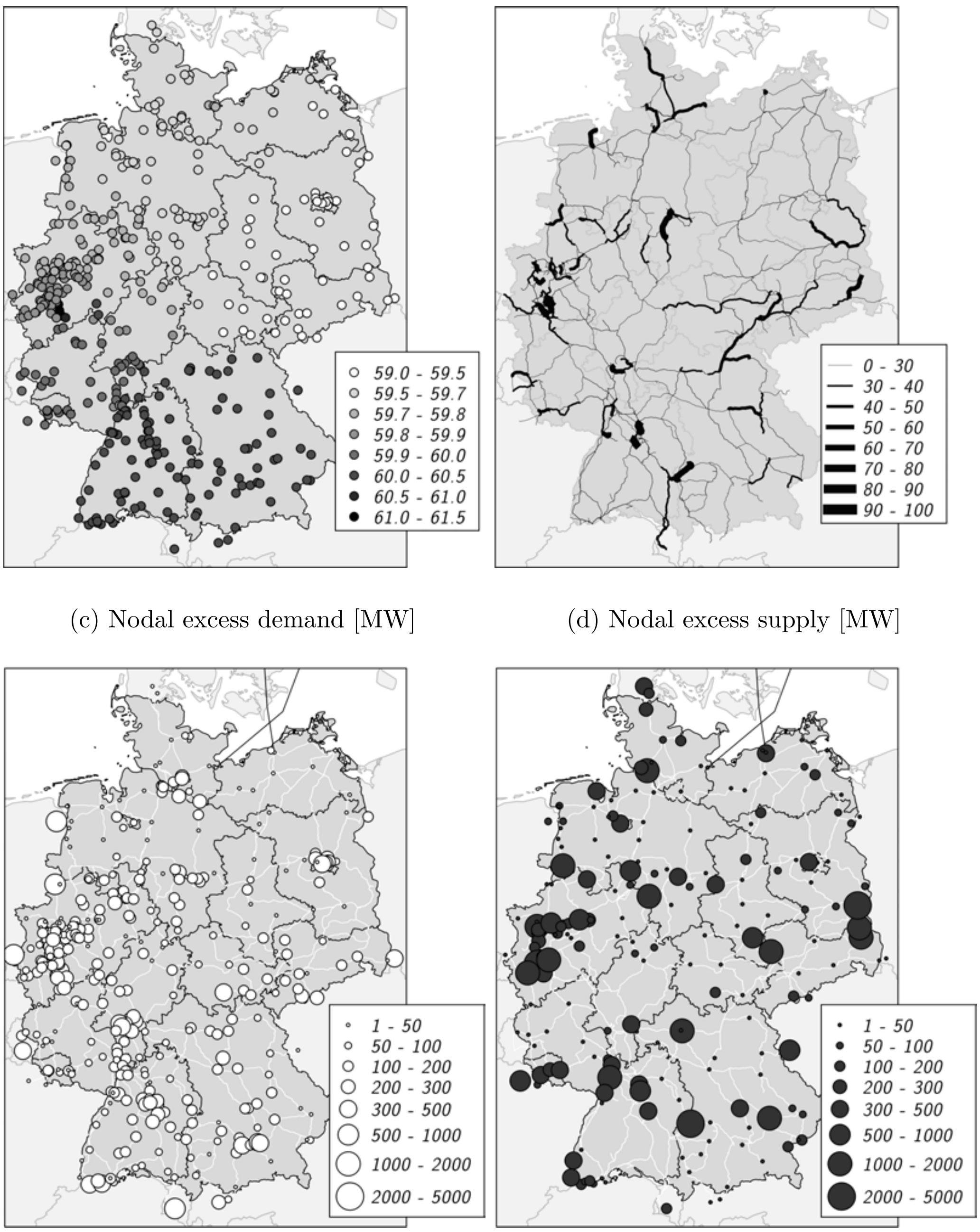
- avg: average nodal results for the entire year in Figure 5 show low nodal price difference of about 2.50 EUR/MWh. Prices are highest in the southeast and increase from eastern to western Germany. Most lines have average utilization below 50% indicating that there are no permanent bottlenecks in the network. Nodal balances indicate excess of demand in highly populated regions and excess of supply at nodes with large conventional power plants (mainly nuclear, lignite, and hard coal). Renewable generation is not as visible in the nodal balances as it is less concentrated in specific nodes. Cross-border flows, an input parameter, show imports from Scandinavia, southwestern Czech Republic, and France and exports to all other neighboring countries.

- h1: the winter hour with peak load and low renewable generation is characterized by operation of almost all conventional generation units (Figure 6). Western Germany, with its large share in conventional capacity, provides additional peak capacity and experiences a high regional surplus in supply. Transmission capacity is sufficient to retain a common electricity price of 114 EUR/MWh. The utilization of transmission lines, connecting supply in western Germany to demand in the north and the south, is particularly high. The system imports from Denmark and the Netherlands and it exports to most other countries;

- h2: the winter hour with high load, no PV, and high wind generation in Figure 7 shows strong differences in nodal prices, ranging between 20 EUR/MWh in eastern Germany and 60 EUR/MWh in the southeast. Conventional generation from the west of Germany (hard coal and gas) is replaced by wind generation in the north. The transmission network illustrates the high power flows from the north to the south. They are intensified by lignite generation in eastern Germany and experience bottlenecks on their way to the southeast. In the southwest, hard coal is the marginal technology setting prices of about 50 EUR/MWh while CCGT generation sets the price in the southeast with about 60 EUR/MWh. Historical cross-border flows in this hour (input parameter) show additional imports from Denmark into the already oversupplied northern region with low locational marginal prices. At the eastern border, there are physical exports to Poland and the Czech Republic and imports in the southeast.

- h3: the winter hour with low load, no PV, and high wind generation in Figure 8 is similar to hour 2. Nodal prices in southern Germany drop to about 40 EUR/MWh, pushing hard coal power plants out of the market. Except for wind generation, nuclear and lignite-fired generation units are still in the market. In hours with high wind generation, the regional excess of supply and the network utilization varies with weather conditions and regional distribution of wind speeds. The hourly wind generation can deviate significantly between regions and, due to moving weather systems, time delays can occur between the northwest and (north)east;

- h4: the summer hour with low load, very high PV, and low wind generation in Figure 9 shows better nodal balances of supply and demand in southern Germany and no bottlenecks in the transmission network. In addition to nuclear and lignite, PV shows high availability with large shares of its capacity being located in the south. There are no bottlenecks in the network which allows a marginal price of about 40 EUR/MWh for all of Germany. It is set by the cheapest hard coal generation units, producing in the northwest. The transmission system supplies the demand centers in the (south)west with power flows from the (south)east. Cross-border power flows export electricity to most neighboring countries.



(a) Nodal prices [EUR/MWh]

(b) Line utilization [%]

(c) Nodal excess demand [MW]

(d) Nodal excess supply [MW]

Figure 5: Average for all hours of nodal model results (avg)

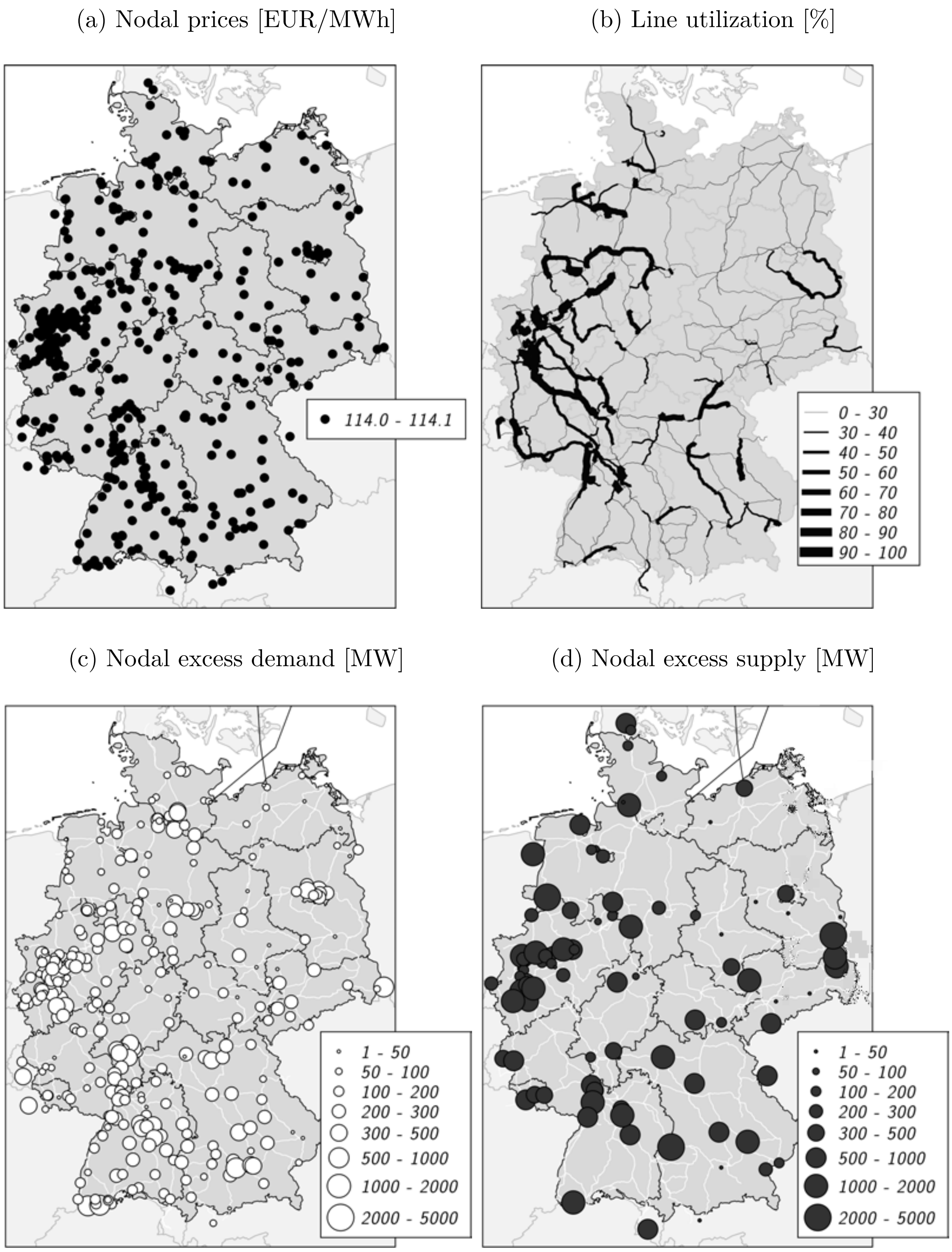
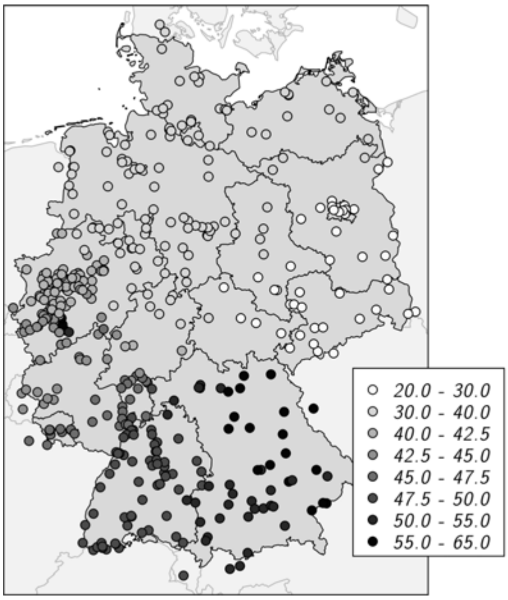
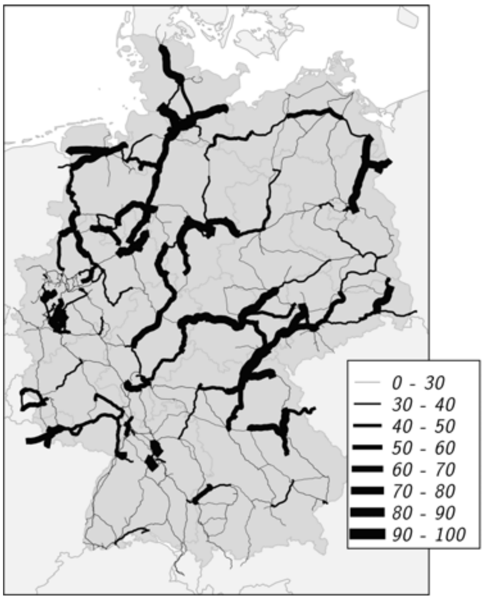


Figure 6: Peak winter demand and low renewable generation (h1)

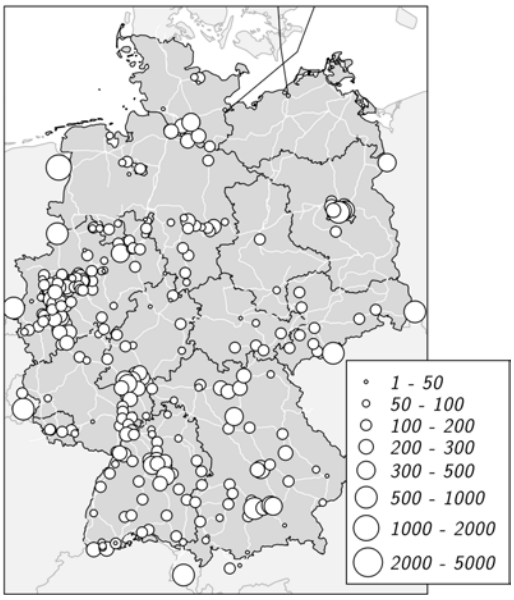
(a) Nodal prices [EUR/MWh]



(b) Line utilization [%]



(c) Nodal excess demand [MW]



(d) Nodal excess supply [MW]

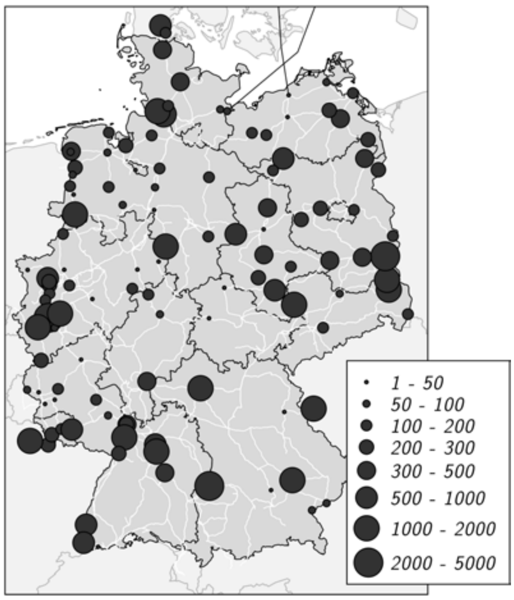


Figure 7: High winter demand, no PV, and very high wind generation (h2)

(a) Nodal prices [EUR/MWh] (b) Line utilization [%]

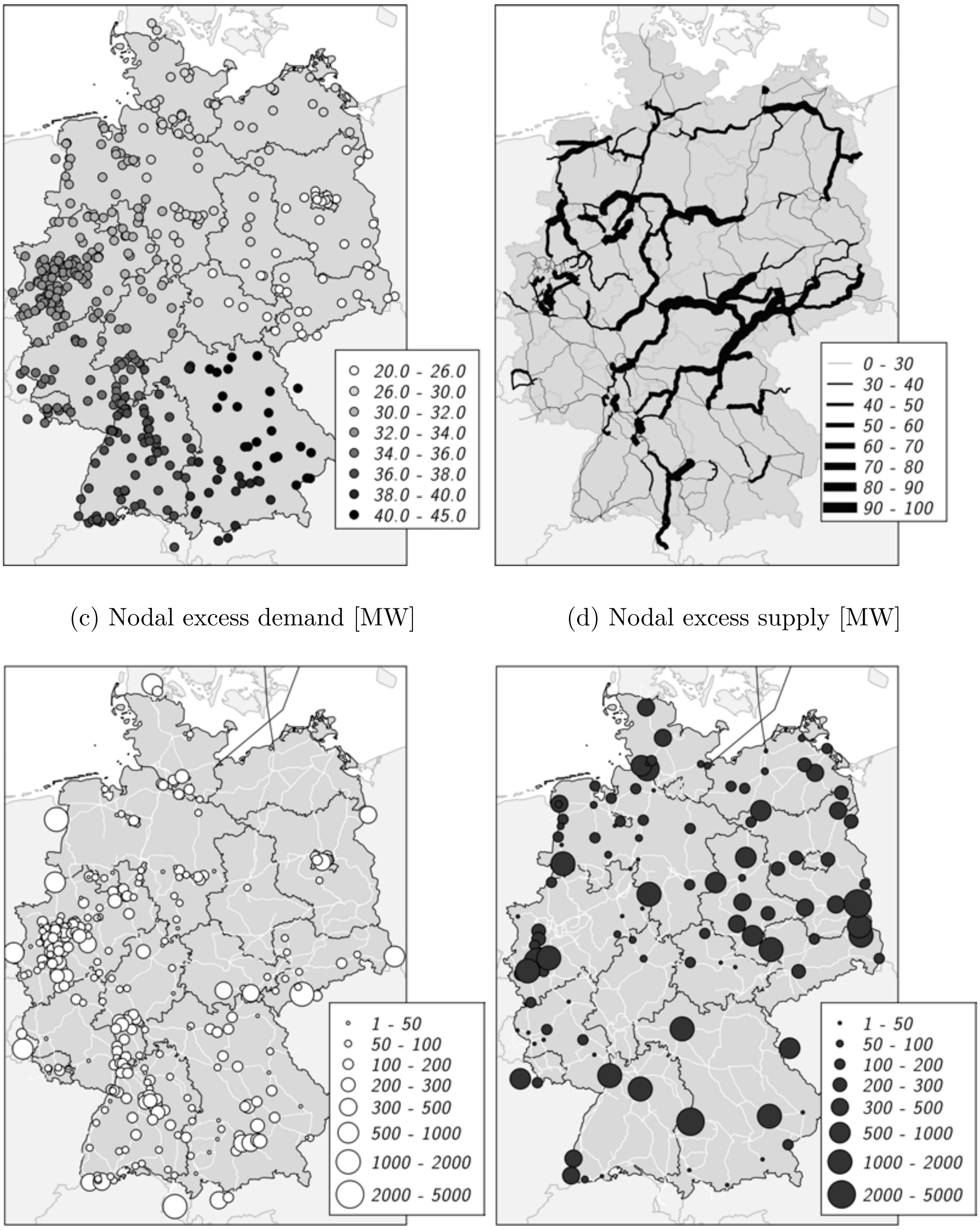


Figure 8: Low winter demand, no PV, and high wind generation (h3)

(a) Nodal prices [EUR/MWh] (b) Line utilization [%]

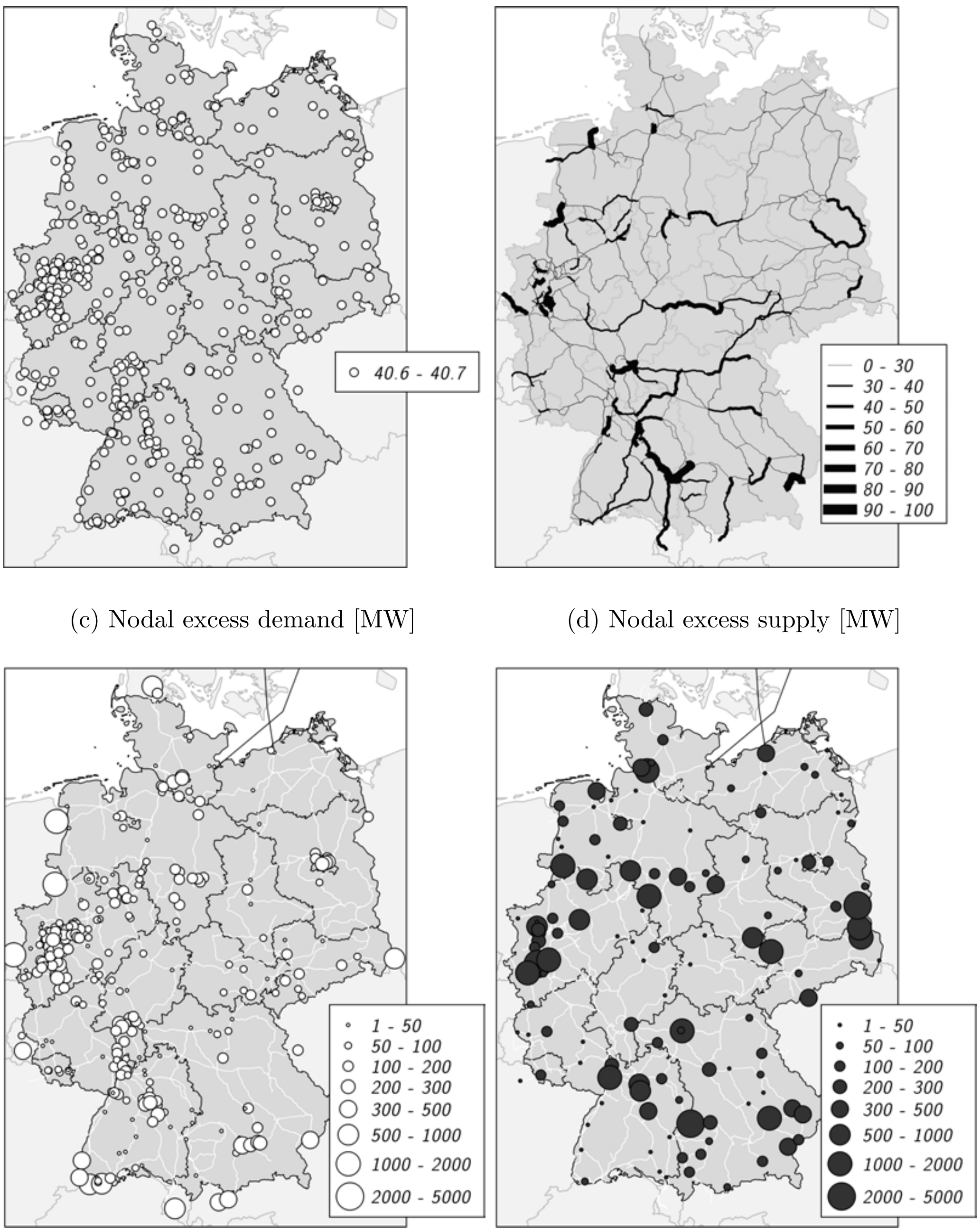


Figure 9: Low summer demand, high PV, and low wind generation (h4)

5.2 Aggregation of model results by space and time

5.2.1 Spatial aggregation of results

Model results can be analyzed on hourly and nodal level or they can be aggregated by space and/or time. The model data includes information which can be used for spatial aggregation, i.e., location by country, state, dena zone, and a six zones aggregation (Figure 10) for all nodes, renewable capacity, generation units, and pumped-storage hydroelectric plants. While the aggregation by country or states has a political dimension, dena zones and the six zones aggregation are better suited to represent regional differences in supply and demand and the internal network flows with their constraints in the transmission system.

(a) States (b) Dena zones (c) Six zones

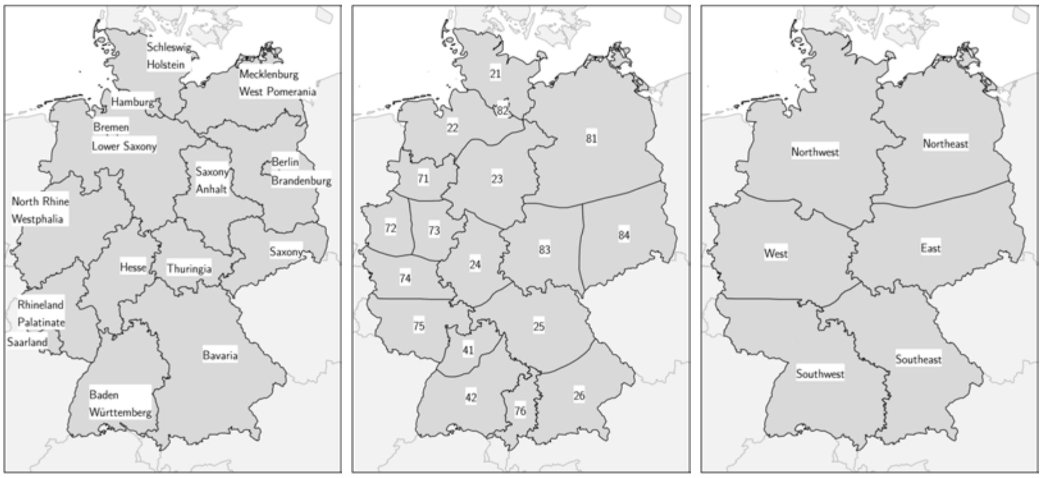


Figure 10: Different spatial aggregations for Germany

5.2.2 Hourly results aggregated to zones

Zonal aggregation can be better suited than the nodal level for the discussion of regional characteristics in the model results. The zonal aggregation in Figure 11 shows very high wind shares in northern Germany in h2 and h3 which replace all fossil generation in the respective zones. In the hour with high wind and low demand (h3), the surplus in wind generation in northern Germany is sufficient to supply most of the demand in the Southwest, replacing coal generation and electricity imports. High generation from photovoltaics in the summer hour (h4) is highest in the southern zones supplying peak demand during the day. Additional coal generation covers electricity demand in the north in hours of low wind generation and there are lower flows from the north to the south. Average annual levels in h1 show hourly excess supply of 4.4 GW in the East, 2.7 GW in the Northwest, and 0.7 GW in the Southeast.

On the contrary, there is average hourly excess demand of 3.9 GW in the Southwest, 0.8 GW in the Northeast, and 1.0 GW in the West which also faces high imports from the Northwest and the East and exports to the Southwest. The difference of 2.1 GW between excess supply and demand indicates higher annual exports than imports with neighboring countries.

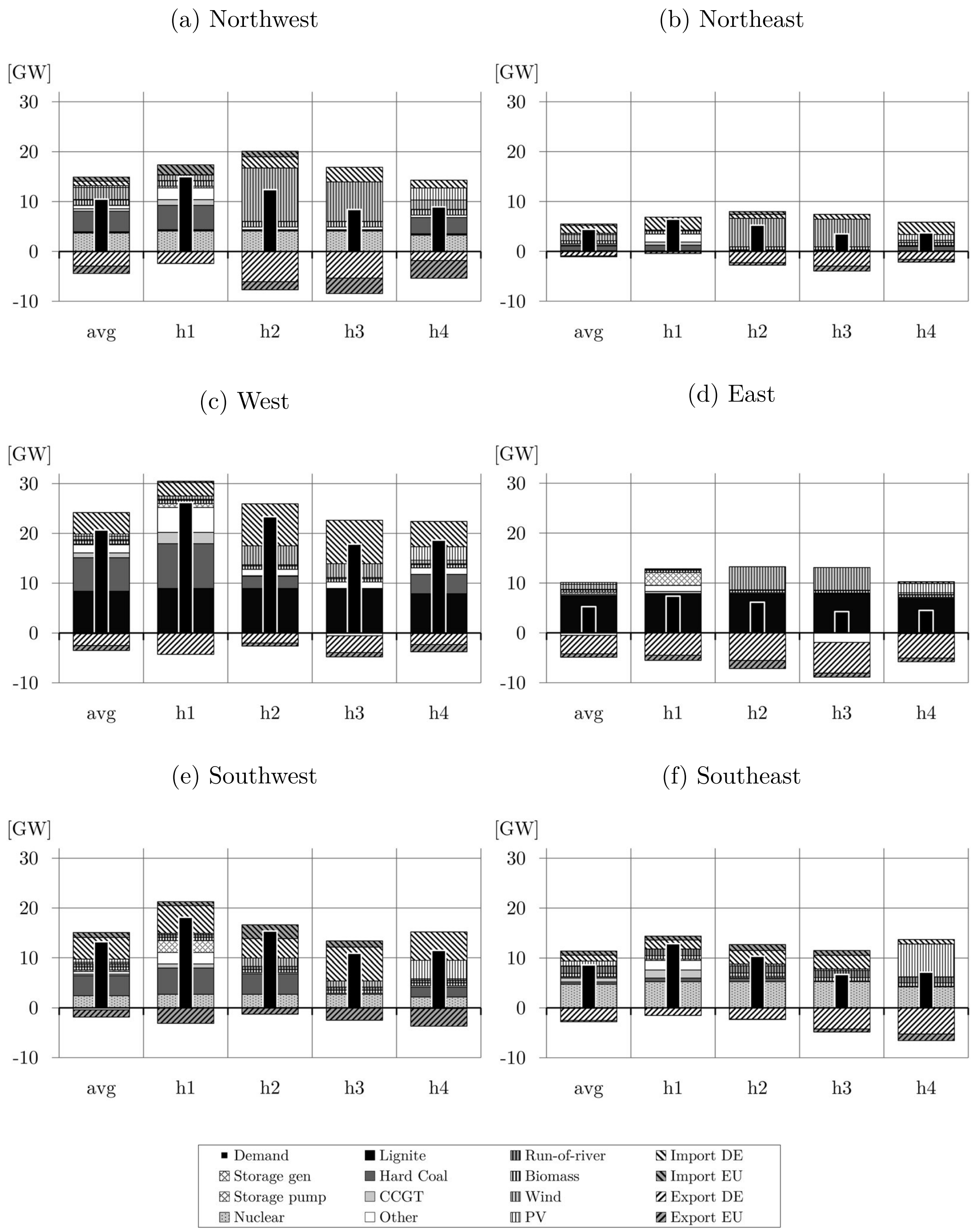


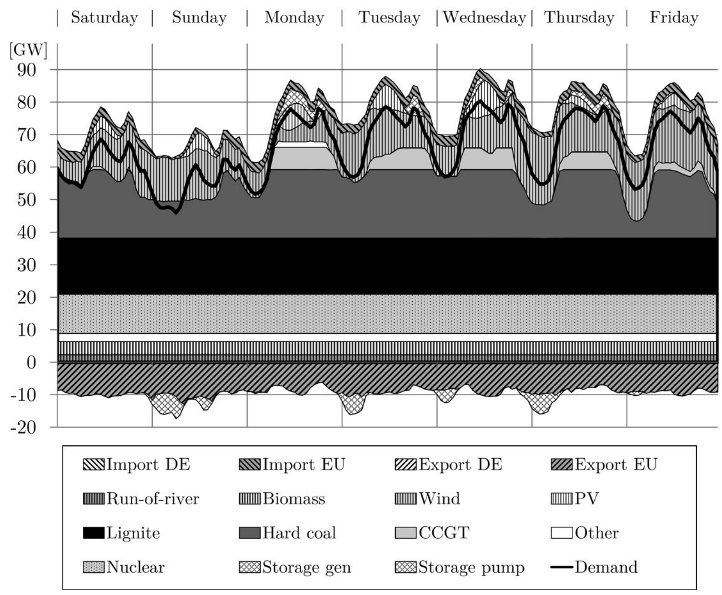
Figure 11: Zonal generation, demand, and trade for exemplary hours (h1–h4)

5.2.3 Hourly results aggregated to Germany and to zones for two weeks

The hourly changes in regional electricity market outcomes are best illustrated with results on 168 consecutive hours of one week.

The **winter week** in Figure 12 shows characteristic demand patterns with two peaks during the day. High wind generation—in the presented week wind generation increases to the end of the week—results in deviating zonal prices. Most of the time, zonal average prices only deviate to a very low extent which is caused by local congestion and price differences in very few network nodes.

(a) National generation, trade, and demand levels



(b) Average electricity price, zonal deviations, and nodal extremes

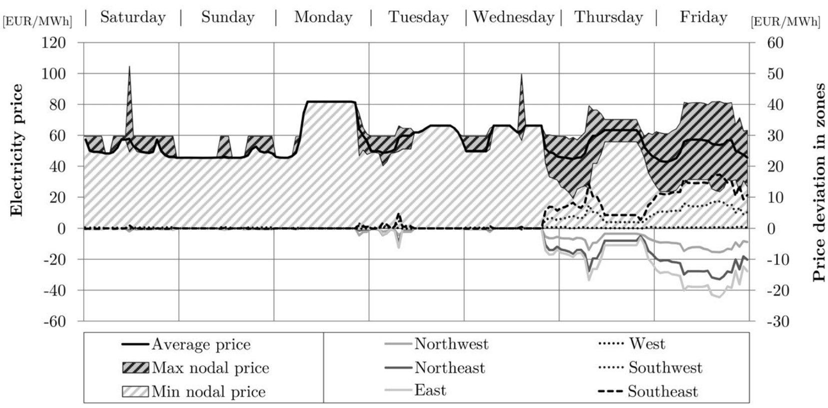


Figure 12: Hourly national results and electricity prices for one winter week

In the high wind situation on Friday, nodal prices vary between 20 EUR/MWh and 80 EUR/MWh. The average price in the West is almost in line with the average national price, while the average zonal price in the south is higher with up to +9 EUR/MWh in the Southwest and +17 EUR/MWh in the Southeast. Average zonal prices are lower in the other zones with maximum deviation of -8 EUR/MWh in the Northwest, -16 EUR/MWh in the Northeast, and -22 EUR/MWh in the East. In 2012, renewable generation mostly replaces CCGT generation during the day and hard coal during the lower demand in the night and at weekends.

Zonal aggregation in Figure 12 indicates that storage, mainly located in the Southwest and East, operates on a night off-peak pumping to day-peak generating schedule. Photovoltaics covers peak demand in the Southeast on some days (Monday to Wednesday) while trade flows within Germany are directed from north to south and exports to neighboring countries occur in the southern zones and in the East. In the high wind situation on Friday, the marginal generation technology remains hard coal in the (South)west and CCGT in the Southeast, explaining the higher zonal average prices of all nodes. In the northern zones, lower zonal prices are the result of hard coal plants being completely replaced by wind generation in off-peak hours and only operating partly during the day. Different marginal generation technologies on a regional level indicate internal congestion in the German transmission network.

The **summer week** has only one daily peak demand around noon which is in the same range as peak load in the winter week (Figure 14). Conventional generation is about 10 GW lower due to the assumption on lower seasonal availability factors. This gap is closed by photovoltaics which correlates well with demand and, compared to wind, has a more predictable daily generation pattern. While there can be some nodes with higher and lower nodal prices, the average zonal electricity prices tend to deviate less during the summer season.

The zonal aggregation in Figure 15 reveals the impact of photovoltaics in the southern zones and regional characteristic of wind generation with increasing output during evening hours in the coastal regions. North to south trade flows are reduced significantly resulting in lower regional imbalances in supply and demand and less network congestion. Pumped-storage hydroelectric plants in the Southwest and East produce less at peak demand. Instead, they supply electricity in evening hours with lower absolute demand but higher residual load levels, considering higher photovoltaic generation during peak demand. In 2012, photovoltaic capacity is not yet sufficient to result in excess supply and low electricity prices during the day which could be used for a second daily pumping and generating cycle for pumped-storage plants.

All in all, the two weeks are not representative for the winter and the summer season. They include some seasonal characteristics in demand patterns and general trends in renewable availability. However, both, photovoltaic and wind generation are affecting the electricity system over the entire year with varying hourly levels. Their (regional) impact also depends on their combined hourly and (regional) availability and their correlation to electricity demand levels in the respective hours.

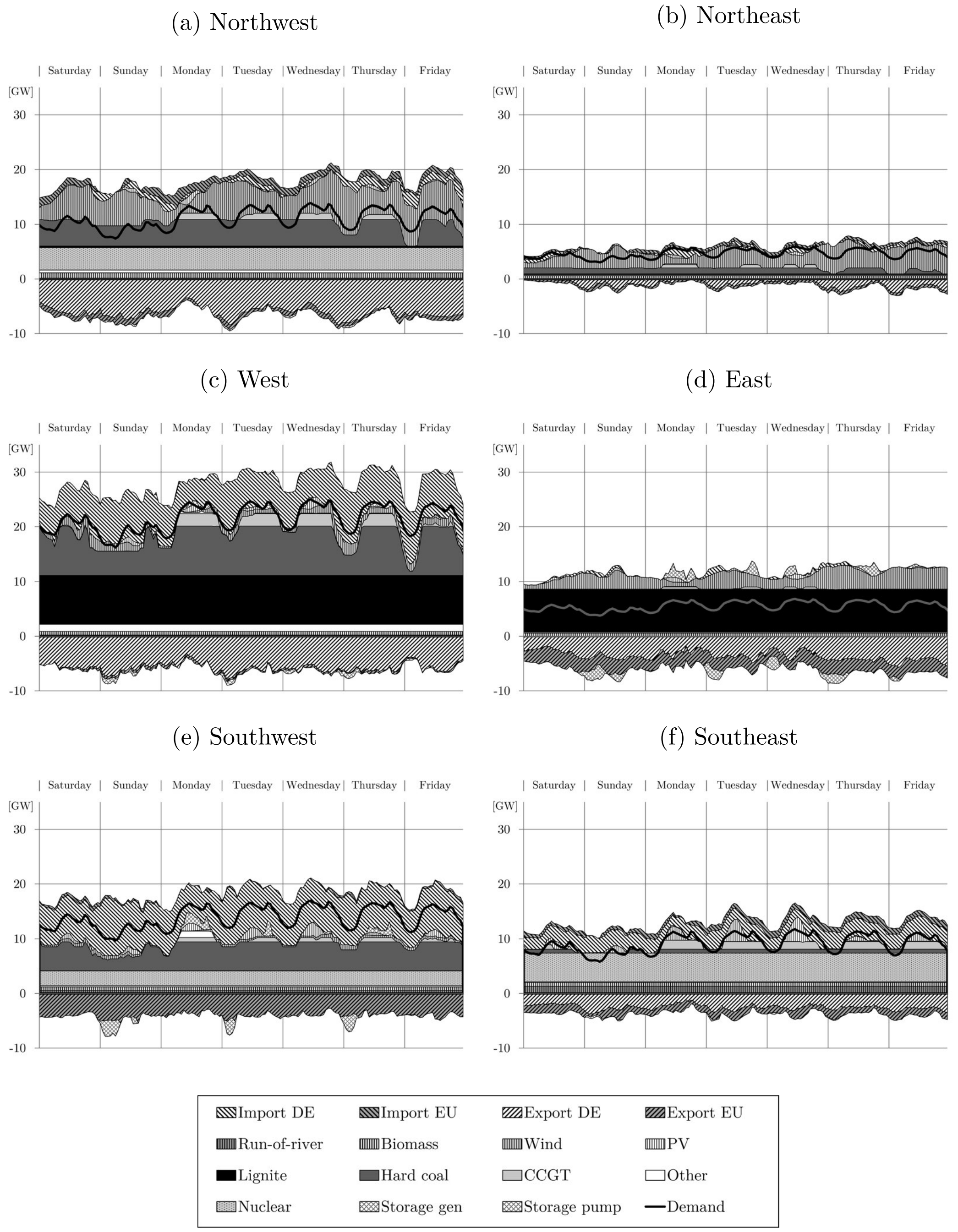
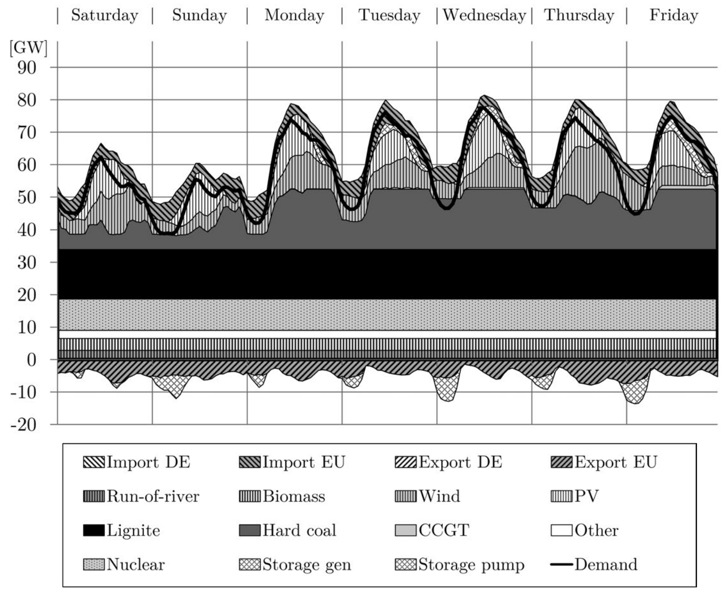


Figure 13: Zonal generation, demand, and trade for one winter week

(a) National generation, trade, and demand levels



(b) Average electricity price, zonal deviations, and nodal extremes

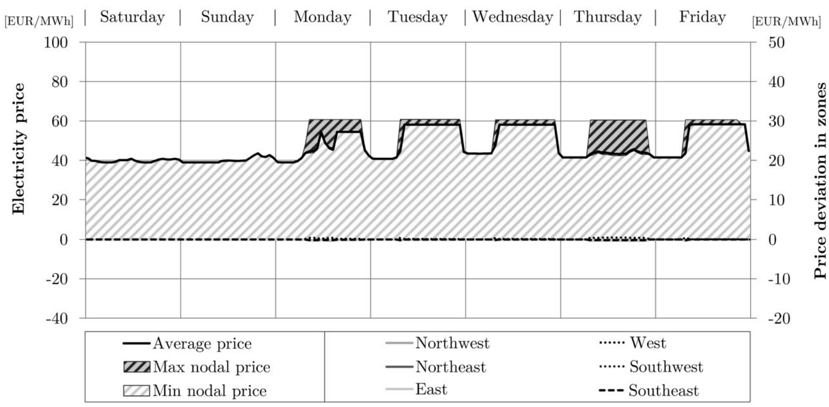


Figure 14: Hourly system state and electricity prices of one summer week

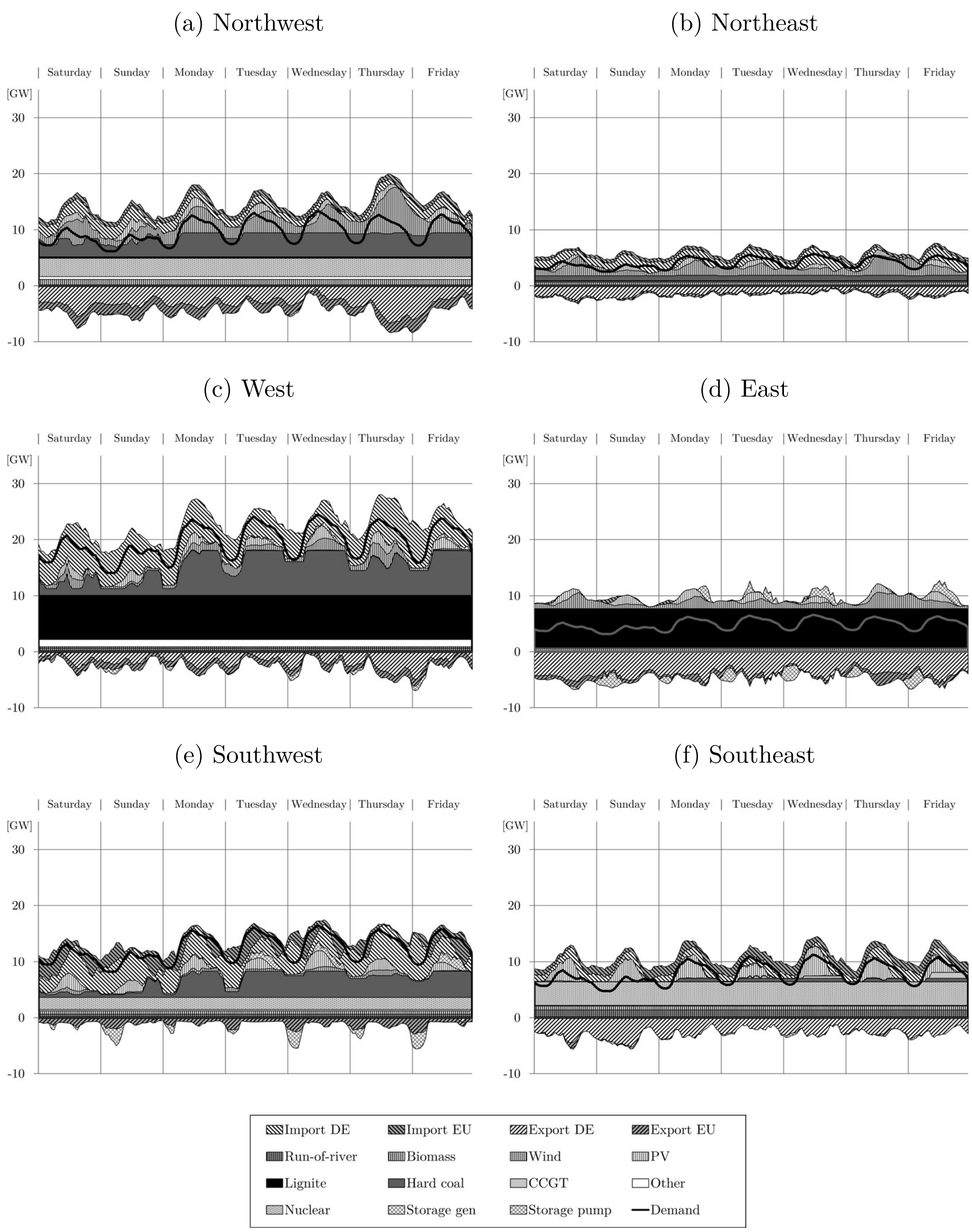


Figure 15: Zonal generation, demand, and trade for one summer week

5.2.4 Annual zonal results on generation, trade, and demand

The annual figures on generation, trade, and demand in Table 4 provide an understanding of the regional characteristics of the system.

[TWh]	**North-west**	**North-east**	**West**	**East**	**South-west**	**South-east**	**Sum**
Nuclear	32.4	0.0	0.0	0.0	21.4	41.6	95.4
Lignite	2.5	1.3	73.7	65.1	0.0	0.0	142.6
Hard coal	35.9	8.4	59.3	0.0	35.4	4.4	143.4
Natural gas	5.9	2.3	11.5	1.7	5.3	7.5	34.2
Other	4.5	1.5	11.4	1.5	2.0	1.1	21.9
Storage	0.3	0.0	1.0	3.4	2.6	0.4	7.7
Hydro	0.6	0.1	2.2	1.0	5.5	12.4	21.8
Biomass	9.4	5.3	5.7	4.0	5.4	6.2	36.0
Wind	21.5	11.0	6.2	9.0	2.5	0.4	50.5
PV	3.2	2.1	3.8	3.2	5.2	8.9	26.4
Generation	116.0	31.9	174.7	88.9	85.5	82.7	579.8
Import DE	8.1	14.2	38.6	0.2	38.5	8.1	110.5
Export DE	-25.6	-8.2	-21.7	-32.5	-0.3	-3.2	-110.5
Import EU	8.4	3.2	0.1	0.9	13.2	10.8	33.9
Export EU	-14.3	-2.3	-8.8	-6.9	-17.2	-22.2	-52.5
Trade balance	-23.4	7.0	8.4	-38.3	34.2	-6.4	-18.6
Storage load	0.4	–	1.4	4.5	3.5	0.6	10.3
Demand	92.1	38.9	181.8	46.1	116.3	75.8	550.9
Final demand	92.6	38.9	183.1	50.6	119.7	76.3	561.2

Table 4: Model results on generation output for six zones in 2012

Compared to national statistics, the spatial disaggregation to six zones reveals an uneven distribution of annual electricity generation of conventional and renewable technologies and of electricity demand:

- the Northwest has one third of total nuclear generation, which is complemented by hard coal generation of the same level. With half of the German wind and substantial biomass generation, 37% of zonal demand is covered by renewables. Together, conventional and renewable generation prevails in 23.4 TWh of annual excess in supply;

- the Northeast has the highest renewable share with 48% of demand. Total renewable output is, however, only half that of the Northwest and, due to the zones low conventional generation, it has to import 18% (7 TWh) of its electricity consumption;

- the West is the zone with the largest share of electricity demand in Germany (33%) but it has an even higher share of fossil generation output in Germany (46%). As its renewable share is the lowest of all zones with only 10%, annual electricity generation is 8.4 TWh short of demand;
- in the East, demand is less than 60% of the zone's generation making it the region with highest export level (38.3 TWh). Supply is characterized by more than 70% in lignite generation, about 20% in renewable generation, and pumped-storage operation;
- the Southwest is the zone with the second-largest demand in Germany (21%), for which it has to import almost one third (34.2 TWh). Generation from hard coal covers about 30%, nuclear 18%, and renewables 15% of demand;
- the Southeast covers 55% of demand with nuclear and 10% with gas-fired generation. The highest hydro and PV levels of the six zones result in 36% of demand being supplied from renewables. Annual generation exceeds demand by 6.4 TWh.

5.2.5 Annual inter-zonal and cross-border flows

The results of hourly line flows on individual transmission lines can be used to determine the cross-zonal physical flows. Figure 16 illustrates annual electricity flows, using bright patterns for cross-zonal flows within Germany and dark patterns for cross-border flows with neighboring countries. The black bars in the center show that the annual net flow balances with neighboring countries are lower than those within Germany (gray bars).

The results on physical exchange with neighboring countries reflect the input parameter on cross-border flows. Except for the Northeast with almost an even balance and the Southeast with 4.9 TWh in imports, Germany has a trade surplus between 4.0–8.5 TWh in each of the other zones. Absolute cross-border flows are higher than netted cross-border flows in the Northwest and the Northeast with imports from Scandinavia and exports to the Netherlands and Poland. In the two southern zones, the Southwest has an additional 13.2 TWh in cross-border flows with mostly imports from France and Switzerland and exports to Austria, Switzerland, and Luxembourg; in the Southeast, physical flows indicate imports from the Czech Republic and exports to Austria.

The physical flows within Germany are results of the model optimization. The West and the Southwest have large net import flows from the other German zones but net export flows to neighboring countries. The opposite case holds for the

Southeast with net outflows within Germany. In internal trade, the East mostly exports (32.5 TWh) and the Southwest mostly imports (38.5 TWh), while the other zones show import and export flows. The Northeast imports 13.9 TWh from the East and exports 8.1 TWh to the Northwest, which itself exports 25.4 TWh to the West. The West has the highest exchange flows of all zones as it also imports from the East (8.4 TWh) and Southeast (4.6 TWh) and exports 21.0 TWh to the Southwest. The Southeast imports from the East (10.2 TWh) and, in addition to the flows to the West, exports 17.5 TWh to the Southwest.

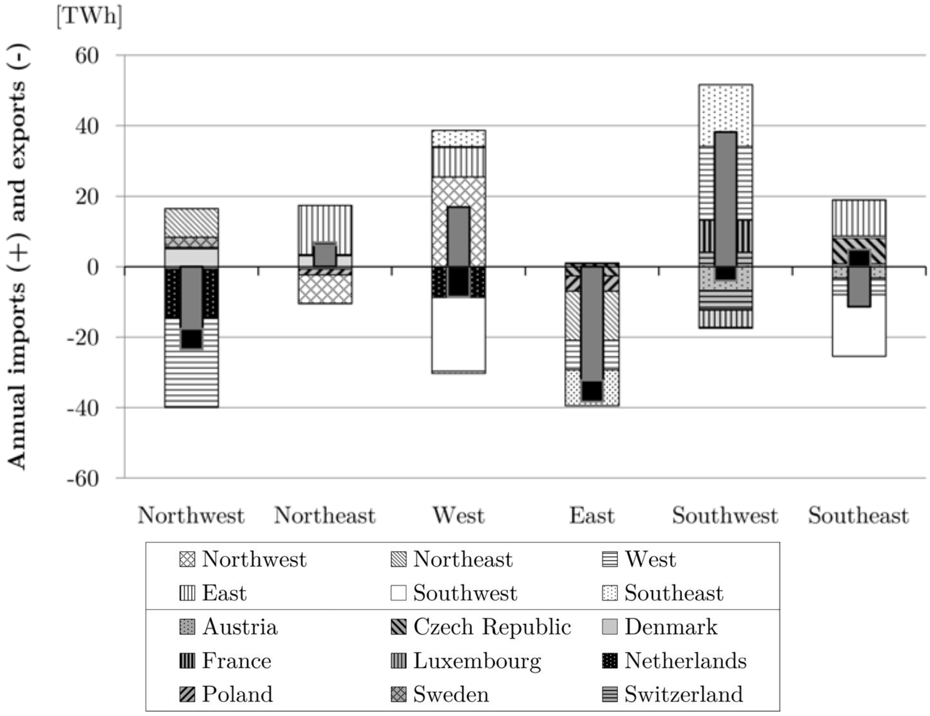


Figure 16: Annual electricity exchange with neighboring zones and countries

5.2.6 Monthly zonal supply and demand balances

Seasonal renewable generation, demand and trade patterns, and assumptions on seasonal availability of conventional power plants have strong effects on model results. Monthly results in Figure 17 show the higher conventional generation in the six winter months made possible by assumptions on seasonal availability, e.g., for nuclear and lignite generation levels. In the north, renewable generation is higher in the winter season due to large wind capacities while photovoltaic generation is dominating in the south resulting in higher levels during the summer season. Monthly conventional output indicates that mostly capacities in the West serve as marginal generators in the system and balance seasonal differences in residual demand.

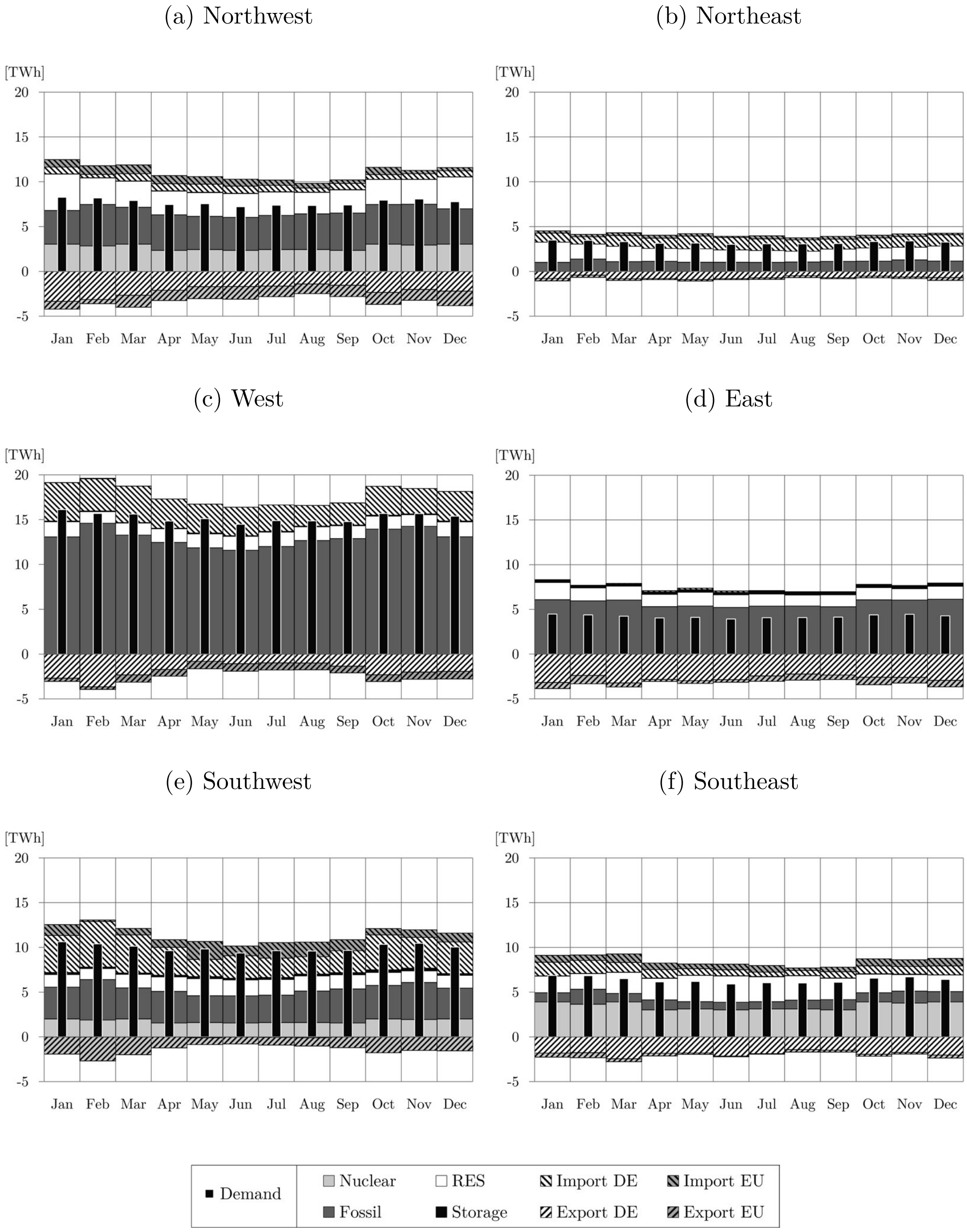


Figure 17: Zonal generation, demand, and trade levels by month for six zones

6 Discussion on limitations

The linear nodal dispatch model ELMOD-DE optimizes the variable generation costs of the power plant dispatch. Thereby, the model approach abstracts from many aspects of the electricity system. Either because detailed technical representation requires non-linear characteristics or additional assumptions on input data. The presented open source model builds upon the high-voltage network, power generation units connected to network nodes in the high-voltage transmission system, regional allocation of demand, and hourly time series for availability of generation, demand, and cross-border flows. In the following, this section describes the limitations and possible extension of the model. Thereby, the focus is not on model calibration to reproduce historic prices and quantities, but on an improved representation of the bottom-up system, focusing on input data and technical system representation.

6.1 The high-voltage network and distribution networks

The dataset represents the German high-voltage transmission system on nodal levels. In the current version, technical line characteristics are approximated with the voltage level and line length. Some of the German TSOs have published technical information on individual transmission lines, which could be used to improve the model representation of the transmission system.

The operation of the transmission network has to be n-1 secure. In the model approach, this circumstance is approximated with a 20% transmission reliability margin. There are methodologies for endogenous implementation of n-1 calculation in the model framework which could be implemented at the cost of model performance. Additional technical aspects are i) the DC load flow linearization which only reflects approximated network flows compared to the real AC flows and ii) no power flow losses. Both would require optimization over non-convex solution spaces. The model does also not account for transformers or the possibility of line switching for TSOs to alter the network topology.

A large share of small scale generation and of electricity demand is connected to lower voltage levels. Yet, the model setup connects electricity demand and generation units to transformer stations of the 220 kV or 380 kV system. Alternative approaches could be i) to replace renewable generation and demand of underlying networks of lower voltage level with vertical load at connecting transformer stations or ii) to extend the network representation with the 110 kV system.

6.2 Electricity and CHP demand

The current representation of electricity demand could be improved by a bottom-up model which elaborates in detail on spatial and temporal distribution of electricity load. Such a model could include specific data on spatial distribution of demand from large industrial consumers for different sectors. The demand of combined heat and power (CHP) is closely related to the electricity sector. In the ELMOD-DE model the deviation of coal and gas generation to historic output levels in 2012 (Table 5) may be mostly related to gas-fired CHP for district heating and industrial consumers. A simple way of correcting the output numbers would be the implementation of minimum generation levels of CHP power plants correlated to weather conditions of the respective hour. On the other side, a proper representation of the regional heat markets and their correlation with electricity markets requires their implementation in the electricity sector model as there are usually several CHP generation units and heat plants supplying one district heating network. Either way, additional CHP generation would result in additional generation output of power plants with higher variable costs than the marginal plant in the market dispatch. Thus, residual load decreases due to heat demand and operation of CHP units, market prices decrease, and generation units with lower variable costs are pushed out of the market.

6.3 Generating units and availability

Conventional capacity is represented by generating unit with its fuel, efficiency factor, and coal transport costs for hard coal plants. The linear model character prohibits the implementation of minimum load levels and efficiency factors for partial load. One technical aspect—that could be included in the linear model at the cost of model performance due to additional inter-temporal constraints—is the cost of changing output levels of conventional generating units. The seasonal availability factors make exogenous assumptions on revision times during the summer months. The model approach also abstracts from uncertainty, neglecting unscheduled outages of power plants (and of other system infrastructure).

The regional renewable availability factors for wind and photovoltaics are calculated using hourly generation levels in 2012 in the control zones of the TSOs (Table 5). They are adjusted according to monthly capacity expansion during the year and the calculated factors are adjusted to cover annual generation levels. Renewable availability factors could be improved with detailed meteorological data on hourly wind speeds and solar radiation on a high spatial resolution. National monthly availability factors for hydropower and an annual factor for biomass assumes an even band of production which neglects possible flexibility.

	Model results	Historic output range	Deviation of levels
Nuclear	95.4	94.2	+1.0
Lignite	142.6	141.5–148.6	
Hard coal	143.4	106.5–108.4	+35.0
CCGT	24.8	66.0–73.4	-35.0
Gas peaker	9.3		
Oil peaker	0.0	6.0	-6.0
Other	13.6	13.6	
Waste	8.3	4.0	
Waste RES		4.0	
Run-of-river	21.8	21.8	
Biomass	36.0	36.0	
Wind onshore	49.8	49.8	
Wind offshore	0.7	0.7	
Photovoltaics	26.4	26.4	

Table 5: Model results, historic values in 2012, and deviation in generation

7 Conclusion

This paper describes the open source model ELMOD-DE which provides a tool to evaluate the German electricity sector on nodal level of the high-voltage transmission system. The nodal pricing approach reveals the theoretical lowest-cost power plant dispatch. Contrary to today's single bidding zone in the German electricity market, the nodal dispatch model prices transmission constraints of individual transmission lines and provides hourly nodal marginal electricity prices. The power plant dispatch could also be referred to as the market result of a single bidding zone with subsequent adjustments of the market dispatch by optimal re-dispatch in hours of internal network congestion (Kunz, 2013).

The results, presented in Section 4, illustrate the wide variety of insights which can be derived from the model framework. Nodal and hourly results can be aggregated by space and time to discuss the regional characteristics of the German electricity sector. On the other hand, nodal hourly results indicate that system states are very specific—they are dependent on regional demand, regional renewable availability, etc.—and every aggregation of results weakens the precision of insights.

The nodal model character allows techno-economic analyses on e.g., congestion management schemes and on investment in generation, storage, and transmission.

Other applications could be the evaluation of renewable scenarios in the context of the Grid Development Plan (NEP), the nuclear phase-out, or the reduction in fossil power generation.

For the discussion of model insights one should always be aware of the model approach with its implication on results and its limitations. While the nodal system representation provides a high level of spatial granularity, it does not represent today's market design. Restricting the model scope to Germany and fixing cross-border flows to historic values of 2012 abstracts from the effects of market adjustments in neighboring countries to changes in the German system. Also, the linear model character does not consider all technical constraints and the model setup abstracts from CHP representation. On the other hand, all input parameters are derived from publicly accessible sources with a high degree of transparency, both on the dataset and the model code. This allows straightforward adjustments and extensions to the open source model to address a wide variety of research questions.

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