Low-carbon transformation of the German and European Electricity Systems

Modeling market implications and infrastructure investments

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Zusammenfassung

Diese Dissertation befasst sich mit der Transformation zu einem kohlenstoffarmen deutschen und europäischen Stromsektor. Mit technisch-ökonomischen Stromsektormodellen werden Fragen des Marktdesigns und Infrastrukturinvestitionen untersucht.

Der erste Teil der Arbeit befasst sich mit dem deutschen Stromsektor. Das erste Kapitel beschreibt das knotenscharfe Kraftwerkseinsatzmodell für das deutsche Stromsystem ELMOD-DE, das auf der DC-Lastflussberechnung beruht. Der zugehörige Programmcode und der stündliche Datensatz für 2012 sind im März 2016 veröffentlicht worden, um mehr Transparenz in die politikorientierte Stromsektormodellierung zu bringen. Das folgende Kapitel nutzt ELMOD-DE zur Analyse einer nördlichen und einer südlichen Preiszone im deutschen Strommarkt. Als Ergebnisse werden Einflüsse auf Redispatch, Abweichungen zonaler Preise und Verteilungseffekte diskutiert. Das dritte Kapitel erweitert ELMOD-DE zu einem gemischt-ganzzahligen Modell und betrachtet für die Jahre 2024 und 2034 knotenscharfe Investitionen in Gaskraftwerke, in Pumpspeicher und in Gleich- und Wechselstromleitungen.

Der zweite Teil der Arbeit besteht aus drei Kapiteln zum Thema Netzausbau. Das erste Kapitel befasst sich mit strategischen Netzinvestitionen aus der Perspektive verschiedener Staaten. Mittel eines spieltheoretischen Modells werden dominante Strategien grenzüberschreitender Netzinvestitionen untersucht sowie der Einfluss der Kostenallokation und die Änderung der nationalen Wohlfahrten. Das nachfolgende Kapitel betrachtet das Problem sich ändernder Netzengpässe im Verlauf der Transformation. Mit einem mathematischen Optimierungsproblem mit Gleichgewichtsnebenbedingungen werden verschiedene regulatorische Ansätze und deren Auswirkung auf Netzinvestitionen getestet. Das letzte Kapitel betrachtet Netzinvestitionen in das europäische Höchstspannungsnetz bis 2050 in einem gemischt-ganzzahligen Optimierungsproblem. Es werden Investitionen in Gleich- und Wechselstromleitungen für drei Szenarien optimiert und die Ergebnisse mit der Energy Roadmap 2050 verglichen.

Schlüsselwörter: Stromsektor, Energiewende, Deutschland, Europa, Kraftwerkseinsatzmodell, Open Source, Preiszonen, Netzausbau, Kooperation.

Abstract

This dissertation addresses the low-carbon transformation of the German and European electricity sectors. It applies techno-economic electricity sector models to research questions on market design and infrastructure investment.

The first part consists of three chapters on Germany. It starts with a chapter on the nodal dispatch model for the German electricity system (ELMOD-DE) which implements the DC load flow approach. In March 2016, the respective model source code and a nodal and hourly dataset for 2012 were published to support the effort of increasing transparency in policy-oriented energy sector modeling. In the following chapter, ELMOD-DE is applied to analyze the effects of one northern and one southern bidding zone on the German electricity market. The results discuss the effect on re-dispatch levels, deviations in zonal prices, and distributional effects. The third chapter extends ELMOD-DE to a mixed-integer linear program (MILP) to determine nodal investment for renewable integration in gas-fired power stations, in pumped-storage hydroelectric plants, and in HVAC and HVDC transmission lines for the years 2024 and 2034.

The second part consists of three chapters on transmission investment. It starts with a chapter on national-strategic decisions on network expansion. A game theory model determines stable expansion strategies, the effect of cost-allocation schemes, and changes in national welfare levels as results of cross-border transmission investment. The following chapter raises the issue of dynamic changes in network congestion during the low-carbon transformation. It applies a mathematical problem with equilibrium constraints (MPEC) to test different regulatory approaches and their effect on network investment. The last chapter, again, uses a MILP to determine network investment for the European transmission network up to 2050. The nodal model optimizes investments in HVDC lines and in the existing HVAC network for three different scenarios, comparing the results to the Roadmap 2050.

Keywords: Electricity sector, system transformation, Germany, Europe, nodal dispatch model, open source, bidding zones, transmission expansion, cooperation.

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List of Abbreviations

AC	Alternating Current
ACER	European Agency for the Cooperation of Energy Regulators
BCE	Base Case Exchange
BDEW	Bundesverband der Energie- und Wasserwirtschaft (German Association of Energy and Water Industries)
BMU	Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety)
BMWi	Bundesministerium für Wirtschaft und Energie (German Federal Ministry for Economics Affairs and Energy)
BNetzA	Bundesnetzagentur (German regulator)
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCTS	Carbon Capture, Transport, and Storage
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSP	Concentrated Solar Power
CWE	Central Western Europe
DC	Direct Current
DIW Berlin	Deutsches Institut für Wirtschaftsforschung (German Institute for Economic Research)

DSM	Demand Side Management
EC	European Commission
ECF	European Climate Foundation
EEG	Erneuerbare-Energien-Gesetz (German Renewable Energy Act)
EEX	European Energy Exchange
EMF	Energy Modeling Forum
EnLAG	Energieleitungsausbaugesetz (Energy Line Extension Act)
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEC	Equilibrium Problem under Equilibrium Constraints
EU	European Union
EU ETS	EU Emissions Trading System
EURELECTRIC	The Union of the Electricity Industry
EWEA	The European Wind Energy Association
FTR	Financial Transmission Right
GAMS	General Algebraic Modeling System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
HRV	Hogan, Rosellón, and Vogelsang
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
IEM	Internal Energy Market
ISO	Independent System Operator
ITC	Inter TSO-Compensation
ITSO	Independent Transmission System Operator
MCP	Mixed Complementarity Problem

MILP	Mixed-Integer Linear Problem
MIQCQP	Mixed-Integer Quadratically Constrained Quadratic Problem
MISO	Midcontinent Independent System Operator
MPEC	Mathematical Program with Equilibrium Constraints
NEP	Netzentwicklungsplan (Grid Development Plan)
NIMBY	“Not-In-My-Backyard”
NREAP	National Renewable Energy Action Plan
NTC	Net Transfer Capacity
NUTS	Nomenclature des Unités Territoriales Statistiques
NYISO	New York Independent System Operator
OECD	Organisation for Economic Co-operation and Development
OCGT	Open Cycle Gas Turbine
PTDF	Power Transmission Distribution Factor
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PV	Photovoltaics
QCP	Quadratically Constrained Problem
RES	Renewable Energy Sources
TSO	Transmission System Operator
Transco	Transmission Company
TRM	Transmission Reliability Margin
TTC	Total Transfer Capacity
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
US	United States
VDE	Verband der Elektrotechnik Elektronik Informationstechnik

Units:

kV kilovolt

MW megawatt

GW gigawatt

MWh megawatt hour

GWh gigawatt hour

TWh terawatt hour

t metric ton

List of Mathematical Notation

$d \in D$	... direct current (DC) transmission lines in the network
$i \in I$	... generation technologies
$l \in L$	... alternating current (AC) transmission lines in the network
$n, k \in N$	... network nodes
$p \in P$	... generating units of power plant
$s \in S$	... pumped-storage hydroelectric plants
$t \in T$	... dispatch time periods (hours)
$\tau, \tau\tau \in \mathrm{T}$	... regulatory periods (years)
$z, x \in Z$	... zones (e.g. bidding zones)
$d \in D^+$	... subset of DC transmission lines for new investments
$n, k \in N_z$	... node-to-zone mapping
$p \in P_n$	... power plant generating units-to-node mapping
$p \in P_z$	... power plant generating units-to-zone mapping
$p \in P^0$	... subset of power plant generating units for initial plants
$p \in P^+$	... subset of power plant generating units for new investments
$s \in S_n$	... pumped-storage hydroelectric plants-to-node mapping
$s \in S_z$	... pumped-storage hydroelectric plants-to-zone mapping
$s \in S^0$	... subset of pumped-storage hydroelectric plants for initial plants
$s \in S^+$	... subset of pumped-storage hydroelectric plants for new investments

Table 1: Sets and mappings for all chapters

a_{nt}	...	intercept of inverse demand function	EUR/MWh
av_{pt}^{unit}	...	availability factor of generating unit	
av_{nit}^{tech}	...	availability factor of technology at network node	
b_{nk}	...	network susceptance matrix	$1/\Omega$
$\hat{b}_l$	...	series susceptance of line	$1/\Omega$
$\hat{c}_p^{\text{unit}}$	...	marginal generation costs of generating unit	EUR/MWh
$\hat{c}_{ni}^{\text{tech}}$	...	marginal generation costs of generation technology	EUR/MWh
$\tilde{c}_l^{\text{line}}$	...	investment costs of additional capacity on AC line	EUR/MW
$\tilde{c}_l^{\text{ac}}$	...	investment costs of additional line circuit AC line	EUR
$\tilde{c}_l^{\text{acup}}$	...	investment costs of voltage upgrade AC line to 380 kV	EUR
$\tilde{c}_d^{\text{dc}}$	...	investment costs of additional line circuit DC line	EUR
$\tilde{c}_p^{\text{unit}}$	...	investment costs of power plant generating unit	EUR
$\tilde{c}_s^{\text{sto}}$	...	investment costs of pumped-storage hydroelectric plant	EUR
δ^{p}	...	private discount rate	
δ^{s}	...	social discount rate	
ϵ	...	price elasticity of demand at reference point	
$\overline{g}_p^{\text{unit}}$	...	maximum capacity of power plant's generating unit	MW
$\overline{g}_p^{+\text{unit}}$	...	maximum capacity of power plant's new generating unit	MW
$\overline{g}_{ni}^{\text{tech}}$	...	maximum capacity of technology at network node	MW
g_{pt}^{spot}	...	production of generating unit in spot market model	MW
h_{ln}	...	network transfer matrix	$1/\Omega$
im_{ln}	...	incidence matrix between line and network nodes	
im_{ln}^{ac}	...	incidence matrix between AC lines and network nodes	
im_{dn}^{dc}	...	incidence matrix between DC lines and network nodes	
m_{nt}	...	slope of inverse demand function	EUR/MWh^2

Table 2: Parameters for all chapters (Part 1)

$\overline{ls}_s$	... maximum energy storage of pumped-storage plant	MWh
$\overline{ls}_s^+$	... maximum energy storage of new pumped-storage plant	MWh
$\overline{pf}_l$	... maximum power flow of transmission line	MW
$\overline{pf}_l^0$	... maximum power flow of initial transmission line	MW
$\overline{pf}_l^{\mathrm{ac}}$	... maximum power flow of AC transmission line	MW
$\overline{pf}_d^{\mathrm{dc}}$	... maximum power flow of DC transmission line	MW
$\overline{pf}_{zx}^{\mathrm{ntc}}$	... maximum net transfer capacity (NTC)	MW
$\overline{pf}_l^+$	... maximum power flow of new transmission line	MW
$\overline{pf}_l^{+\mathrm{ac}}$	... maximum power flow of new AC transmission line circuit	MW
$\overline{pf}_l^{+\mathrm{acup}}$	... maximum power flow of AC transmission line voltage upgrade	MW
$\overline{pf}_d^{+\mathrm{dc}}$	... maximum power flow of new DC transmission line circuit	MW
$pf_{nt}^{\mathrm{export}}$	... cross-border export flow	MW
$pf_{nt}^{\mathrm{import}}$	... cross-border import flow	MW
$\overline{ps}_s$	... maximum capacity of pumped-storage plant	MW
$\overline{ps}_s^+$	... maximum capacity of new pumped-storage plant	MW
ps_{st}^{spot}	... result for pumped-storage operation in spot market model	MW
q_{nt}	... electricity load	MW
r	... return on costs (cost-based regulation)	
$\overline{r}_{nit}^{\mathrm{tech}}$	... maximum renewable capacity	MW
r_{nit}^{spot}	... generation of renewable technology in spot market model	MW
$voll$	... value of lost load	EUR/MWh
$\hat{y}$	... scaling factor of hours to one year	
x_l^0	... initial line reactance	Ω
Π	... Transco profit	EUR

Table 3: Parameters for all chapters (Part 2)

c	... objective value of the respective costs	EUR
c^{rd}	... objective value of re-dispatch costs (re-dispatch model)	EUR
c^{spot}	... objective value of dispatch costs (spot market model)	EUR
fix_{τ}	... fix tariff part	EUR
$fix_{\tau}^{\mathrm{CostReg}}$	... fix tariff part in case of cost-based regulation	EUR
$fix_{\tau}^{\mathrm{HRV}}$	... fix tariff part in case of HRV regulation	EUR
$\lambda 1_{lt\tau}$	... shadow price of positive line capacity constraint	EUR/MWh
$\lambda 2_{lt\tau}$	... shadow price of negative line capacity constraint	EUR/MWh
$\lambda 4_{nit\tau}$	... shadow price of generation capacity constraint	EUR/MWh
$\lambda 5_{t\tau}$	... shadow price of slack constraint	EUR/MWh
ni_{nt}	... net grid input of transmission lines	MW
ni_{nt}^{ac}	... net grid input of AC transmission lines	MW
ni_{nt}^{dc}	... net grid input of DC transmission lines	MW
$p_{nt\tau}$	... shadow price of market clearing constraint	EUR/MWh
pf_{lt}	... power flow on transmission line	MW
pf_{lt}^{ac}	... power flow on AC transmission line	MW
pf_{dt}^{dc}	... power flow on DC transmission line	MW
pf_{zxt}^{ntc}	... cross-zonal trade flows in spot market model	MW
θ_{nt}	... phase angle difference in respect to slack bus $\hat{n}$	
w	... objective value of total system welfare	EUR

Table 4: Variables for all chapters

ens_{nt}	... load not covered by generation	MW
g_{pt}^{unit}	... generation of generation unit	MW
g_{nit}^{tech}	... generation of generation technology at network node	MW
g_{pt}^{spot}	... generation of power plant block in spot market model	MW
g_{pt}^{+}	... ramped up of power plant block in re-dispatch model	MW
g_{pt}^{-}	... ramped down of power plant block in re-dispatch model	MW
ls_{st}	... storage content of pumped-storage plant	MWh
$\overrightarrow{ps}_{st}$	... generation of pumped-storage plant	MW
$\overleftarrow{ps}_{st}$	... pumping of pumped-storage plant	MW
r_{nit}^{tech}	... generation of renewable technology	MW
r_{nit}^{spot}	... generation of renewable technology in spot market model	MW
r_{nit}^{+}	... ramped up renewable generation in re-dispatch model	MW
r_{nit}^{-}	... ramped down renewable generation in re-dispatch model	MW
i_{l}^{line}	... transmission investment of additional line capacity	
i_{l}^{ac}	... transmission investment of additional AC line circuit	
i_{l}^{acup}	... transmission investment of AC voltage upgrade to 380 kV	
i_{d}^{dc}	... transmission investment of additional DC line circuit	
i_{p}^{unit}	... generation investment of additional generating unit	
i_{s}^{sto}	... storage investment of additional pumped-storage plant	

Table 5: Positive and binary/integer variables for all chapters

Chapter 1

Introduction: The low-carbon transformation in the electricity sector

1.1 Motivation

At the time I started researching the electricity sector, the main discussions were all about carbon capture and storage (CCS), concentrated solar power (CSP), and super grids and in my job interview to become a research assistant at the TU Dresden in 2008, Prof. Christian von Hirschhausen asked me how to supply the United States with CSP from Arizona. Obviously, times have changed. The acceleration of the low-carbon transformation, along with many new and some returning questions and some surprises along the way, has been a constant source of motivation to write this dissertation.

The low-carbon transformation of the European electricity system is one of the early stages on the long road to reversing severe climate change. It can therefore become a role model for other regions and sectors. To be successful, stakeholders at European, national, and local levels have to develop solutions to obstacles and resistance which might evolve during the transformation process. The low-carbon transformation fundamentally challenges technical characteristics of the electricity system and has strong implications for market design and infrastructure requirements. It also has to consider the multilateral context of the European market and the interests of various stakeholders, which increase the complexity in finding solutions in the presence of distributional effects:

- following the United Nations conference on climate change (Paris, in 2015), the low-carbon transformation of the global economy will have to be accelerated to limit severe climate change. The low-carbon transformation of the European energy sector could set a successful example to be followed by other regions;
- as of today, wind and solar power are the only technically and economically mature low-carbon technologies with the potential to satisfy European electricity demand. However, their potential is not evenly distributed and their output level is subject to temporal variations. Rapidly increasing their share in conventional electricity systems will result in spatial and temporal challenges for their market and system integration;
- the low-carbon transformation eventually replaces the largest part of fossil and nuclear power generation, resulting in a system designed to serve the characteristics of variable renewable energy sources (RES). In the meantime, the conventional generation fleet is not phased-out at the same speed as the evolution of the new system. This inevitable overlap causes conflicting interests—examples are an oversupply in the market, competition for transmission infrastructure,

and different ideas on market design—putting at risk the smooth transition from a conventional to a RES-based electricity system;

- national visions on the low-carbon transformation and its scheduled timeline increase the structural differences in the neighboring national electricity systems. At the same time, European regulation on the Internal Energy Market (IEM) demands stronger physical integration of national electricity systems with additional investment in cross-border transmission lines.

This description highlights important aspects of the low-carbon transformation in the electricity sector. It paints a picture with a strong dynamic component and a complex mix of interests which frames the six following chapters of my dissertation.

Looking back, my intrinsic motivation to write this dissertation has not only evolved from my curiosity in Operations Research or technological aspects of renewable integration. My background as an industrial engineer, and the opportunity to work as a research assistant at the Chair of Energy Economics and Public Sector Management (TU Dresden) during my time as a graduate student, allowed me to form different perspectives on the energy sector and its complex and sometimes contrary developments. I was given the opportunity to work on Real Options Theory for investment in hard coal power plants with the option to extend them with carbon capture and storage technology, on stochastic dynamic programming, on an economic analysis of vertical integration in the Italian electricity and gas markets, on energy systems and climate change models, and also on electricity sector models.

My first step towards focusing on electricity sector modeling was my involvement in a study project at the TU Dresden in 2008. It analyzed the initial Desertec concept, which envisioned North Africa satisfying substantial amounts of European electricity demand through solar power. The study project determined favorable corridors for high-voltage direct current (HVDC) interconnectors, but also raised questions about the Eurocentric and top-down nature of the initial Desertec vision (Egerer et al., 2009). This tendency to ignore the complex distribution of stakeholder interests, especially at regional level, is widespread in European and national concepts for the low-carbon transformation of the electricity sector. Consecutive projects at the end of my time as a graduate student addressed this issue by applying electricity sector modeling to national-strategic investment in cross-border transmission capacity and on distributional effects of investment in different topologies of a hypothetical North and Baltic Seas Grid.

At the beginning of my time as a doctoral student at the TU Berlin in 2011, I followed up with research on network planning and transmission investment in Germany. This work allowed me to gain an insight into the public perception of transmission projects (there is a strong NIMBY issue at the local level) and its influence on network planning. Public opposition eventually resulted in the partial underground cabling of new transmission lines and the consideration of HVDC technology. It was also during this time that new procedures were initiated for grid development plans in Germany (NEP) and at European level (TYNDP). The second focus of the first year of my PHD was network tarification and cost allocation at European level. During the summer of 2011, I joined the THINK team at the Florence School of Regulation (European University Institute) and participated in the project on EU Involvement in Electricity and Natural Gas Transmission Grid Tarification (Hirschhausen et al., 2012).

During this time, the foundation for this dissertation was laid out with the German part on regional pricing and infrastructure investment and the European part on transmission investment. It is my motivation for all chapters in this dissertation to elaborate on the dynamics and interactions of different developments related to the respective research question and their implications on the involved stakeholders.

The remainder of the introduction continues with an overview of electricity generation in Europe and Germany and discusses the low-carbon transformation in liberalized electricity markets with its implications on infrastructure and distributional effects. The introduction concludes with an outline of the individual chapters of the main part and lists their pre-publications and my own contributions.

1.2 Low-carbon transformation of the electricity sector

The transformation of the European electricity sector in the first half of the 21st century is necessary to phase-out carbon emissions. It is the most fundamental system transformation in the sector's recent history but far from its first one. From its beginnings, electricity generation has relied on coal-firing and hydropower. This mix was challenged by cheap oil in the 1960s/70s, followed by the nuclear dream of the 70s/80s, and the rise of natural gas in the mid-90s. Depending on the national potential in hydropower, the regional availability of fossil resources, and the decisions on energy policy, different national fuel mixes have evolved in the respective countries.

Since the early 2000s, national renewable support schemes along with the technical and economic advances they have triggered have been accelerating the large-scale deployment of renewable generation capacity in the European electricity system. Even though the speed and intensity of the process varies between countries, the large additions on the supply side put pressure on the entire conventional generation system in the integrated European market. This pressure has increased with the stagnation of electricity demand levels following the economic crises since 2008.

Perspectives on Europe and RES, nuclear, and fossil-CCTS

The electricity mix of the eight European countries with the highest electricity generation is illustrated in Figure 1.1 for absolute and relative levels in 2014. In terms of annual generation, Germany and France (about 600 TWh) are followed by the United Kingdom (UK), Spain, and Italy (about 300 TWh) and Poland, Sweden, and Norway (about 150 TWh). Carbon intensity of electricity generation varies between these countries due to different fuel mixes. Coal-firing accounts for 80% in Poland, whereas in Germany its share is 45%, complemented by 16% in nuclear, and 12% in natural gas. In the UK and Spain, the energy mix is more balanced between coal, natural gas, and nuclear, while Italy has replaced most coal with natural gas, and France relies mostly on nuclear power. The Scandinavian system stands out from the rest as its electricity demand is mostly covered by hydropower in Norway and by hydropower and nuclear in Sweden.

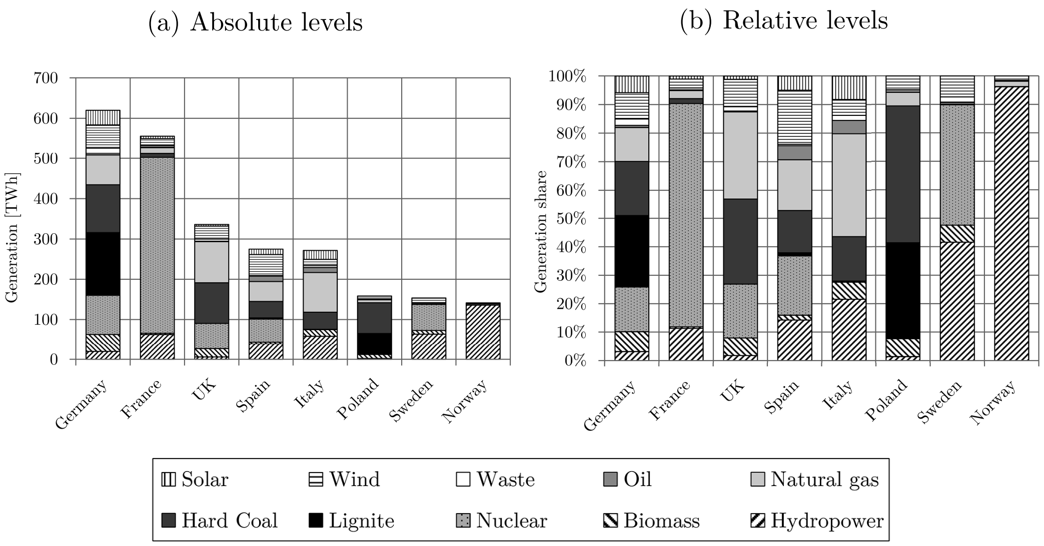


Figure 1.1: National electricity generation by technology in 2014[1]

In recent years, variable RES (i.e., wind power and photovoltaics) have received the largest share of investment in new capacity. In 2014, they provided 24% of electricity generation in Spain, 15% in Germany, and 14% in Italy.[2] By contrast, their level remained very low in Poland (5%), France (4%), and Norway (2%). For the eight countries combined, annual generation output is 2.5 times higher for wind

[1]Own illustration based on data from EC (2016).

[2]RES shares in electricity generation depend on the respective reference level. The numbers in Figure 1.1 state Eurostat data which provide gross generation by fuel type for conventional generation technologies. RES shares can deviate when compared to net generation levels or domestic electricity demand.

compared to photovoltaics.

The trajectory in the transformation of the European energy system follows the 20-20-20 goals (EC, 2008a) which set three key targets: i) a 20% cut in greenhouse gas emissions (from 1990 levels), ii) 20% of EU energy from renewables, and iii) 20% improvement in energy efficiency. For 2030, the targets were increased to: i) a reduction of at least 40% in greenhouse gas emissions compared to 1990 levels, ii) an RES share of at least 27% in energy consumption, and iii) energy savings of at least 27% compared with the reference scenario (EC, 2014a). The long-term reduction targets are described in the Energy Roadmap 2050 with 80–95% in GHG emission reduction, by the middle of the century (EC, 2011b). The electricity sector plays a central role in the realization of these targets as its decarbonization is expected at a faster pace than that of the rest of the energy sector. There are different low-carbon technologies in place to enable the transformation of the European electricity system. As of today, the most dynamic development is the expansion of wind and photovoltaic capacity, whereas the participation of carbon capture, transport, and storage (CCTS) and nuclear power has almost completely stalled.

As of today, CCTS is not available as a large scale solution in the power sector. In its 2030 policy framework, the European Commission suggests that member states with significant fossil generation should support the pre-commercialization stage of CCTS, so that it might be available in the late 2020s (EC, 2014a, p. 15). From today's perspective, this is highly unlikely.

European countries with nuclear power plants from the 1970s and 1980s are struggling with an aging fleet and must confront the question of whether to modernize them and thus extend their lifetime, or whether to eventually replace them and, if so, how. During the rise of nuclear power in the electricity sector, large state-owned utilities built power stations with the support of state subsidies and the security brought by the socialization of risks. Flamanville in France (since 2007) and Olkiluoto in Finland (since 2005) are the only two nuclear power plants (both with a capacity of 1.6 GW) which are currently under construction in the European Union. They are expected to be completed by 2018, but their completion dates have already postponed many times. The final costs are expected to be about three times higher than the initial investment budgets. The only new project currently in the late planning phase is Hinkley Point C in the United Kingdom, with a capacity of 3.2 GW. This project illustrates the extent of financial guarantees required from the state for investors to build a new nuclear power plant. In 2013, the British government, amongst other additional guarantees, agreed to pay 92.50 £/MWh plus inflation for a time span of 35 years (Gov.uk, 2013). As of late 2015, the final investment decision of the investing companies had yet to be made. Commercial operation is scheduled to start in 2023. At the same time, other countries have decided to gradually phase out their nuclear capacity (e.g., Germany and Switzerland) and plant owners have started to question the economic viability of life time extensions in the current market environment (i.e., refurbishment costs to update old nuclear power stations to modern safety standards (World Nuclear News, 2016)).

In the last few years, the low-carbon transformation has been driven by investment in renewable capacities. In 2015 alone, 12.8 GW in wind and 8.0 GW in solar capacity were connected to the European system (EWEA, 2016; SolarPower Europe, 2016). At the same time, the required subsidies for new renewable capacity significantly decreased. In 2016, Germany guarantees new photovoltaic capacity 123.1 EUR/MWh for small roof-top investment and 85.3 EUR/MWh for larger capacities, which is paid over a period of 20 years (BNetzA, 2016). The tariff level for onshore wind is even lower. The European electricity system has so far proven its resilience in integrating the rapidly growing shares of renewable generation from variable sources. However, the large capacity additions on the supply side put pressure on electricity prices and increasingly challenge the business of conventional power generators in the liberalized electricity market.

The German electricity sector

The German fuel mix in the electricity sector (Figure 1.2) illustrates, with a share of about 55%, the dominance of hard coal in western Germany until 1960, when low oil prices started to threaten its status. To protect the domestic coal industry, the German government introduced economic incentives for electricity production from coal-fired power plants (Bundesregierung, 1965). Nevertheless, oil-fired generation with 13% in 1970 and gas-fired generation with 18% in 1975 gained market shares as they satisfied increasing levels of electricity demand. After the two oil crises and the emergence of nuclear power between 1970–1985, the German system reached a mix which consisted of 31–35% in nuclear, 21–31% in hard coal, and 23–33% in lignite generation. In the 20 years between 1985 and 2005, there was little variation in relative shares. In the statistics of the re-united Germany, lignite generation and natural gas both gradually increased by 5% up to 2005, whereas hard coal shares decreased by 10%.

The first step of the development of variable renewables was the Stromeinspeisungsgesetz (Bundesregierung, 1991), which obliged the large utilities to buy renewable electricity generation from small producers for a fixed tariff. The legislation resulted from a remarkable political coalition between a delegate from the Christian Social Union in Bavaria (representing the local interests of the Bavarian small hydro producers) and the Green party (Berchem, 2006). In the 1990s, the tariff level was sufficient for limited investment in wind power in suitable locations. Most importantly, whenever contested in court, the law came out on top at both national and European level. Thus, the Stromeinspeisungsgesetz became the blueprint for consecutive laws in Germany and many renewable schemes in other countries. In Germany it was followed up by the Erneuerbare-Energien-Gesetz (EEG) in 2000 which added the priority feed-in for renewables and a national scheme allocating the subsidy costs on electricity consumption. It also increased and set technology-specific tariff levels (Bundesregierung, 2000). Since then, the EEG has been adjusted several times, whilst maintaining its core characteristics. Only recently has tendering for wind and large photovoltaic plants been tested as an alternative scheme.

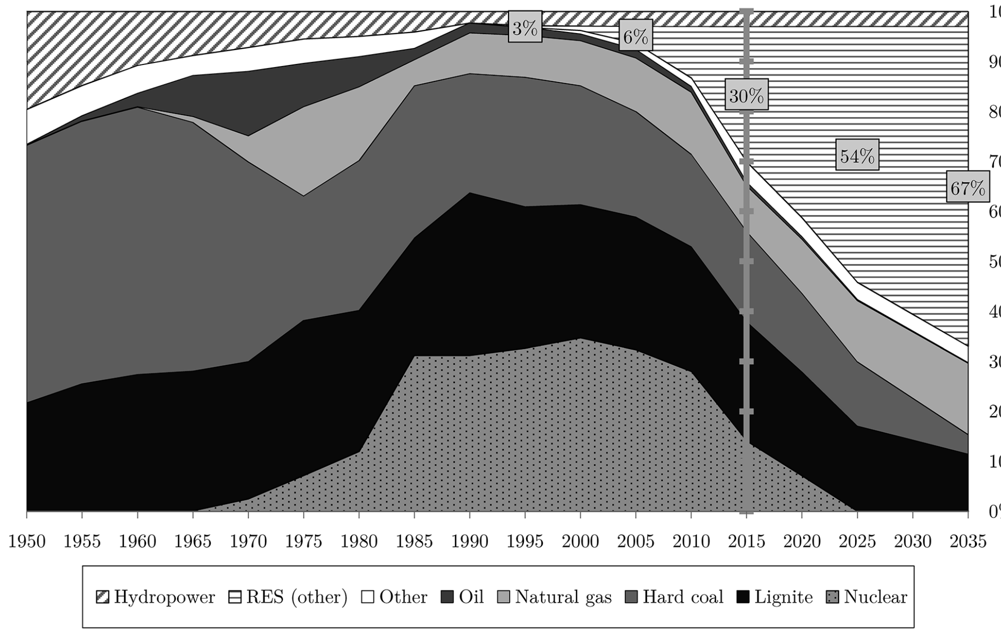


Figure 1.2: Fuel shares in gross electricity generation in Germany[3]

The EEG's effectiveness, which has resulted in continuous annual additions in onshore wind, followed by biomass, photovoltaics, and offshore wind, is illustrated in Figure 1.3. To reach the renewable volumes of the main NEP 2035 scenario (Figure 1.2) of the German Grid Development Plan (NEP), annual renewable extension could even be reduced to 75% of the average annual level of the last ten years. On average, the scenario forecasts renewable generation to increase by about 10 TWh per year.

[3]Own illustration based on data from AG Energiebilanzen e.V. (2015) and the main NEP 2035 scenario of the German NEP (50Hertz et al., 2015). The values before 2015 are interpolated in five-year steps and the ones after 2015 in ten-year steps. The completion of the nuclear phase-out in Germany is scheduled for 2022. The figure does not include Eastern Germany before 1990.

The German Energiewende stands out compared to the low-carbon transformation of other countries, but not because of its renewable investment. There are other countries with higher shares in variable renewable generation (e.g. Spain and Denmark). The Energiewende focuses not only on fast-growing renewable shares, but also on its tight schedule for the nuclear phase-out. Following the nuclear disaster in Fukushima (March 12, 2011), the older generation of nuclear power plants have been shut down (i.e., six reactor blocks with about 6.5 GW in the south and three reactor blocks with 3.6 GW in the north-west). The scheduled shut-down of the remaining nine blocks began in 2015 and will conclude in 2022. The majority of nuclear power stations are located in southern Germany. Their shut-down will increase regional scarcity in conventional generation capacity which adds to the spatial aspect of the low-carbon transformation. By 2025, renewable technologies are expected to supply more than 50% of all generation in Germany. This level is expected to increase to more than two thirds in 2035. However, the trajectory of renewable shares could be even higher due to the nuclear phase-out, emission reduction targets, and even stronger mitigation scenarios (i.e., additional substitution of lignite and hard coal).

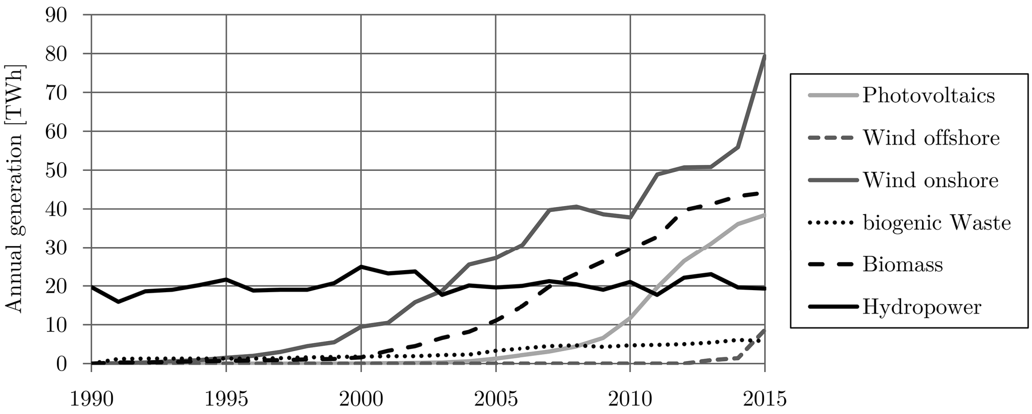


Figure 1.3: Annual renewable generation by technology in Germany[4]

Liberalized electricity markets

Market liberalization in the European electricity sector started in the mid-1990s (EC, 2003b, 2009a, 1996). It resulted in the unbundling of vertically integrated utilities, separating the competitive generation business from the transmission business. Another aspect is the non-discriminatory market access for all generators and the creation of a well-integrated single Internal Energy Market (IEM) with common market

[4]Own illustration based on data from AG Energiebilanzen e.V. (2015).

rules (EC, 2012). The European electricity market did not emerge as a mandatory pool, but as an open market with power exchanges.

The shortfalls of zonal market design compared to nodal pricing was already known at the time the European market liberalization started (Hogan, 1999). The zonal representation assumes equal market prices for all locations within a given zone, even in the case of physically infeasible market results due to internal network congestion. Still, the implementation of a nodal pricing scheme in the European electricity market has never been envisaged (Ehrenmann and Smeers, 2005). Contrary to nodal pricing, national bidding zones with marginal pricing emerged, and implicit market coupling has been gradually introduced between them. Therefore, electricity can be traded freely in the case of sufficient network capacity by paying a one-time network access fee in the country of origin. This procedure succeeded in overcoming the issue of pancaking, i.e., individual network access fees for all countries involved. Norway, Sweden, Denmark, and Italy have implemented multiple national bidding zones, but the national bidding zone configuration in the highly meshed network of Central Europe so far remains unchanged.

In this setting, the low-carbon transformation of the electricity sector has been initiated. The EU Emissions Trading System (EU ETS) was introduced as the main policy instrument at European level. The price signals of CO_2 certificates directly feed into the variable generation costs of fossil power plants, increasing the competitiveness of fuels with low carbon emission factor (e.g., natural gas versus coal). Due to an excess in certificates and therefore very low certificate prices below 10 EUR/t, the impact of the EU ETS on the electricity market has been very limited (EEX, 2013a).

As energy policy remains a strong national domain, the 20-20-20 goals (EC, 2008a) are translated into individual targets for each member state, the so-called National Renewable Energy Action Plan (NREAP). Their realization is subject to national policies and regulation. One objective of the low-carbon transformation is the expansion of the share of renewable generation technologies. So far, this development mostly takes place in the old world of conventional generation capacity supplying base and peak load (Stoft, 2002, chapter 1). With increasing RES shares the variable character of wind and solar generation starts to challenge this view on the electricity market. Due to variable RES, residual demand decreases in hours of high RES availability. Higher RES capacity will increasingly cut into the base load band and challenge the necessity of base load generation.

Except for transmission investment, the potential of demand side management (DSM), the availability and cost of battery technology, and investment in gas-fired backup capacity could become more important with higher RES shares.[5] The extent to which energy-only markets with marginal pricing will survive in electricity systems with very high shares of renewables has yet to be determined.

1.3 Transmission investment and distributional effects

Integrated planning of generation and transmission investment

The spatial distribution of supply and demand is an important aspect in RES-based electricity systems. There are two extreme visions for low-carbon electricity supply with strong implications on the required transmission system.

On the one hand, the idea of an optimized European system proposes the regional concentration of RES in favorable locations. Their generation output would be balanced over large areas, smoothing variability and allowing a reduction in backup capacity. While this comes at the cost of additional long-distance transmission capacities, network investment is considered a comparably low-cost solution and is more than compensated for by lower costs for RES and backup capacity. Prominent examples are the so-called super grid studies (e.g., for the integration of large shares of solar electricity from North Africa to Europe (DII, 2012, 2013; DLR, 2006) or the Solar Grand Plan for the United States (Zweibel et al., 2008)). An important factor is the real cost of transmission investment, which can be significantly higher than the plain material costs. At local level, public opposition against large transit corridors increases network costs. Higher minimum distances become necessary for new lines to gain acceptance. Recent evidence comes from Lower Saxony, a state in the northwest of Germany, where two high-voltage lines are constructed to connect power plants in the north, i.e., hard coal and (offshore) wind farms, to the large demand centers in the west and the south of Germany. It has implemented its own legislation enforcing underground cabling in case the distance of transmission corridors to residential buildings does not meet minimum requirements. In densely populated areas, transmission investment could be far from a low-cost solution for renewable integration, casting doubt on the superiority of the regional approach.

On the other hand, there is the vision of an energy system which relies on a large number of small-scale local solutions, e.g., distributed generation and smart grids with many network cells (Ackermann et al., 2009). While the cost of electricity generation is higher, it does not require additional high-voltage transmission capacity. With technological advances, small-scale generation could become more competitive (e.g., by wind turbines suitable for less favorable wind locations and further reduction in the

[5] Pratley and Farrell (2015) illustrate the low investment costs of gas-fired power capacity compared to the budget of the Hinkely Point C project.

cost of photovoltaics and for battery technology). Demand could be supplied in island networks but most local systems would still be connected to the general electricity network. In the local approach, renewable investment, local storage solution, and local provision of security of supply are more expensive than in the regional approach.

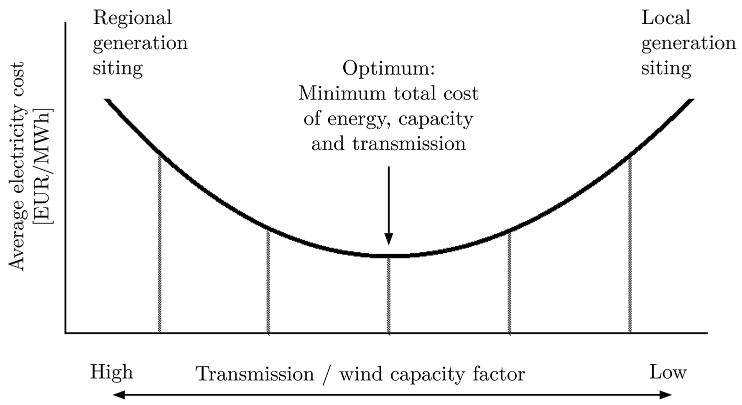


Figure 1.4: Generation siting and transmission investment[6]

The two extremes are illustrated in Figure 1.4. Neither of the two is the optimum from a system perspective. To approach the optimal combination, one has to consider the location of existing conventional, renewable, and pumped-storage capacities, together with the transmission system, regional potential and cost of additional investment, and the spatial distribution of demand. Before market liberalization, large vertically integrated utilities conducted this integrated optimization of generation and transmission in their region of supply. Today, the decisions of generation and network investment are divided between two independent types of companies. The generation business competes in the liberalized electricity market, while ownership and operation of transmission networks are handled by the transmission system operators (TSOs) and paid for by regulated returns. National price zones and renewable support schemes without a regional component do not provide incentives for investment in generation capacity in regions of scarcity. In the German NEP, network expansion has to integrate new conventional and renewable generators into the national transmission system, even if they are located far from demand centers. At European level, the 2030 targets also include the objective of higher physical integration between member states (EC, 2014a). Without any guidance for the spatial allocation of generation and demand in the system, a transformation process close to the optimum in Figure 1.4 seems to be unlikely.

[6]Own illustration based on MISO (2010, p. 7).

Distributional effects of transmission investment

An additional aspect is the distribution of rents which can hamper changes in the electricity sector. Market coupling with implicit auctions allows price convergence in case of sufficient trade capacity, but it results in zonal price differences if the trade constraint becomes binding for the market dispatch. Thus, distributional effects result from the spatial definition of bidding zones and the level of trade capacity. Figure 1.5 illustrates the implications of trade between two zones. Depending on the cost for the additional trade capacity, total system welfare might increase with additional trade capacity. At zonal level the partial price convergence due to electricity trade results in distributional effects between the two zones. Welfare increases in both zones to different extents (bright gray triangles) under the assumption of price-inelastic demand and no costs for the provided trade capacity. At the same time there are distributional effects at zonal level between consumers and producers (dark gray rectangles). The auctioned trade capacity collects a congestion rent which depends on trade volume and the zonal price difference.

Figure 1.5 illustrates the effect of trade on zonal market results and welfare distribution. In the European system, with mostly national bidding zones, this re-distribution takes place between countries, raising the question of transmission investment from a national-strategic perspective. Figure 1.6 shows the effects of different levels in network investment on national welfare levels. Investment costs for additional capacity prevents network investment to the point of full price convergence. Assuming equal sharing of investment costs and congestion rents between the two countries, the two optimal national investment strategies deviate. Country B has an incentive to invest only a little more than half the welfare-optimal transmission capacity, while country A would want to invest more than that capacity. This example illustrates that the uneven distribution of zonal investment costs and welfare benefits can become an issue for decisions on network expansion.

Investment projects in cross-border capacity are subject to bilateral agreement between the two countries involved. The general approach is an equal sharing of investment costs and congestion rents of the cross-border capacity. In case the two countries benefit to different extents, they could also negotiate other agreements. The additional cross-border trade capacity has implications on the entire market and can create winners and losers elsewhere in the system. On the other hand, the two investing countries only consider their own benefits in the investment decision. Thus, bilateral network investment is likely to diverge from the system-optimal expansion plan. This setting with national decisions on network investment can be analyzed in cooperative and non-cooperative game theory.

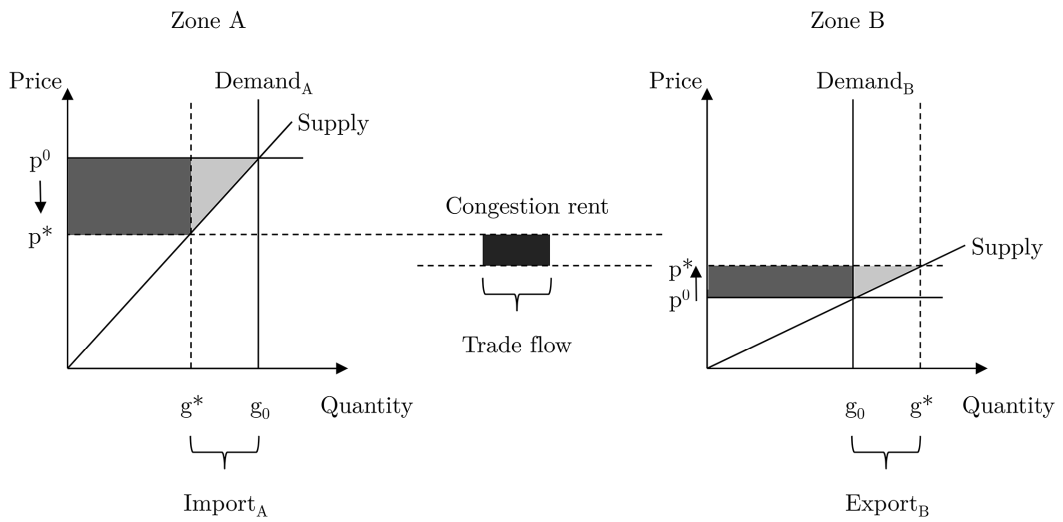


Figure 1.5: Distributional effects of market integration[7]

To provide incentives for the welfare-optimal expansion strategy at European level, some sort of ex-ante or ex-post cost-benefit allocation mechanism could help to gather support for cross-border transmission investment. At European level, Regulation (EU) 714/2009 (EC, 2009b) requests the formalization of the inter-TSO compensation (ITC) mechanism to allocate forward-looking long-run average incremental costs for losses and for infrastructure cost of all new investment and a proportion of the existing infrastructure. Initially, the ITC emerged as an alternative to cross-border transit fees (tariff pancaking). The ITC collects and allocates an annual fund of 100m EUR from/to countries according to different indicators, e.g., transit flows and net flows (Regulation (EU) 838/2010, EC, 2010). The challenge in adjusting the ITC mechanism is connected to the definition of a scheme which allocates transmission costs ex-post to those who benefit based on market results. However, it is very difficult to determine the beneficiaries of single investment projects in the European system. There is an issue of measurement, i.e., calculating re-allocation of welfare ex-post with market results. It seems unlikely that such an approach will accomplish cost-benefit allocation of network investment costs. The ITC has so far not been adjusted to provide cost-benefit allocation for network investment.

Contrary to the ITC approach, the focus has shifted to the promotion of specific projects in trans-European energy infrastructure. The development of energy networks in priority corridors by the accelerated realization of so-called projects of common interest (PCI) is promoted in Regulation (EU) 347/2013 (EC, 2013b). It states that “the costs for the development, construction, operation and maintenance of projects of common interest should in general be fully borne by the users of the

[7] Own illustration based on Hethey et al. (2015, p. 92).

infrastructure. Projects of common interest should be eligible for cross-border cost allocation when an assessment of market demand or of the expected effects on the tariffs has indicated that costs cannot be expected to be recovered by the tariffs paid by the infrastructure users" (EC, 2013b, paragraph (35)). PCIs benefit from an accelerated planning process and the possibility for financial support. EC (2013a) established the Connecting Europe Facility program to accelerate investment in the field of trans-European networks with financial support of 5.85bn EUR between 2014 and 2020. There is also a trend towards emphasizing the importance of cooperation at regional level to find regional solutions between the relevant member states of specific investment projects (EC, 2014a).

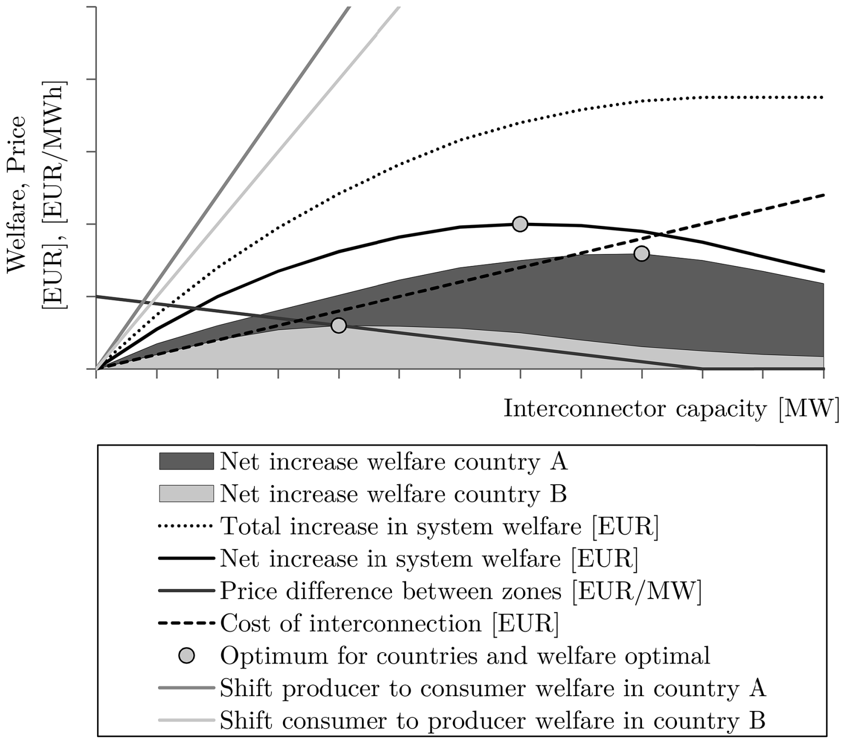


Figure 1.6: Distributional effects of different transmission capacities[8]

[8]Own illustration based on Hethey et al. (2015, p. 113) and Supponen (2011).

1.4 Overview of the thesis with contributions and publications

1.4.1 Three chapters on the German electricity sector

In this doctoral thesis, I apply techno-economic electricity sector models to research questions on market design and infrastructure investment. The dissertation consists of six chapters which have been published in academic journals, conference proceedings, and working papers. The first three Chapters 2–4 in the main part of this dissertation focus on the German electricity sector. Table 1.1 provides an overview of the pre-publications and my own contributions.

Chapter 2 – Open source electricity sector model

This chapter describes the techno-economic spatial optimization model ELMOD-DE. The model is part of the ELMOD family which includes a variety of spatial optimization models for the electricity sector. The model publications and applications of ELMOD are summarized in the literature section. ELMOD-DE employs a similar model formulation to that used by the original ELMOD version for the European system. It applies a bottom-up approach with a nodal representation of generation capacity, electricity load, and the transmission network. The objective function determines the cost-minimizing power plant dispatch. Electricity flows in the high-voltage transmission network are approximated with the DC load flow approach which allows linearized flow constraints.

ELMOD-DE relies exclusively on publicly accessible data sources, which have been used to build a georeferenced dataset on nodal level of the German electricity system, including hourly system data for the year 2012. The dataset and the model code of ELMOD-DE are published as an open source model on the DIW Berlin website and may be freely used and modified by anyone. This chapter also discusses the limitations and possible extensions of the published model version to provide an additional understanding of the utilization of ELMOD-DE. The model is implemented in the General Algebraic Modeling System (GAMS) and solved with the commercial solver CPLEX which requires the respective license. This chapter also illustrates the variety of insights that nodal dispatch models can provide for the German electricity system. This includes examples of model results for hourly nodal system states and aggregated results.

Making ELMOD-DE available as an open source model follows the publication of a data documentation in 2014 with electricity sector data for Germany and Europe for policy-relevant modeling. This is a step towards further transparency in electricity sector modeling. The low-carbon transformation of the electricity sector includes many stakeholders and receives considerable public attention. In this context, transparent and reproducible results of policy-oriented sector modeling are a prerequisite for a serious debate on the controversial issues relating to the transformation process.

Chapter 3 – Splitting the German market into two price zones

This chapter adds to the discussion on locational marginal pricing in the German electricity market. As of 2016, the price zones in the European electricity system mostly follow national borders. The internal transmission network in national bidding zones is not priced into the market. However, the market liberalization and the low-carbon transformation of the electricity sector provide arguments for regional scarcity signals in the market. Locational pricing has proven to be a sensitive topic from a political perspective. The German government argues that the single bidding zone can be retained by transmission investment, enforcing the network from north to south. Splitting the market is seen as a last resort if network investment does not advance in time.

The model application of ELMOD-DE determines the effects of splitting the single German price zone into one northern and one southern bidding area. The dispatch of today's single bidding zone faces an increasing number of hours with technically infeasible market results and requires growing volumes of re-dispatch. Bidding zones could provide regional price signals to the market by auctioning transmission capacity between the two price zones in question. This chapter analyzes the system implications and the distributional effects of the two bidding zones in the German electricity system in 2012 and 2015, respectively.

The model results for the two bidding areas indicate higher prices in the southern zone compared to lower prices in the northern zone in a limited number of hours. The distributional effects are surprisingly small due to modest average annual price differences of 0.4 EUR/MWh in 2012 and 1.7 EUR/MWh in 2015. The results also show a modest decrease in cross-zonal re-dispatch levels, particularly in 2015. However, overall network congestion increases in 2015 and results are sensitive to additional line investment, illustrating the challenge to define stable price zones in the dynamic setting of system transformation.

Chapter 4 – Generation, storage, and transmission investment

The last chapter on the German electricity sector analyzes investment scenarios for the integration of variable renewable energy sources (RES) in the German power system. Since 2012, the transmission system operators (TSOs) prepare annual Grid Development Plans (NEPs) which build upon scenarios for a time horizon of ten and twenty years. In the methodology of the NEPs, transmission investment is the preferred option for spatial system integration of RES. This assumption follows the design of the liberalized German market which does not provide regional scarcity prices (e.g., for directing generation investment and demand).

Chapter	Pre-publications and own contributions
2	Open source Electricity Model for Germany (ELMOD-DE)
	This chapter is based on: *Data Documentation 83, DIW Berlin*, Egerer (2016). The model is published along with the paper on the DIW Berlin website.
	Single author original research article.
3	Two Price Zones for the German Electricity Market: Market Implications and Distributional Effects
	This chapter is based on: *Discussion Paper 1451, DIW Berlin*, Egerer et al. (2015c). Findings and policy implications are published in the DIW Wochenbericht 9/2015, *Energiewende und Strommarktdesign: zwei Preiszonen für Deutschland sind keine Lösung*, Egerer et al. (2015a). A revised version was published as: Two price zones for the German electricity market – Market implications and distributional effects, *Energy Economics 59*, Egerer et al. (2016b).
	Joint work with Jens Weibezahn and Hauke Hermann. The model builds upon ELMOD-DE (Chapter 2). Jonas Egerer and Jens Weibezahn jointly extended the model and implemented it in GAMS. Jonas Egerer had the lead in the joint effort of writing the manuscript.
4	Power system transformation toward renewables: Investment scenarios for Germany
	This chapter is based on: *Discussion Paper 1402, DIW Berlin*, Egerer and Schill (2014b). It was presented at the 11th International Conference on the European Energy Market, 2014 (Krakow) where it is published in the conference proceedings, Egerer and Schill (2014a). A revised version was published as: Power System Transformation toward Renewables: Investment Scenarios for Germany, *Economics of Energy & Environmental Policy 3(2)*, Egerer and Schill (2014c).
	Joint work with Wolf-Peter Schill. The writing of the manuscript and including modeling insights into the paper was executed jointly. The model builds upon ELMOD-DE (Chapter 2). Jonas Egerer had the lead in the setup of the scenarios and the extension of the model including its GAMS implementation.

Table 1.1: Overview on chapters 2–4: Pre-publications and own contributions

An alternative approach, which allows for analyzing different pathways in system development, is the integrated analysis of investment in generation, storage, and transmission. The model application in this chapter implements the assumptions on renewable generation capacities in Germany as described in the NEP's main 2024 scenario and in its 2034 scenario. Alternatives for infrastructure investment (i.e., gas-fired power stations, pumped-storage hydroelectric plants, and transmission lines) are optimized with binary decision variables. The application uses an extended version of the ELMOD-DE model to determine the lowest-cost nodal system states for five cases in 2024 and 2034. Varying assumptions on renewable integration and investment in pumped-storage and transmission lines are implemented in these cases.

The model results shed light on the interaction of generation, storage, and transmission investment. The two extremes of these cases are represented by either almost complete renewable integration or a ban on transmission investment. Both show the highest system costs, one with excessive and the other with no network investment. Surprisingly, there is little to separate the other scenarios in terms of system costs. This result indicates a partial interchangeability of investment in generation, storage, and transmission, taking into account their location in the nodal system.

1.4.2 Three chapters on transmission investment

The second part of this dissertation consists of the three Chapters 5–7 which address different perspectives on investment in the transmission network (i.e., national welfare, a transmission company, and the European system level). Table 1.2 provides an overview on the pre-publications and my own contributions.

Chapter 5 – Cost sharing in transmission investment

This chapter investigates the effects of regional versus bilateral cost sharing on cross-border investment in electricity networks. Network costs are mostly retrieved through transmission tariffs at national level. The market liberalization of the European electricity sector has revealed the national character of transmission networks with comparably low cross-border capacity. The resulting limitation for electricity trade is an obstacle for competition in the European market. While stronger market integration with additional cross-border lines could reduce system costs from a European perspective, the implications at national level are less clear. Market integration by means of transmission investment has an implication on distributional effects. Some countries might benefit more from integration than others and some could even be worse off than before. In addition, the cost of cross-border transmission links has traditionally been shared equally between the two countries involved.

This chapter compares a regional cost sharing framework (proportional allocation) to the traditional bilateral framework (equal allocation). The analysis combines a numerical optimization model of the electricity market and a game-theoretical representation of the choices made by TSOs on capacity expansions as they try to maximize the respective national welfare. It includes a stylized electricity system representing six European countries.

Results reveal that national considerations prevent general agreement on the system-optimal expansion strategy. Also, there is not one single dominant strategy but several stable solutions for network investment. In the stylized example, the implementation of regional cost sharing narrows down the number of stable solutions. While cost sharing is not sufficient to result in the best expansion strategy, the average investment and welfare levels get closer to the system-optimal solution in the remaining stable strategies of the game.

Chapter 6 – Regulatory approaches for transmission investment

This chapter compares the relative performances of different regulatory approaches for transmission investment. The low-carbon transformation towards a power generation system with high renewable penetration has an effect on the utilization of the transmission network. Additional generation close to demand (e.g., distributed generation) could reduce network congestion, thus reducing the need for transmission investment. On the other hand, RES are often of variable character and show a regional concentration (e.g., wind power in coastal regions) increasing network congestion. In the case of conventional power plants located in regions of excess supply which are eventually shut down, the increased network congestion could also be a temporary effect.

This chapter applies a bi-level model formulation of a mathematical program with equilibrium constraints (MPEC) to implement incentive regulation with a combined merchant-regulatory price-cap mechanism. This so-called HRV (Hogan, Rosellón, and Vogelsang) mechanism sets incentives for welfare-optimal transmission investment in a static setting. The additional analysis examines the performance of the HRV mechanism in a dynamic setting for a stylized two-node example, assuming that a shift toward RES may have a temporary or permanent impact on network congestion. This chapter tests different weights and their relative performance to a cost-based rule and a non-regulated approach.

The results indicate that no weight provides convergence to the welfare-optimal solution, yet different weights can be favorable depending on the nature of the network situation in the transformation process.

Chapter	**Pre-publications and own contributions**
5	Regional versus bilateral cost sharing in electricity transmission expansion
	This chapter is based on: Conference Paper at the EEA 2014 conference in Toulouse, Nylund (2014).
	Joint work with Hans Nylund. The writing of the manuscript, extension of the model approach, and including modeling insights into the paper was executed jointly. Jonas Egerer had the lead in the GAMS implementation.
6	Power System Transformation toward Renewables – An Evaluation of Regulatory Approaches for Network Expansion
	This chapter is based on: *Discussion Paper 1312, DIW Berlin*, Egerer et al. (2013d). It was presented at the 10th International Conference on the European Energy Market, 2013 (Stockholm), where it is published in the conference proceedings, Egerer et al. (2013e). A revised version was published as: Power System Transformation toward Renewables: An Evaluation of Regulatory Approaches for Network Expansion, *The Energy Journal 36(4)*, Egerer et al. (2015b).
	Joint work with Juan Rosellón and Wolf-Peter Schill. The writing of the manuscript, the model approach and its implementation in GAMS, and including modeling insights into the paper was executed jointly. Jonas Egerer developed the scenarios and their model application to analyze the incentive scheme in the dynamic setting.
7	European electricity grid infrastructure expansion in a 2050 context
	This chapter is based on: *Discussion Paper 1299, DIW Berlin*, Egerer et al. (2013a). It was presented at the 10th International Conference on the European Energy Market, 2013 (Stockholm) where it is published in the IEEE conference proceedings, Egerer et al. (2013c). A revised version was published as: European Electricity Grid Infrastructure Expansion in a 2050 Context, *The Energy Journal 37(SI3)*, Egerer et al. (2016a).
	Joint work with Casimir Lorenz and Clemens Gerbaulet. The writing of the manuscript, GAMS implementation of the model approach, and including modeling insights into the paper was executed jointly. Jonas Egerer and Clemens Gerbaulet developed the binary model representation for network investment.

Table 1.2: Overview on chapters 5–7: Pre-publications and own contributions

Chapter 7 – European electricity grid expansion in a 2050 context

In the last chapter, the focus shifts to the European system level. The Energy Roadmap 2050 of the European Commission elaborates on different scenarios for the low-carbon transformation of the European energy sector. One aspect of this transformation is the European high-voltage transmission network. While the Roadmap states scenario-specific aggregated figures on network costs until 2050, it does not provide insights into specific network expansion.

This chapter describes the research which has been conducted by the infrastructure assessment sub-group of the Energy Modeling Forum 28 (EMF 28). It applied a large-scale techno-economic mixed-integer investment model to the European electricity transmission network for different policy scenarios, in ten-year intervals up to 2050. The model represents every line of the European high-voltage transmission network and the optional long-distance connections of a HVDC backbone system throughout Europe. This gives a detailed representation of domestic and international power flows and more choices on transmission investment. Voltage upgrades for lines, expansion with additional parallel line systems, and the realization of HVDC backbone lines are the investment decisions made by the model over intervals of ten years The objective function of the cost-minimizing mixed-integer model includes the power plant dispatch and network expansion.

The results of three scenarios are compared to the projections of the Energy Roadmap 2050 by the European Commission. The scenarios differ in their choice of generation technologies and carbon emission reduction targets. The results show that national network expansion will retain the largest share of investment. This chapter also highlights the dependency of long-term network planning on the availability of technology and emission reduction targets. Not only does the absolute level of transmission investment change between the scenarios, but also the regional focus of actual network investment projects.

1.4.3 Research outlook

This dissertation addresses aspects of the low-carbon transformation in the German and European electricity sector. In the first chapter on electricity sector modeling at German level, the publication of the open source model ELMOD-DE aims at more transparency and highlights the importance of reproducible results in policy-relevant sector modeling. Version 1.0.0 of the open source model has been published on the DIW Berlin website in March 2016 and represents the first open source nodal dispatch model with hourly time resolution for Germany.

Further research will have to expand on the basic version with additional modules (e.g., detailed local heat representation, additional technical inter-temporal constraints, and also the system of neighboring countries). However, increased complexity comes at the cost of additional computational resources and has to find solutions to the limited availability of open data. In this regard, efforts like the openmod (2016) project could help to improve the quality and accessibility of open data. In its basic version, ELMOD-DE provides important insight into the spatial characteristics of the German system. As for all optimization models, one has to consider the simplifying assumptions when discussing the results.

This dissertation strongly focuses on the spatial implications of the low-carbon transformation. Both increasing shares of renewable generation and decommissioning of conventional power plants change the regional characteristics of electricity systems. This development challenges the spot market with mostly national bidding zones. With limited influence on power plant siting, transmission investment is provided as the main solution to changing regional distributions in supply and demand. The realization of transmission projects takes many years and time and costs can increase significantly in the case of public opposition at the local level, making it necessary to find alternative solutions for market operation and system integration of renewables. This dissertation examines these challenges with chapters focusing on market design, integrated planning, and distributional effects.

The results indicate the importance of presenting different scenarios and sensitivities. Neither the German nor the European low-carbon transformation is a top-down project. Changes in market design and trade capacity result in redistribution and competing stakeholder interests. The scenario results indicate that there are always competing solutions which, in many cases, are not too dissimilar in terms of cost. These alternative solutions could prove invaluable when dealing with the interests of many stakeholders at national and local levels.

Additional research with an endogenous model representation of stakeholder interests would be a significant addition to the literature. This dissertation addresses the issue of national-strategic transmission investment with a game theory model. An alternative approach is presented by Huppmann and Egerer (2015) with a three-stage equilibrium model to analyze transmission investment in a Nash game. They apply the model to a four-node sample network and illustrate the failure to reach the first-best expansion strategy in the absence of a compensation mechanism. Both models provide an insight into the divergence of cost-optimal solutions at system level and the possible solutions regarding strategic behavior at national level. Future research will also have to address more prominently the conflicting interests between the development of large-scale renewable generation and electricity supply at local level.

Chapter 2

Open source Electricity Model for Germany (ELMOD-DE)

This chapter is based on:

Open source Electricity Model for Germany (ELMOD-DE)

Data Documentation 83, DIW Berlin, Egerer (2016).

ELMOD-DE is available for download on the website of the DIW Berlin.

`http://www.diw.de/elmod`

2.1 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 2.2 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 2.3 is followed by an overview on the dataset in Section 2.4 and an illustration of various nodal and aggregated model results in Section 2.5. Section 2.6 discusses the limitations of the model together with possible extensions and Section 2.7 draws the conclusions.

2.2 Literature

2.2.1 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 chapter follows these examples by providing the technical description of a nodal DC load flow model for the German electricity sector. In alignment with this chapter, 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).[9] The dataset relies on publicly accessible data sources and includes hourly system data for the year 2012.

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

2.2.2 Development of the ELMOD model framework

The electricity model (ELMOD), developed at the TU Dresden by Leuthold et al. (2008b), has continuously been extended at the Chair of Energy Economics (TU Dresden), the Department 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.

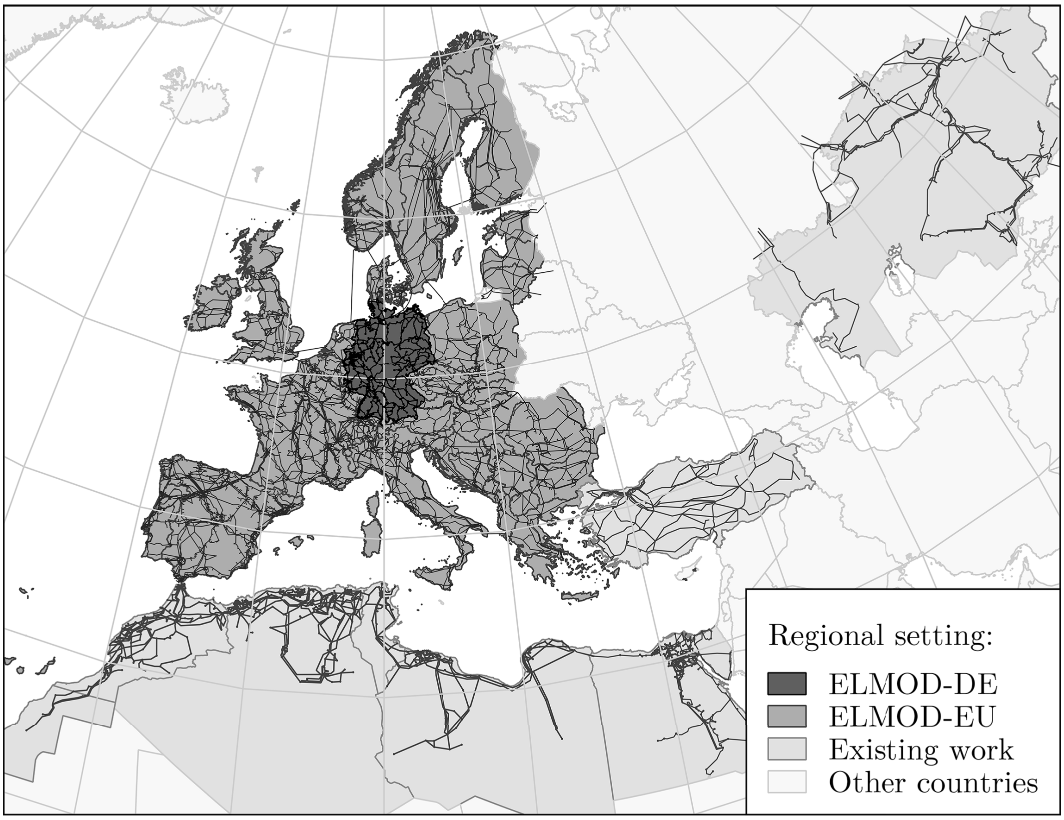


Figure 2.1: Countries in the ELMOD universe

The spatial model scope has been constantly expanded from Germany to most of Europe and beyond (Figure 2.1). 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 2.3–2.4 provide a description of the mathematical model formulation and the dataset of 2012.

2.2.3 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.

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., 2008a; 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. (2015c) discuss the increasing regional imbalances in the German electricity system and a possible division of the German single bidding zone (Chapter 3).

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.

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. (2013b) 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 (2014c) 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 (Chapter 4).

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 (Chapter 7).

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).

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. (2015b) discuss the implications of dynamic system changes on incentive regulation schemes with two-part tariffs and test the robustness of different weights (Chapter 6). 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.

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 (Chapter 5). 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.

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.

2.3 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.[10] 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 2.6 and in Leuthold et al. (2012). Egerer et al. (2015c) in Chapter 3 and Egerer and Schill (2014c) in Chapter 4 directly build upon

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

ELMOD-DE with adjustments in the model implementation and of scenario specific input data. The full mathematical formulation of ELMOD-DE is provided in the following. Table 2.1 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	
$n, k \in N$	... 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 transmission line	MW
θ_{nt}	... phase angle difference in respect to slack bus $\hat{n}$	
ens_{nt}	... load not covered by generation	MW
g_{pt}^{unit}	... generation of conventional generating unit	MW
ls_{st}	... storage content of pumped-storage plant	MWh
$\overrightarrow{ps}_{st}$	... generation of pumped-storage plant	MW
$\overleftarrow{ps}_{st}$	... pumping of pumped-storage plant	MW
r_{nit}^{tech}	... generation of renewable technology	MW
Parameters:		
av_{pt}^{unit}	... availability factor of generating unit	
av_{nit}^{tech}	... availability factor of technology at network node	
b_{nk}	... network susceptance matrix	$1/\Omega$
$\hat{b}_l$	... series susceptance of line	$1/\Omega$
$\overline{g}_p^{\text{unit}}$	... maximum capacity of power plant's generating unit	MW
h_{ln}	... network transfer matrix	$1/\Omega$
im_{ln}	... incidence matrix between line and network nodes	
$\overline{ls}_s$	... maximum energy storage of pumped-storage plant	MWh
$\overline{pf}_l$	... maximum power flow of transmission line	MW
pf_{nt}^{export}	... cross-border export flow	MW
pf_{nt}^{import}	... cross-border import flow	MW
$\overline{ps}_s$	... maximum capacity of pumped-storage plant	MW
q_{nt}	... electricity load	MW
$\overline{r}_{nit}^{\text{tech}}$	... maximum renewable capacity	MW
$voll$	... value of lost load	EUR/MWh

Table 2.1: Sets, mappings, (positive) variables, and parameters of ELMOD-DE

2.3.1 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 2.1 states real power flow on line l between node 1 and node 2.

$$pf_{1,2} = G_l(V_1^2 - V_1V_2\cos(\theta_1 - \theta_2)) + \hat{b}_lV_1V_2\sin(\theta_1 - \theta_2) \tag{2.1}$$

The equation can be simplified assuming small values for differences in voltage angles (Equations 2.2a–2.2b) and low differences in voltage levels (Equation 2.2c).

$$\sin(\theta_1 - \theta_2) \approx \theta_1 - \theta_2 \tag{2.2a}$$
$$\cos(\theta_1 - \theta_2) \approx 1 \tag{2.2b}$$
$$V_1 \approx V_2 \approx 1 \tag{2.2c}$$

Following these simplifications (Schweppe et al., 1988, p. 313f), line flows between nodes 1 and 2 are calculated using the linear Equation 2.3. The model constraint 2.4b implements this formulation with the network transfer matrix h_{ln}.[11]

$$pf_{1,2} = \hat{b}_l(\theta_1 - \theta_2) \tag{2.3}$$

Network inflows and outflows ni_{nt} in Equation 2.4c are calculated from the sum of power flows on all adjacent lines.[12] In the slack bus $\hat{n}$, Equation 2.4d 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

[11] 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.

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

restricted solution space than transport models which allow directed flows.

The dataset includes the network topology and technical information on transmission lines.[13] Capacity constraint 2.4a 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.

$$|pf_{lt}| \leq \overline{pf}_l \qquad \forall \quad l,t \tag{2.4a}$$

$$pf_{lt} = \sum_n \theta_{nt} h_{ln} \qquad \forall \quad l,t \tag{2.4b}$$

$$ni_{nt} = \sum_k \theta_{kt} b_{nk} \qquad \forall \quad n,t \tag{2.4c}$$

$$\theta_{\hat{n}t} = 0 \qquad \forall \quad t \tag{2.4d}$$

2.3.2 Additional model equations

The objective function in Equation 2.5 minimizes generation costs of the power plant dispatch. Objective value c comprises hourly output level of conventional generation units g^{unit}_{pt} multiplied by their variable generation costs $\hat{c}^{\text{unit}}_{pt}$. Variable generation costs are composed of fuel prices, regional transportation costs for hard coal, and CO_2 emission costs.[14,15]

$$\min_{g^{\text{unit}},ens} \mathrm{c} = \sum_{pt} g^{\text{unit}}_{pt} \hat{c}^{\text{unit}}_{pt} + \sum_{nt} ens_{nt} voll \tag{2.5}$$

The energy balance 2.6 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

[13]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.

[14]Other power plants are not considered in the objective function. Variable generation costs for renewable technologies are assumed to be zero. The model includes a dummy variable for load not covered by generation ens_{nt} to avoid infeasible model solutions in any case. Also, the model data abstracts from load changing costs and operation and maintenance costs.

[15]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.

$$\sum_{p \in P_n} g_{pt}^{\text{unit}} + \sum_i r_{nit}^{\text{tech}} + \sum_{s \in S_n} \overrightarrow{ps}_{st} + ni_{nt} = q_{nt} + \sum_{s \in S_n} \overleftarrow{ps}_{st} - ens_{nt} \quad \forall \quad n,t \tag{2.6}$$

Nodal hourly electricity load q_{nt} is an exogenous parameter, given the assumption of price-inelastic demand. Equation 2.7a limits output of conventional power plants to the generating unit's installed capacity $\overline{g}_{pt}^{\text{unit}}$ adjusted with an hourly availability factor av_{pt}^{unit}. Maximum nodal renewable output by technology is set in Equation 2.7b for every hour by installed capacity at the respective node $\overline{r}_{nit}^{\text{tech}}$ multiplied by an hourly availability factor av_{nit}^{tech}.[16]

$$g_{pt}^{\text{unit}} \leq \overline{g}_{p}^{\text{unit}} av_{pt}^{\text{unit}} \qquad \forall \quad p,t \tag{2.7a}$$
$$r_{nit}^{\text{tech}} \leq \overline{r}_{nit}^{\text{tech}} av_{nit}^{\text{tech}} \qquad \forall \quad n,i,t \tag{2.7b}$$

Equations 2.8a–2.8c describe pumped-storage hydroelectric plants. Their installed capacity $\overline{ps}_s$ sets the upper bound for the variables of generation $\overrightarrow{ps}_{st}$ and pumping $\overleftarrow{ps}_{st}$. 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 $t-1$.[17]

$$\overrightarrow{ps}_{st} + \overleftarrow{ps}_{st} \leq \overline{ps}_s \qquad \forall \quad s,t \tag{2.8a}$$
$$ls_{st} \leq \overline{ls}_s \qquad \forall \quad s,t \tag{2.8b}$$
$$ls_{st} = 0.75\overleftarrow{ps}_{st} - \overrightarrow{ps}_{st} + ls_{s(t-1)} \qquad \forall \quad s,t \tag{2.8c}$$

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

[17] 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.

2.4 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 2.2 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[18]
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, 2016) 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 (2013a)
	- 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 2.2: Overview on institutions for data sources

2.4.1 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 2.2, 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

[18]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.

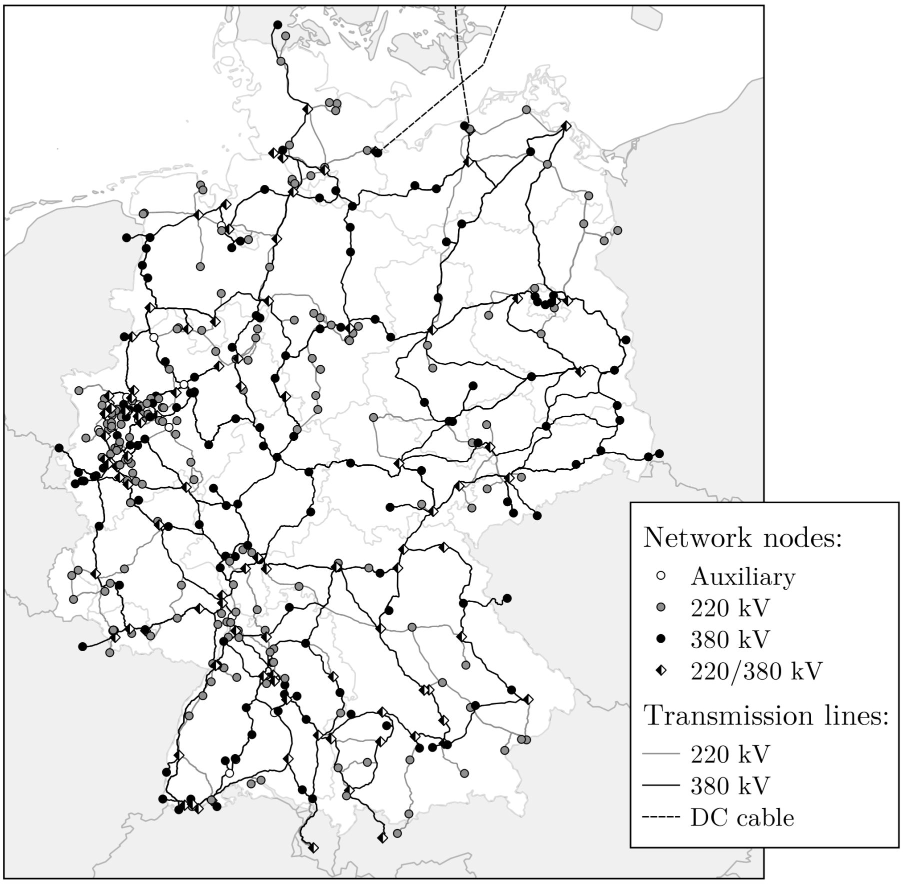


Figure 2.2: High-voltage transmission network in 2012

2.4.2 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.[19] The main demand centers are in western and southern Germany.

2.4.3 Generation capacity

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 2.3). 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 photovoltaic 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.

[19] 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	Units	Capacity [GW]	Price range [EUR/MWh]
Nuclear	9	12.1	9.1
Lignite	61	20.4	14.9–29.0
Hard coal	101	24.7	31.6–54.4
CCGT	26	8.5	55.8–77.0
Gas	208	14.3	73.1–138.7
Oil	50	4.1	116.0–210.7
Other	34	2.9	
Waste	73	1.5	
Storage	32	8.8	
Total	594	97.1	

Renewables	Capacity [GW]
Run-of-river	3.7
Biomass	6.4
Photovoltaic	32.4
Wind onshore	31.5
Wind offshore	0.4
Geothermal	0.02
Total	74.3

Table 2.3: Conventional and renewable generation capacities

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 2.4). 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.

2.4.4 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, p. 12).

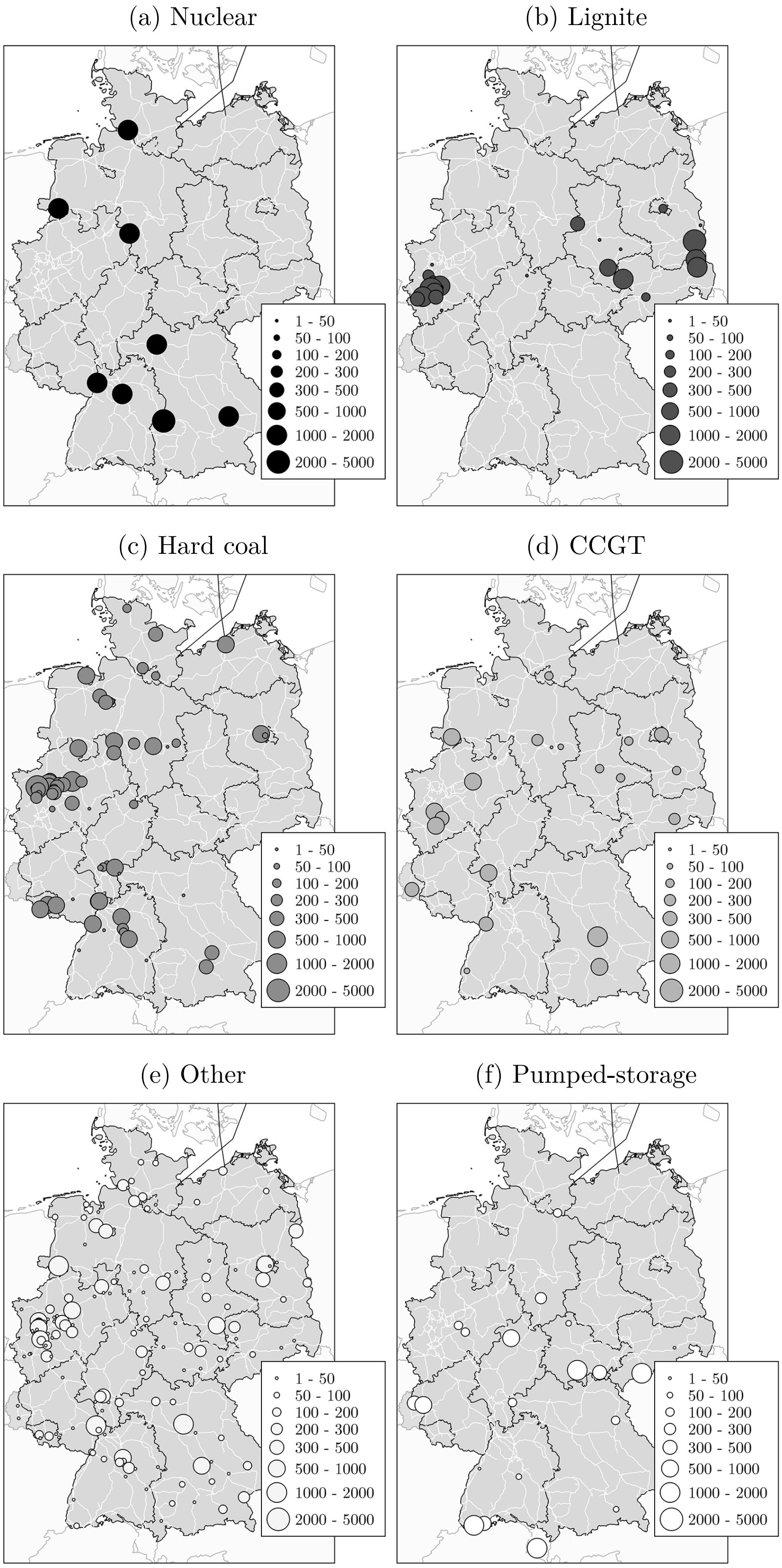


Figure 2.3: Nodal generation capacity of conventional technologies [MW]

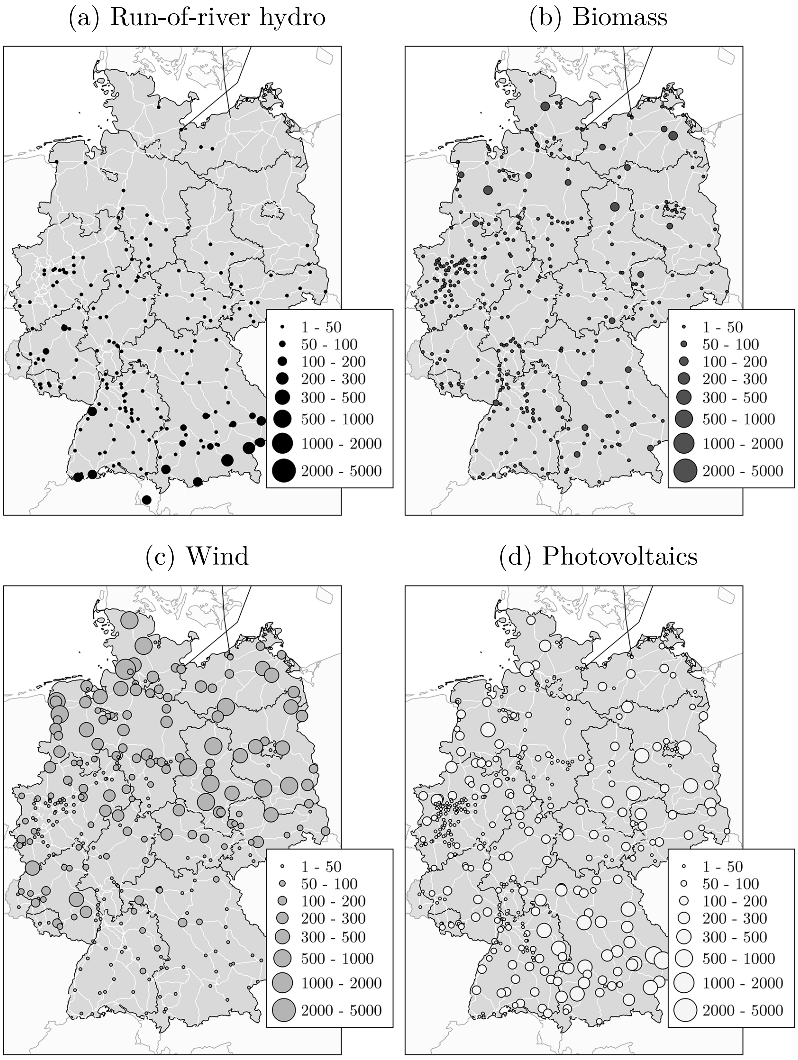


Figure 2.4: Nodal generation capacity of renewable technologies [MW]

2.5 Results

2.5.1 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.

Exemplary hours with specific characteristics

This section presents model results for exemplary hours representing system states with specific characteristics. Figures 2.5–2.9 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 2.5 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 2.6). 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 2.7 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 2.8 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 2.9 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 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.

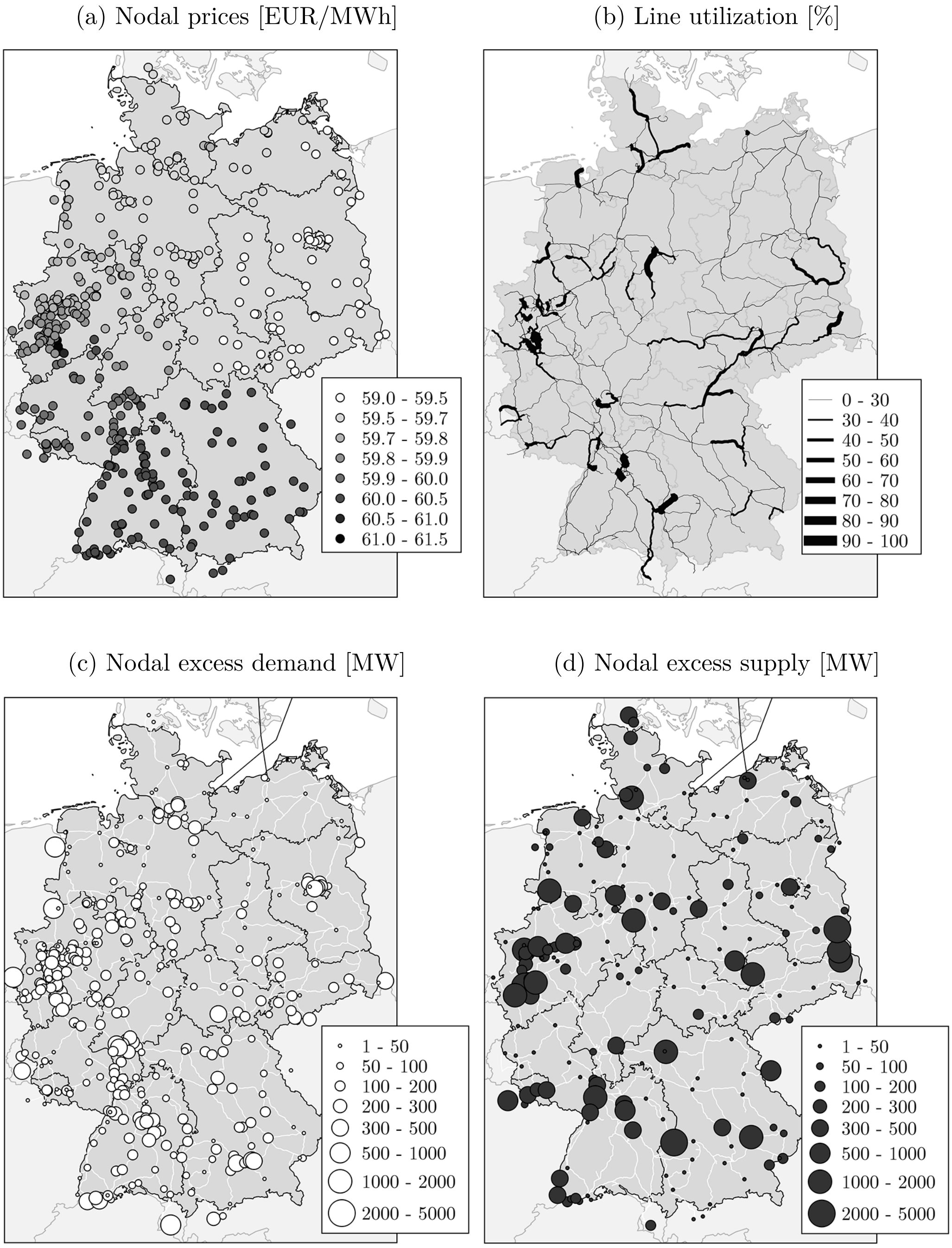


Figure 2.5: Average for all hours of nodal model results (avg)

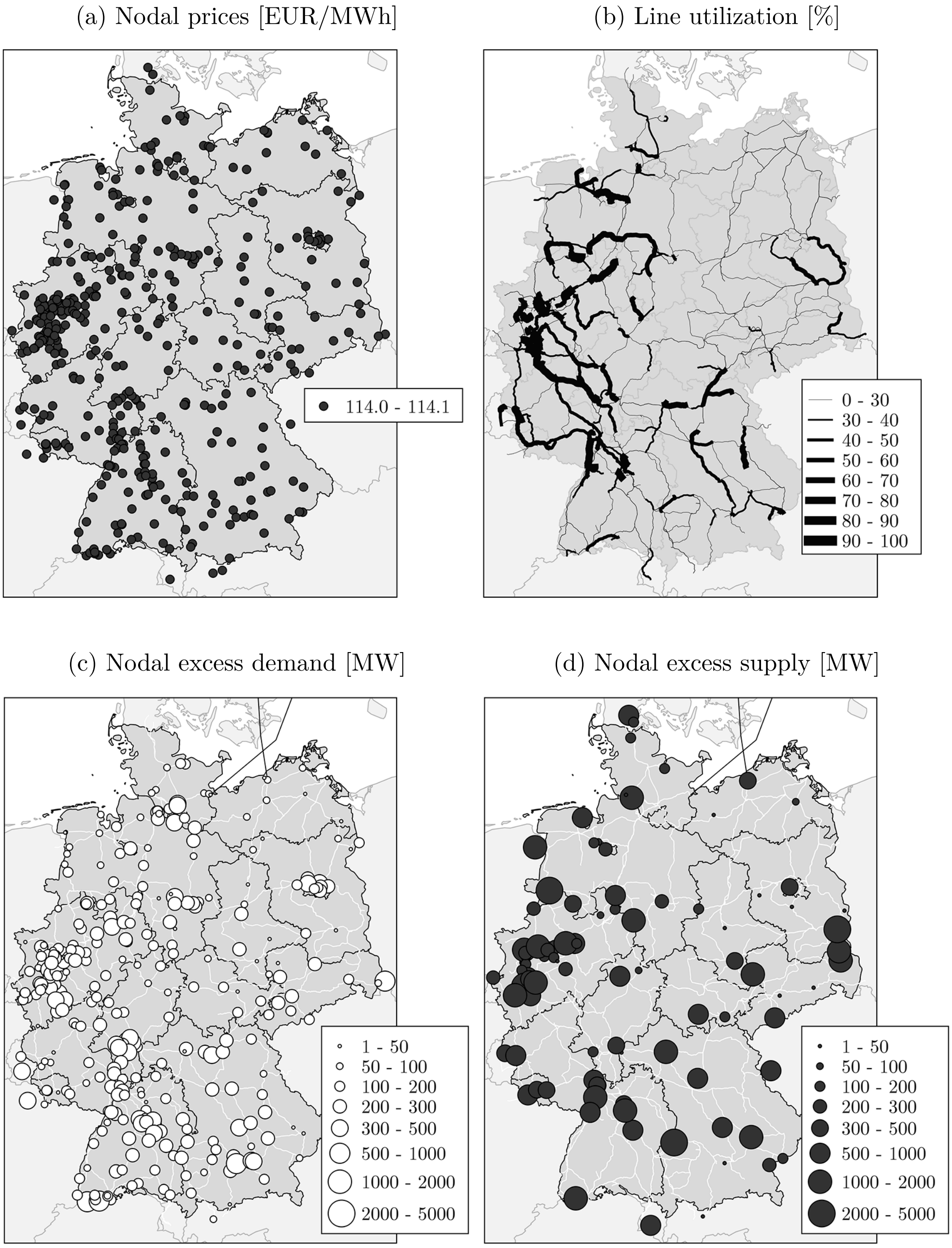


Figure 2.6: Peak winter demand and low renewable generation (h1)

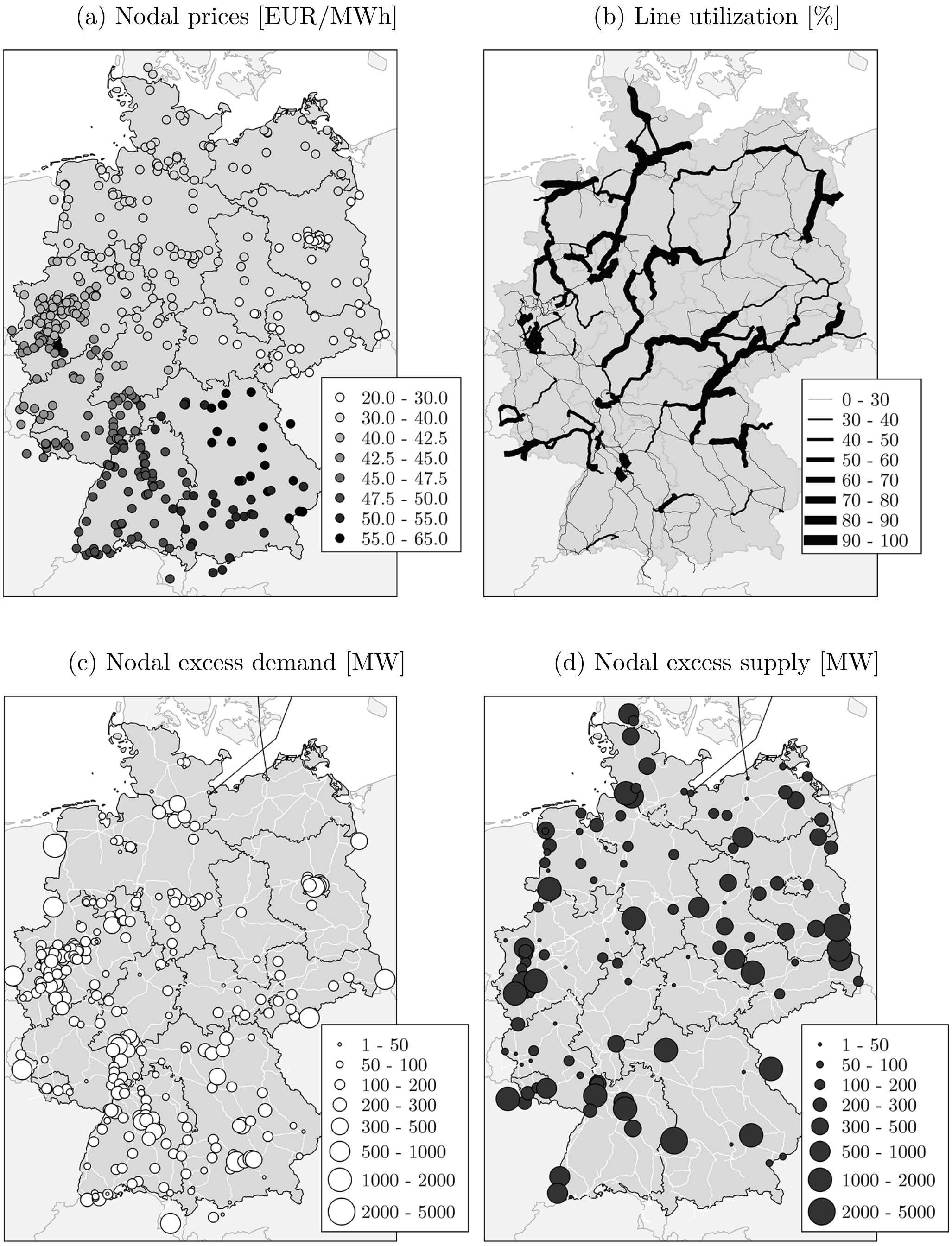


Figure 2.7: High winter demand, no PV, and very high wind generation (h2)

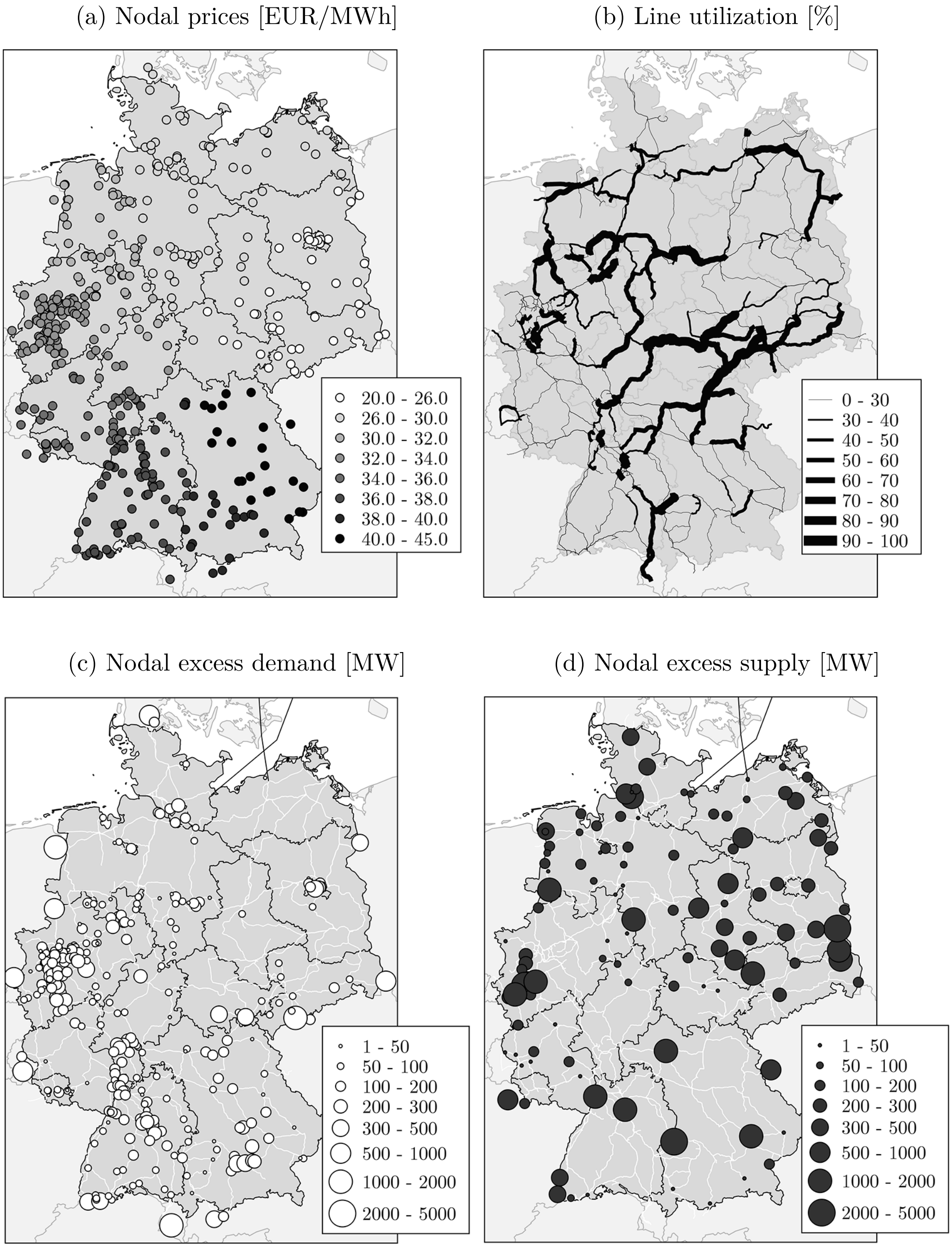


Figure 2.8: Low winter demand, no PV, and high wind generation (h3)

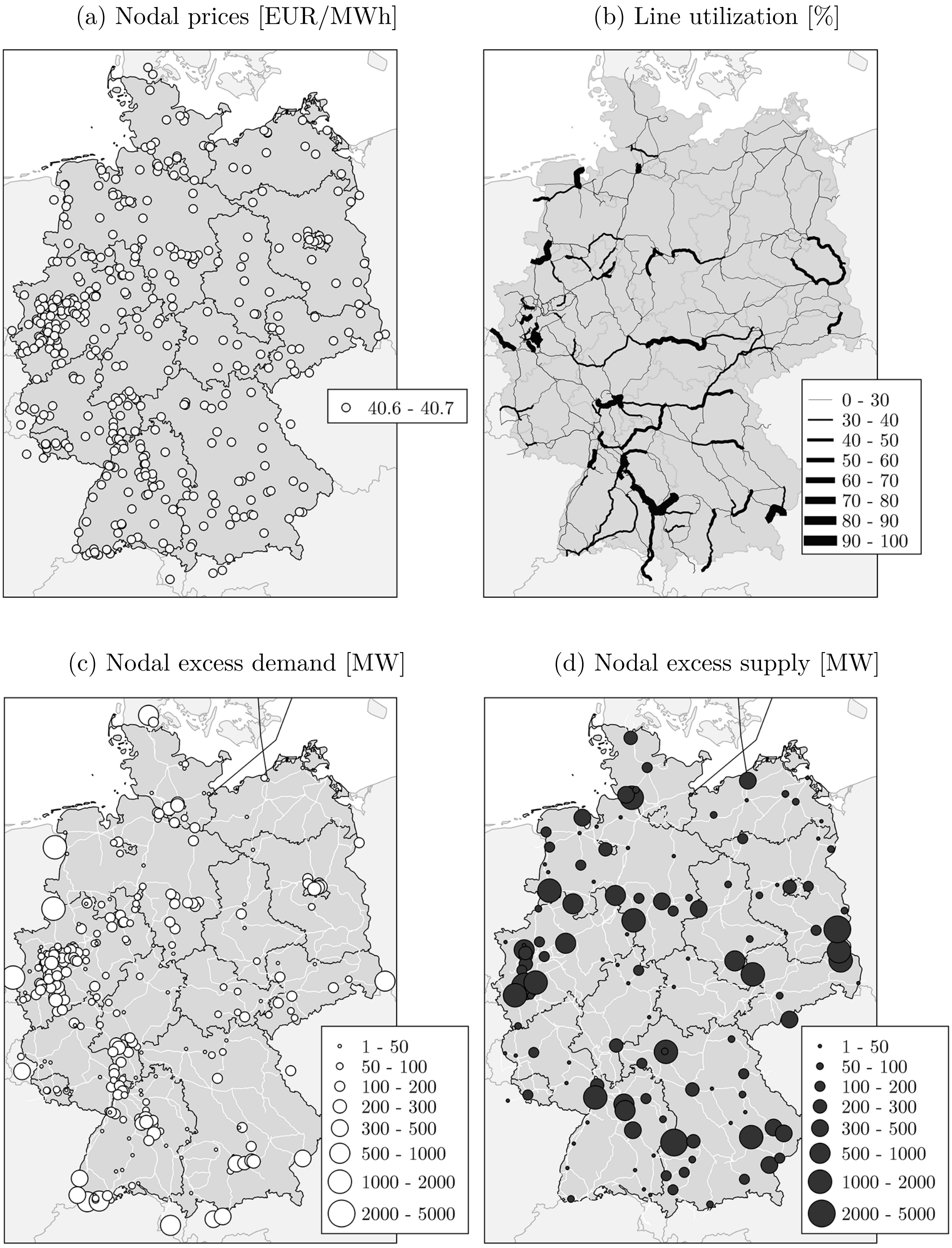


Figure 2.9: Low summer demand, high PV, and low wind generation (h4)

2.5.2 Aggregation of model results by space and time

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 2.10) 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

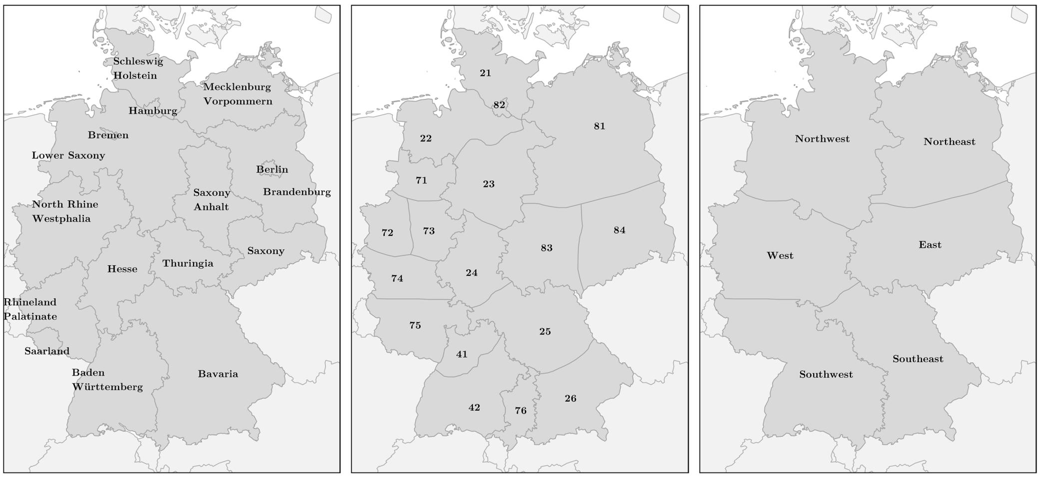


Figure 2.10: Different spatial aggregations for Germany

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 2.11 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.

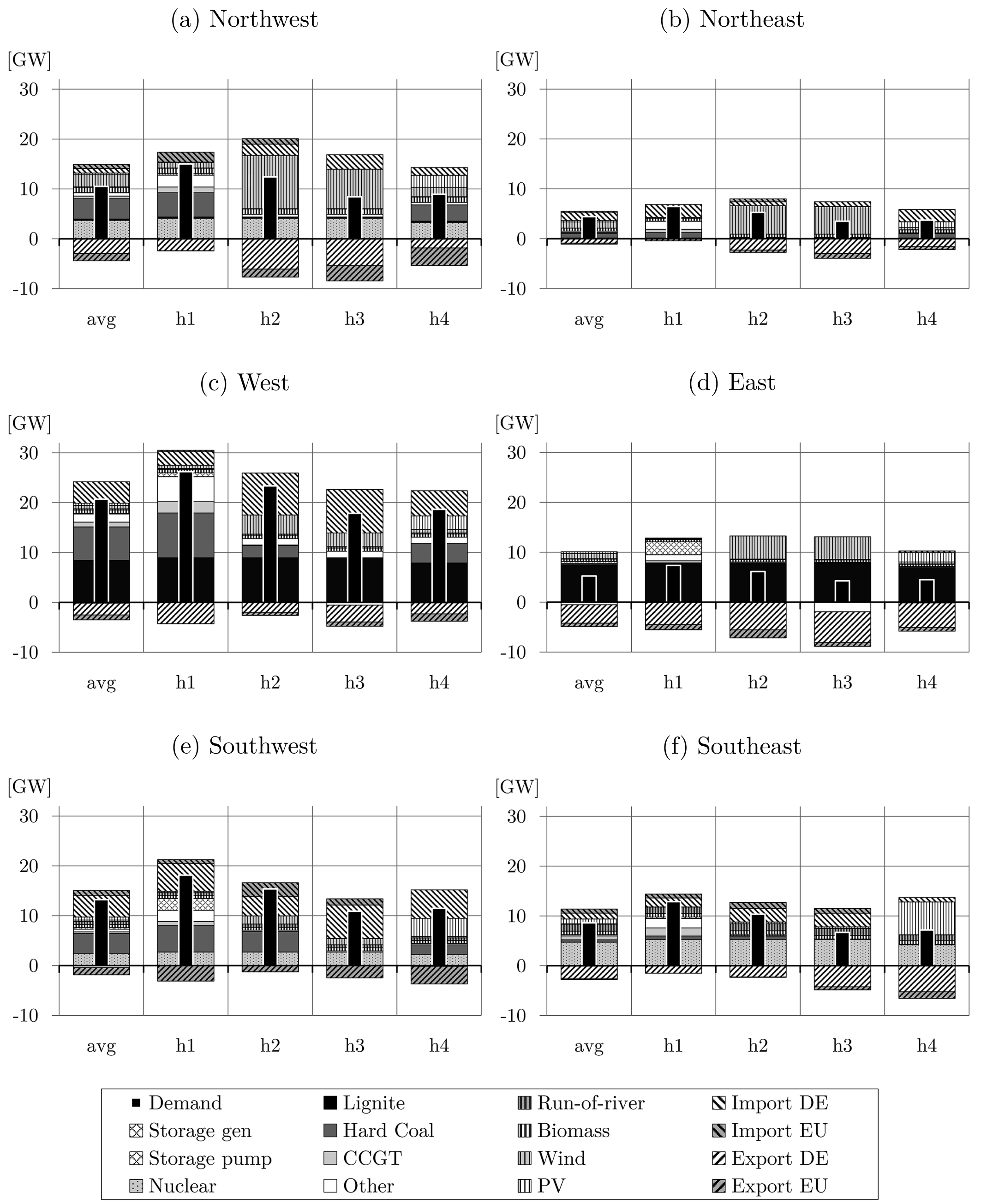


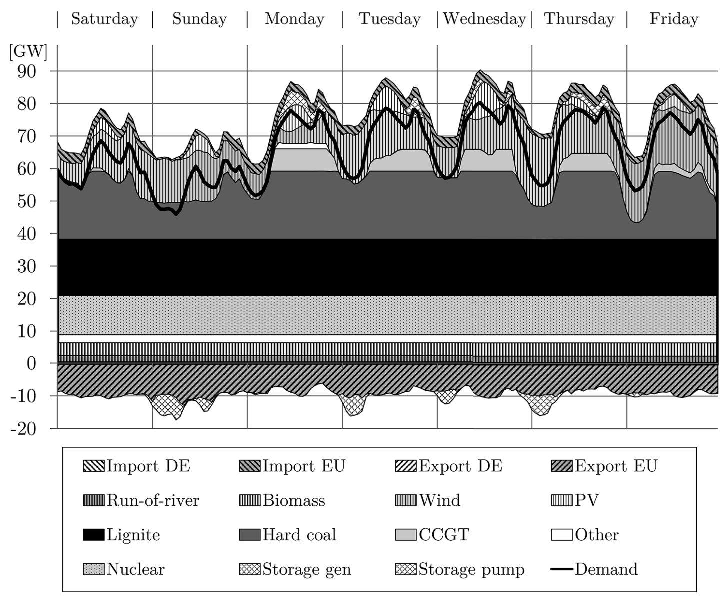
Figure 2.11: Zonal generation, demand, and trade for exemplary hours (h1–h4)

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 2.12 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 average 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

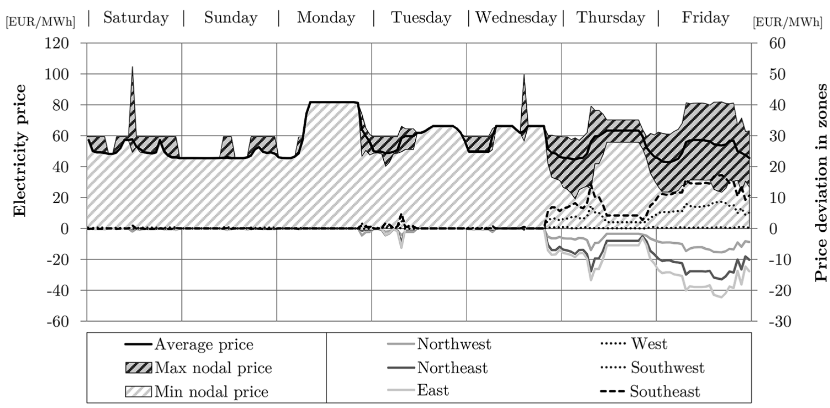


Figure 2.12: Hourly national results and electricity prices for one winter week

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 2.12 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 2.14). 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 2.15 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.

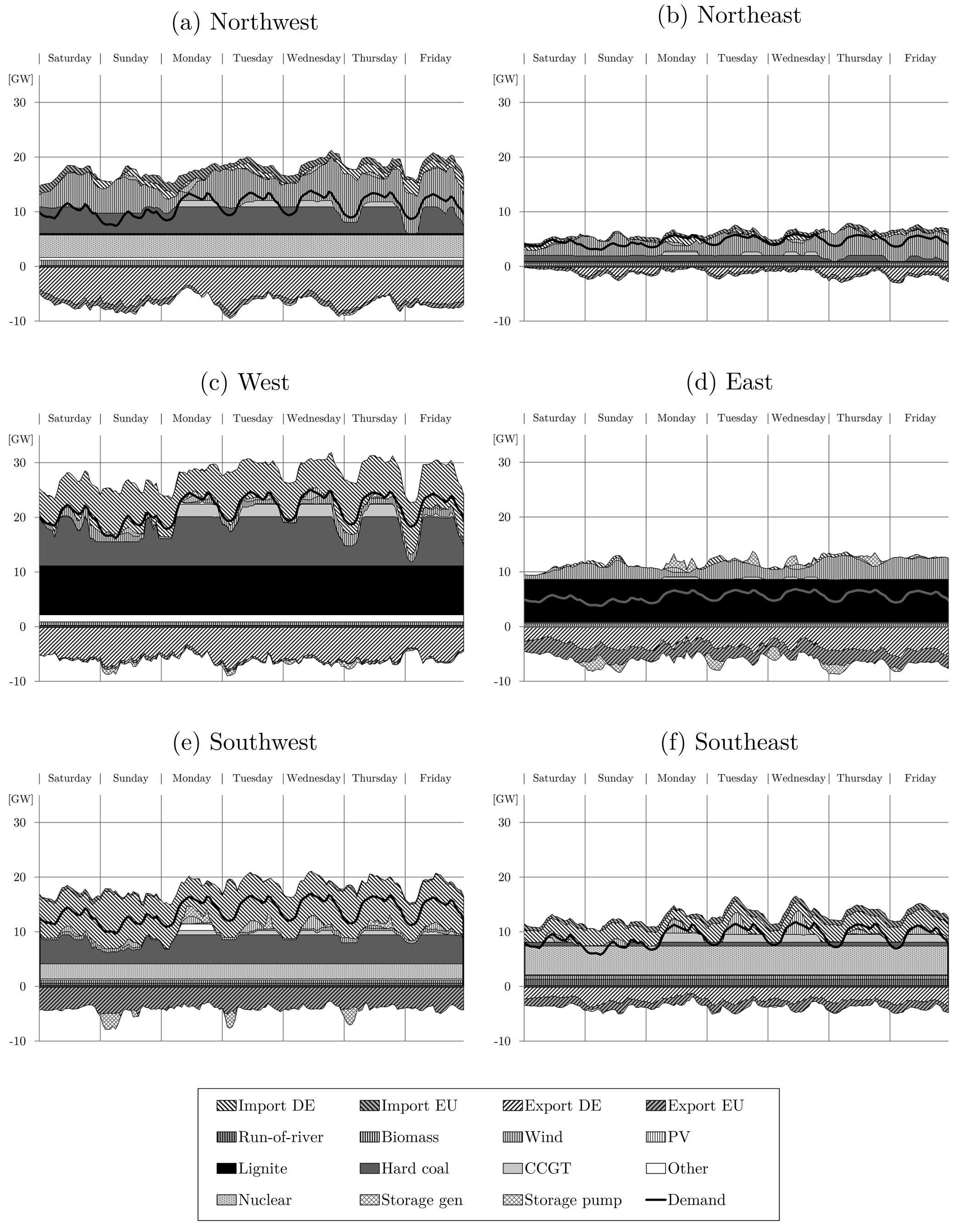


Figure 2.13: Zonal generation, demand, and trade for one winter week

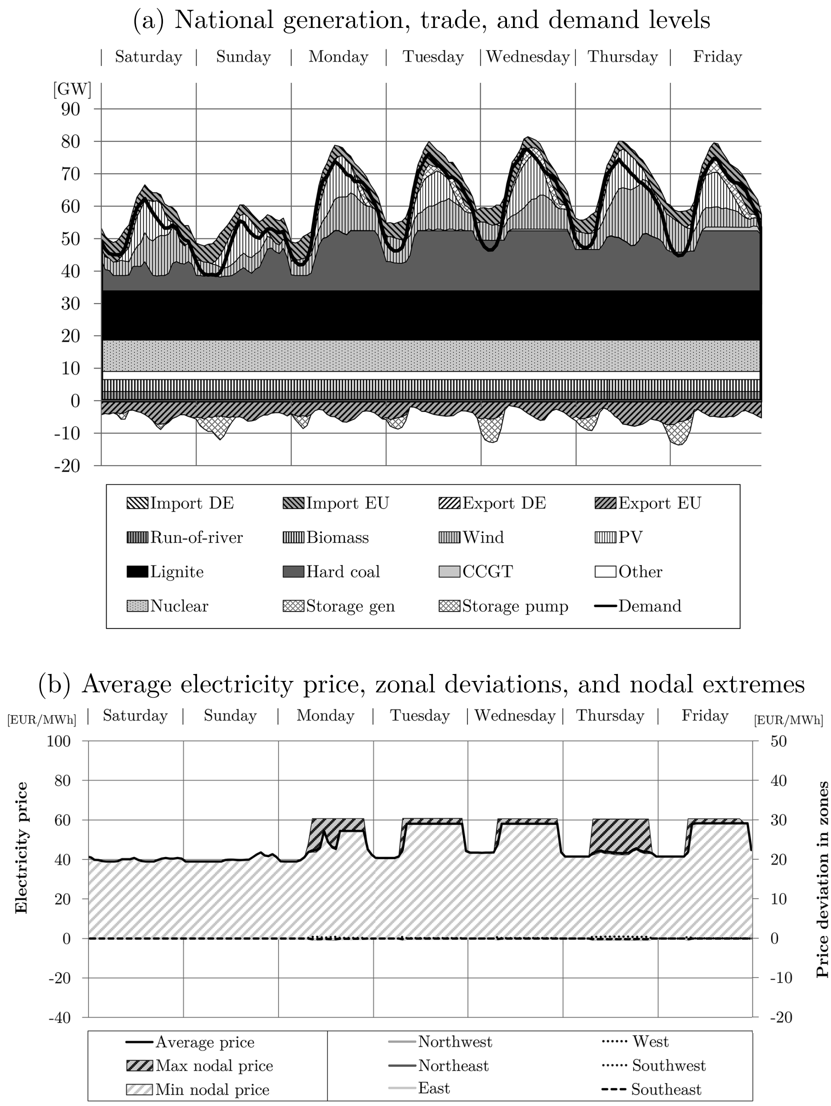


Figure 2.14: Hourly national results and electricity prices for one summer week

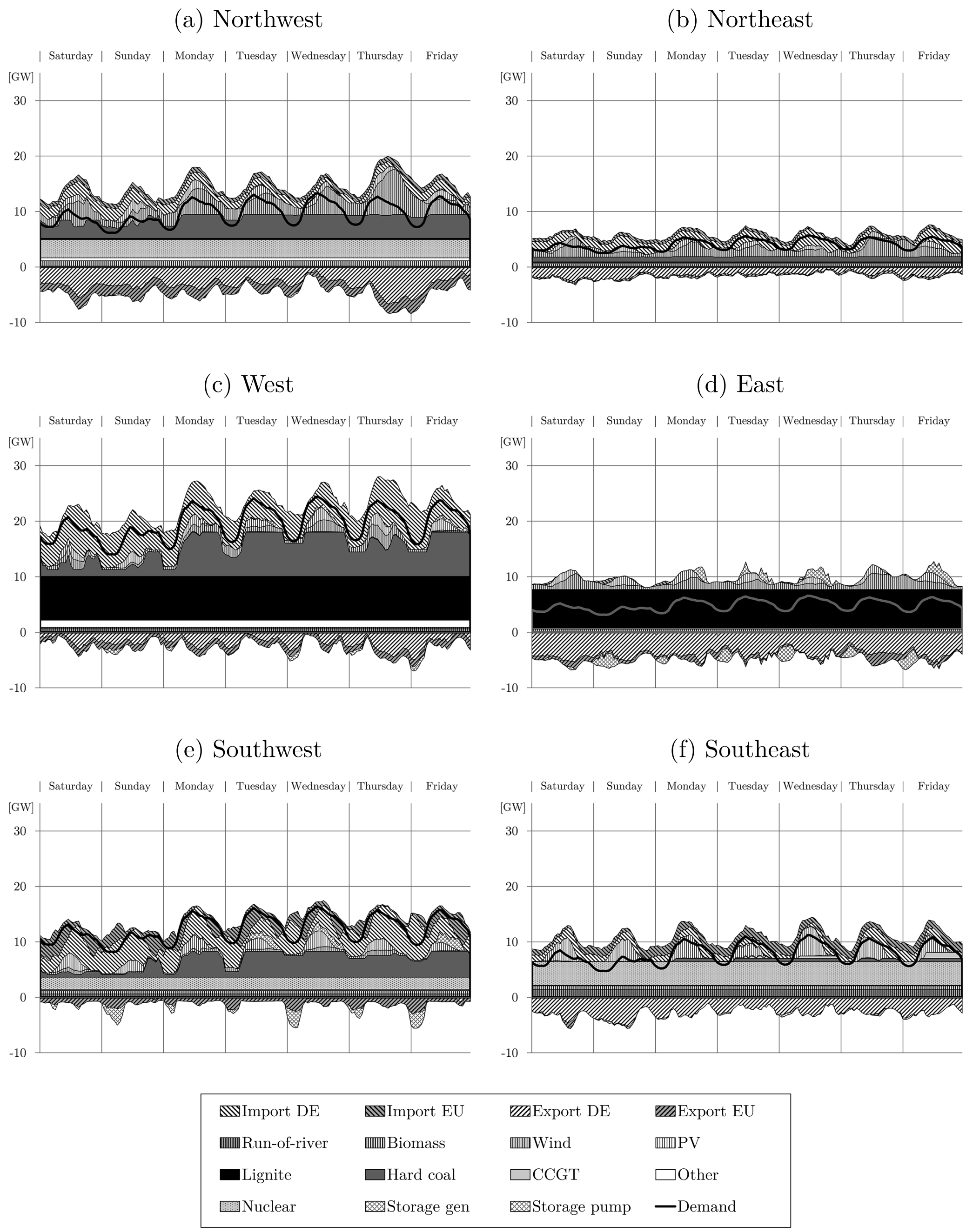


Figure 2.15: Zonal generation, demand, and trade for one summer week

Annual zonal results on generation, trade, and demand

The annual figures on generation, trade, and demand in Table 2.4 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
Run-of-river	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 2.4: 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 photovoltaic levels of the six zones result in 36% of demand being supplied from renewables. Annual generation exceeds demand by 6.4 TWh.

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 2.16 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.

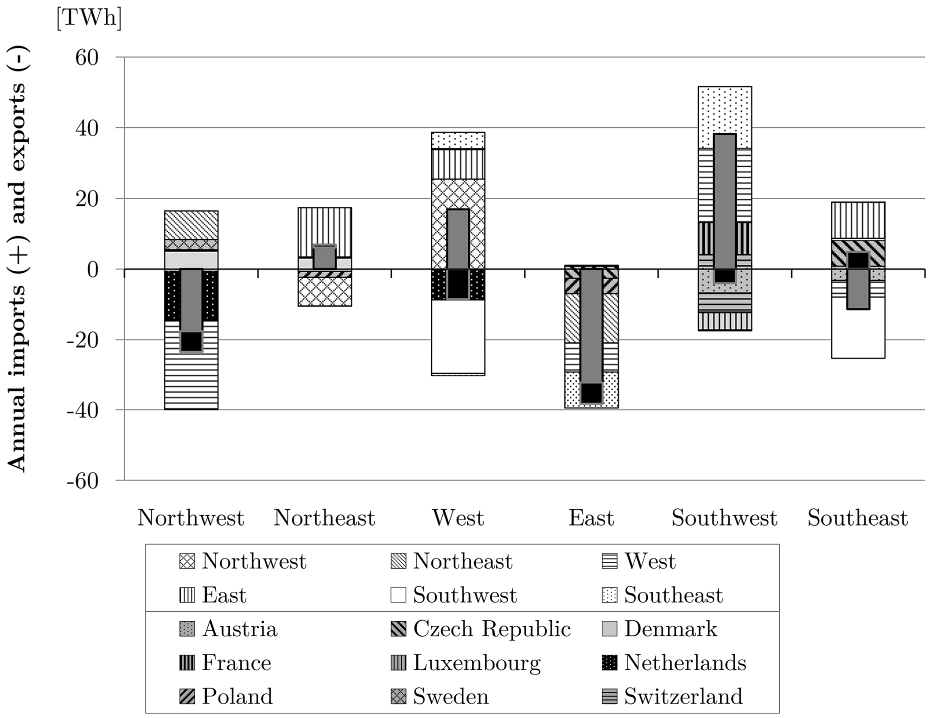


Figure 2.16: Annual electricity exchange with neighboring zones and countries

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 2.17 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.

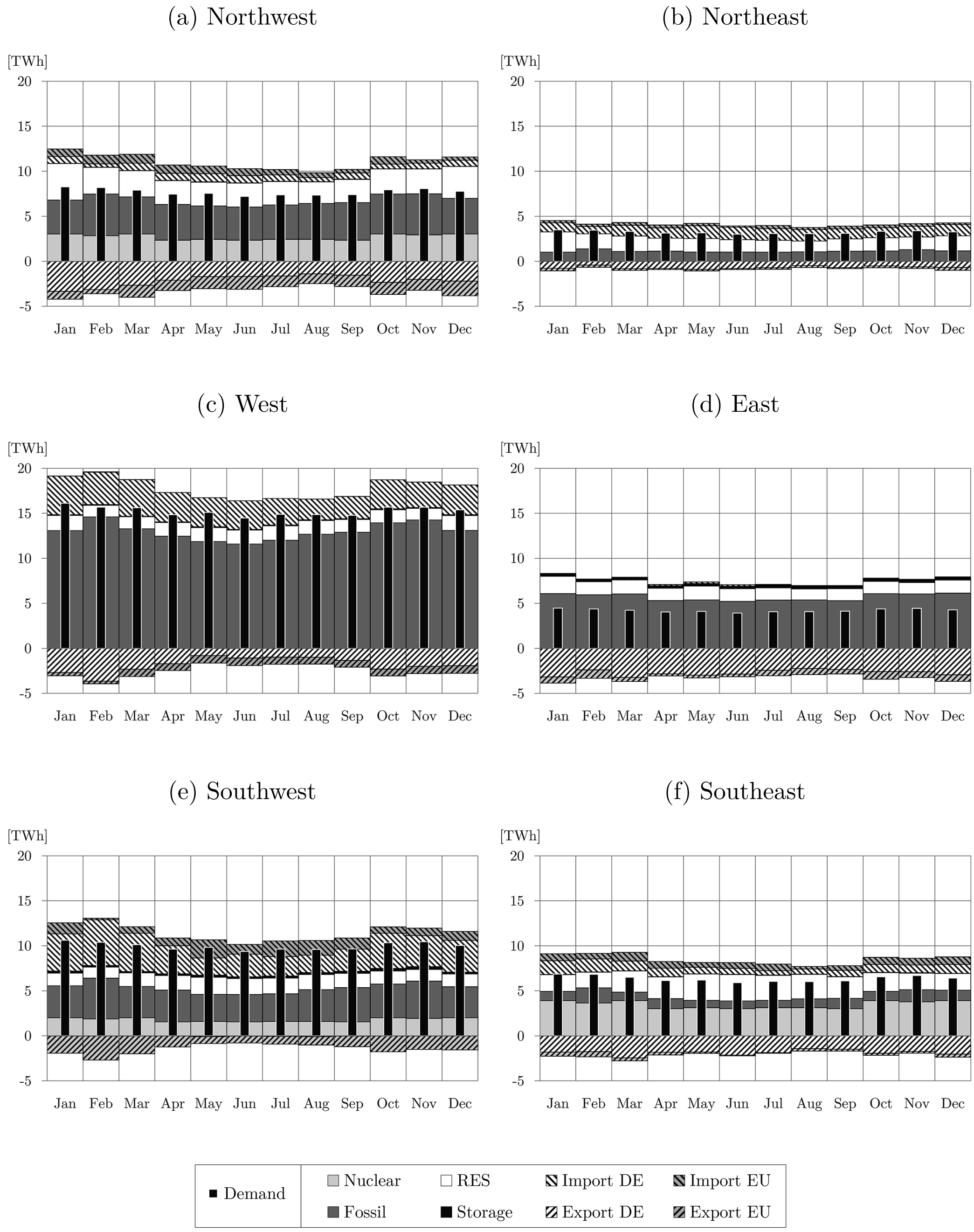


Figure 2.17: Zonal generation, demand, and trade levels by month for six zones

2.6 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. 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.

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.

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 2.5) 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.

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 2.5). 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 2.5: Model results, historic values in 2012, and deviation in generation

2.7 Conclusion

This chapter 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 2.4, 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 scheme (see Chapter 3) and on investment in generation, storage, and transmission (see Chapter 4). 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 and 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.

Chapter 3

Two price zones for the German electricity market – Market implications and distributional effects

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This chapter is based on:
Two Price Zones for the German Electricity Market: Market Implications and Distributional Effects
Discussion Paper 1451, DIW Berlin, Egerer et al. (2015c).
Joint work with Jens Weibezahn and Hauke Hermann.
It was presented at the 14th IAEE European Energy Conference, 2014 (Rome), at the 10th Conference on Energy Economics and Technology, 2015 (Dresden), and at the 9th Internationale Energiewirtschaftstagung, 2015 (Vienna).
Findings and policy implications are published in the DIW Wochenbericht 9/2015, *Energiewende und Strommarktdesign: Zwei Preiszonen für Deutschland sind keine Lösung*, Egerer et al. (2015a).
A revised version was published as:
Two price zones for the German electricity market – Market implications and distributional effects
Energy Economics 59: 365–381, Egerer et al. (2016b).

3.1 Introduction

In liberalized energy-only markets, the marginal pricing scheme is a well-established approach to determine the power plant dispatch in spot markets. However, market results can be technically infeasible if spot markets neglect the spatial location of supply and load as well as physical constraints of the transmission network. Curative congestion management becomes necessary, increasing the price of electricity. Locational price signals could reduce required adjustments to the initial market dispatch. Possible options include adjustments to the existing bidding zone configuration by reshaping existing zones and introducing additional zones (i.e., zonal pricing with alternative bidding zones) or a shift to a nodal market resolution at the level of individual network nodes of the high-voltage transmission system (i.e., nodal pricing).

Market liberalization in Europe was initiated by European legislation (EC, 2003b, 2009a, 1996) but it is implemented through national regulation. This process mostly resulted in national bidding zones with no additional regional price signals.[20] In this context, the development of the Internal Energy Market (IEM) has coupled bidding zones, implicitly auctioning a net transfer capacity (NTC) between them. Compared to nodal pricing with its market integration of power lines with specific network capacities, the zonal representation defines larger bidding areas while aggregating internal and cross-zonal network constraints to NTCs with neighboring bidding zones. With the calculation of the cross-zonal NTCs, preventive congestion management is possible to some extent. Still, a market dispatch can be infeasible in the physical transmission system, requiring curative congestion management, mainly re-dispatch measures. As of 2015 the bidding zones in effect are under scrutiny at European level according to the framework guidelines and the Network Code on Capacity Allocation and Congestion Management (EC, 2014b; ENTSO-E, 2014b). Network security, overall market efficiency, as well as stability and robustness are criteria for reviewing the bidding zone configuration. In 2015, the European Agency for the Cooperation of Energy Regulators (ACER) expressed an opinion that the German-Austrian interconnector requires the implementation of a capacity allocation method (ACER, 2015). The interconnector can only accommodate all physical flows by causing major structural congestion on other transmission lines, i.e., between Germany and the Czech Republic/Poland, between the Czech Republic and Austria, and also on lines within Germany.

Before the low-carbon transformation of the German electricity sector was initiated,

[20] Exceptions are Norway, Sweden, Denmark, and Italy with multiple bidding zones at the national level and a joint bidding zone for Germany and Austria.

the system had been dominated by conventional plants close to load centers. The only major regional imbalance had been, for historical reasons, the surplus in lignite capacity in eastern Germany. Regional price signals were not relevant when market liberalization was initiated, as the lowest-cost national market dispatch could be implemented with the existing physical transmission system. During the last decade, the German electricity system has been undergoing a transformation, increasing regional imbalances between supply and load: eight nuclear power plant units were phased out in 2011 and the capacity of variable renewable generation has increased.[21] Except for a few remaining nuclear power plants, most of the conventional power plants with the lowest variable costs—nuclear and lignite, followed by modern hard coal plants either recently built or under construction—are located in northern Germany.[22] Hard coal power plants in northern Germany also have lower fuel costs as they benefit from cheaper access to imported hard coal compared to their counterparts in southern Germany (mainly Baden-Wüttemberg), which have to pay for long inland transport from the North Sea harbors. Combined cycle gas turbine (CCGT) plants, which, along with nuclear, form a significant part of capacity in Bavaria, have been more expensive than hard coal plants in recent years due to the price spread between hard coal and natural gas and continuously low CO_2 prices. Thus, although there is no shortage of conventional capacity in southern Germany, there is an imbalance between the regional share of capacity in the lowest-cost dispatch and the regional load distribution (Kunz et al., 2013).[23]

Consequently, limited north-south transmission capacity leads to physically infeasible market dispatches in an increasing number of hours, characterized by low load and/or high wind feed-in. As a result, re-dispatch costs have significantly increased from only 25m EUR in 2009 (BNetzA, 2010), to 165m, 113m, and 185m EUR in the years 2012 to 2014 (BNetzA and Bundeskartellamt, 2015). The regional imbalance in supply will increase with the nuclear phase-out and added capacity of new coal power plants and wind power in northern Germany. These circumstances provide possible arguments for the idea of splitting the single German bidding zone into one northern and one southern zone.

[21] The share of renewable generation in the German electricity market reached 22.8% (30.0%) in 2012 (2015), including 8.0% (12.0%) wind and 4.2% (5.9%) photovoltaic (AG Energiebilanzen e.V., 2015). The installed capacity has been about 35% of peak demand for each technology.

[22] The border between northern and southern Germany depends on the context. In this analysis, the regions are split with oversupply of electricity in the north and the center, while a deficit exists in the south. They are confined by the border triangle of Germany, Belgium, and Luxembourg at the western edge to Frankfurt and the northern border of Bavaria. Thus, the southern zone includes the states of Baden-Württemberg, Bavaria, the Saarland, and parts of Rhineland-Palatinate, as well as Hesse.

[23] Regional trends in economic development and population movement, together with lower annual electricity demand after the recession in 2009, also increases the spatial imbalance between supply and demand in the electricity system.

This discussion is attracting increasing attention in Germany (Bettzüge, 2014; Frontier Economics and Consentec, 2011, 2013; Monopolkommission, 2011; Wissenschaftlicher Beirat BMWi, 2014) and in Europe (ACER, 2014; CEPS et al., 2012; Thema, 2013).[24,25] The question is how to adapt markets with increasing regional imbalances. The current measure of choice to retain the single electricity price in Germany is network expansion (BMWi, 2014). The annual German grid development plans (50Hertz et al., 2015) translate into the law on national requirements ("Bundesbedarfsplan"), which includes the specific extension projects (Bundesregierung, 2013). Still, it will take many years for most of the approved investment projects to be completed (e.g., due to local public opposition), while the nuclear phase-out will be completed in 2022. Large capacities of onshore and offshore wind power will add to the regional imbalance. Regional investments in back-up capacity as replacements for nuclear power plants in southern Germany might not affect market dispatch. In the uniform pricing scheme, the proposed gas-fired power plants will not relieve the regional imbalance as long as their variable generation costs are higher than those for coal-fired plants in the northern zone, as is the case for current CO_2 and fuel prices. A rather short-term alternative is the implementation of two bidding zones. However, splitting the single bidding zone causes monetary redistribution between stakeholders by allowing regional price discrimination. While many aspects are relevant to the decision at the level of spatial market aggregation, distributional effects on market participants are of particular importance for moving from one scheme to another (ACER, 2014; Löschel et al., 2013).

Bidding zones require the integration of a cross-zonal NTC capacity in the market and result in market splitting and diverging electricity prices within Germany whenever the NTC capacity becomes a binding constraint.[26] Consequently, the geographic scope of bidding zones and NTC levels auctioned into the market are the relevant parameters determining the effectiveness of zonal price differentiation as well as gains and losses of stakeholders in the zonal markets. Applying an electricity sector model, this chapter elaborates on such a change in the congestion management scheme for the 2012 and 2015 scenarios (including one sensitivity with network extension) and quantifies different effects. Among them are spot prices, re-dispatch levels as well as distributional effects for consumers and producers in the two price zones.[27]

[24] This work does not consider the implications on the Austrian electricity system, which as of 2015 is still part of the existing single bidding zone with Germany.

[25] From a European perspective additional arguments are mentioned, e.g., loop flows in neighboring countries not represented by the current market results.

[26] This work is limited to a short-term analysis of the spot market and neglects dynamic adjustments of market participants, e.g., by investments in power plants due to more volatile regional prices, changes in regional load levels, and possible issues with local market power of generation companies.

[27] This chapter focuses on the German discussion and abstracts from system and distributional

The remainder of this chapter is structured as follows: Section 3.2 reviews the relevant literature on the discussion of zonal and nodal pricing. Section 3.3 introduces the two consecutive model stages of the spot market dispatch and the re-dispatch adjustments. Section 3.4 presents and discusses the model results for two bidding zones in the German electricity system. The last section summarizes the numeric analysis and concludes with policy implications.

3.2 Literature on zonal and nodal pricing

Compared to zonal pricing with mostly coordinated market coupling in Europe, some markets have implemented a nodal pricing scheme.[28] Nodal pricing is often considered a benchmark for efficient congestion management. It allows for transmission pricing by considering loop flows and line-specific congestion in the market (Hogan, 1992, 1997; Stoft, 1997). Brunekreeft et al. (2005) and Rubio-Oderiz and Perez-Arriaga (2000) also suggest that nodal pricing (and complementary capacity charges) signals the efficient location of generation investment. However, changing market designs from zonal to nodal pricing is not a general trend in electricity markets. In the European debate on the configuration of bidding zones, nodal pricing is not currently high on the agenda.

Ehrenmann and Smeers (2005) compare different zonal congestion management schemes that have been in the discussion in Europe during that time. Assuming that certain identifiable structural bottlenecks exist within the network, bidding zones adjusted according to the lines in question result in a more efficient dispatch than one uniform price. Yet, an aggregation of several cross-border lines between zones imposes new issues when loop flows are taken into account. Holmberg and Lazarczyk (2015) compare the efficiency of three existing market designs in electricity markets: nodal, zonal, and discriminatory pricing (pay-as-bid). They conclude that all three designs lead to the same efficient dispatch but zonal pricing generators receive additional payments from system operators.

Frontier Economics and Consentec (2011, 2013), on the other hand, raise concerns about some issues connected to the reconfiguration of existing bidding zones in the European market coupling regime. The possibility of a regular reassessment of bidding zones threatens a stable and predictable investment climate. Furthermore, the configuration of bidding zones must account for possible illiquidity and issues of market power in smaller zones. Bjørndal et al. (2003) also look at the possibility of

implications on European level. The model scope is limited to the German electricity sector.

[28] The most prominent example is the Pennsylvania-New Jersey-Maryland (PJM) interconnection in the northeastern part of the US.

exercising market power. In addition, they show that a zonal design for the Nordic power market leads to completely different results regarding price, flows, congestion, and social surplus compared to a nodal approach.

The literature on market power in zonal and nodal electricity markets follows two opposing lines of argument. Introducing bidding zones or nodal schemes in the spot market splits markets and reduces regional market liquidity in the hours that trade capacity becomes a binding constraint (Frontier Economics and Consentec, 2011, 2013). Weak interconnection with the rest of the market, scarce generation resources compared to regional load, and high regional market concentration increase the locational market power of generation companies. On the other hand, Harvey and Hogan (2000) argue that one has to distinguish between the effects of increasing competition by network investment and the effects of creating larger bidding zones. In the case of transmission constraints, cost averaging and reallocation subsidize the monopolist and increase the profits of exercising market power for larger bidding zones. Thus, concealing transmission constraints within larger bidding zones does not mitigate market power. The more transparent nature of a nodal market reduces market power since generators cannot use their knowledge of physical constraints in bidding zones in their own favor. The spatial price information of nodal pricing supports the market and more tools are available to control market power.

Hogan (1999) also points out the shortfalls of a zonal market design compared to nodal pricing. A zonal representation gives the impression that different locations within each zone are similar in their pricing, in some circumstances providing wrong pricing information for market participants. Internal congestion with a strong and, due to loop flows, sometime incomprehensible effect on the electricity network is not visible and the market dispatch therefore becomes less transparent. Market rules have to be more complex in order to reflect the physical constraints of the transmission system within bidding zones not considered in the market dispatch (e.g., re-dispatch measures). Identical prices at different nodes would already show in a nodal layout, obviating the need for a zonal pooling of nodes.

Neuhoff et al. (2011) discuss additional options for congestion management in European power networks. They point out that only nodal pricing has the potential to achieve full market integration. Zonal pricing is described as a less complex design, yet problems arise from the optimal configuration of possible bidding zones. While this design matches quite well with the less complex transmission system in the Nordic countries, it is less useful for the highly meshed continental European system. Congested lines are difficult to identify as they tend to change constantly with increasing levels of varying renewable generation (Neuhoff et al., 2013).

Supponen (2011), on the other hand, argues in favor of splitting Europe into further bidding zones which better reflect congestion in the network within countries in order to improve investment signals for (interconnector) transmission capacity. Using a six-node demonstration network, Oggioni and Smeers (2013) show that the configuration of bidding zones and especially the determination of NTCs between zones are crucial for the efficiency of a zonal pricing design, like the European market coupling. Burstedde (2012) analyzes potential bidding zones for the Central Western European electricity market. The approach aggregates nodes in the network by locational marginal prices using cluster analysis. Dispatch, re-dispatch, and total system costs are calculated for different zone configurations. A nodal pricing model serves as a benchmark. Results show that an optimized zonal market configuration only leads to a small increase in total system cost compared to nodal pricing. With the right choice of NTCs to represent scarcity signals for transmission, a better *ex-ante* market dispatch is reached and fewer requirements for re-dispatch occur for the optimized zones.

Breuer et al. (2013) and Breuer and Moser (2014) use a similar methodology for the delimitation of bidding zones. Clustering nodes with similar prices to a varying number of zones, they find that about 10 to 15 zones would be optimal for the European market taking into account the trade-off between network security and market efficiency, on the one hand, and stability of bidding zone delimitation, on the other hand. Due to the ever-changing nature of the electricity system with the ongoing commissioning and decommissioning of plants and lines, delimitation of zones should change frequently, which does not favor market participants. All three publications on bidding zone configuration split Germany into at least one northern and one southern zone. Some scenarios split the northern zone even further between west and east (Breuer et al., 2013; Breuer and Moser, 2014; Burstedde, 2012).

Wawer (2007) points out that zonal pricing is a possible option for Germany, since existing rules of the European Energy Exchange (EEX) state that, in case of congestion between control areas, separate auctions for each zone can be instated. When re-dispatch costs continue to increase, a zonal market design should be introduced. Bjørndal and Jørnsten (2007) for the Nordic power market and Kunz and Zerrahn (2015) for the German power market show that coordination between transmission system operators (TSOs) is important to reduce system costs for congestion management in zonal markets. Weigt et al. (2010) and Nüßler (2012) argue that with the rising necessity for re-dispatch, useful counter measures are either high-voltage direct current (HVDC) point-to-point connections from north to south (a grid extension contained in part in the German network development plan) and/or a change in market design towards regionally differentiated prices.

Kunz (2013) applies a nodal re-dispatch model to examine a further increased congestion situation for the German spot market and re-dispatch. Nüßler (2012) uses a European spot market model optimizing for 288 type hours with scenarios on the development of the European electricity sector in 2015, 2020 and 2025. Re-dispatch in Germany is calculated with an aggregated model of 33 zones, aggregated inter-zonal flow capacity, and power transmission distribution factors (PTDFs). He finds that there will be a steady increase in re-dispatch despite network investment and recommends a change of the market design (i.e., towards a splitting of the German bidding zone). Trepper et al. (2015) analyze the same regional setting of two price zones with three consecutive models: investment in Europe, spot market (case of two price zones), zonal dispatch mixed-integer linear problem (MILP) model of Germany aggregating nodes and lines to 21 network buses with PTDFs for the German system. They also recommend the introduction of a northern and a southern bidding zone in order to reduce congestion and re-dispatch volumes. However, they see a problem in the political justification of distributional effects and therefore bring up the idea of an ex-post aggregation of locational prices for demand, similar to the approach in the Italian system. Their calculations of re-dispatch costs only compare the total system costs of a simulation with transmission constraints with those of a simulation without any transmission constraints. This approach will most likely underestimate total re-dispatch costs.

The aforementioned literature highlights the challenges of bidding zones compared to nodal pricing. Since adjusting bidding zones is part of the current European approach in meeting the necessities of increasing regional imbalances, the determination of bidding zones and NTC levels is an important challenge. In the case of the large German bidding zone, splitting it into smaller areas could be an option. The alternative is network extension to limit the expected increase of internal congestion and re-dispatch. This work expands on the existing literature on zonal pricing in Germany with a numerical model analysis. It highlights the challenges to provide a zonal spot market in Germany with reasonable trade constraints. Model results give an insight into the system and distributional effects of two proposed price zones and re-dispatch on nodal level.

3.3 Numerical optimization models

3.3.1 General modeling approach

This work applies a bottom-up electricity sector model, separately optimizing the two consecutive steps of 1) market settling in the spot market illustrated in Figure 3.1 and 2) for re-dispatch illustrated in Figure 3.2. A single bidding area with a uniform hourly electricity price is compared to a market design with two bidding zones.[29]

In the first step, the spot market model separately determines a cost-minimizing market dispatch for each week. Therefore, in the case of uniform pricing (i.e., one bidding zone), the only constraint is that electricity generation has to settle hourly load (Figure 3.1). The hourly market result includes operation of conventional, renewable, and pumped-storage hydroelectric plants and the spot market price of electricity. It reflects the lowest-cost generation dispatch of the supply function (merit order) but does not consider the physical system with its regional distribution of generation and load and their connection by transmission lines. This market dispatch might prove to be technically infeasible for implementation in the transmission network.

Thus, in a second step, it can become necessary to alter the market result in the nodal re-dispatch model (Figure 3.2). This hourly optimization of cost-minimizing re-dispatch represents actions by the TSO, altering generation levels for individual power plants (i.e., up- and down-regulation) until transmission flows are within the technical specifications of every transmission line.[30] The nodal re-dispatch model uses results of the spot market model for hourly generation levels of individual power plants as a starting point. It takes into account the location of these power plants at specific network nodes as well as a nodal distribution of electricity load. The network implementation includes a detailed representation of high-voltage transmission lines. Electricity flows are distributed on transmission lines according to the DC load flow approximation (Schweppe et al., 1988).

The case of zonal pricing assumes two separate bidding zones in the spot market and allocates supply and load to zones according to their spatial distribution. This results in two bidding zones with their own hourly merit order and electricity load (Figure 3.1). The spot market only allows for inter-zonal trade to a certain degree, the so-called net transfer capacity (NTC), which accounts for limited physical transmission capacity. In hours where this trade limit becomes a binding constraint, the market results of the zonal case diverge from those of uniform pricing. The market dispatch sees some generation shift from the exporting to the importing zone and zonal market prices diverge with a lower price on electricity in the exporting and a higher one in the importing zone. The re-dispatch model follows the same approach as in the case of uniform pricing but can have a different initial point for

[29]Section 3.3.2 discusses simplifications and limitations of the model approach and relates it to other publications. The detailed mathematical description of the model equations follows in Sections 3.3.3 and 3.3.4 and input data of the model in Section 3.3.5. The nomenclature is summarized in the List of Mathematical Notation, Tables 1–5, pages xxi–xxv.

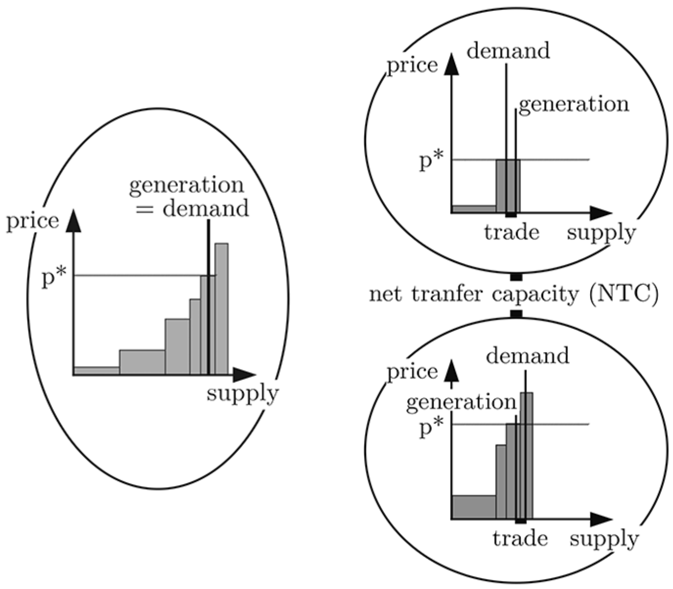
[30]The model only considers re-dispatch required to prevent network flows exceeding the thermal limits of transmission lines. Other causes of re-dispatch (e.g., regional voltage stability) are not included as they require more technical model approaches.

hourly generation levels of power plants. In these hours, when spot market results for uniform and zonal pricing diverge, less re-dispatch might reflect well on zonal pricing if the trade constraints in the spot market provide a reasonable approximation of bottlenecks in the transmission network.

In summary, spot market results demonstrate the impact of bidding zones on spatial generation levels and distribution effects on consumers and producers in the respective bidding zones. Re-dispatch shows the extent and spatial distribution of adjustments necessary to reach the least-cost generation dispatch in the nodal model for different bidding zone configurations in the spot market.

Uniform pricing model
for single bidding zone

Zonal pricing model
for two bidding zones



Input parameters:

- Hourly demand by bidding zone
- Hourly available generation capacity for each power plant and each renewable technology by bidding zone
- Capacity and storage size of pumped-storage plants
- NTC between two bidding zones

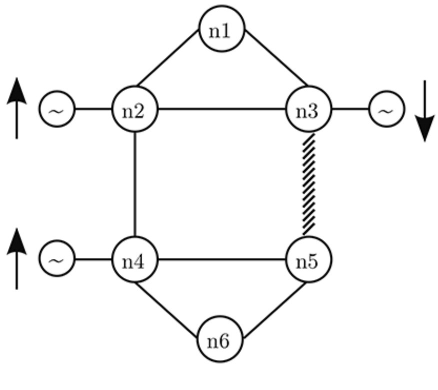
Hourly model results:

- Spot market price by bidding zone
- Generation level for each generating unit
- Generation level for each renewable technology
- Operation of pumped-storage hydroelectric plants
- Trade flows between bidding zones

Figure 3.1: Spot market models with weekly runs of 168 hours

Nodal re-dispatch model

(exemplary re-dispatch to reduce line flow on $l_{3,5}$)



Input parameters:

- High-voltage transmission network with nodal resolution and physical line characteristics
- All input parameters of spot market (except NTC level) disaggregated to nodal level
- Generation results of spot market (generating units, renewables, and pumped-storage hydroelectric plants)

Hourly model results:

- Re-dispatch (i.e., up- and down-regulation) of generation levels for each generating unit and for renewables

Figure 3.2: Hourly re-dispatch model for adjustments of spot market dispatch

3.3.2 Limitations of the model approach

The methodology is applied to the German electricity market as of 2012 and to scenarios for 2015. Therefore, it assumes simplifications for the spot market and re-dispatch model, the determination of bidding zones and NTC levels, and has a spatial limitation to the German market in an integrated European system. These limitations have to be taken into consideration for the evaluation of the results.

Model simplifications

The spot market and re-dispatch models abstract from reality by assuming perfect competition, perfect foresight, and by relaxing technical constraints.

The approach neglects market players and their bidding strategies. The optimization of the spot market dispatches power plants and pumped-storage hydroelectricity in order to minimize system costs. Also, spot market and re-dispatch are modeled in two separate steps. Thus, the approach is not suited for addressing possible issues of strategic behavior and market power. This work also abstracts from uncertainty as it does not consider forecast errors in demand and in intermittent generation or power plant and transmission line outages. Uncertainty could be an additional source for re-dispatch resulting in higher levels than those calculated in the model results.

Finally, the models abstract from non-linear technical restrictions like minimum load, load changing constraints, partial load efficiency, and must-run conditions of thermal power plants (e.g., combined heat and power (CHP) plants). They also do not represent load changing costs for conventional power plants. Generation results overestimate hard coal generation, as must-run for mostly gas-fired CHP plants is neglected. In summary, the technical simplifications overestimate system flexibility and result in fewer hours with extreme prices in the spot market (either very low and even negative prices or price spikes). In re-dispatch, power plants with low variable generation costs have to reduce generation output less frequently. Must-run CHP plants located in zones with down-regulation could increase re-dispatch requirements but are not available for down-regulation themselves. On the other hand, power plants with must-run conditions could reduce the regional imbalance of the spot market dispatch and re-dispatch levels if they are located in the importing zone.

Representation of re-dispatch

The re-dispatch model follows a cost-based approach and assumes perfect coordination of re-dispatch in Germany. The model adjusts the spot market result to reach the lowest possible generation dispatch costs, given the available options for up-/down-regulation. Therefore, it only considers variable generation costs of the respective power plant's generating unit but abstracts from additional payments for load changing and opportunity costs. By neglecting load changing costs the model overestimates optimal re-dispatch levels. Opportunity costs have not been refunded in the regulatory scheme in Germany so far (BNetzA, 2012b). In 2015 however, the practice to exclude opportunity costs is under review raising questions on future refund levels for re-dispatch.

The re-dispatch model allows for changing output of all conventional and renewable generation capacities.[31] In 2015, regulation requires generating units with more than 10 MW to participate in re-dispatch. Thus, the model allows the use of small-scale generation capacity for re-dispatch which is not included in the regulation. This simplification has very limited implications on results as the respective power plants

[31] All generation and load from subordinated voltage levels is allocated to the nearest node of the high-voltage transmission system. Thus, distributed generation is included in the optimization of the generation dispatch.

have comparably high variable costs and the model hardly uses them for re-dispatch. Still, the barrier of 10 MW has recently been lowered from 50 MW, indicating the increasing value of smaller generating units for system security.

The spot market model includes an inter-hourly optimization of the operation of pumped-storage hydroelectricity. As the re-dispatch model optimizes hour by hour it does not include the intertemporal consideration of pumped-storage plants. To avoid issues of consistency for storage levels, changes in pumped-storage operation are excluded in the re-dispatch model.[32] The implications of not including pumped-storage in re-dispatch on model results are not straightforward due to the intertemporal optimization. The pumped-storage capacity in Germany is shared between the middle and in the south of the country. The case with two bidding zones results in additional pumped-storage operation. Zonal spot market prices provide additional incentives for pumping in the northern zone and generation in the southern zone in hours of diverging electricity prices.

The focus of the re-dispatch model is the analysis of spatial implications which market dispatch of uniform and zonal pricing has on re-dispatch. The linear structure of the model results in a similar dispatch to nodal pricing. The limitations for pumped-storage plants prevent equal results. Thus, the model formulation for re-dispatch is closer to the required adjustments of the spot market dispatch reaching the benchmark of nodal pricing than to a more restricted re-dispatch, which only has to obtain feasibility, as conducted by TSOs. It is important to remember this aspect of the re-dispatch model for the discussion of the model results.

Bidding zone delimitation and NTC calculation

There are several methods for the delimitation of bidding zones (see Section 3.2). The current situation in Europe mostly reflects national borders as zonal borders with different suggestions to form new bidding zones (Breuer and Moser, 2014; Burstedde, 2012; Supponen, 2011). In the case of Germany mainly two zones are being discussed: one zone with high wind generation in the north and one zone with high demand in the south. Another option is a further division of the northern zone which is composed of the main demand centers in western Germany with large conventional capacity, the coastal regions with increasing onshore and offshore wind capacity, and the east with low demand and excess lignite capacity. Regional imbalances in the northern zone change with the hourly availability of wind generation, which

[32] Re-dispatch of pumped-storage hydroelectricity would require additional assumptions. According to the regulation, compensation for re-dispatch for in-/decreasing generation or increasing pumping is estimated using average acquisition costs for pumped water in the previous quarter of the year plus additional costs for losses and network fees. Reduction of pumping is considered as load management and not included in re-dispatch (BNetzA, 2012b).

makes the definition of additional zonal borders less clear than the division between northern and southern Germany.[33] This work focuses on the zonal setting with one northern and one southern border. It is the most discussed option in the political arena, representing most of the congested lines in 2012, and providing an alternative in case of stalled progress of network expansion (BMWi, 2014).

The optimal level of net transfer capacity (NTC) is difficult to determine.[34] In practice, it would be decided by the TSO according to different calculation methods (ETSO, 2001). Starting out from a so-called base case exchange (BCE) the total transfer capacity (TTC) is determined by shifting generation between the two zones as long as the physical system is secure. Finally, a transmission reliability margin (TRM) is subtracted to form the NTC. Based on the circumstances (load, renewable production, etc.) the NTC is adjusted regularly but there is no common algorithm, shared by all TSOs, that allows for a transparent and comprehensible calculation.[35]

NTC levels are also typically lower than aggregated physical line capacity between two zones to account for intra-zonal congestion, uncertainty, and other externalities. On average, the available import (export) NTC of Germany, aggregated for all neighboring countries, was 12.3 GW (8.9 GW) in 2014 (BNetzA and Bundeskartellamt, 2015). This application assumes fixed NTC values and tests all levels between 6 GW and 10 GW in steps of 1 GW between the two bidding zones in Germany. The selected level is based on considerations of the calculations explained above.[36]

Limitation of spatial scope to Germany

The spatial representation of the model is limited to the German electricity system.

The representation of neighboring countries in the spot market would allow for endogenous model results on imports and exports in the spot market. In the case of zonal pricing, lower prices in the northern zone reduce imports and increase exports and vice versa for higher prices in the southern zone. This effect results in lower average price differences between the two bidding zones in Germany. Lower prices in northern Europe and higher prices in southern Europe could result in a decline in transit flows. These effects are not included in the model analysis.

[33]Since open cast mining and firing of lignite will be in the decline in the next years due to the government's climate goals in the light of the Paris agreement, this chapter models only the two zones for Germany. In the 2020 perspective, additional wind capacity is likely to increase internal congestion in the northern zone.

[34]Central Western Europe launched flow-based market coupling on May 20, 2015 for capacity calculation replacing NTC-based methods.

[35]Neuhoff et al. (2013) includes a detailed description of NTC calculation and their operational application by European TSOs.

[36]The analysis of weekly model results indicate that variable NTC levels could further reduce re-dispatch in Germany.

The focus on Germany allows for using historic values for physical cross-border flows (i.e., hourly physical imports and exports reported by the TSOs). Physical cross-border flows are subject to flow-distribution on transmission lines. In the highly meshed networks of Central Europe, they deviate to a large extent from trade flows in the zonal spot market. The consideration of historic cross-border flows provides more realistic network flows in the re-dispatch model. Of course, changes of cross-border flows as a result of two bidding zones are not included.

3.3.3 Mathematical formulation of the spot market model

The spot market model determines the power plant dispatch with the cost-minimizing objective function 3.1 for total variable generation costs c^{spot} of conventional generating units in the respective hours t. Variable generation costs $\hat{c}_{pt}^{\text{unit}}$ of the respective power plant's generating unit p are calculated by fuel price, carbon emission factor of the fuel, cost of carbon emission allowances, and the unit's efficiency factor. Renewable generation is assumed to a have variable generation cost of zero. For this application the spot market model optimizes power plant operation in weekly blocks of 168 hours.[37]

$$\min_{g^{\text{unit}}} \mathrm{c}^{\text{spot}} = \sum_{pt} g_{pt}^{\text{unit}} \hat{c}_{pt}^{\text{unit}} \tag{3.1}$$

The model constraints of the supply side account for conventional generation 3.2a, renewable generation 3.2b, and pumped-storage hydroelectric plants 3.2c–3.2e. Hourly conventional generation output g_{pt}^{unit} is limited for every generating unit to its hourly available generation capacity. This parameter calculates by installed turbine capacity $\overline{g}_{pt}^{\text{unit}}$ adjusted by a seasonal availability factor av_{pt}^{unit}. Maximal hourly renewable generation r_{nit}^{tech} of each technology i at the respective network node n is determined by aggregated generation capacity $\overline{r}_{nit}^{\text{tech}}$ and hourly availability level av_{nit}^{tech}. The three constraints for the representation of pumped-storage hydroelectric plants s include: an inter-hourly constraint on the charging level of each plant ls_{st}, cycle efficiency of 75%, limitation of pumping $\overleftarrow{ps}_{st}$ and generation $\overrightarrow{ps}_{st}$ to the turbine rating $\overline{ps}_s$, and an upper bound for the charging level $\overline{ls}_s$. Both cases, uniform and zonal pricing,

[37] In the weekly runs pumped-storage hydroelectric plants have inter-hourly constraints on the charging level 3.2e. The model optimizes the operation over the course of 168 hours. This allows the weekly load pattern and hourly renewable generation levels to be reflected. The storage level is assumed to zero in the first and last hour of the week (i.e., Friday to Saturday at midnight) to account for the connection of the weekly model runs.

have the same objective function and generation constraints.

$$
\begin{aligned}
g^{\text{unit}}_{pt} &\leq \overline{g}^{\text{unit}}_{p} av^{\text{unit}}_{pt} && \forall \quad p,t && \text{(3.2a)}\\
r^{\text{tech}}_{nit} &\leq \overline{r}^{\text{tech}}_{ni} av^{\text{tech}}_{nit} && \forall \quad n,i,t && \text{(3.2b)}\\
\overrightarrow{ps}_{st} + \overleftarrow{ps}_{st} &\leq \overline{ps}_{s} && \forall \quad s,t && \text{(3.2c)}\\
ls_{st} &\leq \overline{ls}_{s} && \forall \quad s,t && \text{(3.2d)}\\
ls_{st} &= 0.75\overleftarrow{ps}_{st} - \overrightarrow{ps}_{st} + ls_{s(t-1)} && \forall \quad s,t && \text{(3.2e)}
\end{aligned}
$$

As of 2015, the single bidding area with one electricity price for Germany does not value internal network constraints on market prices. The market dispatch includes the lowest-cost generation capacities of the merit order covering hourly load levels. Spatial scope and number of energy balances determine the bidding zone configuration in the spot market. The case with a single bidding zone is represented by a single energy balance 3.3 including all generation $g^{\text{unit}}_{pt}, r^{\text{tech}}_{nit}, \overrightarrow{ps}_{st}$, fixed hourly cross-border flows for imports pf^{import}_{nt}, and exports pf^{export}_{nt} with neighboring countries, as well as load $q_{nt}, \overleftarrow{ps}_{st}$ in each hour. Marginal values on the hourly energy balance represent hourly electricity prices in the spot market.

$$
\begin{aligned}
&\sum_{p} g^{\text{unit}}_{pt} + \sum_{n}\left(\sum_{i} r^{\text{tech}}_{nit} + pf^{\text{import}}_{nt}\right) + \sum_{s} \overrightarrow{ps}_{st} \qquad \forall \quad t \qquad \text{(3.3)}\\
&\qquad = \sum_{n}\left(q_{nt} + pf^{\text{export}}_{nt}\right) + \sum_{s} \overleftarrow{ps}_{st}
\end{aligned}
$$

In the case of two bidding zones, each bidding zone z has its own energy balance 3.4a. Hourly supply, demand, and cross-border flows aggregate to one of the two zones. Inter-zonal trade pf^{ntc}_{zxt} is limited by the NTC level $\overline{pf}^{\text{ntc}}_{zx}$, an aggregated zone-to-zone trade capacity in the spot market, in Equation 3.4b. In case the constraint on the trade capacity becomes a binding one in a specific hour, the marginal value of the two energy balances (i.e., variable cost of the marginal power plants) and thus the zonal spot market prices differ between the two zones.

$$
\begin{aligned}
&\sum_{p\in P_z} g^{\text{unit}}_{pt} + \sum_{s\in S_z} \overrightarrow{ps}_{st} + \sum_{n\in N_z}\left(\sum_{i} r^{\text{tech}}_{nit} + pf^{\text{import}}_{nt}\right) + \sum_{x} pf^{\text{ntc}}_{zxt} \qquad \forall \quad z,t \qquad \text{(3.4a)}\\
&\qquad = \sum_{n\in N_z}\left(q_{nt} + pf^{\text{export}}_{nt}\right) + \sum_{s\in S_z} \overleftarrow{ps}_{st}\\
&|pf^{\text{ntc}}_{zxt}| \leq \overline{pf}^{\text{ntc}}_{zx} \qquad \forall \quad z,x,t \qquad \text{(3.4b)}
\end{aligned}
$$

3.3.4 Mathematical formulation of the re-dispatch model

The spot market model is followed by a re-dispatch model with a nodal network representation of the electricity system. Model inputs are nodal conventional, renewable, and pumped-storage operation levels resulting from the spot market dispatch. The implementation of the DC load flow approach (Schweppe et al., 1988) provides the initial flow distribution on individual high-voltage transmission lines. The re-dispatch model adjusts the spot market dispatch in case it causes line flows exceeding the physical limits of lines. Technical feasibility is reached by re-dispatch, that is, decreasing output of some power plants and increasing output for others until the dispatch obeys every single line flow constraint in the high-voltage transmission network. The re-dispatch is not organized in a market but conducted with the objective function 3.5 of minimizing generation costs c^{rd}. Increasing output of conventional generation g^{+}_{pt} causes variable generation costs. On the other hand, decreasing generation levels g^{-}_{pt} save variable costs. Typically, system costs increase as power plants initially not in the market dispatch replace power plants with lower variable generation costs initially dispatched. This formulation optimizes joint re-dispatch at the national level. It does not restrict cross-zonal re-dispatch between the two bidding zones.[38]

$$\min_{g^{+},g^{-}} \mathrm{c}^{\mathrm{rd}} = \sum_{pt} g^{+}_{pt}\hat{c}^{\mathrm{unit}}_{pt} - \sum_{pt} g^{-}_{pt}\hat{c}^{\mathrm{unit}}_{pt} \tag{3.5}$$

The re-dispatch model guarantees line flows not exceeding the lines' maximum flow capacity $\overline{pf}_l$ in 3.6a.[39] Changes in the output levels of power plants affect the network input ni_{nt} and the line flows pf_{lt}, which are calculated using the linear approximation of the DC load flow approach in the Equations 3.6b–3.6d. The voltage angle θ_{nt} is fixed to zero for one node $\hat{n}$ which is defined as slack bus. Network transfer matrix h_{ln} and network susceptance matrix b_{nk} combine information on network topology and line susceptance.

Generation output of conventional units can be maximally increased by the difference between the hourly available power plant capacity and the scheduled output level g^{spot}_{pt}, in 3.6e. The scheduled output level of the market dispatch can be decreased to zero in 3.6f. The same holds for renewable capacity r^{spot}_{nit}, in 3.6g and 3.6h.

[38] Low NTC levels can result in a spot market dispatch which is not using all available transmission capacity on cross-zonal lines. Thus, the re-dispatch model can generate negative re-dispatch costs utilizing the transmission capacity by optimizing the nodal generation dispatch.

[39] The maximum flow capacity includes a 20% TRM to approximate n-1 security.

$$|pf_{lt}| \leq \overline{pf}_l \qquad \forall \quad l,t \tag{3.6a}$$

$$ni_{nt} = \sum_k \theta_{kt} b_{nk} \qquad \forall \quad n,t \tag{3.6b}$$

$$pf_{lt} = \sum_n \theta_{nt} h_{ln} \qquad \forall \quad l,t \tag{3.6c}$$

$$\theta_{\hat{n}t} = 0 \qquad \forall \quad t \tag{3.6d}$$

$$g^+_{pt} \leq \overline{g}^{\text{unit}}_p av^{\text{unit}}_{pt} - g^{\text{spot}}_{pt} \qquad \forall \quad p,t \tag{3.6e}$$

$$g^-_{pt} \leq g^{\text{spot}}_{pt} \qquad \forall \quad p,t \tag{3.6f}$$

$$r^+_{nit} \leq \overline{r}^{\text{tech}}_{ni} av^{\text{tech}}_{nit} - r^{\text{spot}}_{nit} \qquad \forall \quad n,i,t \tag{3.6g}$$

$$r^-_{nit} \leq r^{\text{spot}}_{nit} \qquad \forall \quad n,i,t \tag{3.6h}$$

At the same time the energy balance 3.7a must hold for each single node. Imports and exports to neighboring countries remain fixed to historic hourly cross-border flows. Pumped-storage hydroelectricity is fixed to the spot market dispatch and is not available for re-dispatch (as discussed in Section 3.3.2).

$$\begin{aligned} \sum_{p \in P_n} (g^{\text{spot}}_{pt} + g^+_{pt} - g^-_{pt}) + \sum_i (r^{\text{spot}}_{nit} - r^-_{nit}) \qquad \forall \quad n,t \\ + pf^{\text{import}}_{nt} + \sum_{s \in S_n} ps^{\text{spot}}_{st} + ni_{nt} = q_{nt} + pf^{\text{export}}_{nt} \end{aligned} \tag{3.7a}$$

The models are implemented using the General Algebraic Modeling System (GAMS) version 24.2 and solved by the commercial solver CPLEX.

3.3.5 Model data for 2012 and scenarios for 2015 and line extension

This analysis uses the dataset for the German electricity sector with data from 2012 which is published in the detailed data documentations and only relies on public sources.[40] The input parameters include network topology, power plant data, temporal system data, and price data. The electricity sector data is disaggregated to the nodal level of the German transmission system.

The network topology consists of 438 network nodes and 938 transmission lines representing the high-voltage transmission system of 220 kV and 380 kV (Figure 3.3). The re-dispatch model requires line-specific network data, i.e., maximum power

[40] The data section in this chapter describes the main characteristics of the dataset while additional information can be found in the data documentations (Egerer et al., 2014a; Egerer, 2016). The nodal model including data for Germany is published as an open source model on the DIW Berlin website (see Chapter 2 and `www.diw.de/elmod`).

flow $\overline{pf}_l$, line susceptance, and starting and ending node.[41] The spot market model does not include any trade constraint for a single bidding zone and assumes different NTC level between 6 and 10 GW for two bidding zones (in steps of 1 GW).

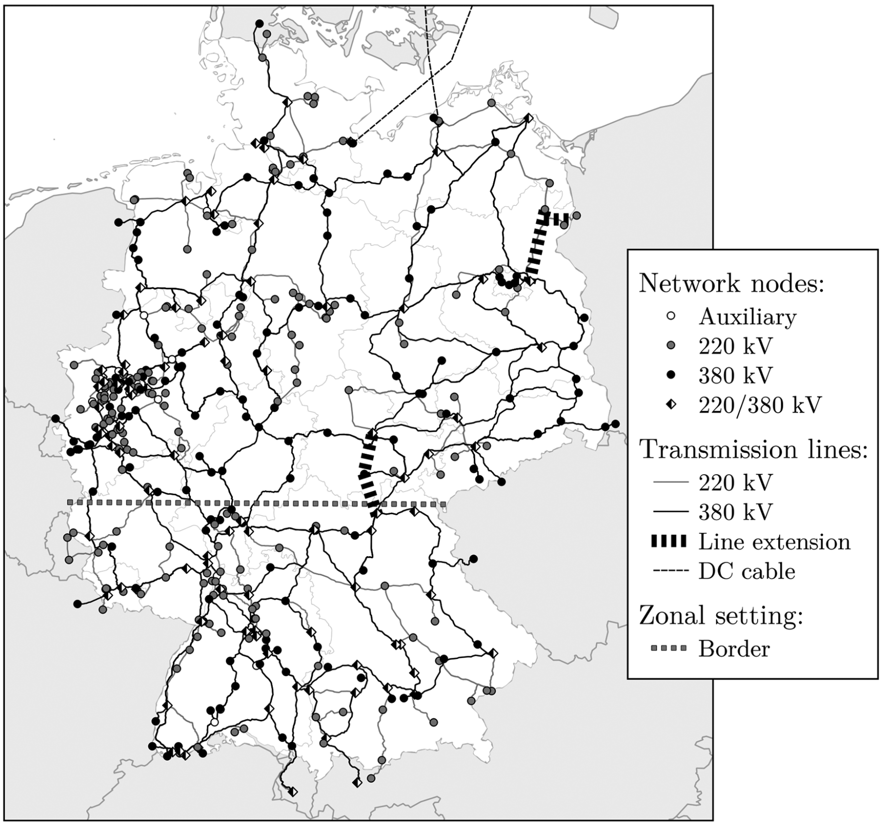


Figure 3.3: High-voltage transmission network in 2012, two bidding zones, and additional lines in the transmission extension scenario

Data on generation capacity and electricity load is linked to network nodes. Generation capacity includes conventional thermal power plants (559 generating units with 85.6 GW), 32 pumped-storage hydroelectric plants (8.8 GW pumping/generation capacity with total storage capacity of 53 GWh), and renewable technologies (74.3 GW). The spatial distribution of hourly electricity load on network nodes deviates between peak (86 GW) and off-peak load (36 GW).[42] The aggregation of the

[41]The network transfer matrix h_{ln} and network susceptance matrix b_{nk} are derived with start and end node and line susceptance (Leuthold et al., 2012). Physical properties of transmission lines are approximated by their length and voltage level with assumptions on specific technical parameters for overhead power lines.

[42]There is no publicly available data on nodal hourly electricity load in Germany. To approximate spatial load distribution, a regional load key is calculated according to peak/off-peak electricity load on state level in Germany. Distribution factors for states are subject to linear interpolation for national hourly load levels between peak/off-peak. Within states, proximity of network nodes to population centers and monetary measures determine the nodal allocation key of demand.

nodal data to the two bidding zones shows proportionally higher shares for lignite, hard coal, and wind power in the northern zone compared to nuclear, hydropower, and photovoltaics in the southern zone (Table 3.1).

Temporal input data uses hourly time series with 8784 hours for the year 2012.[43] Hourly national load levels and the nodal distribution key lead to hourly nodal demand q_{nt}. Installed capacity of conventional thermal power plant units $\overline{g}_{pt}^{\text{unit}}$ together with a seasonal availability factor av_{pt}^{unit} calculates hourly available capacity. Maximum available renewable power generation defines by installed capacity $\overline{r}_{nit}^{\text{tech}}$ adjusted with regional hourly availability factors for wind and photovoltaics av_{nit}^{tech} provided by German TSOs. Compared to the previous ten years, 2012 was, by and large, an average year for wind and solar in Germany (BMWi, 2015). Only wind generation in coastal regions was below average in the second half of the year (IWR, 2013) while photovoltaics output was a few percentage points above average.[44] Biomass is implemented with an annually fixed hourly availability factor while the seasonal characteristic of hydropower is included with a monthly varying factor. Import flows pf_{nt}^{import} from and export flows pf_{nt}^{export} to neighboring countries are fixed parameters. They are implemented at respective network nodes of cross-border lines and represent hourly physical cross-border flows as measured by German TSOs in 2012.

Price data includes fuel prices (Table 3.2), regional cost factors for inland transport of hard coal increasing towards the south of Germany between 2–20 EUR/t[45], and the price for CO_2 emission allowances of 7.94 EUR/t.

The 2015 scenario tests the sensitivity of the 2012 model results by adjusting regional generation capacities (Table 3.1) while using 2012 data for all other parameters (ceteris paribus). In the 2015 scenario, the northern zone sees additional onshore and offshore wind investment. At the same time, several new hard coal plants (+5.5 GW) commence operations, resulting in an overall increase of 1.2 GW, after eliminating old coal capacities. In the south, one nuclear power plant is scheduled to be shut down in 2015. Half of this capacity is compensated for by one new coal power plant while additional peak capacity (-1.3 GW) retires. Photovoltaics is expected to exceed 40.0 GW (+9.0 GW) with about equal shares for both zones. While the overall conventional capacity hardly changes, a shift of 2.0 GW takes

[43] By and large, 2012 has been an average year for the electricity system. One exception has been the very tight supply situation in the first half of February 2012 due to very cold weather conditions in Germany and neighboring countries. This event is likely to increase re-dispatch requirements due to tight network situations.

[44] Calculations for hourly availability factors consider sub-annual monthly capacity additions. Total photovoltaic capacity increased about 30% (+7.6 GW) and onshore wind about 7% (+2.1 GW) over the course of 2012.

[45] Transport costs in the variable costs range between 0.7–7.4 EUR/MWh depending on location and efficiency of the hard coal generating unit.

place from the southern to the northern zone. An additional sensitivity for the 2015 scenario tests the effect of investment in transmission infrastructure. It includes the transmission line Vieselbach-Altenfeld-Redwitz (two circuits of 380 kV) between the northern and southern zone, increasing the physical transmission capacity between eastern and southern Germany as well as the line Uckermarkleitung allowing for better wind integration northeast of Berlin. These two corridors are part of the EnLAG projects; their absence has caused a large share of re-dispatch in recent years (BNetzA and Bundeskartellamt, 2015).[46] Both lines were either approved or under construction at the end of 2015 (BNetzA, 2015).

[GW]	2012			2015		
Technology	North	South	Total	North	South	Total
Nuclear	4.1	8.0	12.1		-1.3	-1.3
Lignite	20.4	–	20.4	+0.6		+0.6
Hard coal	17.6	7.1	24.7	+1.2	+0.6	+1.8
CCGT	5.2	3.2	8.4	+1.0		+1.0
Gas	8.4	3.9	12.3	-1.2	-0.2	-1.4
Oil	2.1	1.7	3.8	-0.2	-1.2	-1.4
Waste	1.1	0.4	1.5			
Other	2.3	0.1	2.4	-0.1		-0.1
Pumped-storage[47]	3.9	4.9	8.8			
Sum conventional	65.1	29.3	94.4	+1.3	-2.1	-0.8
Hydropower	0.6	3.1	3.7		+0.1	+0.1
Biomass	4.3	2.1	6.4	+0.4	+0.2	+0.6
Wind onshore	28.5	3.0	31.5	+5.6	+0.6	+6.2
Wind offshore	0.4	–	0.4	+2.6		+2.6
Photovoltaics	16.8	15.6	32.4	+4.7	+4.3	+9.0
Sum renewable	50.6	23.7	74.3	+13.2	+5.2	+18.4
Peak load in zones	54.6	31.4	86.0			

Table 3.1: Generation capacities and peak load for 2012 and change in 2015

[EUR/MWh]	Fuel				
	Nuclear	Lignite	Hard coal	Natural gas	Oil and other
Fuel price	3.0	4.0	11.4	32.4	48.4

Table 3.2: Fuel prices for conventional thermal power plants

[46]In 2009, the EnLAG law (Bundesregierung, 2009) has taken effect which outlines the facilitated implementation of 24 extension projects (EnLAG projects) in the German high-voltage transmission system.

[47]Pumped-storage in southern Germany includes 1.1 GW in Luxemburg and 1.5 GW in Austria connected to the German system.

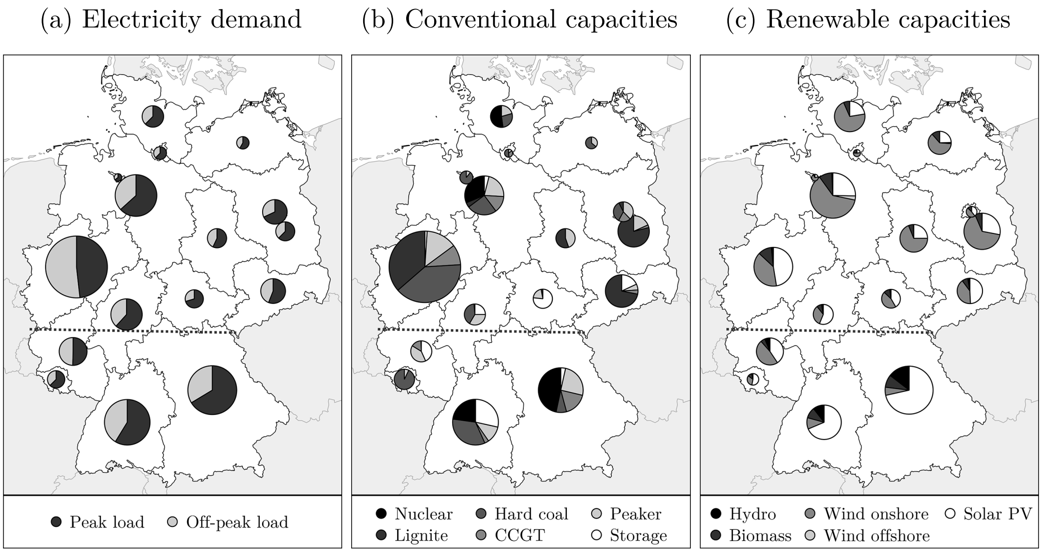


Figure 3.4: Spatial electricity data by state for the German electricity sector in 2012

The regional characteristics of the input data are illustrated in Figure 3.4 with an aggregation of nodal data on state level for demand, conventional power plants, and renewable generation capacities. Also, Table 3.1 states the numbers for the analyzed northern and southern bidding zone which are confined by the border triangle of Germany, Belgium, and Luxembourg at the western edge to Frankfurt and the northern border of Bavaria. Annual electricity demand in the northern zone (357 TWh) is significantly higher than in the southern zone (194 TWh) but demand in the northern zone is concentrated in the west. Also, input data assumes different spatial allocation of load in peak and off-peak hours. Conventional capacity illustrates the historical role of nuclear (northwest and south) and lignite (west and east) as base load technologies which are supplemented by hard coal in most regions except for Bavaria and the east of Germany. In the southern part, conventional capacity together with hydropower and pumped-storage hydroelectricity covers about the peak load while off-peak demand can be provided in large shares by nuclear power.[48] Most conventional generation capacity following nuclear power in the merit order (i.e., lignite and hard coal) is located in the northern bidding zone.[49] The southern part of Germany sees large additional renewable generation in hours of

[48]In 2011, about 6.5 GW of nuclear power (six units) have been shut down in southern Germany and 3.6 GW (three generating units) in the northwest. The remaining nuclear capacity will be phased out gradually until 2022.

[49]Fuel costs include inland transportation costs for imported hard coal which are higher in southern Germany. Thus, hard coal plants closer to the North Sea cost have lower variable costs in the merit order. Due to the high price spreads between hard coal and natural gas and low historical CO_2 prices even old coal-fired power plants have lower variable generation costs than modern gas-fired CCGT plants.

high solar radiation in the summer months. In comparison to wind generation, photovoltaics has a positive temporal and spatial correlation with electricity load. Load levels are higher during the day and about half of photovoltaic capacity is based in southern Germany. The northern bidding zone provides conventional generation exceeding regional demand (hard coal in the west and lignite in the east). In hours with high wind generation, onshore wind power increases the spatial imbalance of supply and demand in the spot market. This imbalance further increases with continuous onshore wind investment and is intensified by additional offshore wind investment in northern Germany and existing regional surplus generation of lignite power plants in the east of Germany. The sensitivity of this development is examined in the 2015 scenario. Compared to 2012, the increasing share of wind power and the regional shift in conventional capacity with low variable generation costs is likely to increase the regional imbalance in the least-cost generation dispatch for many hours.

3.4 Results

The results section distinguishes between the effects two bidding zones have on the market dispatch, on re-dispatch levels, and also on distributional implications. A sensitivity run for 2015 presents the effect of limited network investment reinforcing the German transmission network.

3.4.1 Implications of two bidding zones on the spot market dispatch

Differences in spot market dispatch between uniform and zonal pricing result from the additional market constraint for trade flows between the two bidding zones. In hours with binding trade constraints, zonal prices diverge and generation output is shifted between bidding zones.

Figure 3.5 illustrates commercial flows in the spot market model which are mostly directed from north to south while few summer hours have small reverse flows. The seasonal characteristics of the trade flows show high electricity exchanges in many hours during the winter months when the NTC of 8 GW becomes binding and prices are higher in the south. The constraint from south to north is never binding in the spot market. Thus, implications of zonal pricing depend mostly on the load pattern during the winter (e.g., severe versus mild weather conditions) and the respective hourly wind generation levels. The annual trade flows increase from 29.8 TWh in 2012 to 40.7 TWh in 2015 (north to south) and decrease from 0.6 TWh in 2012 to 0.3 TWh in 2015 (south to north).

The average annual electricity price differential between the northern and southern zone for an NTC of 8 GW is rather low with 0.4 EUR/MWh in 2012 and grows to

1.7 EUR/MWh in 2015.[50] The two bidding zones do not split the market in most hours of the year. In the results for 2012, zonal prices deviate in about 450 hours with a maximum difference of 33.6 EUR/MWh and an average difference of 6.9 EUR/MWh (Figure 3.6a). Many hours with a significant price difference occur in January and February, with price levels in the spot market of about 50 EUR/MWh in the northern zone, and more frequently deviating zonal prices in hours with high wind power generation (Figures 3.7a–3.7b). Hours with a high residual load in the southern zone are more likely to result in high price differentials while the opposite causality holds for the northern zone to a lesser extent (Figures 3.7c–3.7d).

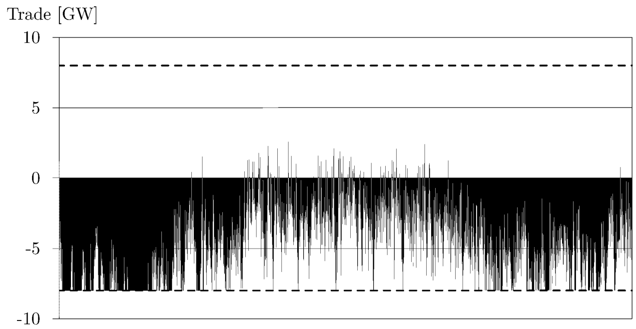


Figure 3.5: Hourly trade flows north to south (-) and south to north (+) over the year 2015 (Jan–Dec) for the NTC of 8 GW

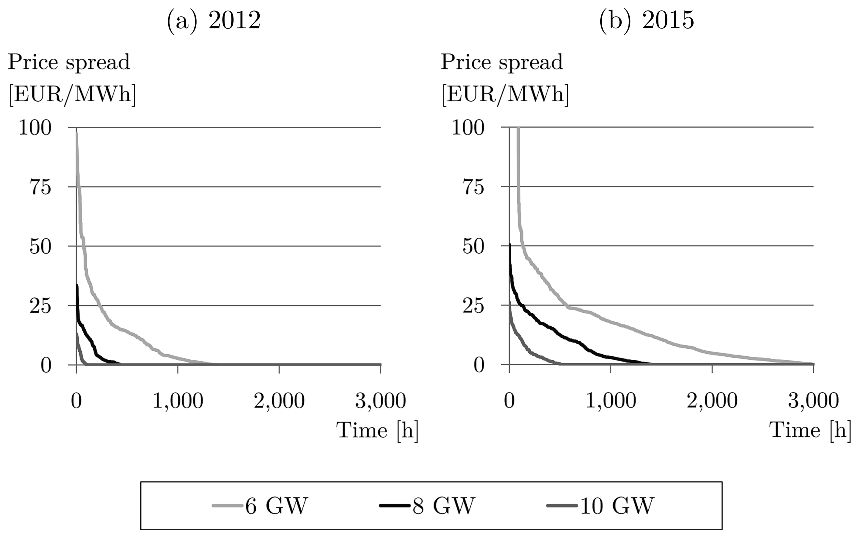


Figure 3.6: Price mark-ups of the southern zone compared to the northern zone

[50] Increasing/decreasing the NTC level by 1 GW decreases/increases the price differential by a factor of two to three. Due to the model assumptions, the zonal price difference could be underestimated. Thema (2013) predicts a price differential of 3.8 EUR/MWh for an NTC of 7 GW in 2012 in a market study on two price zones in Germany, which decreases to 1.5 EUR/MWh for 10 GW.

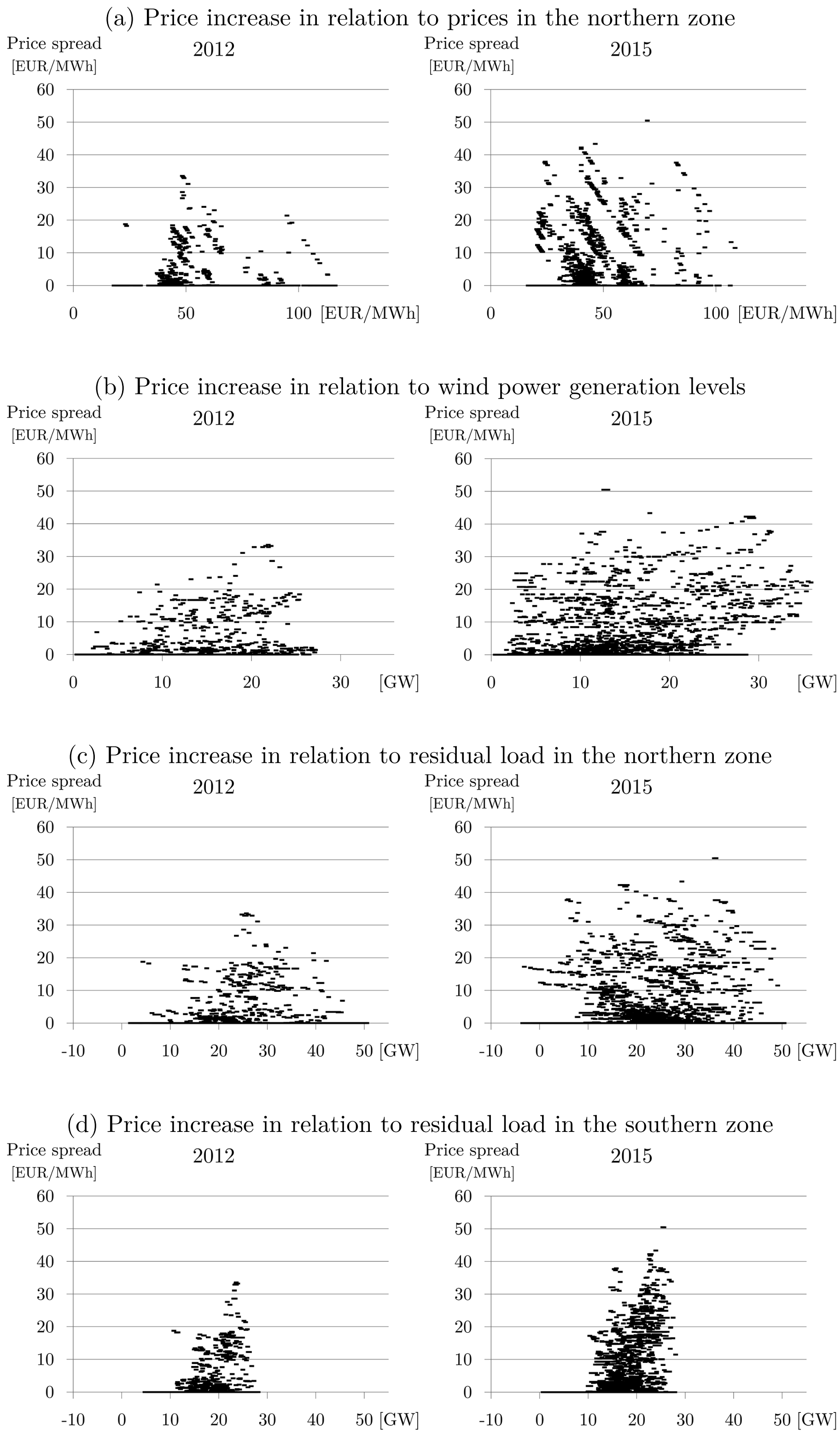


Figure 3.7: Price increase in the southern zone compared to the northern zone

The results for 2015 reflect the growing regional imbalance in generation capacity of low variable costs, both for wind turbines and conventional power plants. Zonal prices in Figure 3.6b deviate in 1455 hours of the year for an NTC level of 8 GW with a maximum difference of 50.5 EUR/MWh and an average difference of 10.2 EUR/MWh. The number of hours with a difference in zonal prices increases in situations where coal sets the marginal price in the northern zone (i.e., at about 40–50 EUR/MWh) as well as with high wind generation (levels above 28 GW always result in a price differential). For lower NTC values, commercial import flows and electricity supply in the southern bidding zone are not sufficient to settle zonal electricity load in all hours (e.g., 90 hours with supply shortage for an NTC of 6 GW).

The implementation of the NTC between the two bidding zones affects the power plant dispatch in the spot market (Table 3.3). In the southern zone, output increases by about 0.5 TWh in 2012 and 2.4 TWh in 2015, while it decreases in the northern zone. The absolute regional redistribution mostly affects hard coal and, to a lesser extent, gas-fired power plants. The relative changes are smaller in the northern zone but reach 2%/3% for hard coal-/gas-fired power plants in the southern zone in 2012 and about 4%/10% in 2015.

[TWh]		**Fuel**					
		Nuclear	Lignite	Coal	Gas	Other	RES
2012	North	32.4	142.6	(-0.4) 103.9	(-0.1) 21.3	18.8	88.1
	South	63.0	–	(+0.3) 39.5	(+0.2) 14.0	3.2	49.0
2015	North	32.4	(-0.1) 145.7	(-1.9) 99.8	(-0.3) 12.6	18.2	109.4
	South	52.9	–	(+1.6) 37.5	(+0.8) 7.8	3.2	55.9

Table 3.3: Zonal generation by fuel for two price zones and difference compared to one price zone (in parentheses)

3.4.2 Implications of two bidding zones on re-dispatch

Even though the zonal market dispatch has higher generation costs at first, it can reduce the amount of curative congestion management measures allocating increasing levels of re-dispatch costs parallel to the market. Figure 3.8 illustrates the change in annual zonal re-dispatch levels for different NTC values in 2012 and 2015.

For very high NTCs, zonal pricing becomes ineffective as the dispatch in the spot market converges with the level of the single bidding zone. In this case, re-dispatch implementing the lowest-cost dispatch in 2012 (given the physical system and model limitations) is mainly redistributing generation from north (-1,437 GWh) to south (+1,255 GWh) but also increasing output in the northern zone (+399 GWh).

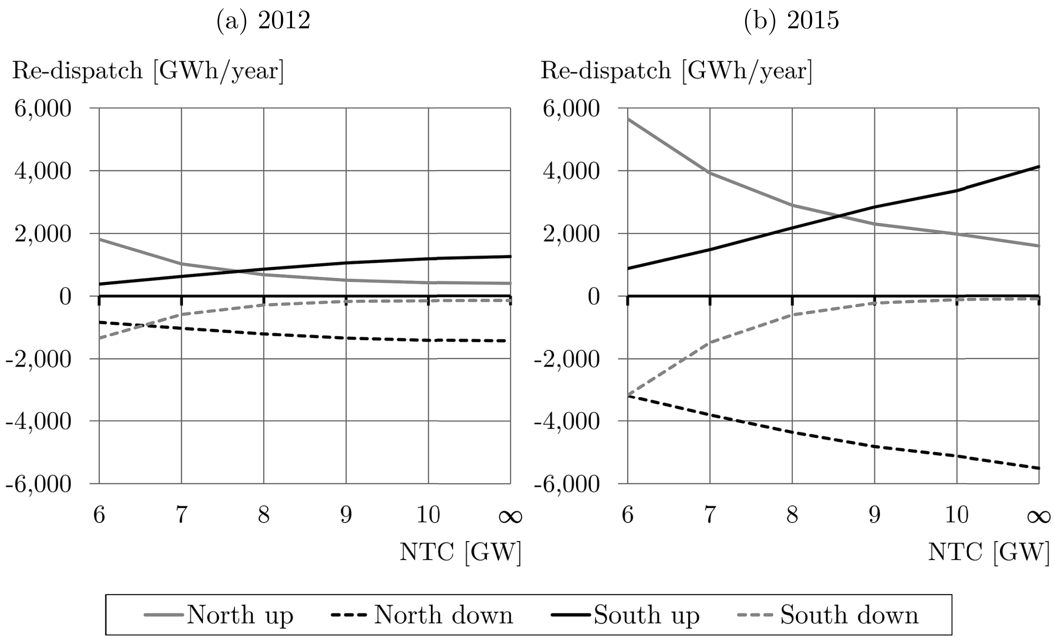


Figure 3.8: Re-dispatch for different NTC levels with up- and down-regulation

The 2015 results show a similar outcome when multiplied by a factor of three. Compared to the annual demand of 550 TWh, 5.7 TWh (1%) of generation is reallocated by re-dispatch. In general, a lower NTC reduces cross-zonal re-dispatch levels, that is, shifting generation between the northern (lower down-regulation) and the southern zone (lower up-regulation).

In the model results for 2012 and 2015, the NTC of 8 GW has the lowest re-dispatch levels.[51] However, the implementation of two bidding zones only allows a limited reduction of overall re-dispatch in 2012. Levels decrease from 1,655 GWh for the single price zone to 1,544 GWh (-7%) before they start to increase again for lower NTCs.[52] In 2015 the growing spatial system imbalance in the spot market dispatch is reflected in a threefold increase of re-dispatch. Zonal pricing allows for a reduction from 5,720 to 5,071 GWh (-11%).[53]

[51]There might be deciding factors for NTC levels other than the total re-dispatch level. Addressing all congestion and imbalances within each bidding zone by the cross-zonal trade capacity would result in significantly lower values for the NTC and higher re-dispatch levels within each zone. Other motivations for choosing NTC levels could be the maximization of congestion rents by the TSO or a preference on zonal price differentials to limit redistribution levels.

[52]The re-dispatch level in the German electricity system induced by current reached 1,962 GWh in 2012 and 2,368 GWh in 2014 (BNetzA and Bundeskartellamt, 2013, 2015).

[53]An additional option to improve the effect of two bidding zones is the sub-annual adjustment of NTC levels. Combining the weekly runs with the NTC value resulting in the lowest weekly re-dispatch levels—values vary between 6 and 10 GW—allows for about 10% higher reductions in re-dispatch.

The main effect of zonal pricing is lower re-dispatch between the bidding zones, decreasing by about 35% for an NTC of 8 GW in 2015. In the south, re-dispatch measures remain mostly upwards, but levels decrease for coal-fired power plants by about 1,500 GWh and gas-fired power plants by about 500 GWh. Total downward re-dispatch in the southern zone increases only by about 500 GWh (Table 3.4, Figure 3.9), resulting in an overall reduction of cross-zonal re-dispatch of almost 1,500 GWh. In the northern bidding zone, down-regulation does not decrease to the same extent as up-regulation in the southern zone. Instead, re-dispatch uses more up-regulation in the northern zone. This generation in the northern bidding zone is not related to the congested lines in the physical transmission system but is replaced in the spot market by generation from the south. The results indicate that one northern and one southern bidding zone improve the regional spot market result. However, the two zones might not be capable of providing sufficiently differentiated price signals to solve the issue of increasing re-dispatch levels. This seems to be the case for the northern bidding zone in particular with its increasing internal re-dispatch level in 2015.[54]

[GWh]		**Uniform pricing**					
		Lignite		Coal		Gas	
2012	North	+38	-129	+146	-1,078	+215	-229
	South	–	–	+819	-75	+432	-72
2015	North	+407	-1,882	+658	-2,980	+529	-642
	South	–	–	+3,014	-59	+1,111	-33

		Zonal pricing					
		Lignite		Coal		Gas	
2012	North	+40	-119	+397	-907	+244	-180
	South	–	–	+589	-109	+272	-176
2015	North	+520	-1,770	+1,662	-2,117	+714	-475
	South	–	–	+1,577	-246	+597	-355

Table 3.4: Zonal re-dispatch levels per technology

[54]For lower NTC levels, negative effects start to increase. Capacity in the northern bidding zone is replaced in the market dispatch by more expensive generation in the southern bidding zone. Under the assumption of optimal (cost-minimizing) re-dispatch, the capacity in the north is scheduled into the market (up-regulation), replacing the more expensive generation capacity in the south (down-regulation). Re-dispatch contrary to the initially predominant north-south imbalance starts to increase.

Re-dispatch mostly affects power plants fired by hard coal and natural gas. In 2015 with uniform pricing, re-dispatch is responsible for 3.0 TWh (almost 10%) of hard coal generation and 1.1 TWh (about 15%) of gas generation in southern Germany (Tables 3.3 and 3.4). In the northern bidding zone, similar absolute levels occur at higher output levels in the spot market. The implementation of two bidding zones reintegrates about half of the re-dispatch volume into the spot market in the southern zone.

However, the spot market requires a limitation on the trading capacity to reduce re-dispatch between the two bidding zones. This zonal constraint does not just affect those power plants in the northern zone causing network congestion but replaces the most expensive generation capacities in the market dispatch in hours of a binding NTC. It is mostly the hard coal power plants in the western regions of the northern bidding zone that are affected. These plants have higher fuel costs than comparable coal power plants located closer to the coast due to higher coal shipment costs. Yet, their impact on the major bottlenecks in the transmission network—that is, lines for wind integration in the north and most important the corridor between eastern and southern Germany—is limited. The two bidding zones also affect the generation output of hard coal plants on the coast for low load and/or high wind feed-in. In the eastern part—a region with frequent oversupply—the most expensive technology in the market (i.e., lignite) is rarely affected by the two bidding zones, as its variable costs are lower than for most other fossil technologies in the northern bidding zone.

The re-dispatch model down-regulates both, i) hard coal generation close to the North and Baltic Seas (even though with decreasing levels at zonal pricing), causing network problems in hours of high wind generation in the coastal region, and ii) lignite generation in eastern Germany (low changes at zonal pricing), creating—together with wind generation—severe congestion on lines between eastern and southern Germany. For up-regulation, the model mostly uses, i) hard coal plants and some gas capacities in western Germany for re-dispatch in order to create a technically feasible generation dispatch[55] which are ii) followed by more expensive generation capacity in the south. Zonal pricing—compared to uniform pricing—increases up-regulation of generation capacities in the west of the northern zone while it reduces up-regulation in the southern zone. These effects of two bidding zones result in overall lower re-dispatch than for the single bidding zone. The decrease in up-regulation in the southern zone is higher than the increase in down-regulation and, inversely, the decrease in down-regulation in the northern zone is higher than the increase in up-regulation (Figure 3.9).

[55]Some older lignite plants in western Germany with higher fuel costs than their counterparts in the east are occasionally not included in the sport market dispatch. Still, due to their better location in the system, they are used for up-regulation in re-dispatch.

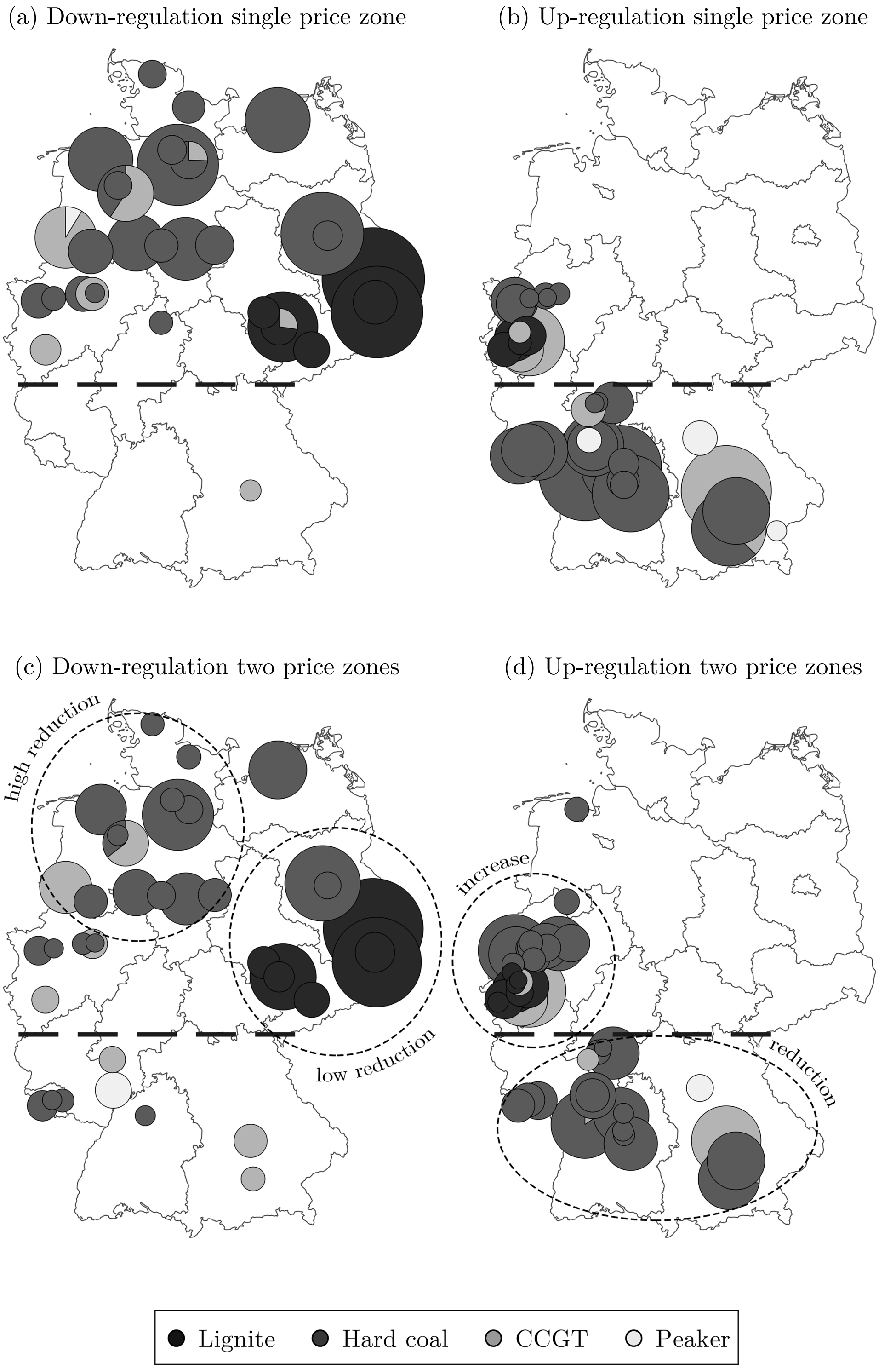


Figure 3.9: Re-dispatch in 2015 for one and for two price zones (NTC 8 GW)

3.4.3 Distributional implications

As can be seen from the literature, shifts in the regional pricing scheme, either by re-shaping market zones or changing cross-zonal trade capacity affects market prices, creating winners and losers. In the case of two bidding zones for Germany, the implications on different stakeholders of one zone (i.e., consumers and producers of different technologies) are the same in 2012 and 2015. Yet, the level of redistribution increases by the same magnitude as does the price differential (0.4 EUR/MWh in 2012 and 1.7 EUR/MWh in 2015). The overall distributional effects are visible but do not reach exorbitant numbers. Zonal price differences can be very high but only occur in a limited number of hours, resulting in comparably low average price effects. Stakeholders in each price zone are also only affected by the respective share of lower/higher prices in their zone, not the total price differential. Therefore, price increases in the south are about three times higher than the opposite decreases in the north. While absolute values of distributional effects can be higher in the northern zone, the relative change is higher in the southern zone. Consumers benefit from lower prices in the north while producer rents decrease and vice versa with increasing prices in the south (Table 3.5). In 2012, the total redistribution between consumers and producers is limited to about 50m EUR in both zones. In 2015, distributional effects increase, as consumers see their payments increase by 275m EUR in the south and a reduction of 163m EUR in the north.

[m EUR]		**Consumer rents**	**Producer profits** Conventional	RES	**Revenue trade flows**[56]	**TSO rents**
2012	North	+35.2	-30.4	-16.2	+2.0	+25.0
	South	-58.4	+36.0	+10.9	-8.3	
2015	North	+163.4	-127.0	-78.9	+8.3	+118.5
	South	-274.6	+149.3	+57.0	-32.7	

Table 3.5: Annual change in payments and rents for two bidding zones

At the same time redistribution for generation increases to about 200m EUR. In the north, renewables (-79m EUR), followed by lignite (-66m EUR), hard coal (-39m EUR), and nuclear plants (-15m EUR) are the generation technologies that lose the most profits in 2015. On the contrary, in the south, nuclear (+74m EUR), renewables (+57m EUR), hard coal (+55m EUR), and CCGT plants (+13m EUR)

[56] Zonal pricing also affects changes in payments for import and revenues from exports with neighboring countries. Table 3.5 aggregates these effects on the zonal level. The financial trade balance indicates revenues from two price zones in the north and additional costs in the south. This work does not discuss the results in detail, as cross-border flows are fixed and neighboring markets not modeled endogenously.

are the biggest profiteers. The auctioning of trade capacity in the spot market provides scarcity rents to the TSO, increasing from 25m EUR in 2012 to 119m EUR in 2015.

Breaking down the total redistribution in Table 3.5 to values per MWh in Table 3.6 provides an insight into the interdependency of price deviations with load and generation. Electricity demand in the south pays a higher than average zonal price mark-up due to additional zonal scarcity in hours of high load.[57] In the north, price reduction for demand is in line with the average price decrease. Similar patterns can be observed on the supply side with the difference that generation benefits from lower price decreases in the north and higher mark-ups in the south. Results are driven by two factors: i) exogenous seasonable availability factors are higher in the winter than in the summer months and ii) generation technologies with higher variable costs operate mostly in hours of increased scarcity when prices tend to increase more in the south and decrease less in the north. The seasonal effect explains the results for technologies operating at full capacity in most hours, i.e., nuclear and lignite. Hard coal and, in particular, gas-fired power plants in the south benefit additionally from the regional scarcity signals, (i.e., higher prices in the southern zone in 2015). Finally, the merit order effect of renewable generation increases with two bidding zones. Consequently, mark-ups are lower in the south and price declines are higher in the north for renewable feed-in.

[EUR/MWh]		**Price**	**Demand**	**Producer**				
				Nuclear	Lignite	Coal	Gas	RES
2012	North	-0.10	-0.10	-0.10	-0.10	-0.10	-0.04	-0.18
	South	+0.26	+0.30	+0.29	–	+0.33	+0.28	+0.22
2015	North	-0.46	-0.46	-0.47	-0.45	-0.40	-0.30	-0.72
	South	+1.22	+1.41	+1.40	–	+1.47	+2.20	+1.02

Table 3.6: Effect of two price zones on average prices, demand, and producers

3.4.4 Implications of network extension

Scenario with network extension in 2015

The scenario with network extensions includes one major line investment between the northern and southern bidding zone. The line Vieselbach-Altenfeld-Redwitz, illustrated in Figure 3.3 between the northern and southern bidding zone, provides

[57] The change in consumer rents is calculated by the hourly change in electricity prices between the single and two price zones multiplied by the hourly zonal load.

additional transmission capacity parallel to the link that causes the greatest re-dispatch levels in the model results. For the single price zone, represented by an unlimited NTC in Figure 3.10, overall re-dispatch levels decrease from 5,720 GWh to 4,094 GWh, but remain at twice the level of 2012. The entire reduction of re-dispatch with network extension (about 1,600 GWh) is between the northern and southern bidding zone.

For the two bidding zones, the NTC value with lowest re-dispatch increases to 10 GW. Re-dispatch declines to 3,850 GWh (-6%) and the remaining levels are shared almost evenly on reallocation between the northern and southern zone and internal measures within the northern zone. The price difference is reduced to 0.4 EUR/MWh. Price differentials occur in 556 hours with a maximum price difference of 26.2 EUR/MWh and an average price difference of 5.7 EUR/MWh. Distributional effects are in the range of the 2012 results.[58] Thus, the importance of the analyzed bidding zones on network congestion and re-dispatch levels decreases with network investment.

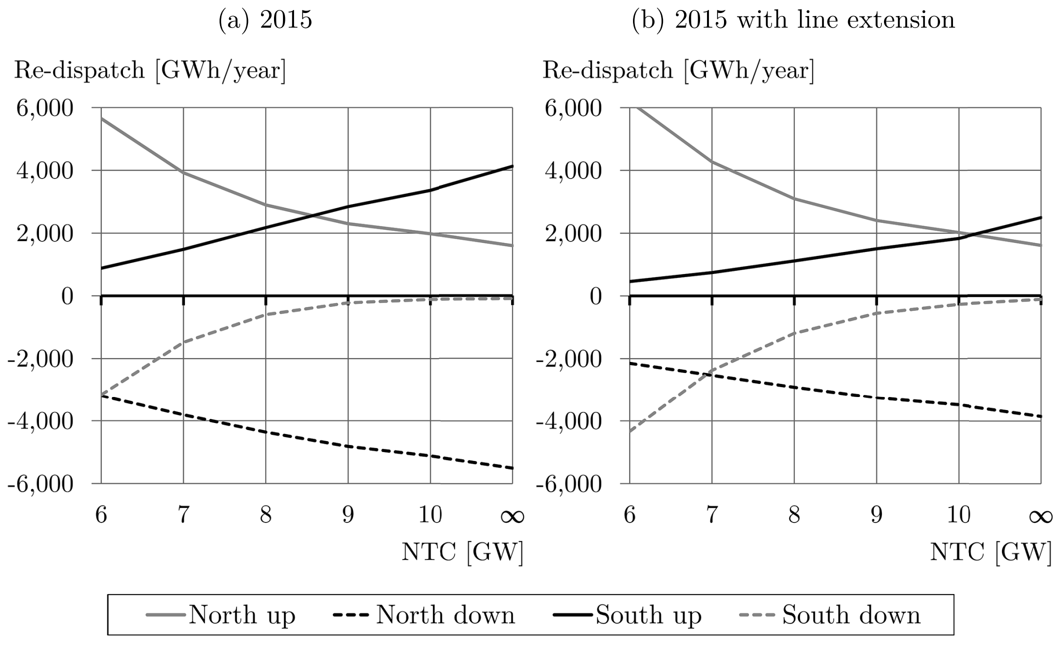


Figure 3.10: Implication of line extension on zonal re-dispatch

[58]Due to the high level of re-dispatch remaining for two bidding zones, an alternative zonal setting could improve the results. For two bidding zones the western part of the northern zone could be added to the south, focusing more on excess generation—lignite, hard coal, and wind in the north and east—instead of on the scarcity in southern Germany.

Outlook for 2020 and beyond

The model limitations do not allow for statements on the German system in 2020 and beyond. Yet, the results can provide indication for the interaction of bidding zones, renewable capacity, network extension, and the shut-down of nuclear and fossil power plants.

In general, providing price information on temporary regional scarcity and excess in regional electricity supply are a prerequisite to create regional electricity markets. In the model results for two bidding zones, imbalances with strong regional price differences occur in a limited number of hours. These prices can provide invaluable market information for the dispatch and closure decisions of fossil power plants. They could also direct regional investments in back-up capacity, supply and demand flexibility, and storage capacity. At the same time, average price differences and distributional issues of regional pricing are lower than one might expect. These results weaken the argument of distributional issues (e.g., regional price increases) and show the creation of regional market incentives as a consequence of changes in the spatial definition of bidding zones.

Grid enforcement as suggested in the grid development plans remains the central approach to address regional imbalances in Germany (BMWi, 2014). The proposed HVAC and HVDC lines will further enforce north to south connections and will allow for better integration of additional wind generation into the system. This analysis shows that network investment for 2015, relieving structural bottlenecks, can reduce re-dispatch in the single national price zone. A system with very high renewable shares in Germany will increase structural north-south imbalances. Two or more bidding zones remain an option to represent this structural imbalance in short-term market prices. An optimal and stable definition of bidding zones, which is beyond the scope of this work, has to consider the regional dynamics of the German energy transition.

The development of the European electricity system is driven by market integration and the low-carbon transformation. The electricity system will see higher renewable shares in Germany and its neighboring countries and better cross-border integration. Thus, it will become harder to justify the traditional definition of bidding zones along the national borders from a system perspective, as today's zones might not be able to provide relevant scarcity information to the market.

3.5 Conclusion

This chapter analyzes some of the potential effects of one northern and one southern bidding zone on the German electricity market in 2012 and 2015. An additional scenario with network extension in 2015 is also considered. The existing single bidding zone in the German electricity market does not reflect regional imbalances and the transmission network in the market dispatch. The concentration of fossil generation capacity with comparably low variable costs—not internalizing all external costs—and wind power in the northern and eastern parts of Germany combined with limited north-south transmission capacity causes an increasing amount of curative congestion management measures. For Germany's present-day single price area the model results of this chapter predict a threefold increase of re-dispatch levels over the course of expected changes of generation capacities from 2012 to 2015. From a network perspective, internal congestion can be addressed by transmission investment to strengthen the north-south connections. Investment in the transmission network has been facilitated in Germany by legislation in 2009 and the network development plans starting in 2012. Still, investments in transmission lines take many years to be realized and their prospects are uncertain. To reduce re-dispatch measures, scarce transmission capacity can also be addressed by pricing it into the electricity market.

For the case of two price zones in Germany, model results indicate slightly declining re-dispatch levels, in particular between the bidding zones. In hours of strong regional imbalances, one can observe significant price differences, which could set regional incentives for investment in supply and demand in the long-term, an aspect not elaborated on in this chapter. One important consideration when moving from one pricing scheme to another are the distributional implications for stakeholders. Predicted differences in average electricity prices between the two bidding zones are rather low in the model results (1.7 EUR/MWh in 2015) compared to the wholesale price and network charges. However, stakeholders benefit and lose in different ways. Total figures of redistribution between consumers and producers in the northern and southern zones amount to several hundred million Euros per year. The impact of these figures could prove challenging to communicate to the stakeholders, especially at Federal State level. Additional system and distributional implications with neighboring countries—price zones change the import and export patterns—are not addressed in this chapter. In the case of high wind feed-in in northern Germany, a lower electricity price in the northern zone could reduce imports into and increase exports from the zone. Hours with scarcity and higher prices in southern Germany could reduce exports to southern Europe. These effects may be important in the context of the European discussion on bidding zones and require further research.

Several developments will increase regional system imbalances in the medium-term. Amongst them are the low-carbon transformation which requires additional capacity of onshore and offshore wind in northern Germany and the shut-down of carbon intensive generation units. Completed by 2022, the nuclear phase-out plan is also creating additional scarcity of generation capacity in southern Germany. Regardless of network extension, additional research should analyze the implications of different approaches to regional pricing in an electricity sector increasingly dominated by renewable generation.

Chapter 4

Power system transformation toward renewables: Investment scenarios for Germany

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This chapter is based on:

Power System Transformation toward Renewables: Investment Scenarios for Germany

Discussion Paper 1402, DIW Berlin, Egerer and Schill (2014b).

Joint work with Wolf-Peter Schill.

It was presented at the 9th Conference on Energy Economics and Technology, 2014 (Dresden), at the 11th International Conference on the European Energy Market, 2014 (Krakow) where it is published in the conference proceedings, Egerer and Schill (2014a), at the 37th IAEE International Conference, 2014 (New York), and at the 19ème séance du Séminare de Recherches en Économie de l'Energie de Paris-Sciences-Lettres, 2015 (Paris).

A revised version was published as:

Power System Transformation toward Renewables: Investment Scenarios for Germany

Economics of Energy & Environmental Policy 3(2): 29–43, Egerer and Schill (2014c).

4.1 Introduction

Germany is experiencing substantial growth in renewable energy. According to the Federal German Energy Concept, which is a cornerstone of Germany's *Energiewende*, renewable energy sources (RES) should account for at least 35% of gross power demand supplied by 2020, 50% by 2030, and 80% by 2050 (BMWi and BMU, 2010).[59] Due to the limited potential of hydropower and biomass in Germany, this implies substantial growth of renewable electricity generation from wind and solar power, respectively. These sources are characterized by fluctuating feed-in patterns, an uneven geographical distribution of potential, and a low capacity credit. Supply from wind and solar power has to be balanced with demand at all network nodes at all times. This poses challenges for the overall power system. Several strategies are under discussion, including flexible thermal power plants, power storage, and transmission grid expansion (Denholm and Hand, 2011; Milligan et al., 2012).

The requirements of such investments are studied for different countries, but largely focus on individual options and rarely analyze the interactions of combined implementations. Sioshansi et al. (2012) discuss technical issues as well as policy-related barriers to actual storage deployment in power markets. Perez-Arriaga and Batlle (2012) provide a general review of the challenges of integrating fluctuating RES into power systems and identify necessary regulatory adjustments. While generation and transmission capacity expansion were centrally coordinated in the formerly vertically integrated industry, decisions are now made by multiple agents driven by market forces. Weijde and Hobbs (2012) propose a two-stage stochastic optimization model for network planning, which they apply to Great Britain. They show that stochastic approaches may enable lower-cost planning decisions than deterministic methods do when considering uncertainty. Munoz et al. (2012) build upon this approach and apply an extended model, which also respects Kirchhoff's voltage law, to a stylized Californian system. Denholm and Hand (2011) simulate different scenarios with high shares of variable RES in the Texas power system. For very high renewable penetrations, substantial capacities of both daily storage and demand-side management are required in order to avoid excessive curtailment. The analysis, however, excludes transmission constraints.

EWI and energynautics (2011) carry out a long-term study on the European power system, iterating a dynamic power plant investment and dispatch optimization model with a transmission investment model described by Fürsch et al. (2013). For example, they find that transmission upgrades bring benefits by substituting for

[59]The macro-economic effects of this renewable expansion strategy are discussed by Blazejczak et al. (2014).

costly storage investments. Nagl et al. (2013) propose European power plant mixes for different shares of RES, applying a dynamic stochastic optimization model. The stochastic approach results in higher overall system costs compared to a deterministic model, such as the one used in this analysis. While stochastic models have distinct advantages, their temporal and spatial resolution has to be much lower compared to the one presented in this analysis in order to ensure solvability. In addition, internal transmission grids are rarely modeled explicitly, instead approximated by assumed net transfer capacities or aggregated transmission systems between regions.

For the specific German situation, there are several policy-oriented studies on infrastructure requirements for renewable integration. Dietrich et al. (2010) optimize the location of power plant investments in the German system with a fixed transmission network on a nodal level. Weigt et al. (2010) analyze wind power integration in Germany in 2015 with a network and dispatch model that neglects investments into power plants and storage. They find that high-voltage direct current (HVDC) lines as connections to major load centers in western and southern Germany are promising for wind integration. In a study commissioned by the German government, Prognos et al. (2010) simulate the future German power plant fleet, using a European dispatch and investment model. The German transmission network, however, is not considered in the analysis. In contrast, the Grid Development Plan (NEP)[60] focuses on expansion requirements of the German transmission system. This plan, which is drafted on a yearly basis by German transmission system operators (TSOs) to provide a 10 to 20 year forecast, is based on a European market dispatch model, the results of which feed into a technical transmission model (50Hertz et al., 2014). Investments into power plants and storage, however, are not determined endogenously, but are entered as exogenous parameters into the dispatch model.

Our contribution to the literature is to carry out a techno-economic model analysis in order to determine investment scenarios for a power system with increasing shares of RES. Investments into thermal power plants, pumped-storage hydroelectric plants, and the transmission grid are optimized simultaneously from the perspective of a central planner. As for the spatial resolution, we model the German high-voltage transmission network on a nodal level. We look at the year 2024, by which the remaining nuclear capacity in Germany will have been completely phased out, and also at 2034, which represents a longer-term system transformation toward fluctuating RES. Our calculations are based on scenarios for the German NEP but do not primarily aim to prove or disprove its outcomes. Rather, we are interested in the intricate interaction between investments in power plants, storage, and transmission. Although the modeling exercise reflects the specific German situation, both our

[60]The abbreviation NEP stands for the German name: Netzentwicklungsplan.

approach and the general findings are also relevant for other countries with thermal power plant fleets that shift toward fluctuating RES.

4.2 Mixed-integer generation, storage, and transmission investment model

We use an integrated optimization model for dispatch, transmission, and investments that includes a nodal disaggregation of the high-voltage transmission network and applies the DC load flow approach (Leuthold et al., 2012; Schweppe et al., 1988). Endogenous investments in generation, storage, and transmission infrastructure are characterized by integer variables. The model simultaneously decides on all investment options, comparing them from an endogenous perspective. The objective value is total system costs, which consist of annualized fixed costs for new investments and variable generation costs (fuel and CO_2) of existing and new conventional power plants, scaled to one year with the factor $\hat{y}$. The model thus determines an investment mix that minimizes overall system costs for one static year in the objective function 4.1.

$$\begin{aligned}\min_{\substack{g^{\text{unit}}, i^{\text{unit}}, i^{\text{sto}} \\ i^{\text{ac}}, i^{\text{dc}}}} \mathrm{c} = \sum_{p,t} \left(\hat{c}^{\text{unit}}_{pt} g^{\text{unit}}_{pt} \right) \hat{y} \\ + \sum_{l \in L} \tilde{c}^{\text{ac}}_{l} i^{\text{ac}}_{l} \\ + \sum_{d \in D^{+}} \tilde{c}^{\text{dc}}_{d} i^{\text{dc}}_{d} \\ + \sum_{p \in P^{+}} \tilde{c}^{\text{unit}}_{p} i^{\text{unit}}_{p} \\ + \sum_{s \in S^{+}} \tilde{c}^{\text{sto}}_{s} i^{\text{sto}}_{s}\end{aligned} \tag{4.1}$$

The model includes capacity constraints for generation of conventional power plants in Equation 4.2a and for hourly renewable generation in Equation 4.2b. Operation of pumped-storage hydroelectric plants faces constraint 4.2c on the generation and pumping capacity, 4.2d on the upper limit of the storage level, and the inter-temporal balance on the storage level in Equation 4.2e. Electricity flows are constrained by the thermal line ratings in 4.2f and by their distribution in the network approximated by the DC load flow linearization in the Equations 4.2g–4.2i. New HVDC lines are modeled as point-to-point transport flows in 4.2j.

$$
\begin{aligned}
g_{pt}^{\text{unit}} &\leq \overline{g}_{p}^{\text{unit}} av_{pt}^{\text{unit}} && \forall \quad p \in P^0, t && \text{(4.2a)}\\
r_{nit}^{\text{tech}} &\leq \overline{r}_{ni}^{\text{tech}} av_{nit}^{\text{tech}} && \forall \quad n, i, t && \text{(4.2b)}\\
\overrightarrow{ps}_{st} + \overleftarrow{ps}_{st} &\leq \overline{ps}_{s} && \forall \quad s \in S^0, t && \text{(4.2c)}\\
ls_{st} &\leq \overline{ls}_{s} && \forall \quad s, t && \text{(4.2d)}\\
ls_{st} &= 0.75\overleftarrow{ps}_{st} - \overrightarrow{ps}_{st} + ls_{s(t-1)} && \forall \quad s, t && \text{(4.2e)}\\
|pf_{lt}^{\text{ac}}| &\leq \overline{pf}_{l} + \overline{pf}_{l}^{+\text{ac}} i_{l}^{\text{ac}} && \forall \quad l, t && \text{(4.2f)}\\
pf_{lt}^{\text{ac}} &= \sum_{n} \theta_{nt} h_{ln} && \forall \quad l, t && \text{(4.2g)}\\
ni_{nt}^{\text{ac}} &= \sum_{k} \theta_{kt} b_{nk} && \forall \quad n, t && \text{(4.2h)}\\
\theta_{\hat{n}t} &= 0 && \forall \quad t && \text{(4.2i)}\\
ni_{nt}^{\text{dc}} &= \sum_{d} pf_{dt}^{\text{dc}} im_{dn}^{\text{dc}} && \forall \quad n, t && \text{(4.2j)}
\end{aligned}
$$

Line investments i_l^{ac} in high-voltage alternating current (HVAC) lines of the alternating current (AC) grid are included in the line capacity constraint of the existing lines, in Equation 4.2f. Other investments are introduced in additional constraints, i.e., new generation capacity i_p^{unit} in 4.3a, new pumped-storage plants i_s^{sto} in 4.3b, and new high-voltage direct current (HVDC) lines i_d^{dc} in 4.3c.

$$
\begin{aligned}
g_{pt}^{\text{unit}} &\leq i_{p}^{\text{unit}} \overline{g}_{p}^{+\text{unit}} av_{pt}^{\text{unit}} && \forall \quad p \in P^+, t && \text{(4.3a)}\\
\overrightarrow{ps}_{st} + \overleftarrow{ps}_{st} &\leq i_{s}^{\text{sto}} \overline{ps}_{s}^{+} && \forall \quad s \in S^+, t && \text{(4.3b)}\\
|pf_{dt}^{\text{dc}}| &\leq i_{d}^{\text{dc}} \overline{pf}_{d}^{+\text{dc}} && \forall \quad d \in D^+, t && \text{(4.3c)}
\end{aligned}
$$

The energy balance 4.4 ensures that generation of existing and new power plants together with the network inflows minus network outflows is equal to (inelastic) demand in every node at every hour.

$$
\sum_{p \in P_n} g_{pt}^{\text{unit}} + \sum_{i} r_{nit}^{\text{tech}} - q_{nt} + \sum_{s \in S_n} (\overleftarrow{ps}_{st} - \overrightarrow{ps}_{st}) + ni_{nt}^{ac} + ni_{nt}^{dc} = 0 \quad \forall \quad n, t \qquad \text{(4.4)}
$$

In order to ensure solvability of the model, we make some simplifying assumptions. First, we disregard ramping constraints of thermal power plants, and abstract from restrictions related to the combined provision of heat and power. Accordingly, the use of flexible generators and pumped-storage hydroelectricity may be underestimated, whereas generation of inflexible base load power plants is overrated. In turn, the optimal level of investments in flexible assets such as gas-fired power plants and, in particular, pumped-storage hydroelectricity may be underestimated in our model. We also disregard the provision of reserves and other ancillary services, which should have a similar effect. Furthermore, the topology of the AC network is fixed to 2012, such that no new lines between previously unconnected nodes are possible. However, all existing HVAC connections may be expanded. Likewise, the physical flow distribution on existing connections is fixed to the initial flow pattern in the topology in order to prevent non-convexity. We also disregard exchange with neighboring countries and accordingly assume fully domestic balancing of supply and demand. We thus abstract from existing low-cost renewable integration potentials in neighboring countries. In general, this should lead to an overestimation of domestic infrastructure requirements, especially regarding power plants and storage. Nonetheless, the domestic perspective chosen here is highly relevant to German policy makers, as the Energiewende is currently carried out as a national project.[61]

4.3 Input data and scenarios

The model is applied to different scenarios for 2024 and 2034, corresponding to the planning forecast of the German Grid Development Plan (NEP) of 2014. Because of numerical restrictions, it is impossible to model all subsequent hours of the respective year. Instead, we consider every second hour of four representative weeks covering all seasons, including the peak load hour.[62] Exogenous assumptions on generation capacities, fuel prices, and power demand are derived from the NEP 2014 scenario framework. The NEP is drafted on a yearly basis by the German transmission system operators (TSOs) in a multistage process. After a period of public consultation, the German regulator approves a final version of the NEP, which is then incorporated into

[61] A more general disclaimer refers to optimality gaps of mixed-integer optimization models. In our application, relative optimality gaps are always below 1% but vary between scenarios. The corresponding absolute gaps are often in the same order of magnitude as infrastructure investments into single power plant units, storage facilities, or transmission lines. Accordingly, we cannot make definitive statements about the advantageousness or disadvantageousness of individual power plants, storage facilities, or transmission lines. Readers should focus on general insights of the analysis, not on the specific numbers.

[62] Assessing the effects of this simplification on model results is challenging. Extreme situations of demand and renewable feed-in may be slightly overestimated. Drawing on other hours may, for example, slightly alter the level and the regional distribution of optimal infrastructure investments. Likewise, scaling historic feed-in patterns of wind and photovoltaics of the reference year 2012 to 2024 and 2034 levels neglects expectable smoothing effects related to changes both in the geographical distribution of generators and in generator design. This may lead to a slight overestimation of renewable surpluses and respective investments in storage and transmission lines (see Schill, 2014).

federal legislation. We draw on the scenario framework for the NEP 2014 (50Hertz et al., 2014; BNetzA, 2012a), more specifically on the medium scenarios B 2024 and B 2034. Table 4.1 depicts the development of generation capacities in these scenarios compared to the reference year of 2012. Nuclear power is already phased out completely by 2022;[63] lignite and oil capacities are lower in 2024, while hard coal capacity only starts decreasing after 2024 due to the construction of several hard coal power plants that will come online between 2012 and 2024. The plan foresees additional natural gas and pumped-storage hydroelectric capacities in B 2024 and/or B 2034, the construction of which has not started as of March 2014 (planned). These are not considered in our analysis as investments in new power plants are determined endogenously. Where thermal capacities decrease through 2034, there is a disproportionately high increase in renewable generation capacities, which reflects their comparatively low capacity factors. By 2034, onshore wind power remains the technology with the largest capacity installed followed by photovoltaics; offshore wind has the largest growth rate.

	2012 Status quo	**2024** B	**2034** B
Nuclear	12.1	–	–
Lignite	21.3	15.4	11.3
Hard coal	25.5	25.8	18.3
Oil and other	8.3	5.6	3.9
Natural gas	26.9	22.4	22.0
Pumped-storage	6.4	6.3	6.3
Natural gas (planned)	–	5.9	15.7
Pumped-storage (planned)	–	3.7	3.7
Wind onshore	31.0	55.0	72.0
Wind offshore	0.3	12.7	25.3
Photovoltaics	33.1	56.0	59.5
Biomass and other	6.5	10.2	11.5
Hydropower	4.4	4.7	5.0

Table 4.1: Generation capacities of the scenario framework 2014[64]

The variable generation costs are calculated from the fuel price (Table 4.2), the price of CO_2 certificates, and the efficiency of power plants. The assumptions in the NEP predict slightly increasing natural gas prices, stable hard coal and lignite prices, and 29 EUR/t CO_2 in 2024 and 48 EUR/t CO_2 in 2034. Lignite power plants remain the fossil technology with the lowest variable costs while modern combined cycle gas turbine (CCGT) power plants become cheaper than hard coal plants in 2034.

[63]For a discussion on the nuclear phase-out in Germany see Kunz and Weigt (2014).
[64]Source: NEP 2014 (50Hertz et al., 2014; BNetzA, 2012a).

		2011	2024	2034
Oil	[EUR/t]	593	594	721
Natural gas	[EUR/MWh$_{th}$]	26	27	28
Hard coal	[EUR/t SKE]	107	81	88
Lignite	[EUR/t MWh$_{th}$]	1.5	1.5	1.5
CO_2 certificate price	[EUR/t]	15	29	48

Table 4.2: Fuel and CO_2 certificate prices[65]

In addition, for parameters not included in the NEP scenario framework, we draw on data collected from several public sources including, for example, time series for electricity demand, seasonal availability factors for power plants, regional hourly availability factors for wind and photovoltaics, as well as a regional distribution of renewable generation capacity and load. The topology of the German high voltage network reflects the state of the year 2012 (Egerer et al., 2014a). Transmission line capacity constraints include a transmission reliability margin (TRM) of 20% in order to approximate n-1 security. In order to reduce numerical complexity, the topology is aggregated such that only meshed elements are included. We also abstract from cross-border lines. Overall, the model includes 326 nodes and 743 lines.

	Investments in			
Scenario	Gas power plants	Transmission lines	Storage plants	Costs of RES curtailment
Reference scenario	√	√	√	–
Decreased curtailment 100	√	√	√	100 EUR/MW
Decreased curtailment 1000	√	√	√	1,000 EUR/MW
No network extension	√	–	√	–
Exogenous storage	√	√	Exogenous	–

Table 4.3: Investment options in the different scenarios

Drawing on these parameters, we examine five scenarios (Table 4.3) that include different assumptions on the available infrastructure options and the costs of renewable curtailment: a Reference scenario without additional constraints; two Decreased curtailment scenarios, in which curtailed renewable generation is penalized

[65]Source: NEP 2014 (50Hertz et al., 2014; BNetzA, 2012a).

with 100 EUR/MWh and 1,000 EUR/MWh, respectively, in the objective function; a No network extension scenario that does not allow any investments in transmission lines; and an Exogenous storage scenario that assumes that pumped-storage hydroelectric capacity will be built according to the NEP 2014 scenario framework.

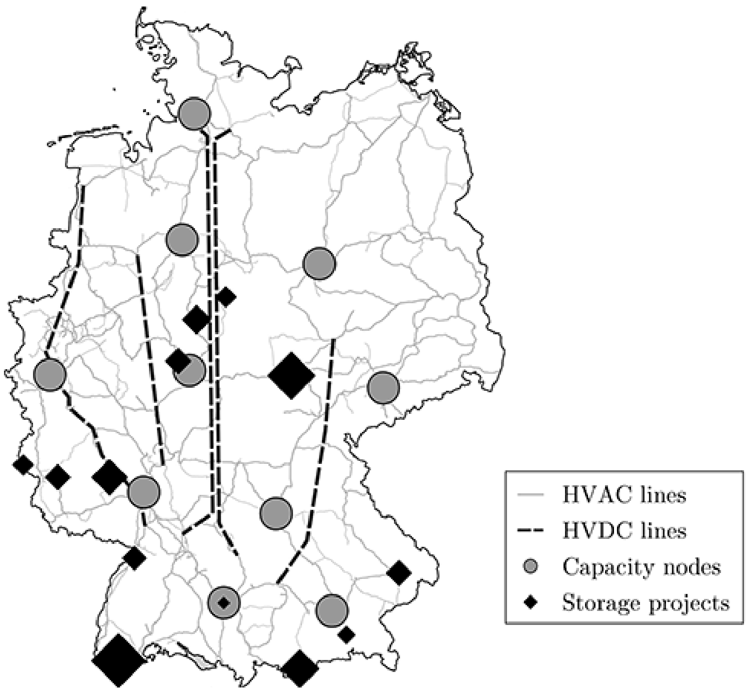

Figure 4.1: Endogenous options for infrastructure investments

Depending on the respective scenario, the following investment options are available (Figure 4.1):

- Generation capacity can be built in steps of 500 MW at ten important network nodes in the transmission systems, which are distributed all over Germany (gray dots). Investment options are combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) power plants;

- a list of 13 pumped-storage hydroelectric projects (dark diamonds) that are actually planned is considered with specific capacities and locations, in Table 4.4);

- existing HVAC transmission lines can be extended by additional 380 kV circuits with capacities of 1.7 GW;

- six new HVDC point-to-point connections are possible (dashed lines) in steps of 1 GW.

	NEP scenario B 2024	**NEP scenario** B 2034	**Capacity** [MW]	**Federal state**
Atdorf	√	√	1,400	Baden-Wuerttemberg
Schmalwasser	√	√	1,072	Thuringia
Jochberg		√	700	Bavaria
Heimbach			600	Rhineland-Palatinate
Nethe	√	√	390	North Rhine-Westphalia
Schweich	√	√	307	Rhineland-Palatinate
Waldeck 2			300	Hesse
Riedl			300	Bavaria
Forbach (extension)	√	√	275	Baden-Wuerttemberg
Leinetal			200	Thuringia
Vianden (extension)			200	Rhineland-Palatinate
Einöden	√	√	150	Bavaria
Blautal	√	√	60	Baden-Wuerttemberg

Table 4.4: List of pumped-storage hydroelectric projects

	Specific investments	**Life time**	**Efficiency**
	(m EUR/km)	(years)	(percent)
HVAC transmission lines	1.4	40	
HVDC transmission lines	1.4	40	
	(m EUR)		
HVAC transformer	4	40	
HVDC converter	338	40	
	(m EUR/GW)		
CCGT power plants	800	35	60
OCGT power plants	400	30	45
Pumped-storage plants	1,200	40	80

Table 4.5: Investment parameters[66]

We do not consider thermal investments in technologies other than gas-fired power plants. Nuclear power is not an option in Germany according to the law, lignite is not compatible with the German government's emission targets, and hard coal cannot compete with natural gas in the medium term given NEP's CO_2 price assumptions. Moreover, we abstract from including demand-side measures such as load shifting and load shedding as endogenous variables. While such measures may become more relevant in the future, a solid parametrization of costs and technical characteristics is challenging. The NEP scenario framework, which we draw on, already assumes

[66] Data assumptions based on the scenario framework of the NEP 2014 (50Hertz et al., 2014; BNetzA, 2012a), Schröder et al. (2013a), and own assumptions.

some level of peak shaving by reducing peak load from 87 GW in 2012 to 84 GW in 2024 and 2034. We implicitly assume that additional demand-side measures cannot compete with pumped-storage hydroelectricity in terms of specific investments and operational costs.

Annualized fixed costs for investments are calculated from specific investments and assumptions on the technical life time of the installation (Table 4.5). Pumped-storage hydroelectric plants have a fixed energy to power ratio of seven hours. A four percent discount rate is applied. The mixed-integer character of the model allows for a realistic representation of lumpy investments into transmission lines and pumped-storage hydroelectric projects.

4.4 Results

4.4.1 Reference scenarios 2024 and 2034

In the 2024 Reference scenario, we determine investments into new gas-fired power plants and transmission lines, but no investments into pumped-storage hydroelectricity. Eight GW of CCGT generation capacities are added.[67] This number is close to the overall level of capacity additions assumed in the scenario framework of the NEP 2014. The regional focus of these investments is in southern and western Germany, namely in Bavaria, Hesse, North Rhine-Westphalia and Baden-Wuerttemberg (Figure 4.2).

The observed lack of pumped-storage hydroelectric investments can be explained by relatively high specific investments. In addition, opportunities for arbitrage are limited due to small hourly price differentials caused by a flat merit order of conventional power plants and by the large feed-in of photovoltaics during daytime. Additional HVAC lines total more than 700 km, with a focus on connections between Saxony/Thuringia and northern Bavaria, as well as between Lower Saxony and North Rhine-Westphalia. In addition, there are minor investments in a HVDC line of around 200 km, connecting large wind capacities located on the North Sea coast to North Rhine-Westphalia. Renewable energy has a share of nearly 48% of overall power generation, compared to lignite and hard coal with around 19% and 18%, respectively. Old and new gas-fired power plants account for nearly 12%. Renewable power generation is curtailed by around 1.3 TWh due to network constraints, corresponding to 0.5% of the maximum yearly feed-in. Avoiding such curtailment by means of

[67] We do not find investments into open cycle gas turbines in any scenario. This result is probably driven by neglecting flexibility constraints of thermal power plants in the analysis. Short-term system flexibility is not valued in the model which abstracts from ramping constraints and market uncertainty. A consideration of increasing short-term flexibility requirements in the context of increasing renewable shares may result in additional capacities of storage and open cycle gas turbines, and conversely reduce the level of less flexible CCGT investments.

additional network or storage capacity would be more expensive in the 2024 scenario compared to generating an equivalent amount of electricity in conventional power plants.[68] Yearly CO_2 emissions by the German power sector are around 230m tons, or 427 g/kWh, respectively. The optimization for 2034 is carried out without rolling planning, meaning the model does not enforce investments of a 2024 run to be present in the respective 2034 scenario.

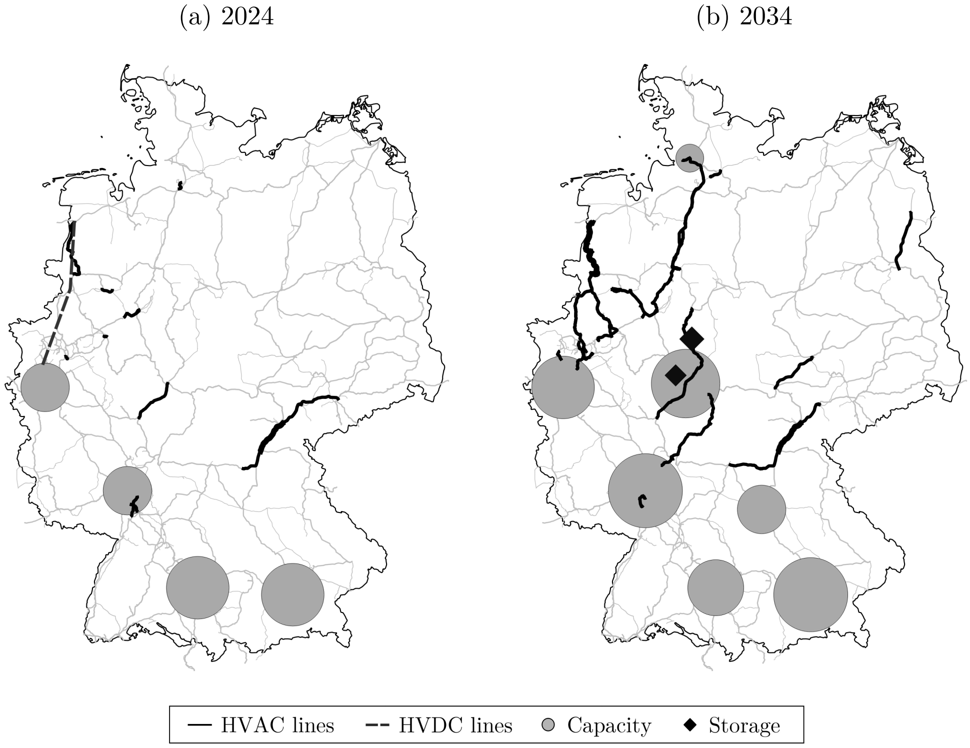

Figure 4.2: Geographic location of investments in the reference scenarios

The results of the 2034 reference scenario, however, do largely include the nodal power plant and storage investments of the 2024 reference. The same also holds for regional network enforcements, though the choice between HVAC and HVDC lines slightly changes in western Germany. Compared to 2024 results, we find much larger infrastructure investments in the 2034 Reference scenario. This result is driven by an exogenously decreasing thermal power plant fleet and an increasing penetration of variable RES. CCGT capacity additions amount to 16.5 GW, twice the level of 2024. Again, this magnitude is in line with the scenario framework of the NEP 2014. As in the 2024 reference scenario, the regional focus of these investments is southern and western Germany. In contrast to 2024, there are also two small additional pumped-

[68]A similar point is made by Schill (2014) regarding renewable surpluses in Germany.

storage hydroelectric projects in North Rhine-Westphalia and Hesse, around 0.7 GW in total. HVAC line extensions add up to around 2,800 km, which is roughly three times the amount of the overall line investments in the 2024 reference scenario. AC investments again focus on connections between Saxony/Thuringia and northern Bavaria and between Lower Saxony and North Rhine-Westphalia. RES' share in overall power generation increases to 60% by 2034, while the shares of lignite and hard coal decrease to about 12 and 6 percent, respectively. The share of old and new gas-fired power plants grows to 18%. Renewable curtailment increases to 5.7 TWh (1.7%). CO_2 emissions decrease substantially to 140m tons, or 259 g/kWh, respectively.

4.4.2 Alternative scenarios

Investments in the other scenarios differ substantially from the reference scenarios (Table 4.6). In the Decreased curtailment scenarios, additional investments into storage and transmission lines are required in order to reduce renewable curtailment. These are particularly high in the scenarios where renewable curtailment is penalized with 1,000 EUR/MWh: in 2024, more than 4,700 km of HVAC lines and 2.5 GW of storage are required.

	CCGT [GW]	**Storage** [GW]	**HVAC** [km]	**HVDC** [km]
Reference scenario	8.0	–	708	220
Decreased curtailment 100	7.5	1.1	876	690
Decreased curtailment 1000	7.0	2.5	4,737	–
No network extension	10.0	–	0	–
Exogenous storage	5.5	3.7	563	220

Table 4.6: Investments in different scenarios in 2024

By 2034, respective AC and DC investments of nearly 1,800 km and 7,900 km are built by the model (Table 4.7). Additional HVDC lines directly connect northern and southern German regions. These investments are triggered by large onshore and offshore wind capacities in the north and high electricity demand in the south and the west. Note that AC investments are smaller in 2034 compared to 2024, as these are largely substituted with HVDC lines.[69] Accordingly, the additional HVAC lines in the Decreased curtailment 1000 scenario of 2024 have the characteristic of stranded investments. At the same time, 4.5 and 5.1 GW of pumped-storage hydroelectricity

[69] We assume higher investment costs for HVDC than for HVAC technology, motivated by higher converter costs. However, flows on point-to-point HVDC lines bridge long distances from north to south and reduce loop flows in the AC network. We do not make strong statements on the choice of technology as model decisions on AC and DC investments are very sensitive to scenario assumptions and optimality gaps.

are added in the 2034 scenarios of Decreased curtailment, which constitute most of the investment potential available to the model. Investments in gas-fired power plants are slightly lower compared to the respective reference scenarios as these are partly substituted by the additional storage and transmission capacities.

	CCGT [GW]	**Storage** [GW]	**HVAC** [km]	**HVDC** [km]
Reference scenario	16.5	0.7	2,787	–
Decreased curtailment 100	14.5	4.5	1,836	4,010
Decreased curtailment 1000	14.5	5.1	1,751	7,880
No network extension	18.0	0.6	–	–
Exogenous storage	15.0	3.7	2,917	–

Table 4.7: Investments in different scenarios in 2034

In the No network extension scenarios, somewhat higher power plant investments are required compared to the reference scenario as transmission bottlenecks during hours of peak residual load cannot be relieved. The geographic distribution of the additional plants also shifts toward northern Bavaria in 2024 and toward western Germany in 2034 (Figures 4.3 and 4.4). However, there are no investments in pumped-storage hydroelectricity in 2024 and only small investments in 2034. This may be explained by the specific locations of the storage facilities, because these cannot be fully utilized without additional integration into the transmission system.

In the Exogenous storage scenarios, the assumed storage expansion of 3.7 GW, which corresponds to the NEP 2014 scenario framework,[70] partly substitutes investments in gas-fired power plants compared to the reference scenario. Moreover, the geographic distribution of new power plants further shifts towards southern Germany in both 2024 and 2034. Network investments do not change much compared to the reference scenario.

[70]The Grid Development Plan foresees additional pumped-storage hydroelectric capacities of around 3.7 GW by 2024 and 4.4 GW by 2034. In the numerical application, we have used a value of 3.7 GW for both 2024 and 2034 in order to make the scenarios comparable.

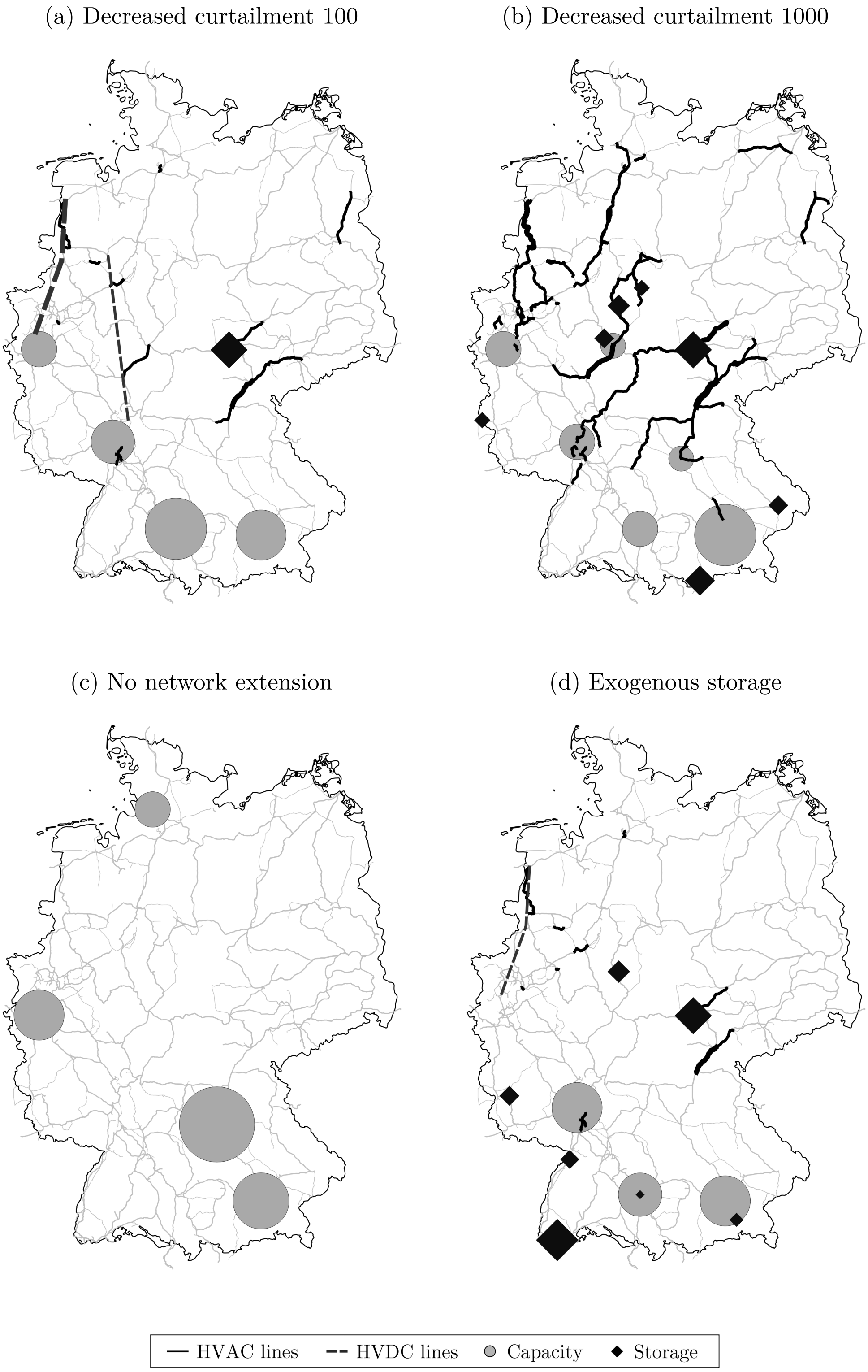

Figure 4.3: Geographic location of investments in the different scenarios in 2024

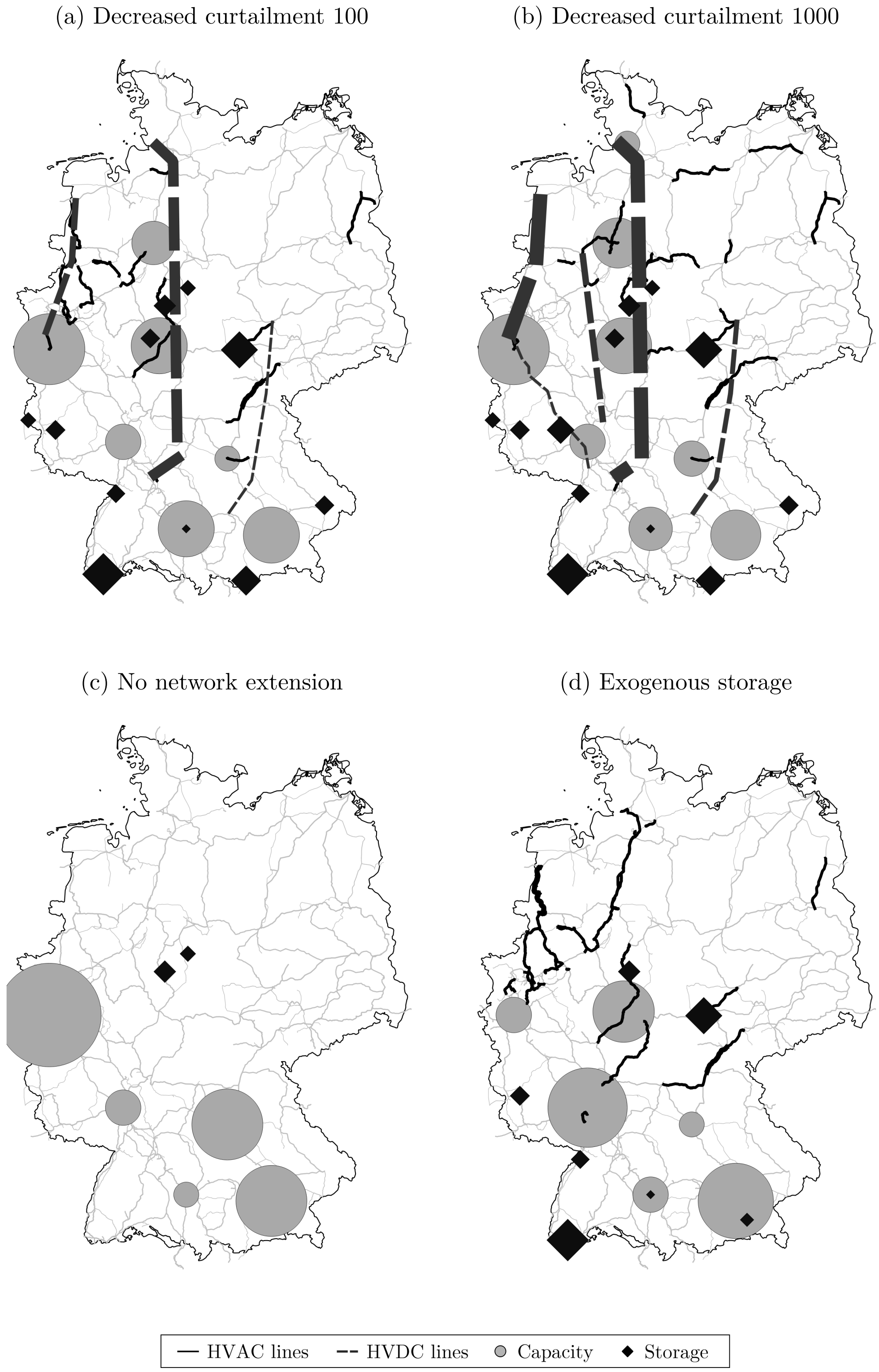

Figure 4.4: Geographic location of investments in the different scenarios in 2034

4.5 Discussion

4.5.1 Investments affect renewable and conventional generation

Model results indicate that additional network and storage capacities may not just foster the system integration of renewable power, but also of existing coal power stations, as these investments allow an increase in the use of technologies with low variable costs. By 2024, network and storage capacity expansion allows for the use of about an additional 0.7 TWh (1.3 TWh) of renewable power in the Decreased curtailment 100 (1000) scenario compared to the reference scenario. By 2034, 2.8 TWh (3.5 TWh) of renewable energy can be integrated through additional infrastructure investments compared to the reference scenario. At the same time, power generation from base load lignite-fired plants and mid-load hard coal plants increases at the cost of gas-fired generation (Figure 4.5). In the Exogenous storage scenarios we find corresponding effects on the dispatch. Compared to the reference scenarios, additional pumped-storage hydroelectric capacities allow for the use of around an additional 0.2 TWh of renewable power by 2024, and 1.1 TWh by 2034. At the same time, additional storage allows hard coal plants to increase their production by 4.6 and 2.2 TWh, respectively. In contrast, renewable curtailment in the No network extension scenario is 4.0 TWh higher compared to the reference in 2024, and even 18.4 TWh higher in 2034. In this case, no storage is built by 2024 and only 0.6 GW are added by 2034. This lack of storage can be explained by the projects' specific geographic locations in the context of unrelieved transmission bottlenecks. At the same time, the utilization of the new gas-fired plants is high, while power generation from lignite decreases.

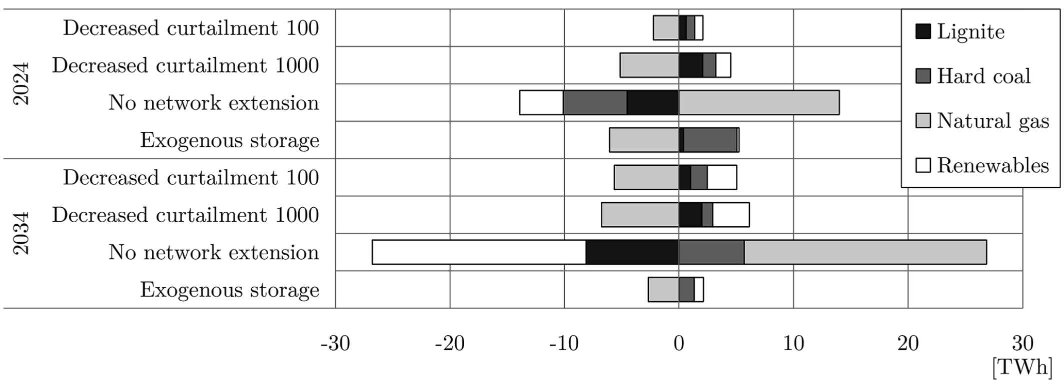

Figure 4.5: Changes in power generation compared to the reference scenario

4.5.2 CO_2 emissions reflect changes in power plant dispatch

The different levels of power generation from RES and coal-fired plants are reflected by respective CO_2 emissions. Compared to the reference scenarios, yearly emissions barely change in the Decreased curtailment cases because the increased utilization of lignite and hard coal plants compensates for emission reductions related to improved renewable integration. In the No network extension scenarios, CO_2 emission effects are more pronounced: in 2024, emissions are around 6m tons lower compared to the reference scenario because of decreasing power generation from lignite and hard coal; by 2034, this effect reverses because of substantially increasing curtailment of renewable generation, such that emissions increase by nearly 2m tons compared to the reference. Assuming Exogenous storage, emissions increase by around 3m tons by 2024, as the additional storage facilities—together with network extensions—allow for a high utilization of lignite and coal plants. By 2034, this effect vanishes. Accordingly, relaxing regional network restrictions and providing additional storage capacity may not just foster renewable integration but could also cause a temporary increase in CO_2 emissions, depending on the power plant fleet.[71]

4.5.3 Power system costs differ only slightly

Yearly power system costs—consisting of variable costs and annualized fixed costs of new investments—differ only slightly between the scenarios (Figure 4.6). The most expensive cases are the No network extension scenarios, as the investment option with the best ratio between reducing variable system costs and annualized fixed costs is not available here. Yearly system costs are around 300m EUR higher compared to the reference in 2024, and around 1bn EUR higher in 2034. In contrast, the Decreased curtailment 100 scenario is only slightly more expensive than the reference (around 30m EUR in 2024 and 80m EUR in 2034). The Decreased curtailment 1000 scenarios have considerably higher system costs—although not as high as in the No network extension case—as more infrastructure options have to be applied in order to further reduce curtailment. System costs of the Exogenous storage scenarios, which assume storage investments of 3.7 GW, are only slightly higher than the reference case, especially by 2034 (around 40m EUR higher).

Importantly, pumped-storage hydroelectricity not only has an arbitrage value and a capacity value in the power system, but may also provide ancillary services such as operating reserves (Denholm et al., 2010). Such additional system benefits are not included in the model. Likewise, ramping-related flexibility requirements will continue to increase in Germany in the course of ongoing expansion of variable RES.

[71] A similar effect is shown for the case of increasing demand-side flexibility by Holland and Mansur (2008).

Accordingly, moderate investments into pumped-storage hydroelectricity appear to be beneficial from a system perspective, even if such investments are small in the reference scenarios.

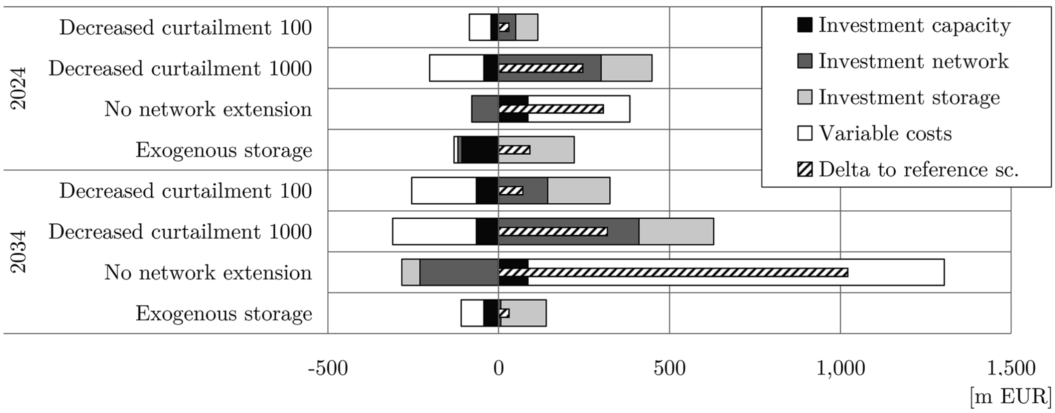

Figure 4.6: Changes in system costs compared to the reference scenario

4.6 Conclusion

We examine different investment scenarios for the German power system with increasing shares of RES for 2024 and 2034, using an integrated dispatch, transmission, and investment model with a high spatial resolution. In particular, we study the interdependence between investments in generation capacity, pumped-storage hydroelectricity, and transmission as well as their impact on power plant operation and system costs.

Based on the numerical results discussed above, we suggest several conclusions. First, the requirement for investments into generation, storage, and transmission increases through 2024 within the context of an aging thermal power plant fleet and a strong capacity build-up of fluctuating renewable generators. To some extent, investments into CCGT plants, pumped-storage hydroelectricity, as well as HVAC and HVDC transmission lines may be substituted against each other. In a cost-minimizing system, however, a mix of all investment options is required in the longer run. Considerable investments into CCGT plants are found in all scenarios. Importantly, these generation capacities have to be placed in specific regions. In 2024 most new CCGTs are located particularly in southern Germany, where nuclear capacities are phased out. 2034 results indicate that additional CCGTs in western Germany replace hard coal and lignite capacities. In reality, the current German market design provides few incentives for system-optimal power plant placement, and policy makers should work toward proper regional investment incentives.

As for pumped-storage hydroelectricity, our model determines rather small capacity requirements by 2024, and moderate investments by 2034. Nonetheless, pumped-storage hydroelectricity appears to be a no-regrets option from a system perspective: overall system costs of the scenarios with more or less storage differ only slightly, while pumped-storage hydroelectric facilities at the same time have additional system values related to the provision of reserves and other ancillary services, which are not included in the optimization. Such additional benefits may outweigh the slightly higher system costs of the exogenous storage scenarios; a detailed analysis of this issue is left for future research.[72] In any case, given that our longer-term scenarios indicate growing storage requirements—even without considering additional system values—early planning for new pumped-storage hydroelectric facilities appears to be favorable.

Regarding transmission investments, we identify several HVAC lines that are to be expanded in virtually every scenario. It may be favorable to prioritize the development of these projects. Making definitive statements about the need for or advantage of individual HVAC or HVDC connections, however, is beyond the scope of this analysis; moreover, line investments strongly depend on future power plant and storage deployments, both of which are uncertain in the context of a competitive power market. In any case, some network extensions are required in most cases analyzed here.

In general, most investment options analyzed here face long lead times, especially storage and transmission investments. With the perspective of a long-term transition towards a largely renewable-based system, it appears to be reasonable to administratively prepare such infrastructure projects early on. This argument is even more valid if there is a political intention to reduce renewable curtailment, which may be motivated by climate policy concerns, among other reasons. With the perspective of further increasing renewable shares after 2034, early planning which prioritizes renewable integration, as in the decreased curtailment scenarios, may thus be beneficial.

[72] Gas-fired power plants may also contribute to the provision of ancillary services. The relative importance of ancillary services revenues, however, is larger for pumped-storage hydroelectric facilities.

Chapter 5

Regional versus bilateral cost sharing in electricity transmission expansion

This chapter is based on:
Regional versus bilateral cost sharing in electricity transmission expansion
Conference Paper at the 29th Annual Congress of the European Economic Association (EEA 2014, in Toulouse), Nylund and Egerer (2014).
Joint work with Hans Nylund.
It was presented at the Berlin Conference on Electricity Economics, 2013 (Berlin), at the 7th Annual Trans-Atlantic INFRADAY, 2013 (Washington D.C.), and at the 29th Annual Congress of the European Economic Association, 2014 (Toulouse).

5.1 Introduction

The planning and expansion of electricity transmission grids have mainly been done from a national perspective because the investment costs of new capacity are paid nationally, or shared between two countries when building a new cross-border link. This is despite the fact that the benefits of new grid capacity often spread to several neighboring countries and that grid planning from a supranational perspective could bring higher overall benefits. This topic has taken on greater importance due to the liberalization of electricity sectors around the world and the progression of system transformation towards renewable generation. It is particularly relevant in Europe, where insufficient cross-border capacities have been identified as one obstacle to the on-going integration of national electricity markets into a single European market. The European Union (EU) initiated the process through Directive 96/92/EC (EC, 1996), followed by Directive 2003/54/EC, which concludes that the "experience in implementing this Directive [96/92/EC] shows the benefits that may result from the internal market in electricity, in terms of efficiency gains, price reductions, higher standards of service and increased competitiveness" (EC, 2003a, p. 37). In recent years the focus has shifted towards infrastructure. The need for additional cross-border infrastructure, which is unlikely to come about in nationally planned systems, resulted in several initiatives. The European Commission (EC, 2009a) accelerated the unbundling between generation/supply and the transmission system operator (TSO) and initiated the Ten-Year Network Development Plan (TYNDP). In addition, EC (2010) addresses the issue of cost allocation for transmission investments.

The cost structure of electricity transmission systems generally consists of high fixed costs and low variable costs. Transmission tariffs are the main source of cost recovery. Depending on market design, some rents are also collected as congestion rent on capacity between price areas. While these rents may cover some of the costs, they are generally not sufficient (Perez-Arriaga et al., 1995). In the European interconnected electricity system, the costs are not shared system-wide but within some entity, such as the TSO's control area (which is typically nation-wide).[73] Thus, the agents benefiting from transmission capacity may not always coincide or be limited to the ones paying for the capacity. From this perspective, transmission infrastructure in multinational markets has some public goods characteristics (see Nylund (2014) for a discussion). There exists an inter-TSO compensation (ITC) mechanism for transit of electricity (EC, 2010), but it is not currently designed to provide financial compensation for new capacity.

[73]Germany is an exception with its four different TSOs.

To what extent can the sharing of investment costs between several countries help to overcome this issue?

In Europe, the investment costs of cross-border links are traditionally shared equally between the two countries involved in the expansion. The sometimes widespread regional effects of grid expansions have motivated discussions on regional cost sharing according to benefit distribution, as for example in the proposed EU policy for projects of common interest (PCI) in Regulation (EU) 347/2013 (EC, 2013b). Real world examples of regional cost sharing are also present with the case of the “Priority Cross-sections” program by the (former) regional TSO group Nordel (2004). Since each country/TSO has the power to decide on their own investments, cooperation on expansions needs to be incentive-compatible and rational for each participant. Within EU policy and regulatory framework it is possible to envision the formation of a general agreement for cost sharing in transmission expansions with regional benefits. An intuitive and transparent way to allocate the investment costs in such an agreement is in proportion to the benefits received, defined by joint cost-benefit analyzes (CBAs).

This chapter discusses the nationally-motivated extension of cross-border transmission capacity in an investment game. Combining non-cooperative and cooperative elements of game theory provides an insight into stable investment strategies and the challenges of meshed electricity systems. It is outlined as follows: Section 5.2 introduces related literature; Section 5.3 describes the model framework; and Section 5.4 outline its application to the electricity systems of six European countries. Results of the optimization and the game theoretic analysis on transmission extension and economic welfare for bilateral cost sharing compared to regional cost sharing are presented and discussed in Section 5.5. The expansion decisions of the TSOs are modeled by non-cooperative game theory and a numerical optimization model of the stylized electricity systems of six European countries. Section 5.6 concludes.

5.2 Literature

This section provides an overview on related publications on cooperative and non-cooperative decision making in transmission investment. Nylund (2014) analyzes different allocation rules for regional cost sharing in transmission expansions and recommends the proportional rule. An important question to answer, therefore, is what the effects on expansions would be if the traditional bilateral cost sharing was replaced by a regional cost sharing agreement. The problem of cost allocation in electricity transmission has been studied by game theory models for the national context (Contreras and Wu, 1999; Zolezzi and Rudnick, 2002). However, with a social planner trying to maximize the social welfare of one single country, the transmission investment diverges from the welfare-optimal investment for the entire multi-national system (Buijs and Belmans, 2012; Saguan and Meeus, 2014). Huppmann and Egerer (2015) propose a three-stage equilibrium model to analyze transmission investment in a Nash game. The model is applied to a four-node sample network and illustrates the failure to reach the first-best expansion in the absence of a compensation mechanism.

The economic analysis is based on welfare theory applied to an electricity spot market with short-term marginal cost pricing. The welfare term is defined as the consumer and producer surplus as well as network congestion rents. The market price is determined by the intersection of the inverse demand function and the supply curve defined by the marginal costs of the suppliers. Exchange capacity between different price zones is implicitly auctioned into the market dispatch to maximize system welfare. This setting represents the prevailing market design in Central and Western Europe. It also indicates that the market dispatch of the entire system is optimized without considering implications on the national level. As soon as limited inter-zone capacity becomes binding, electricity prices deviate across different national price zones. While additional cross-border capacity is required for the on-going integration of national electricity markets, these investments also affect the national welfare level. Thus, national regulators and TSOs might have second thoughts on investments which provide this additional exchange capacity. The two deviating objectives of integration and national welfare are illustrated in Figure 5.1. The problem formulation separates the decision on transmission investments in the upper level (leader) from the market dispatch in the lower level (follower) into a bi-level optimization problem. The central planner with the objective of welfare optimization is a special case of investment planning with a single objective. As the leader and the follower have the same objective value the bi-level model can be simplified to a common linear optimization problem (Kirschen and Strbac, 2004).

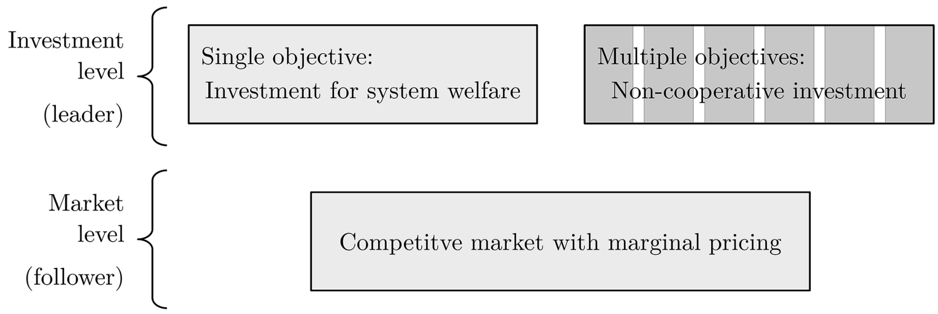

Figure 5.1: Bi-level optimization problems

More generally, the objective of the leader diverges from the optimization of system welfare in the market dispatch. The formal representation results in a mathematical problem with equilibrium constraint (MPEC). Buijs and Belmans (2012) argue that the benchmark for transmission planning should be a Pareto planner rather than a central planner. In this case, only investments that do not decrease any country's welfare remain possible. They apply the bi-level optimization model with a Pareto planner as well as single profit-seeking countries as leaders in the upper level. Other examples of applications of bi-level models to electricity transmission can be found in Garces et al. (2009) and Jenabi et al. (2013). Compared to one leader, this work assumes an interaction between several nationally-motivated transmission planners. Consideration not only of the market effects of transmission planning, but also the interaction of multiple national transmission planners, results in a generalized Nash equilibrium. These models with multiple objectives (leaders), so called equilibrium problems with equilibrium constraints (EPEC), are very difficult to handle. Thus, this approach does not formulate an optimization problem to find optimal strategies. Rather, it examines the payoff matrix for a set of possible expansion strategies with a game theory model for stable outcomes.

5.3 Methodology

The following approach, describing the investment game in trade capacity for the electricity market, combines elements of non-cooperative and cooperative game theory. It determines stable investment strategies within a discrete solution space for two allocation schemes of investment costs and two different representations of electricity flows.

5.3.1 General framework

Welfare-optimal market results can be calculated with the supply and the demand functions of the respective markets and the trade capacities between them. Depending on the market design, the network nodes in this chapter can represent either aggregated market zones (in markets with bidding zones) or individual transformer stations of the high-voltage transmission system (in markets with nodal pricing). In the following, network nodes are regarded as countries and network investment increases trade capacities between them. The assumption of one node per countries is a strong simplification of investment costs for additional trade capacity. Thus, the model application in this chapter has a stylized character when describing the incentives of individual countries in the expansion game.

From a system perspective, investment in additional trade capacity should maximize system welfare. This objective does not consider the implications on national welfare levels. Network investment is likely to create winners and losers due to an uneven distribution of welfare effects. In a perfect world, a cooperative solution between all players, including compensation payments, could secure the support for the system-optimal solution. This work limits compensation payments to the allocation of network investment costs. It does not allow the compensation of welfare losses which might result from investments.

In this setting, every player of the game has the power to decide on investment in additional trade capacity on links connected to its node. The decision makers in the transmission expansion game are assumed to be the TSOs which follow the request of national regulators to maximize national welfare levels. By game theoretic terminology, they are labeled as the players in the game.[74] Due to the complexity of the game, the other parameters of the electricity system (e.g., generation capacity) are assumed to be constant.

In the analyzed framework, a player tries to increase the welfare value of its node by strategic decisions on investment in the network links connected to this node. Obviously, both players, connected by the respective line, are involved in the investment and have to agree for the realization of its expansion. We also make the assumption that players can decide on the investment only once. The existing exchange capacity is available in the electricity market and cannot be reduced by holding back capacity by any player. The framework combines an electricity sector model and a game theory model in consecutive order for the following steps:

1. a numerical electricity sector model determines the welfare-optimal network expansion strategy for the entire system with mixed-integer variable on transmission investment;

2. a linear version of the model calculates the payoff matrix of nodal welfare results for every combination of the discrete line investments for the different network links;

3. a game theory model derives stable outcomes for the pre-defined cost allocation schemes. This is done for both of the discussed allocation rules for network investment costs (equal and proportional).

[74]The approach also allows more than one node per player. From a national perspective more than one node could reflects auctions of trade capacity to the market within the respective country, e.g., in case of several bidding zones or nodal pricing.

5.3.2 Optimization models

The problems are implemented in the General Algebraic Modeling System (GAMS) and solved using the commercial solver CPLEX.

Transmission investment model

In the first step, a bi-level optimization model calculates the optimal network investment strategy for the entire model scope. The results provide the benchmark for the solutions of the investment game. The upper level of the model describes a central planner maximizing system welfare minus network investment costs while the lower level optimizes the market dispatch. As both levels have the same objective value of welfare maximization the bi-level character of the model can be reduced to one joint objective function. The problem formulates as a mixed-integer linear problem (MILP) with integer variables on the discrete choice of additional transmission capacity. The resulting expansion strategy optimizes system welfare and does not consider national welfare outcomes. System welfare w is maximized in the objective function 5.1 by the area below the inverse demand function minus generation costs, summed up over all countries n, hours t, and technologies i, minus network investment costs.[75] The positive integer variable i_l^{line} invests in discrete steps of $\overline{pf}_l^+$ in network capacity for every network link l and with investment costs $\hat{c}_l^{\text{line}}$.

$$\max_{g^{\text{tech}},q,i^{\text{line}}} \mathrm{w} = \sum_{nt} \left(a_{nt} q_{nt} + 0.5 m_{nt} q_{nt}^2 - \sum_i g_{nit}^{\text{tech}} \hat{c}_i^{\text{tech}} \right) \hat{y} - \sum_l i_l^{\text{line}} \hat{c}_l^{\text{line}} \tag{5.1}$$

$$\begin{aligned}
\text{s.t.} \quad g_{nit}^{\text{tech}} &\leq \overline{g}_{ni}^{\text{tech}} av_{nit}^{\text{tech}} && \forall \quad n,i,t && (5.2a)\\
\overrightarrow{ps}_{nt} + \overleftarrow{ps}_{nt} &\leq \overline{ps}_n && \forall \quad n,t && (5.2b)\\
ls_{nt} &\leq \overline{ls}_n && \forall \quad n,t && (5.2c)\\
ls_{nt} &= 0.75 \overleftarrow{ps}_{nt} - \overrightarrow{ps}_{nt} + ls_{n(t-1)} && \forall \quad n,t && (5.2d)\\
|pf_{lt}| &\leq \overline{pf}_l + i_l^{\text{line}} \overline{pf}_l^+ && \forall \quad l,t && (5.2e)\\
q_{nt} + \overleftarrow{ps}_{nt} &= g_{nt} + \overrightarrow{ps}_{nt} + ni_{nt} && \forall \quad n,t && (5.2f)
\end{aligned}$$

[75] Both, system welfare (by the factor $\hat{y}$) and investment costs state annualized levels. The inverse demand function is defined by the prohibitive price a and the negative slope of the demand function m. Both calculate from a reference point on the demand function, i.e., a combination of load and electricity price, and by the related point elasticity of demand.

Transport flow equations:

$$ni_{nt} = \sum_l im_{ln} pf_{lt} \qquad \forall \quad n, t \tag{5.3a}$$

DC load flow equations:

$$pf_{lt} = \sum_n \theta_{nt} h_{ln} \qquad \forall \quad l, t \tag{5.4a}$$

$$ni_{nt} = \sum_k \theta_{kt} b_{nk} \qquad \forall \quad n, t \tag{5.4b}$$

$$\theta_{\hat{n}t} = 0 \qquad \forall \quad t \tag{5.4c}$$

Additional constraints of the model are equation 5.2a on generation which limits the hourly output for every technology g_{nit}^{tech} to the installed generation capacity $\overline{g}_{ni}^{\text{tech}}$ multiplied by an hourly availability factor av_{nit}^{tech}. Three constraints describe the operation of pumped-storage hydroelectric plants. They include the maximal turbine capacity $\overline{ps}_n$ which limits $\overrightarrow{ps}_{nt}$ and $\overleftarrow{ps}_{nt}$, the variables for generation and pumping, in Equation 5.2b. Storage content ls is constrained in Equation 5.2c by the maximum storage level $\overline{ls}_n$. Equation 5.2d relates the storage level of the hour t to the operation of the storage, with a cycle efficiency of 75%, and to the storage level in the previous hour $t-1$. Except for the free variable w (objective value), all other variables are defined as positive variables.

A special characteristic of power flows is their physical flow pattern, which includes loop flows throughout the network. In the transmission expansion game, both, directed transport flows and power flows, are examined. The approach with transport flows assumes that electricity can be allocated freely on the direct links between two countries without the occurrence of loop flows. The transmission capacity of the link remains the only limiting factor. The approach with power flow requires electricity, which is injected in the network, to take direct and indirect paths to the location of consumption. This characteristic has implications for the transmission expansion game as it can cause positive as well as negative externalities on the level of available transmission capacity.

Constraints of the case with transport flows include the energy balance and three constraints for electricity flow. The energy balance 5.2f requires generation to equal demand plus exchange ni_{nt} with the network for every hour and country. The positive and negative capacity constraint in 5.2e limits the power flows pf_{lt} on each link to a maximum exchange capacity $\overline{pf}_l$ in both directions. Network expansion relaxes this constraint. The value of the parameter $\overline{pf}_l^+$ defines the step size for the expansion of network capacity and is multiplied with i_l^{line}, the integer variable for network investment. The relation between the links and the countries is included in the incidence matrix im_{ln} in Equation 5.3a.

Loop flows in the network are implemented with the DC load flow approximation (Schweppe et al., 1988) which requires two additional constraints. The consideration of loop flows includes the same capacity constraint on line flow and network expansion of Equation 5.2e. The free flow variable pf_{lt} is constrained in the additional Equation 5.4a by the angle difference times the network transfer matrix h_{ln} which reflects the physical network characteristics. To enforce unique solutions for the flow angles θ_{nt} the value for theta is forced to zero for one reference country $\hat{n}$ in Equation 5.4c. The energy balance 5.2f remains identical to the case with transport flows but network in- and outflows in 5.4b depend on the flow angles and the physical network characteristics in the network susceptance matrix b_{nk}. The additional constraints in the load flow approach result in a more restricted solution space. As the flow allocation on individual lines relies on the entire network, capacity expansion between countries might not be fully available without additional investments in indirect routes between the two countries.

Dispatch model

The second step of the approach calculates the national welfare outcomes for the two cost sharing frameworks. To limit the number of possible investments the solution space of the game is restricted to combinations of capacity up to the level in the welfare-optimal solution plus one additional expansion step for every transmission link. For each combination, a reduced linear version of the mixed-integer model is solved with fixed integer variables i_l^{line}. National welfare levels are calculated by consumer and producer surplus plus 50% of the cross-border congestion rents for each link adjacent to the country. The allocation of investment costs is discussed in the following game theory model.

5.3.3 Game theory model

The third step of the framework applies a combination of cooperative and non-cooperative game theory. The decision makers in transmission expansions are assumed to be the TSOs, which by game theoretic terminology are labeled as the players in the game. A fundamental assumption on the behavior of the players is that they will make rational choices among the different payoff options available to them. The relevant payoffs are defined as the national welfare outcomes of different expansion options, given by step two in the optimization model and specified as the level of consumer and producer surplus plus congestion rent and minus the investment cost. A TSO is therefore assumed to represent the interest of its country when making expansion decisions, and the terms TSO, Country, and Player can therefore be interpreted as interchangeable entities in the following analysis. The expansion game will be analyzed under two different cost allocation rules for the investment costs of expansions: (a) bilateral sharing between two connecting countries based on the equal rule; and (b) regional sharing between all countries that benefit based on the proportional rule (in proportion to the benefits received). Thus, depending on the cost allocation scheme, the values in the payoff matrix change.

Expansions in cross-border links require the cooperation of at least two TSOs. When modeling the decisions on expansions it is therefore relevant to consider that an expansion choice cannot be realized independently by one player, but needs to be matched with the choice of at least one more player. The inter-dependencies in grid expansions that underlie the national welfare outcomes are incorporated into the payoff matrix from the optimization model. In order to identify the outcomes that are likely to result from the game, it is assumed that players have exclusive decision rights on expansions connecting to their own territory. A player is therefore defined as a veto player for the own expansions that it can block. An outcome is defined as stable if it is not blocked by any player. To derive the stable outcomes it is therefore important to know who has the right to decide on a particular expansion.

The procedure to identify the stable outcomes includes: (1) The optimization model that derives the payoff matrix for all technically feasible outcomes using a step-wise procedure that increases trade capacities in pre-defined steps. The step-wise procedure starts from a baseline grid and continues up to pre-defined maximum capacities. (2) The set of outcomes is refined to the stable outcomes by using the following assumptions and procedure. For each incremental capacity step on a specific trade link, and conditional on the capacity on other trade links, a player's payoff can either be increased, decreased or remain unchanged compared to the previous step. A veto-player is assumed to block capacity steps that have a lower payoff compared to the previous or following step. All non-blocked outcomes can therefore be derived by checking all capacity expansion steps and their combinations for each player with this procedure. The stable outcomes are then defined as the non-blocked outcomes with the highest payoffs for each player (the dominated strategies are eliminated) and are equal to the Nash equilibriums in pure strategies for the game (Varian, 1992). This means that in the stable outcomes each player makes an optimal choice given the expectation of what the other players will choose.

Will the game have a unique stable outcome? The answer to this question depends on the payoff distributions and the veto rights of players in the different outcomes. If there is a single outcome with the highest payoffs for all players, it will be a unique outcome of the game. However, in games where veto-players prefer different outcomes it is not possible to predict a unique outcome without additional assumptions on how the players resolve conflicts. In practice this may depend on many factors, which in turn are difficult to formalize. Yet, without any further assumptions we can characterize the set of stable outcomes for the different cost sharing frameworks and flow representations by how close they are to the optimal welfare outcome, and by the number and range of the outcomes. It is also interesting to characterize each outcome by dividing the players into those who make expansions and those who do not. This is conveniently formalized by coalition structures that partition the set of players into expanding and non-expanding players for each outcome. The following results section will present and analyze the stable outcomes in this way.

The players' choices on expansions can be summarized as a multinational expansion plan, which remains fixed for a given time-period. The players' farsightedness in choosing strategies is therefore limited to the development of the given plan, and does not take into account any strategic implications for future negotiations of expansion plans. The assumptions on the game are summarized as follows:

Assumptions on the game:

- static game with simultaneous moves, described in strategic form with: players=TSOs; strategies=transmission expansion choices; payoffs=national welfare;
- complete information, meaning that the complete payoff matrix is known to all players;
- each player has exclusive decision power over grid expansions on its own territory;
- the number of expansion options is finite;
- the stable outcomes of the game are defined by Nash equilibriums in pure strategies;
- the strategic considerations include blocking of expansion by single players and preferring different stable outcomes:
  - if any player has the power to increase its own welfare, given a particular outcome, by reducing or increasing investment on one of its own lines the outcome is not considered to be stable;
  - also the incentive to diverge to a different expansion path can result in a non-stable outcome if all players involved in changed planning are better off compared to the initial outcome.

Assumptions on the local objective function:

- players are rational and seek to maximize their own welfare;
- welfare is defined as the sum of consumer surplus, producer surplus and congestion rents minus costs for transmission investments. The congestion rent is shared equally between the two adjacent players.

Assumptions on the market design:

- short-term marginal pricing with implicit auctioning of exchange capacity defines the market outcome;
- static setting for generation capacities, their variable costs, and the demand functions;
- transfer flows are modeled with the two approaches a) transport flows and b) load flows (DC load flow approximation).

Assumptions on cost sharing:

- bilateral game: expansion costs for cross-border links are shared equally (50/50) between the two TSOs involved only;
- regional game: players have signed a general agreement stating that the investment cost of expansions will be shared in proportion to benefits received for each player, including players that receive positive spill-over benefits. There is no compensation for negative spill-overs, with the motivation that it may induce strategies for gaining compensation instead of participating in building new expansions.

5.4 Application

The framework is applied to a set of six countries, illustrated in Figure 5.2. The model data provide a general representation of the real world electricity market setting with some assumptions where necessary. The stylized network represents the national electricity systems of Belgium and the Netherlands combined (BN), France (FR), Germany (DE), Switzerland (CH), Austria (AT), and Italy (IT). The connections represent lines with existing trade capacity for electricity between the countries.

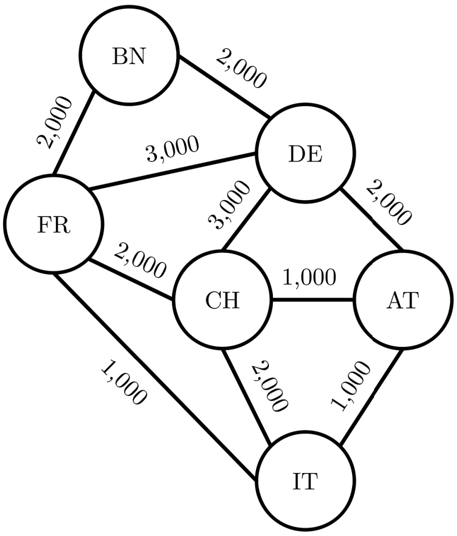

Figure 5.2: Stylized network with six countries and exchange capacity [in MW]

The model is run for 672 operational hours (4 weeks) composed of 168 hours (1 week) from each season of the year 2012. The four weeks represent the strong seasonal and daily variation in hourly demand and renewable generation levels. The welfare results are then aggregated to annual values to make them easier to interpret and evaluate.

The dataset includes parameters of yearly and hourly character for the reference year of 2012. The infrastructure data (parameters on the network and the generation capacity) is kept constant for all hours of the year. The level of demand and availability of renewable generation varies on an hourly basis. The initial trade capacities between the six countries represent realistic net transfer capacities (ENTSO-E, 2011). All transmission lines are considered to be equal in their physical characteristic (length, and impedance in the load flow model). Since the stylized model only includes the capacity and not the line lengths, expansion costs are assumed with a general hourly cost factor of 10 EUR/MWh.[76] This is high for an individual line, but is also chosen to reflect the required upgrades of the hinterland networks which are not represented in the scope. It also addresses the issue of social acceptance for new transmission lines. Both these aspects increase the real cost of additional cross-border trade capacity.

The hourly demand function for electricity is derived for each country with an hourly reference demand for every country (ENTSO-E, 2013), a reference price (45 EUR/MWh) and the short-run elasticity of demand (-0.10).[77] The dataset includes eleven different generation technologies. Table 5.1 shows the installed capacity on national level.

[MW]	**BN**	**FR**	**DE**	**CH**	**AT**	**IT**
Hydropower	200	19,000	2,400	13,500	7,200	12,200
Wind	3,800	7,600	31,300	100	1,400	3,100
Photovoltaics	1,900	3,800	32,500	0	200	17,000
Biomass	1,800	1,100	3,500	400	2,500	1,100
Nuclear	5,800	63,100	12,100	3,000	0	0
Lignite	0	0	18,700	0	0	0
Hard coal	6,000	6,200	25,400	0	1,200	8,400
CCGT	3,900	3,400	7,600	0	3,000	2,800
Gas	10,400	100	18,800	300	1,800	30,800
Oil	1,300	7,200	3,800	100	0	18,200
Pumped-storage	1,300	5,300	6,400	1,700	4,400	6,600

Table 5.1: National generation capacities for each generation technology[78]

Approximated values for the variable generation costs of the technologies are stated in Table 5.2. The power plants are assumed to be available with a fixed percentage over the entire year. Exceptions are wind and photovoltaics with an hourly availability factor based on regional data for 2012.[79]

Storage capacity is implemented to operate throughout one model week, has a storage size equal to seven times its generation capacity, and runs with a cycle efficiency of 0.75.

[76] Rosellón and Weigt (2011) use a line expansion cost of 100 EUR per km and MW.

[77] As the elasticity of demand has strong implications the results section includes a sensitivity test with an elasticity of -0.25. Dahl (2011) provides a survey of estimated electricity demand elasticities and presents a median short-run elasticity of -0.14.

[78] The generation capacities are aggregated from detailed power plant data (Platts, 2012) and from EWEA (2013) and EurObserv'ER (2013) for renewable generation capacity.

[79] The regional time series include data by the following TSOs: 50Hertz (2013), Amprion (2013), TenneT TSO (2013); Terna (2013); TransnetBW (2013); and RTE (2013); as well as by EEX (2013b). In case no data is available for one country and technology the time series of the neighboring country is applied. For a more realistic representation (revision downtime, etc.) the availability factors for conventional capacities are fixed to 0.85 and to 0.60 for biomass.

[EUR/MWh]	**Variable costs**
Hydropower	0
Wind	0
Photovoltaics	0
Biomass	10
Nuclear	12
Lignite	15
Hard coal	40
CCGT	50
Gas	80
Oil	140

Table 5.2: Variable costs for each generation technology[80]

5.5 Results and discussion

5.5.1 System welfare-optimal expansion

Before presenting and comparing the results of the expansion games, we give a brief description of the optimal system welfare level for the load flow (transport flow) model. The welfare-maximizing expansion strategy provides an annual net increase of 3.33bn (2.65bn) EUR. The gain with additional capacity is higher in the load flow model due to the more constrained network setting. The additional cross-border capacity is also greater with 20,000 (17,000) MW and requires 1.75bn (1.49bn) EUR of annualized capital expenditures. Figure 5.3 displays the welfare-optimal expansion strategy. In the load flow model, the expansions of cross-border capacity are located between IT and all its neighbors and in the triangle of BN, FR, and DE. Due to the unconstrained flow distribution in the transport model (lower externality by loop flows), the investments increase from FR to BN and IT and decrease on the other lines. The welfare distribution between the countries has no effect on the welfare-optimal investment decision.

[80] The calculation of variable generation costs assumes resource prices of 2 EUR/MWh for lignite, 12 EUR/MWh for hard coal, 26 EUR/MWh for natural gas and 47 EUR/MWh for oil, efficiency values of 35% for gas turbines, 40% for steam turbines and 56% for combined cycle turbines, and a CO_2 price of 10 EUR/t. The assumed prices are in the range of market prices for the last years. The variable costs are rounded to the stated values.

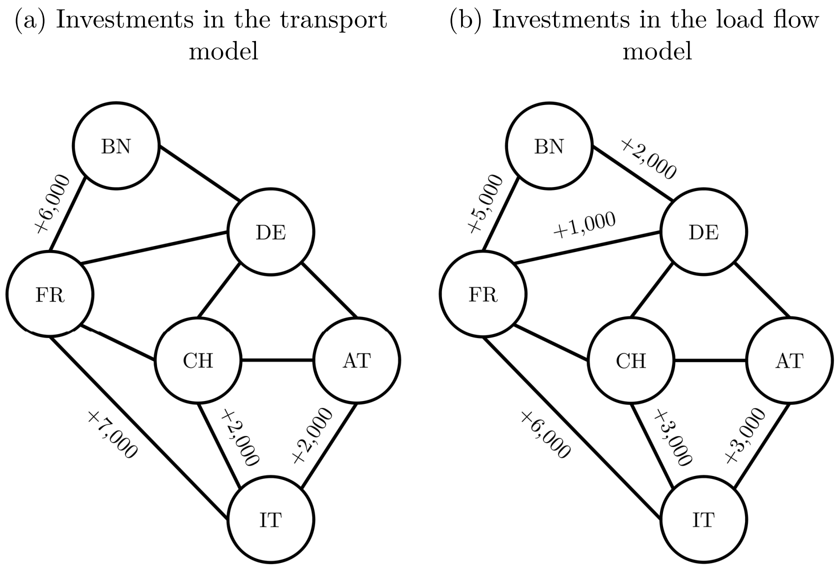

Figure 5.3: Welfare-optimal transmission investments [in MW]

5.5.2 Non-cooperative results

The outcome of the strategic interaction between TSOs on grid expansions is defined by the set of stable outcomes for each cost sharing framework and flow representation.

Transport flow model

With equal sharing, the game for the transport flow model results in 28 stable outcomes. The average capacity expansion is 11,900 MW (70% of the optimum) and the average welfare gain is 2.1bn EUR (79% of the optimum). The aggregations to national level (Table 5.3) indicate a wide range of possible welfare changes for each country. Except for AT, the average welfare results are below those given by the system welfare optimum. Yet, the stable outcomes give a strong incentive for gaming as most countries could get national welfare gains of several 100m EUR compared to the system welfare optimum.

According to the system welfare benefits, the outcomes can be aggregated into two general categories in this case. The first category of 17 outcomes includes strategies with a 1,000 MW expansion between FR and DE but only limited upgrades of the links from FR to BN and IT (at most 5,000 MW in combined capacity). The second category of 11 outcomes excludes the expansion to DE, and the links from FR to BN and IT are expanded with at least 12,000 MW in combined capacity. In the second category the average expansion increases from 8,700 MW to 16,800 MW and the average welfare gain from 51% to 98% of the welfare optimum. In a game with such a broad distribution of possible outcomes it could be difficult to decide on a common expansion plan and it is a high-risk strategy to have joint planning with insufficient investments.

In the case of regional cost sharing the number of stable outcomes is reduced to eight as the redistribution of costs according to benefits creates more balanced national payoffs (Table 5.4). The average welfare gain is 2.5bn EUR (94% of the optimum) and the average capacity increase is 19,900 MW (117% of the optimum). The over-investment in the average case, compared to the welfare optimum, is partly due to an over-investment of 1,000 MW between DE and BN or FR in all but one outcome, and an over-investment of 1,000 MW between IT and AT as well as CH. In this case it is clear that regional cost sharing will give a better outcome from a welfare perspective compared to bilateral sharing.

[m EUR]	**AT**	**BN**	**CH**	**DE**	**FR**	**IT**
Minimum	137	-112	122	-801	475	84
Maximum	440	772	710	-293	1,451	1,139
Average	323	363	362	-559	925	703
Optimum	239	410	390	-754	1,380	985

Table 5.3: National welfare changes for equal cost allocation (bilateral)

[m EUR]	**AT**	**BN**	**CH**	**DE**	**FR**	**IT**
Minimum	118	462	310	-837	1,164	876
Maximum	282	551	373	-690	1,378	1,051
Average	233	505	346	-786	1,286	959
Optimum	227	468	332	-754	1,356	1,021

Table 5.4: National welfare changes for proportional cost allocation (regional)

Load flow model

The coalition structures in Table 5.5 are denoted by grouping the investing TSOs as one coalition and the non-investing TSOs as separate players. In the payoff columns the non-investing TSOs' payoffs are marked in gray. With equal sharing, the game for the load flow model results in six stable outcomes.

While the overall number of stable outcomes is lower than in the transport flow model, their relative performance to the welfare optimum is similar. The average capacity expansion is 12,300 MW (62% of the optimum) and the average welfare gain is 2.7bn EUR (82% of the optimum). The stable outcomes also include two types: (1) two strategies (excluding BN/DE or CH) with lower average welfare gains (64%) and capacity investments (50%) and; (2) four strategies (including all countries except for one without DE) closer to the system optimum (91% welfare and 68% capacity increase).

Coalition	**Expansions** [MW]	**Payoffs** [m EUR]						
Bilateral cost sharing		AT	BN	CH	DE	FR	IT	%
{AT, CH, FR, IT}, {BN}, {DE}	3,000: CH-IT 4,000: AT-IT 4,000: FR-IT	436	26	93	-261	384	1,397	62
{AT, BN, DE, FR, IT}, {CH}	1,000: AT-IT 1,000: DE-FR 3,000: FR-IT 4,000: BN-FR	291	685	-460	87	1,129	448	65
{AT, BN, CH, FR, IT}, {DE}	3,000: AT-IT 3,000: BN-FR 3,000: CH-IT 5,000: FR-IT	348	535	-21	-246	1,151	1,443	96
{AT, BN, CH, DE, FR, IT}	1,000: DE-FR 1,000: CH-IT 2,000: AT-IT 3,000: BN-FR 4,000: FR-IT	441	558	-182	-40	1,097	817	81
	1,000: BN-DE 2,000: AT-IT 2,000: CH-IT 3,000: BN-FR 4,000: FR-IT	306	666	159	-181	1,052	1,054	92
	1,000: BN-DE 3,000: BN-FR 3,000: CH-IT 4,000: AT-IT 5,000: FR-IT	414	605	115	-259	1,025	1,276	95

Table 5.5: Stable states for equal cost allocation (bilateral) with load flows

Coalition	**Expansions** [MW]	**Payoffs** [m EUR]						
Regional cost sharing		AT	BN	CH	DE	FR	IT	%
{AT, BN, CH, DE, FR, IT}	1,000: DE-FR 3,000: BN-DE 3,000: CH-IT 4,000: AT-IT 4,000: BN-FR 5,000: FR-IT	431	721	145	-384	1,120	1,158	96
	1,000: DE-FR 1,000: CH-IT 3,000: AT-IT 3,000: BN-DE 4,000: BN-FR 5,000: FR-IT	413	687	57	-371	1,190	1,283	98

Table 5.6: Stable states for proportional cost allocation (regional) with load flows

With regional sharing, only two outcomes remain stable (Table 5.6). Both are close to the welfare optimum (96% and 98%) and include 20,000 MW in capacity increase (with a slightly different distribution on lines than in the welfare optimum). Also, individual countries have similar payoffs for both options. In this application the regional cost allocation combined with a load flow representation is able to provide good results both for welfare and capacity. The lower number of stable outcomes indicates the reduced possibilities of gaming for specific outcomes as the loop flows make them more reliant upon each other.

Sensitivity analysis

The short-run demand elasticity is of central importance as it determines the effect of price changes on consumer surplus. Thus, in addition to an inelastic demand (elasticity of -0.10), the sensitivity of the results is tested using a demand elasticity of -0.25.

In the system-optimal outcome of the transport flow model, the overall welfare gain decreases by 30% and the expansion capacity decreases on three lines by 1,000 MW each to 14,000 MW. With equal sharing the average welfare gain is 91% of the optimum and capacity expansion 75% of the optimum; with regional sharing it is 95% for welfare and 111% for capacity.

In the load flow model the optimal outcome is 27% lower in welfare and has 4,000 MW lower capacity (16,000 MW in total). All lines (except IT to AT/CH) decrease by 1,000 MW. For equal sharing the average welfare gain is at 82% and capacity expansion at 69%, while regional sharing yields an average of 90% for welfare and 98% for capacity.

5.6 Conclusion

This chapter analyzes transmission expansion in cross-border electricity networks and how it is affected by the way investment costs are shared between countries. Two cost sharing frameworks have been compared: traditional bilateral cost sharing by the equal rule between connecting countries only; and regional cost sharing by the proportional rule according to benefits received for all countries that benefit. The analysis was conducted using a numerical optimization model applied to a stylized network with six European countries, in combination with a game theoretical model that predicts the results of strategic interaction between countries in expansion decisions.

Results show that several possible stable outcomes can result under both cost sharing frameworks. The outcomes are fewer and much less spread out with regional sharing, indicating that the uncertainty of the outcome under this framework is lower. In the best cases the bilateral outcomes are on par with the best of the regional outcomes, but on average the outcomes differ significantly. Regional sharing gives an average capacity increase equal to the system welfare optimum, whereas bilateral sharing reached 62% of the optimum on average, using a load flow representation of the grid. The corresponding increase in total welfare is 97% of the optimum with regional sharing and 82% with bilateral. Comparing the two shows that regional sharing gives 18-19% larger welfare on average and 62-67% more capacity. Average investment costs increase by the same percentage as capacity since a standard cost per MW capacity is used in the models. With a transport flow representation there are more stable outcomes for both sharing frameworks, while the average welfare gains are similar to the load flow results. The difference in welfare gain between the two cost sharing frameworks is reduced when demand elasticity is changed from -0.10 to -0.25, but regional sharing still gives around 10% higher welfare on average.

Regional sharing gives better results because it makes more investments profitable by allocating the costs to more players, and also prevents players that receive positive spill-over benefits from expansions to free-ride on others, thereby reducing the risk of expansion options being blocked by some countries due to negative welfare effects. In the absence of a supranational planner that can impose the first-best solution, it appears that regional cost sharing is a close second best. A regional agreement of the type presented in this study imposes new rules on the interactions between TSOs in their grid planning. However, it does not imply that grid planning must be done by a supranational planner, rather it gives TSOs the economic incentives (in terms of national welfare) to pursue expansions that are closer to a supranational planner's choice. A regional cost sharing framework is in this sense a compromise between bilateral cost-sharing and the idealized supra-national planner. Still, the realization of a regional cost sharing agreement on a European scale may face serious opposition since it could involve a large number of countries with diverging priorities with regards to infrastructure investments. In this sense it is reassuring that bilateral sharing gives, at least on average, a reasonably good welfare outcome.

It is also possible to consider combinations of the two separate cases studied here. Regional sharing could be limited to particular investments that are difficult to realize under bilateral sharing. This seems to be the reasoning behind the EUs proposal for regional cost sharing of special Projects of Common Interest (PCIs) and the Nordic TSOs' Priority Cross-sections program. In a real world application of regional sharing it could also be relevant to include some internal expansions since the trade capacities on cross-border links can be limited by the capacity of internal grids.

Chapter 6

Power system transformation toward renewables: An evaluation of regulatory approaches for network expansion

This chapter is based on:
Power System Transformation towards Renewables: An Evaluation of Regulatory Approaches for Network Expansion
Discussion Paper 1312, DIW Berlin, Egerer et al. (2013d).
Joint work with Juan Rosellón and Wolf-Peter Schill.
It was presented at the 10th International Conference on the European Energy Market, 2013 (Stockholm), where it is published in the conference proceedings, Egerer et al. (2013e) at the 13th IAEE European Energy Conference, 2013 (Düsseldorf), and at the 28th Latin American Meeting of the Econometric Society, 2013 (Mexico City).
A revised version was published as:
Power System Transformation toward Renewables: An Evaluation of Regulatory Approaches for Network Expansion
The Energy Journal 36(4): 105–128, Egerer et al. (2015b).

6.1 Introduction

The transformation toward a low-carbon economy is one of the most ambitious projects of the European Union (EU) in the first half of the 21st century. To promote this pathway, the EU formulated binding reduction targets through 2020 with the 20-20-20 goals.[81] In the long-term, the EU has set emission reduction targets of 80-95% by 2050 compared to 1990 levels (EC, 2011a). The principal sectors for potential emission reductions are found in the energy system, with electricity being of particular importance. In the electricity sector, fossil fuels are increasingly being replaced with renewable generation technologies. It is broadly accepted that the power system will have to integrate an increasing share of renewables, as most EU members are making investments in new generation capacity based on wind, solar, biomass, and hydro. However, the role of conventional power generation facilities, both existing and new, during the renewable integration process is less clear. In Europe, lignite, coal, and natural gas, as well as nuclear in some countries, might build a bridge to the large-scale integration of non-conventional renewable technologies.

Regarding infrastructure, the transformation towards a low-carbon economy requires a transmission capacity different to the existing one. However, network planning is increasingly complex when integrating renewable electricity. The role of network regulation in a dynamic renewable-integration process presents significant challenges. The owning transmission system operators (TSOs) carry out operations within the system while investments in renewable and decommissioning in conventional generation capacities are taking place. In a system with centralized planning, the regulator should ensure that the transmission company (Transco) carries out the proposed transmission expansion. Under a more decentralized market structure, the regulator should provide investment incentives through regulatory mechanisms, such as cost-plus or incentive regulation. In any case, the regulator will require market information to carry out its responsibilities. Typical regulatory challenges include the implied impacts on network development, as well as potential under- or overinvestments by network operators during the renewable integration process.

In this chapter, we address the rationale for transmission investment under a renewable integration process. We focus on some basic characteristics and drivers of transmission investment in an energy transformation process characterized by network capacity expansion and the gradual shift from conventional power (e.g., coal) towards renewable energy sources (e.g., wind). In particular, we compare the relative

[81] The 20-20-20 goals for 2020 refer to (i) a reduction in EU greenhouse gas emissions of at least 20% below 1990 levels; (ii) 20% of EU energy consumption to come from renewable resources; and (iii) a 20% reduction in primary energy use compared with projected levels, which is to be achieved through improving energy efficiency (EC, 2008a).

performance of a combined merchant-regulatory price cap mechanism, using different weights, with cost-based regulation as well as with a non-regulated approach in a dynamic system that assumes a transformation toward a power generation system with high renewable penetration.

The remainder is structured as follows. In Section 6.2, we carry out a literature review on the regulation of transmission investment under market and renewable integration. In Section 6.3, we present a bi-level model for transmission investment with different regulatory schemes for the Transco in a changing market setting under an intertemporal process of renewable integration. In Section 6.4, we provide fundamental stylized examples which help one to understand the possible drivers of network congestion changes in the context of the transformation toward renewable power. For a simple two-node network, three distinctive developments of the generation mix with different implications on network congestion are presented. In Section 6.5, we present and discuss the results of the relative performance of a combined merchant-regulatory price cap mechanism, a cost-based rule, and a non-regulated approach under the dynamic generation settings. The final section concludes with a discussion about avenues for further research into the appropriate definition of weights for incentive regulation under renewable integration.

6.2 Literature review on the regulation of transmission investment

Chapter 6 analyzes the role of electricity transmission in the integration of renewable energy sources. This presupposes a possibility of the regulator focusing on incentivizing investment from an independent Transco through adequate price regulation (Vogelsang, 2001). This approach has gained importance, both in theory and practice, due to liberalization processes in various electricity systems that prioritize vertical separation, mainly between generation and transmission activities. Such unbundling measures are shown to promote investment. Pollitt et al. (2007) review the econometric evidence and international experience with generation and transmission unbundling (New Zealand, Australia, Chile, Argentina, Nordic Countries, and the United States), concluding that, as opposed to other market architectures, the unbundling of electricity generation and transmission—together with well-regulated independent transmission system operators (ITSOs)—can deliver highly competitive energy markets and facilitate timely transmission investments. Newbery (2005) reaches a similar conclusion for the electricity market in the United Kingdom. Using measures of product market reform from the Organisation for Economic Co-operation and Development (OECD), Alesina et al. (2005) also find that electricity investment increases as vertical integration decreases.

The role of transmission investment as an important factor in the transformation of the whole electricity market via appropriate price signals from liberalization and regulatory reform processes is also recognized in most studies. Brunekreeft et al. (2005) and Rubio-Oderiz and Perez-Arriaga (2000) highlight the importance of a nodal-pricing system (and complementary capacity charges) in signaling the efficient location of generation investment. That is, establishing appropriate measures for incentivizing an efficient development of transmission networks is crucial not only for the development of the grid but also for power generation, marketing, distribution, and system operation itself. Likewise, transmission planning in centralized systems as well as incentivized transmission expansion in decentralized market architectures have relevant impacts on consumer and generator surplus (Rosellón and Weigt, 2011; Sauma and Oren, 2007).

A regulator has several alternatives to regulate the transmission price of a Transco in liberalized market environments. Cost-of-service (or cost-plus) regulation has traditionally been used in the practice of electricity utilities. It implies setting prices to equalize average cost, and usually signals a restriction on the rate of return on capital. It has a basic advantage in that it promises certainty and long-term commitment from the regulator, two crucial elements for long-term investments in utilities. However, incentives for cost minimization are almost nonexistent as the complete restitution of costs hardly promotes investment in improving efficiency. The other extreme of regulation, price cap regulation, usually provides more incentives for cost minimization but the drawback is less certainty for the investing firm. This explains why price cap schemes are usually combined in practice with cost-plus regulation.[82]

Regarding regulation for electricity transmission investment of an independent Transco in meshed networks, there are several alternatives. Two are especially interesting for the approach used in this analysis one based on financial transmission rights (FTRs; merchant approach), and another based on the incentive price cap regulation. The merchant approach is based on FTR auctions within a bid-based, security-constrained economic dispatch with nodal pricing of an independent system operator (ISO). The ISO runs a power-flow model that provides nodal prices derived from shadow prices of the model's constraints. FTRs are subsequently calculated

[82] For example, an initial price cap ($P0$) might be decided by the regulator and fixed for a first period of, say, five years (regulatory lag). $P0$ is only adjusted during these first five years by inflation and efficiency indexes (*RPI-X* factor). After the initial five-year regulatory lag, a cost-of-service revision of the regulated company is carried out by the regulator. A second price cap ($P1$) is determined and adjusted by a new *RPI-X* factor for the next five years. This process is repeated going forward (Ramírez and Rosellón, 2002). In Germany, incentive regulation is complemented with cost-based elements like the so-called investment budgets for transmission expansion.

as hedges from nodal price differences. The ISO retains some capacity or FTRs in order to deal with externalities caused by loop flows, so that the agent expanding a transmission link compensates other agents unreservedly in the event of loss of property rights (Bushnell and Stoft, 1997; Kristiansen and Rosellón, 2006). FTR auctions have mainly been implemented in Northeast US (NYISO, PJM ISO, and New England ISO).

The incentive approach relies on a price cap on the two-part tariff of an independent Transco (Vogelsang, 2001).[83] Incentives for efficient investment result in expansion of the transmission grid through the gradual rebalancing of the fixed and variable charges of the two-part tariff. Convergence to steady-state Ramsey-price equilibrium relies on the type of weights used. Transmitted volumes for each type of service are used as weights for the various corresponding prices so that the Transco's profits grow as capacity utilization and network expansion increase. In equilibrium, the rebalancing of fixed and variable charges depends on the ratio between the output weight and the number of consumers. There are two basic ways to regulate price structure: one with fixed weights (tariff-basket regulation) and another with variable weights (average revenue regulation). In the case of the former, a price cap is established over the weighted sum of prices for different products. Weights might be output (or throughput) quantities from the previous period (chained Laspeyres), quantities from the current period (Paasche), intertemporally fixed quantities (fixed Laspeyres), or projected quantities that correspond to the steady-state equilibrium (ideal weights, as in Laffont et al. (1996).[84] Variable (endogenous) weights are usually associated with average-revenue regulation, which sets a cap on income per unit but does not set fixed weights that limit the relative variation of prices. Compared to tariff-basket regulation, this offers the firm greater flexibility in tariff rebalancing but results in a lack of convergence to a welfare-maximizing equilibrium.[85] The literature proves that, under non-stochastic (or stable) conditions of costs and demand and myopic profit maximization (i.e., when the firm does not take into account future periods

[83] A Transco needs to be regulated since it is a natural monopoly. Vogelsang (2001) concentrates on incentive regulation of natural-monopolistic activities of the Transco, independently from power generation.

[84] The steady-state equilibrium is characterized by prices whose optimal distance from marginal cost is inversely proportional to the elasticity of demand. These are referred in the literature as Ramsey-Boiteaux prices (Armstrong et al., 1994, chapter 3).

[85] More specifically, average-revenue regulation is a price cap regime that sets an upper limit on revenues per unit and is the preferred way of regulating prices of firms whose costs depend on total production and whose products are commensurable. Compared to tariff-basket regulation, average-revenue regulation does not fix weights that limit variation among relative prices (Armstrong et al., 1994, chapter 3). Sappington and Sibley (1992) prove in a two-part tariff model that by setting the usage charge at a low level the average-revenue restriction might be relaxed in future periods and thus allows the firm to increase future prices. This means that the regulated firm has incentives to set its tariffs strategically so that both consumer surplus and total surplus are lowered.

in its current profit maximizing behavior), the use of the chained Laspeyres index makes the prices of the regulated firm intertemporally converge to Ramsey-Boiteaux pricing (Bertoletti and Poletti, 1997; Loeb and Magat, 1979; Sibley, 1989; Vogelsang, 2001, 1989). The chained Laspeyres structure simultaneously reconciles two opposing objectives: the maximization of social welfare and the individual rationality of the firm (i.e., non-negative profits). Social surplus is redistributed to the monopoly in such a way that long-term fixed costs are recovered but, simultaneously, consumer surplus is maximized over time.[86]

Tanaka (2007) also proposes various incentive mechanisms: a Laspeyres-type price cap on nodal prices, a two-part tariff cap also based on Laspeyres weights, and an incremental surplus subsidy, where the regulator observes the actual cost but not the complete cost function. These mechanisms are shown to achieve optimal transmission capacity from the effects of capacity expansion on flows and welfare. However, both Tanaka (2007) and Vogelsang (2001) abstract from technical electricity transmission constraints (loop flows), and suggest well-behaved transmission capacity cost functions, which appear to be very strong assumptions for loop flowed meshed electricity networks.

A combination of the merchant and the incentive-regulation approaches was developed by Hogan, Rosellón, and Vogelsang (Hogan et al., 2010, HRV). A crucial aspect here is the redefinition of the transmission output in terms of incremental FTRs in order to apply the same regulatory logic of Vogelsang (2001) to real-world networks within a power-flow model. The HRV model deals with loop flows in meshed networks and achieves well behaved transmission cost functions Rosellón et al. (2012). The Transco intertemporally maximizes profits subject to a cap on its two-part tariff, but the variable fee is now the price of the FTR output based on nodal prices. Although immersed in an intertemporally-regulated, profit-maximizing environment, the bi-level HRV model really assumes a static market setting in the sense of identical output behavior during each period. The Transco is actually able to alter the market result over time as it decides investments in transmission infrastructure (upper-level problem). Additional transmission lines change the constraints on the network (flow pattern and capacity), therefore typically allowing for an improved market dispatch with higher welfare (lower-level problem). This allows the Transco to receive a share of the welfare gains due to its two-part tariff structure. The fixed fee of the tariff intertemporally rebalances (with respect to the variable fee) to make up for lost congestion rents, and convergence to steady-state equilibrium is achieved through the use of proper weights (typically, Laspeyres weights). This approach also applies to more general situations including more realistic electricity flows like DC load flow

[86]The social surplus is made up by consumer, producer, and government surpluses (if present).

with loop flows. The HRV model has already been numerically applied to simplified grids of Western Europe, Northeast United States, and South America (Rosellón et al., 2011; Rosellón and Weigt, 2011; Ruiz and Rosellón, 2012).

With the HRV mechanism, the regulator promotes welfare-beneficial network developments through an increased regulated return in the two-part tariff. This mechanism works as long as the welfare changes in the system can be directly linked to transmission investment. In previous HRV research, however, the complex issue of intertemporal interactions between generation, transmission, and demand has not been considered.[87]

Naturally, other incentive-based mechanisms for transmission investment exist in the literature. For instance, Léautier (2000) and Joskow and Tirole (2002) propose mechanisms based on a measure of welfare loss with respect to the Transco's performance. The regulator rewards the Transco when the capacity of the network is increased so that congestion rents are decreased. The regulator might also punish the Transco for taking advantage of a congested network by increasing fees and accumulating higher congestion rents.[88] Alternatively, Contreras et al. (2009) propose an incentive scheme for transmission expansion based on a cooperative-game model where the Shapley value is used to reward investors according to their value added to social welfare.[89]

One common feature across all of the above incentive regulation mechanisms is that they rely on a market-integration economic rationale; that is, the efficient expansion of the transmission network to the nodes with the cheapest generation technologies (but possibly with high carbon emissions). Policy making based on such criteria is common in practical network-expansion planning decisions, even under an associated process of large-scale integration of renewable generation, as seen in the case of the German transmission grid development (50Hertz et al., 2012).

Schill et al. (2015) study the performance of various regulatory mechanisms under transmission market integration with both varying demand and wind generation. Specifically, they compare the HRV mechanism to a cost-based and a non-regulated approach with hourly time resolution in demand and fluctuating wind power. They

[87] See Ruiz and Rosellón (2012), Rosellón et al. (2011), Rosellón and Weigt (2011), and Schill et al. (2015).

[88] Another variation is an out-turn based regulation. Out-turn is defined as the difference between the price for electricity actually paid to generators and the price that would have been paid absent congestion (Léautier, 2000). The Transco is made responsible for the full cost of out-turn, plus any transmission losses.

[89] The Shapley Value is an a priori evaluation of the prospects of a player in a multi-person game consisting of a set N of players and a coalitional function v that associates to every subset S of N (the coalition) a real number v(S), which is the maximal total payoff the members of S can obtain (the worth of S). The Shapley value associates to each player in that game a unique payoff, his value and turns out to be exactly his expected marginal contribution to a random coalition (Winter, 2002).

show that HRV regulation leads to welfare outcomes far superior to other modeled alternatives under the assumption of intertemporal stability in the power generation mix. However, a system with increasing shares of generation from renewable energy will need to be combined at least temporally with conventional base-, mid-, and peak load generation. Therefore, network extensions for combined integration of carbon-intensive base load and renewable generation might face the risk of excessive stranded transmission investments in the medium term.[90] In this analysis, we study this basic issue with a simple model presented in the following section.

6.3 Formulation of two-stage model for regulatory setting

We follow the approach of Schill et al. (2015). Table 6.1 lists all variables which deviate from the general mathematical notation (Tables 1–5, pages xxi–xxv) due to optimization over several regulatory periods (τ).

Type	**Symbol**	**Description**	**Unit**
Variables	$b_{nk\tau}$	... network susceptance matrix	$1/\Omega$
	$pf_{lt\tau}$	... power flow on line l in hour t	MW
	$\theta_{nt\tau}$	... voltage angle at node n in hour t	
Positive variables	$g_{nit\tau}^{\text{tech}}$	... generation of technology i in node n	MWh
	$i_{l\tau}^{\text{line}}$	... investment in line l	MW
	$\overline{pf}_{l\tau}$	... capacity of line l	MW
	$q_{nt\tau}$	... load at node n in hour t	MWh
	$x_{l\tau}$	... line reactance of line l	Ω

Table 6.1: Variables adjusted for regulatory periods in Chapter 6

We assume a market design with nodal pricing based on real power flows. A single Transco holds a natural monopoly on the transmission network. The Transco decides on network extension. Accordingly, we assume that only the Transco maximizes profit, which consists of congestion rents and—depending on the regulatory regime—a fixed income part. As the Transco is not involved in electricity generation, an independent system operator (ISO) manages the actual dispatch in a welfare-maximizing way. The ISO collects nodal payments from loads and pays the generators. The difference between these payments is the congestion rent, which is assumed to be transferred to the Transco. We model a welfare-maximizing benchmark (WFMax), in which

[90] We assume perfect foresight regarding the changing generation mix. Weijde and Hobbs (2012) study the economics of electricity transmission planning under uncertain economic, technological, and regulatory conditions.

a social planner makes combined decisions on network expansion and dispatch, as well as three different regulatory cases in which we assume that the Transco is either unregulated (NoReg), cost-regulated (CostReg), or HRV-regulated regarding network expansion. We compare these cases to a baseline without any network expansion. The problem formulation entails two decision levels (bilevel programming). In the regulatory cases, the Transco's profit maximization constitutes the upper-level optimization problem. In the welfare-maximizing benchmark, the upper-level program represents the social planner's maximization problem. On the lower level, we formulate the ISO's welfare-maximizing dispatch as a mixed complementarity problem (MCP).[91] The combination of lower- and upper-level problems constitutes a mathematical program with equilibrium constraints (MPEC).[92] We assume a standard linear demand function (6.1):

$$p_{nt\tau} = a_{nt} + m_{nt} q_{nt\tau} \tag{6.1}$$

where $p_{nt\tau}$ is the electricity price at node n in regulatory period τ and hour t, whereas $q_{nt\tau}$ describes the corresponding electricity demand.[93] Given the electricity demand in Equation 6.1, the objective function 6.2 and the system constraints 6.3a–6.3e represent the TSO's welfare maximization problem.

$$\max_{g,q} \mathrm{w} = \sum_{\tau} \left(\sum_{t} \sum_{n} \Big(\int_0^{q_{nt\tau}} p_{nt\tau}(q_{nt\tau}) dq_{nt\tau} - \sum_{i} \hat{c}_{ni}^{\mathrm{tech}} g_{nit\tau}^{\mathrm{tech}} \Big) \frac{1}{(1+\delta^{\mathrm{s}})^{\mathrm{t}-1}} \right) \tag{6.2}$$

$$\begin{aligned}
s.t. \quad & \sum_{n} \frac{im_{ln}}{x_{l\tau}} \theta_{nt\tau} - \overline{pf}_{l\tau} \leq 0 && \forall \quad l,t,\tau && (\lambda 1_{lt\tau}) && (6.3a)\\
& -\sum_{n} \frac{im_{ln}}{x_{l\tau}} \theta_{nt\tau} - \overline{pf}_{l\tau} \leq 0 && \forall \quad l,t,\tau && (\lambda 2_{lt\tau}) && (6.3b)\\
& \sum_{i} g_{nit\tau}^{\mathrm{tech}} - \sum_{k} b_{nk\tau} \theta_{kt\tau} - q_{nt\tau} = 0 && \forall \quad n,t,\tau && (p_{nt\tau}) && (6.3c)\\
& g_{nit\tau}^{\mathrm{tech}} - \overline{g}_{ni}^{\mathrm{tech}} \leq 0 && \forall \quad n,i,t,\tau && (\lambda 4_{nit\tau}) && (6.3d)\\
& \theta_{\hat{n}t\tau} = 0 && \forall \quad t,\tau && (\lambda 5_{t\tau}) && (6.3e)
\end{aligned}$$

[91] An MCP allows formulating economic equilibrium models as systems of nonlinear equations, complementarity problems or variational inequalities. These extensions accommodate market and game-theoretic equilibrium models (Rutherford, 1995).

[92] Hobbs et al. (2000) are among the first to apply an MPEC approach to power market modeling. See also Gabriel et al. (2013).

[93] In the numerical application in Section 6.4, we do not make use of the hourly resolution of the model formulation. Instead, we rely on stylized average values.

The two-level MPEC model requires an MCP formulation for the lower problem. The dispatch problem (lower level) is transferred into the MCP formulation with Equations 6.4a–6.4h. We model real load flows between single nodes with the simplified DC load flow approach (Leuthold et al., 2012; Schweppe et al., 1988). The constraints must be satisfied in every single hour t.

$$0 \leq -a_{nt} - m_{nt} q_{nt\tau} + p_{nt\tau} \quad \perp \quad q_{nt\tau} \geq 0 \tag{6.4a}$$

$$0 \leq \hat{c}_{ni}^{\text{tech}} - p_{nt\tau} + \lambda 4_{nit\tau} \quad \perp \quad g_{nit\tau} \geq 0 \tag{6.4b}$$

$$\begin{aligned} 0 = {} & \sum_l \frac{im_{ln}}{x_{l\tau}} (\lambda 1_{lt\tau} - \lambda 2_{lt\tau}) \\ & - \sum_k p_{kt\tau} b_{kn\tau} - \begin{cases} \lambda 5_{t\tau} & if\ n = \hat{n} \\ 0 & else \end{cases} \quad , \quad \theta_{nt\tau}\ free \end{aligned} \tag{6.4c}$$

$$0 \leq -\sum_n \frac{im_{ln}}{x_{l\tau}} - \theta_{nt\tau} + \overline{pf}_{l\tau} \quad \perp \quad \lambda 1_{lt\tau} \geq 0 \tag{6.4d}$$

$$0 \leq \sum_n \frac{im_{ln}}{x_{l\tau}} - \theta_{nt\tau} + \overline{pf}_{l\tau} \quad \perp \quad \lambda 2_{lt\tau} \geq 0 \tag{6.4e}$$

$$0 = \sum_i g_{nit\tau}^{\text{tech}} - \sum_k b_{nk\tau} \theta_{kt\tau} - q_{nt\tau} \quad , \quad p_{nt\tau}\ free \tag{6.4f}$$

$$0 \leq \overline{g}_{ni}^{\text{tech}} - g_{nit\tau}^{\text{tech}} \quad \perp \quad \lambda 4_{nit\tau} \geq 0 \tag{6.4g}$$

$$0 = \theta_{\hat{n}t\tau} \quad , \quad \lambda 5_{t\tau}\ free \tag{6.4h}$$

Equations 6.4a–6.4c represent the partial derivatives with respect to $q_{nt\tau}$, $p_{nt\tau}$, and the voltage angle $\theta_{nt\tau}$. The incidence matrix of the network im_{ln} provides information on how the nodes are connected by transmission lines l. The parameter $x_{l\tau}$ describes the reactance for each transmission line and $b_{nk\tau}$ the network susceptance between two nodes. Equations 6.4d and 6.4e ensure that the power flows on each line do not exceed the respective line's capacity $\overline{pf}_{l\tau}$ and 6.4f ensures nodal energy balance: generation minus net outflow has to equal demand at all times. Equation 6.4g constrains generation of technology s to the maximum available generation capacity at the respective node and the respective time period. Finally, Equation 6.4h establishes a point of reference for the voltage angles by endogenously fixing the value of $\theta_{nt\tau}$ to zero for the slack bus $\hat{n}$.

Where the lower-level problem 6.4a–6.4h must be solved for every single hour t, the upper-level problem needs to be inter-temporally optimized over all regulatory periods τ. For the three regulatory regimes, the upper-level problem is represented by Equation 6.5):

$$\max \Pi = \sum_{\tau} \Bigg(\bigg(\sum_{t} \sum_{n} \Big(p_{nt\tau} q_{nt\tau} - \sum_{i} p_{nt\tau} g^{\text{tech}}_{nit\tau} \Big) + fix_{\tau} - \sum_{l} \sum_{\tau\tau < \tau} \tilde{c}^{\text{line}}_{l} i^{\text{line}}_{l\tau\tau} \bigg) \frac{1}{(1+\delta^{\text{p}})^{\tau-1}} \Bigg) \tag{6.5}$$

The Transco's decision variable is capacity extension of transmission lines $i^{\text{line}}_{l\tau}$, which incurs extension costs $\tilde{c}^{\text{line}}_{l}$ (annuities). Both future revenues and future costs are discounted with a private discount rate δ^{p}. In the NoReg case, transmission investments have to be fully recovered by congestion rents, i.e., the fixed part is constrained to zero ($fix_{\tau} = 0$). Accordingly, the Transco will only invest in lines if it leads to increases in congestion rent that are larger than extension costs. In the CostReg case, we assume that the Transco not only receives congestion rents, but may also charge an additional fixed-tariff part that reimburses the line extension cost and grants an additional return on costs (cost-plus regulation). Equation 6.6 shows that the fixed part of a given period includes the costs (annuities) of all network investments made so far plus a return on costs r. With positive r, the Transco may find it optimal to expand all transmission lines infinitely. We thus include an upper limit for line extensions in the CostReg case such that no single line capacity is allowed to exceed the optimal level as determined by the welfare-maximizing benchmark.[94] In the HRV case, the Transco may also charge a fixed-tariff part, for which Equation 6.7 sets a cap. It includes current and previous period quantity weights $q^{\text{weight}}_{nt(\tau+1)}$, $q^{\text{weight}}_{nt\tau}$, $g^{\text{weight}}_{nit(\tau+1)}$, and $g^{\text{weight}}_{nit\tau}$. In its general form, it also includes a retail price index RPI and an efficiency factor X. We set both RPI and X to zero in the model application, as we assume real prices and neglect efficiency gains. In summary, in both the CostReg and the HRV cases, the Transco is able to recover network extension costs by the fixed-tariff part. In contrast, this is not possible in the NoReg case.

$$fix^{\text{CostReg}}_{\tau+1} = \sum_{l} \tilde{c}^{\text{line}}_{l} i^{\text{line}}_{l\tau} (1+r) + fix^{\text{CostReg}}_{\tau} \tag{6.6}$$

[94] Note that this requires the regulator to have sufficient knowledge about which lines should be increased. In the numerical simulations, line extensions in the CostReg case are substantially smaller than welfare-optimal extension levels in most cases because the marginal benefit of cost-plus regulation would not compensate for the Transco's marginal congestion rent loss. An exception is the case of temporarily increased congestion, in which the Transco invests nearly optimally under CostReg because this allows a temporary increase of congestion rents (see Section 6.5). In the case of permanently decreasing congestion, no line extension takes place regardless of the regulatory regime.

$$\frac{\sum_n \sum_t \left(p_{nt(\tau+1)} q^{\text{weight}}_{nt(\tau+1)} - \sum_i p_{nt(\tau+1)} g^{\text{weight}}_{nit(\tau+1)}\right) + fix^{\text{HRV}}_{\tau+1}}{\sum_n \sum_t \left(p_{nt\tau} q^{\text{weight}}_{nt\tau} - \sum_i p_{nt\tau} g^{\text{weight}}_{nit\tau}\right) + fix^{\text{HRV}}_{\tau}} \leq 1 + RPI - X \tag{6.7}$$

Table 6.2 provides an overview of the different types of weights used in the analysis. (Quasi-)Ideal weights are derived from welfare-optimal results (indicated by an asterisk).

	Laspeyres	**Paasche**	**Average Laspeyres-Paasche**	**(Quasi-)Ideal**[95]
$q^{\text{weight}}_{nt(\tau+1)}$	$q_{nt\tau}$	$q_{nt(\tau+1)}$	$\frac{1}{2}(q_{nt(\tau+1)} + q_{nt\tau})$	$q^*_{nt(\tau+1)}$
$q^{\text{weight}}_{nt\tau}$	$q_{nt\tau}$	$q_{nt(\tau+1)}$	$\frac{1}{2}(q_{nt(\tau+1)} + q_{nt\tau})$	$q^*_{nt\tau}$
$g^{\text{weight}}_{nit(\tau+1)}$	$g_{nit\tau}$	$g_{nit(\tau+1)}$	$\frac{1}{2}(g_{nit(\tau+1)} + g_{nit\tau})$	$g^*_{nit(\tau+1)}$
$g^{\text{weight}}_{nit\tau}$	$g_{nit\tau}$	$g_{nit(\tau+1)}$	$\frac{1}{2}(g_{nit(\tau+1)} + g_{nit\tau})$	$g^*_{nit\tau}$

Table 6.2: Overview of weights

In the baseline and in the welfare-maximizing benchmark case, the upper-level problem does not represent a Transco's profit-maximization, but rather a social planner's maximization of social welfare, which is described by 6.8. The social planner uses a social discount rate, δ^s, which may be smaller than the private discount rate δ^p used by a Transco.[96]

$$\begin{aligned} \max \text{ w} = \sum_{\tau} \Bigg(\sum_t \sum_n \Big(a_{nt} q_{nt\tau} + \frac{1}{2} m_{nt} q^2_{nt\tau} - \sum_i \hat{c}^{\text{tech}}_{ni} g^{\text{tech}}_{nit\tau} \Big) \\ - \sum_l \sum_{\tau\tau<\tau} \tilde{c}^{\text{line}}_l i^{\text{line}}_{l\tau\tau} \frac{1}{(1+\delta^{\text{s}})^{\tau-1}} \Bigg) \end{aligned} \tag{6.8}$$

[95]Following Laffont et al. (1996), ideal weights would require using, in each period, the predicted fixed q^* and g^* prevailing in the steady-state welfare-optimal equilibrium, not period-specific (also predicted) equilibrium quantities. However, in a dynamic generation setting with an exogenously changing generation mix, in which there may be no smooth convergence to a steady-state, our quasi-ideal period-specific weights prove to perform better.

[96]In the model application, we assume $\delta^s = 0.04$ and $\delta^p = 0.08$. Evans and Sezer (2004) present empirical estimates of social discount rates for different countries. Private discount rates are typically higher due to various factors including risk premia.

In all regulatory cases, network extension leads to inter-period constraints on line capacity (6.9a), line reactance (6.9b), and network susceptance (6.9c).

$$\overline{pf}_{l(\tau+1)} = \overline{pf}_{l\tau} + i^{\text{line}}_{l\tau} \tag{6.9a}$$

$$x_{l(\tau+1)} = \frac{\overline{pf}^{0}_{l}}{\overline{pf}_{l(\tau+1)}} x^0_l \tag{6.9b}$$

$$b_{kn(\tau+1)} = \sum_l im_{ln} \frac{im_{lk}}{x_{l(\tau+1)}} \tag{6.9c}$$

The problem is implemented in the General Algebraic Modeling System (GAMS) and solved using the commercial solver NLPEC. As the feasible region of the MPEC problem is non-convex, a large number of different starting points are used in order to find good local optima.[97] First, the welfare-optimal benchmark and all regulatory cases are solved using the case without expansion as a starting point. Second, all cases are repeatedly solved with the solution of WFMax serving as a starting point. Afterwards, all cases are repeatedly solved in varying order, using the (feasible) solution of one case as a starting point for the next case. We find that local optima converge to some characteristic values during this solution procedure. After several iterations, solutions do not improve any more. The best available solutions are then considered as good approximations of global optima.

6.4 Test cases

The locations of renewable power generators usually differ from those of conventional power plants. For example, lignite plants are always located near lignite mines in order to minimize transportation costs. Likewise, hard coal plants are usually built where the coal can easily be shipped. In contrast, wind power plants are usually constructed at places where their natural potential is greatest (e.g., at coastlines or even offshore). Solar power is often installed near the load (e.g., on roof tops). Thus both (centralized) wind power and (decentralized) solar power may lead to very different transmission requirements compared to conventional power plants. Accordingly, an energy system transformation toward renewable power supply may either increase or decrease congestion in existing transmission systems.

Exactly how network congestion changes in the context of such an energy transformation depends very much on the existing transmission system, the choice of renewable technologies (for example, wind or solar power), and the timeframe considered. We thus analyze four stylized cases of changing generation capacities in a

[97] Non-convexity is not a major issue given the small size of our stylized model.

simple two-node network (n1, n2) over a timeframe of 20 years.[98] Both nodes are connected by a capacity-constrained transmission line with a bi-directional capacity of 50 MW in the initial period. Figure 6.1 shows the network setting in the initial period.

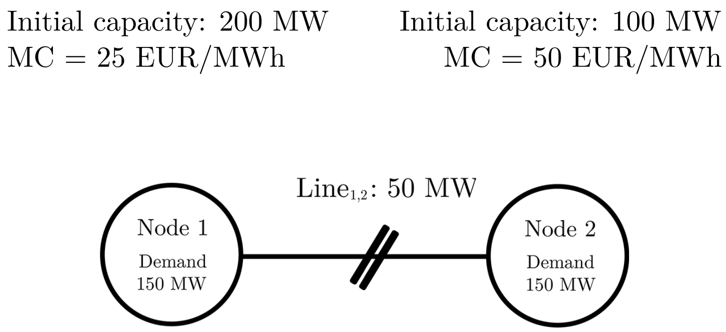

Figure 6.1: Network setting in the initial period

Demand at both nodes is characterized by a linear demand curve with a reference demand of 150 MW at a reference price of 30 EUR/MWh. The price elasticity of demand is -0.25 at the reference point. There are two conventional generation technologies (base, peak) with marginal costs of 25 EUR/MWh and 50 EUR/MWh, respectively. The cheaper conventional technology is assumed to be located at node 1, the more expensive technology at node 2. Renewable power is dispatched without marginal costs, which is true for both wind and solar power.[99] For reasons of simplicity, we abstract in our model of Section 6.3 from fluctuations in demand and in renewable generation. The four stylized cases (see Figure 6.2) with changes in generation capacity are:

1. **The static case:** There are no changes in generation technologies over time.
2. **Temporarily increased congestion:** Renewable generation capacities increase over time at node 1. This could be interpreted as wind power replacing hard coal plants in coastal areas. There is an overlap of renewables being phased in and conventional generators being phased out, such that congestion is temporarily increased.
3. **Permanently increased congestion:** Growing renewable capacities at node 1 over-compensate the phase-out of conventional power plants at this node, giving rise to permanently increased congestion.

[98] There is only one representative hour, t.

[99] We implicitly assume full spot market integration of renewables. Under the assumption of a feed-in tariff for renewables, our analysis could be applied to any renewable technology including biomass, because variable costs under such a regime do not matter for renewable dispatch.

4. **Permanently decreased congestion:** Renewable power generation increases equally at both nodes (e.g., wind power at node 1 and solar power at node 2) such that conventional generation is completely phased out. Consequently, transmission congestion vanishes.

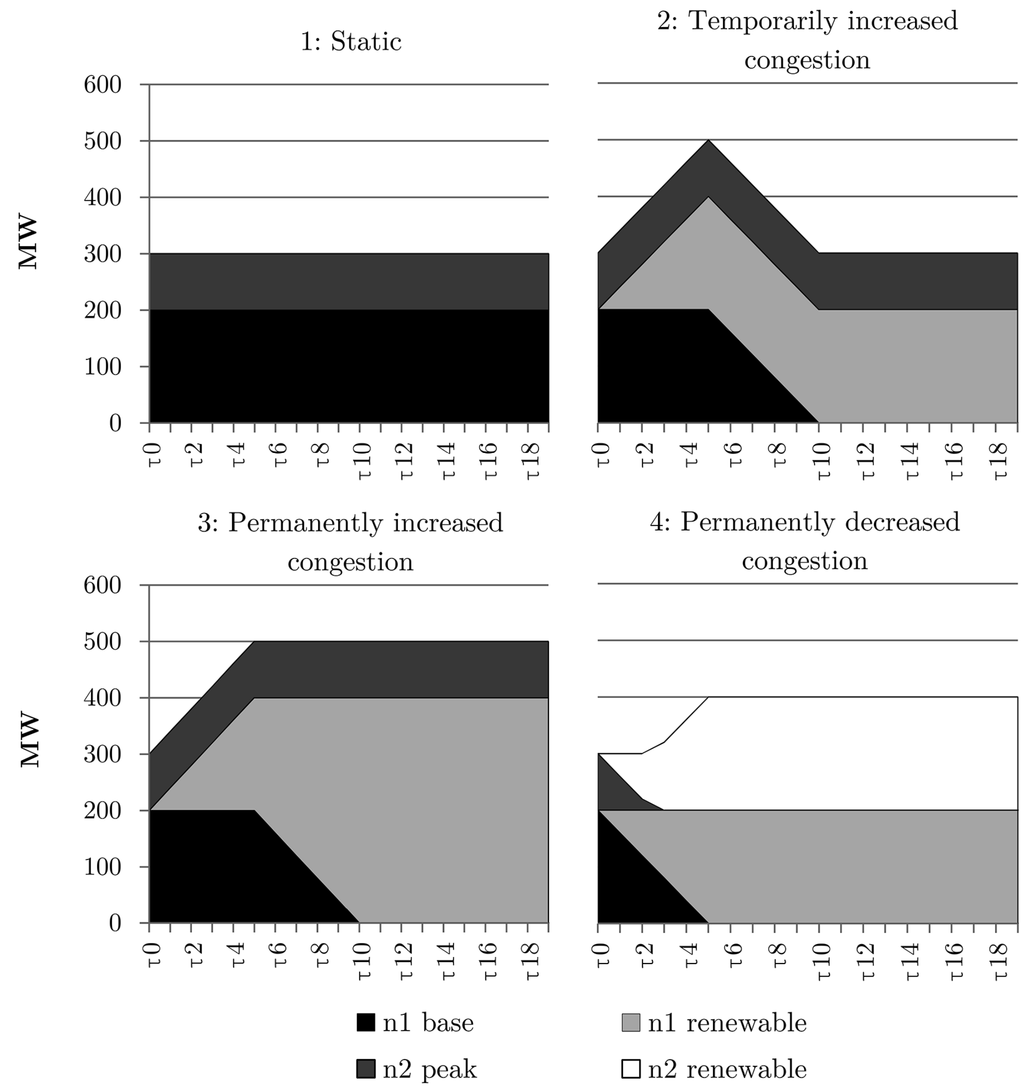

Figure 6.2: Exogenous development of generation capacities in different cases

Figure 6.3 provides more insight in the transmission congestion implications of the assumed inter-temporal changes of the generation mix. It shows how network congestion rent develops in all cases due to the exogenous changes in generation capacity discussed above, assuming that no network expansion takes place in any period. Accordingly, congestion rent does not change in case 1. Note the temporally increased congestion between $\tau 1$ and $\tau 9$ in case 2 due to the delayed phase out of conventional generation in node 1, compared to the two jumps in congestion rent in period $\tau 1$ and $\tau 6$ in case 3, which is the result of conventional capacity phasing out at node 1 and zero-cost renewables setting the price at this node. In case 4, network congestion vanishes completely from $\tau 3$ on. The values have been calculated using the model described in Section 6.3, with the network expansion variable fixed to zero.

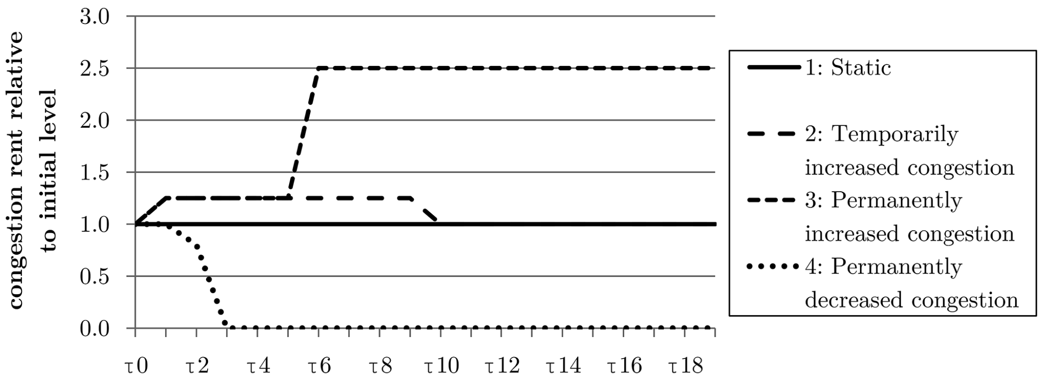

Figure 6.3: Development of the congestion rent (without network expansion)

In Section 6.5, we analyze the effects of the three regulatory regimes on transmission expansion and welfare in all of the above cases. We compare them to the baseline without expansion and the welfare-maximizing optimum. First we do so using Laspeyres weights in the HRV model. Then, we try out other possibilities such as Paasche weights, average Laspeyres-Paasche weights, and ideal weights.

6.5 Results

6.5.1 Laspeyres weights

Figure 6.4 shows network expansion results for the two-node cases. In the static case—in which generation capacities do not change over time—line expansion under HRV regulation converges to the welfare-optimal level over time. The Transco compensates for extension-related congestion rent losses with a corresponding increase in the fixed-tariff part. Vogelsang (2001) shows that the rebalancing of the variable and fixed fees will lead to a slow convergence to a steady-state equilibrium. In contrast, both the cost-regulatory case and the scenario without regulation do not lead to network expansion. These findings confirm the results of previous numerical simulations.[100] The slowness in convergence is because Laspeyres weights reflect the previous-period

[100] See Rosellón and Weigt (2011), Rosellón et al. (2011), Ruiz and Rosellón (2012), and Schill et al. (2015).

state of demand only, so that the compensating increase in the fixed part of the two-part tariff falls somewhat short of the actual increase in consumer surplus in the current period.

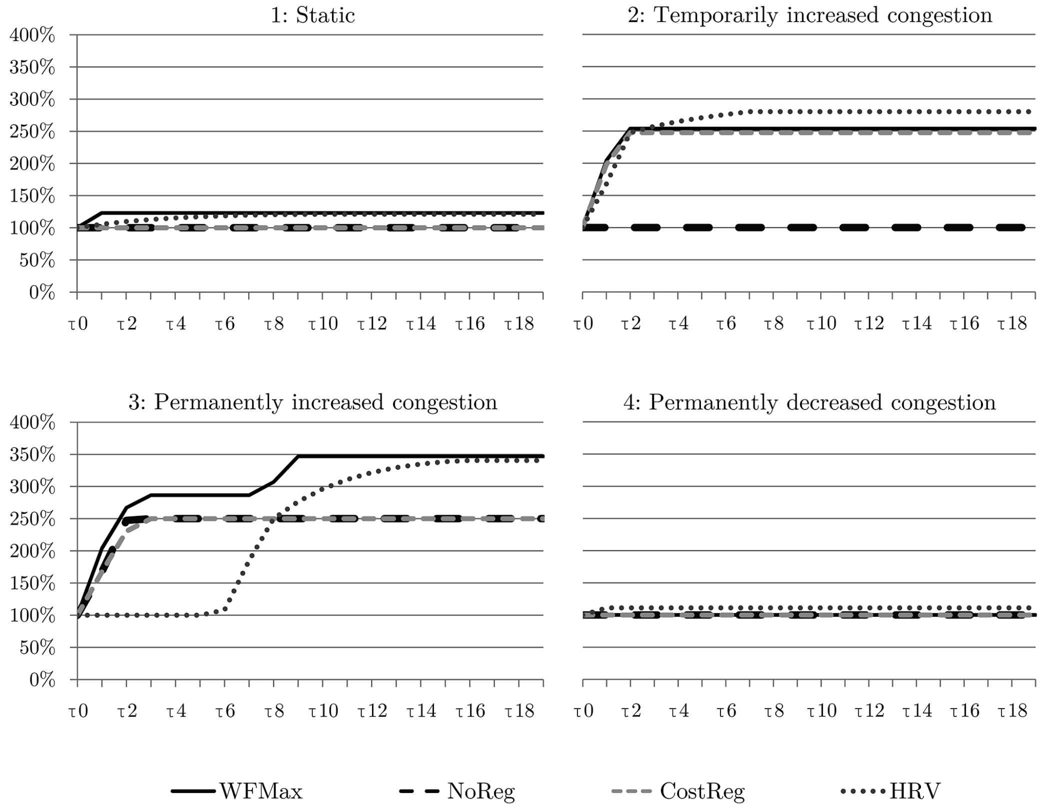

Figure 6.4: Line extension results (relative to initial capacity, Laspeyres weights)

In the cases with exogenously changing generation capacities, however, these results do not necessarily hold any longer. In case 2, which assumes temporarily increased network congestion due to growing renewable capacities, HRV leads to overinvestments as compared to the welfare-optimal benchmark. When rebalancing the fixed and variable tariff parts according to the regulatory cap, the Transco is rewarded for stranded investments. The main reason for this finding is that the chosen Laspeyres weights (previous period quantities) are not optimal, as they do not reflect exogenous decreases in congestion rents in future periods and they incorporate gains in congestion-rents arising both from the transmission expansion process and from the change in the generation mix. Laspeyres weights have previously been described as adjusting too slowly to a changing environment since the weights only reflect the past state of demand or costs (Fraser, 1995; Neu, 1993). In our model, the convergence speed seems to be slower than the exogenous change in network congestion. In contrast, the cost-regulatory approach leads to a nearly optimal network expansion. This is because a moderate line extension results in temporarily higher flows and accordingly increased congestion rents which, together with the cost-plus revenues given by Equation 6.6, outweigh the (discounted) congestion rent losses in later periods (see analysis of congestion rents below and Figure 6.5. Without the cost-plus revenues, no extension takes place (NoReg).

In case 3, with permanently increased congestion, HRV-triggered network expansion approaches optimal levels in the final periods. However, the Transco finds it optimal not to invest before the seventh period, as it benefits much of increased congestion rents in the first periods, which are rebalanced against growing fixed parts later on. In contrast, both the cost regulatory case and NoReg lead to substantial line capacity extension in early years because these allow the Transco to permanently increase congestion rents; however, neither CostReg nor NoReg provide incentives to the Transco to expand capacity to optimal levels in later periods, as congestion rent losses would be too high.

In case 4, we do not find any network investments in the welfare-optimal case, as congestion decreases exogenously and vanishes completely after period 3. CostReg and NoReg also do not lead to any network investment. Yet under HRV regulation, some overinvestment occurs, because the regulatory cap rewards the Transco for removing congestion in the first periods.

As a consequence of the line investments shown in Figure 6.4, we find (nominal) congestion rents to develop as shown in Figure 6.5. While HRV regulation largely removes congestion rent over time in the static case, it leads to overly reduced congestion in case 2, in which the exogenous congestion shock is only of a temporary nature. A related observation can be made in case 4. Yet, in case 3, we find that the Transco's delay of investments enables it to benefit from relatively very high congestion rents around the ninth period, which it is then able to rebalance with the fixed part in the following periods. As shown in Figure 6.6, the Transco is even willing to choose a negative fixed part in the first periods in order to "make room" for even higher fixed parts in future.[101]

[101] The provision of absolute numbers on the ordinate (in Euro) would not be meaningful due to the stylized nature of our 2-node example.

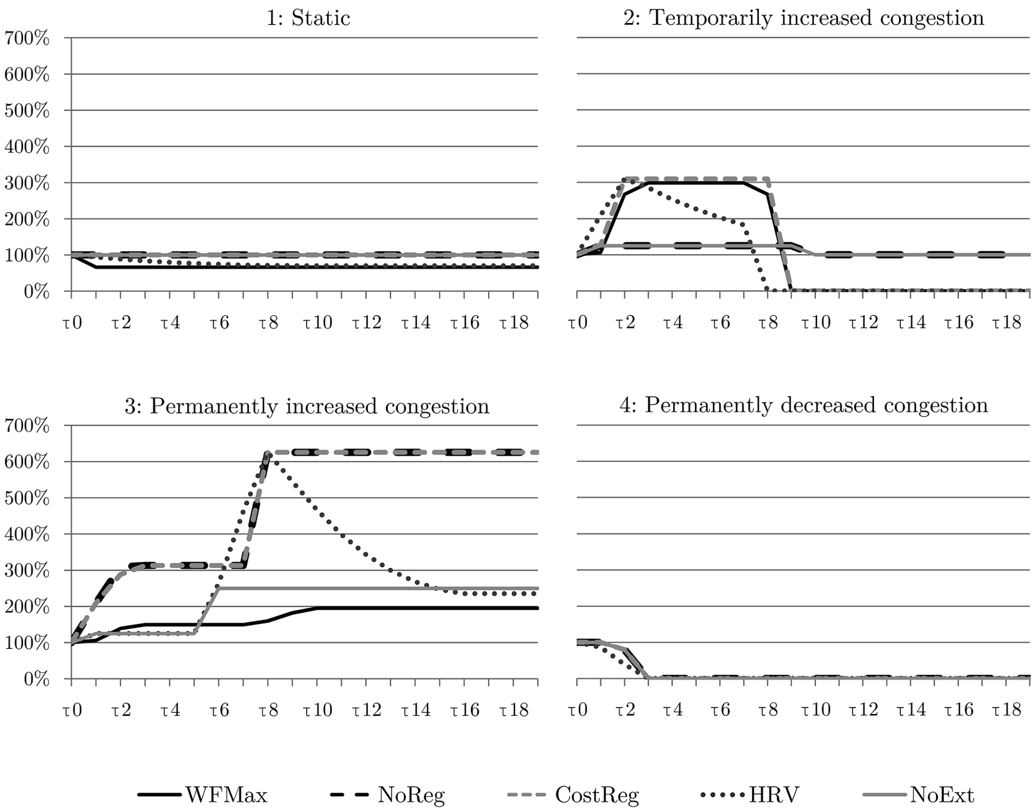

Figure 6.5: Congestion rents (nominal values relative to initial value)

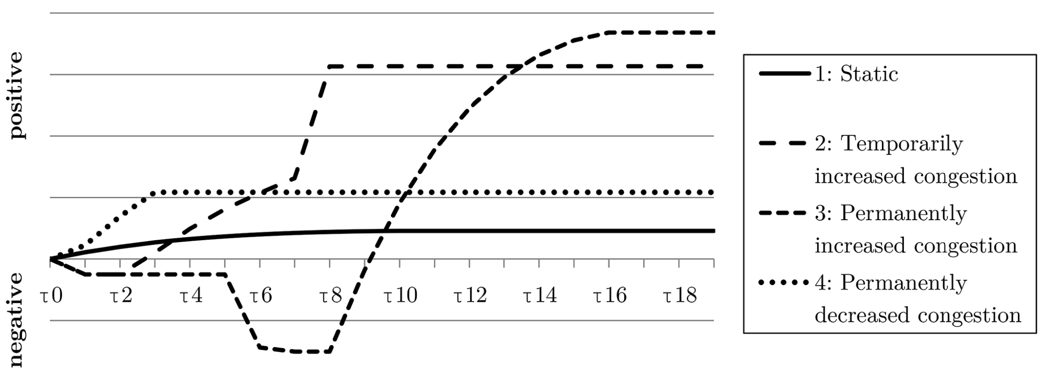

Figure 6.6: Development of the fixed part in case of HRV regulation

6.5.2 Other types of weights

The results presented so far show that some of the properties of the combined merchant-regulatory incentive regulation, as established in the literature, may no longer hold in the context of exogenous changes of generation capacities when Laspeyres weights are used. In the next sub-sections, we study the effects of using other type of weights in the HRV regulatory-cap formula.

Paasche weights

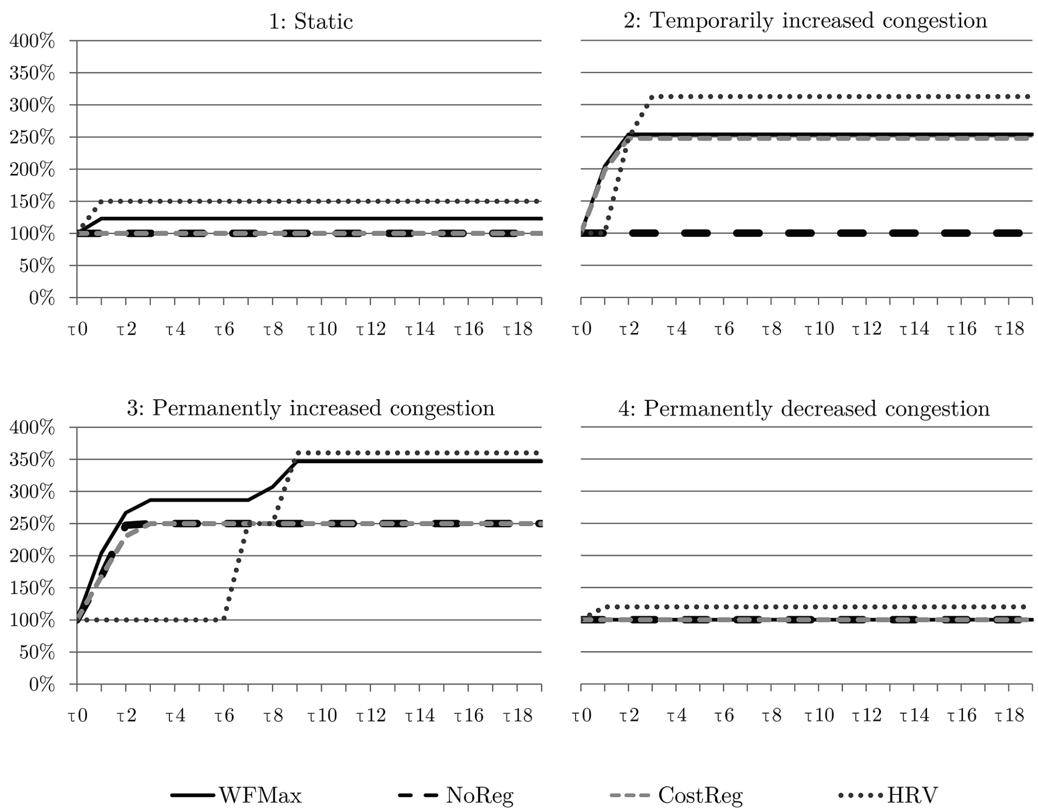

Figure 6.7: Line extension results (relative to initial capacity, Paasche weights)

Paasche weights use same-period quantities as weights in the regulatory constraint. They are theoretically shown in the literature to lead to overinvestment under incentive regulation (Vogelsang, 2001). The main logic is that the Transco tends to set a variable price in the two-part tariff (and an implied Paasche weight quantity) that relaxes the price cap in such a way that the fixed part can be excessively increased in relation to the consumer surplus of network users. Compared to Laspeyres weights, Paasche weights typically lead to too much investment and, consequently, to divergence from the steady-state equilibrium. In fact we confirm this in our simulations.

Figure 6.7 depicts network expansion results for the modeled cases. In all cases, line expansion under HRV regulation notably exceeds the welfare-optimal level over time. Paasche weights do not reflect exogenous decreases in congestion rents in future periods, which has an even larger effect on extension results than in the case of Laspeyres weights. Another difference to Laspeyres weights refers to the fact that total network extension is carried out in the first period in cases 1 and 4. This contrasts to gradual line extension in the Laspeyres case.

Average Laspeyres-Paasche weights

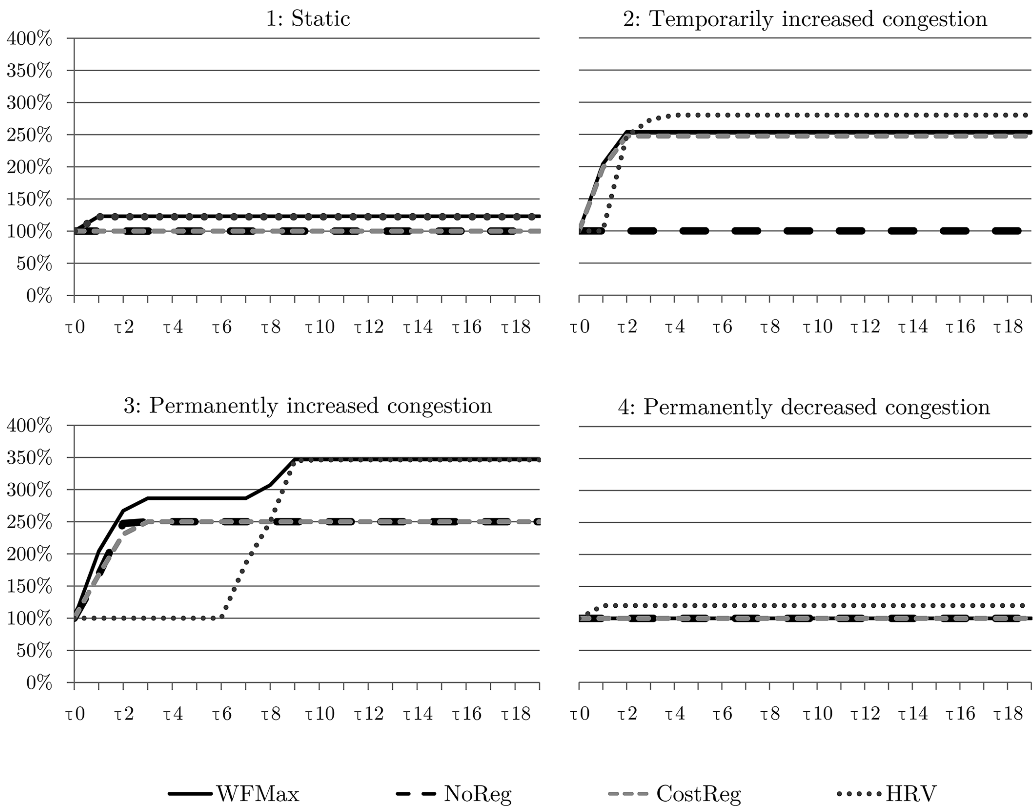

Figure 6.8: Line extension results (relative to initial capacity, average Laspeyres-Paasche weights)

A simple average of Laspeyres and Paasche weights is used in the literature as a linear approximation of idealized weights (Vogelsang, 2001). They are only exact for linear demand curves and may, in theory, lead to strategic behavior (cycles) if demands are nonlinear, but this has limited practical significance (Vogelsang, 1988). The average

Laspeyres-Paasche weight is optimal only in a stationary environment with linear demand because in that case the fixed fee of the two-part tariff defined by the price cap is equal to the change in consumer surplus of network users. Thus, the price cap equals the incremental surplus subsidy (Sappington and Sibley, 1988). In a dynamic scenario, when demand differs between periods, the average Laspeyres-Paasche weight makes the fixed fee no longer equal to the change in consumer surplus because the Laspeyres part belongs to consumer surplus in the past period and the Paasche weight to consumer surplus in the current period. In our simulations, we confirm that, under HRV regulation, this type of weight actually leads to less overinvestment in cases 2 and 3 compared to pure Paasche weights (Figure 6.8). Noticeably, in the static case, total network extension is carried out in the first period, as was also observed in the case of Paasche weights. This once again contrasts to the Laspeyres case, in which lines are extended gradually.

Ideal weights

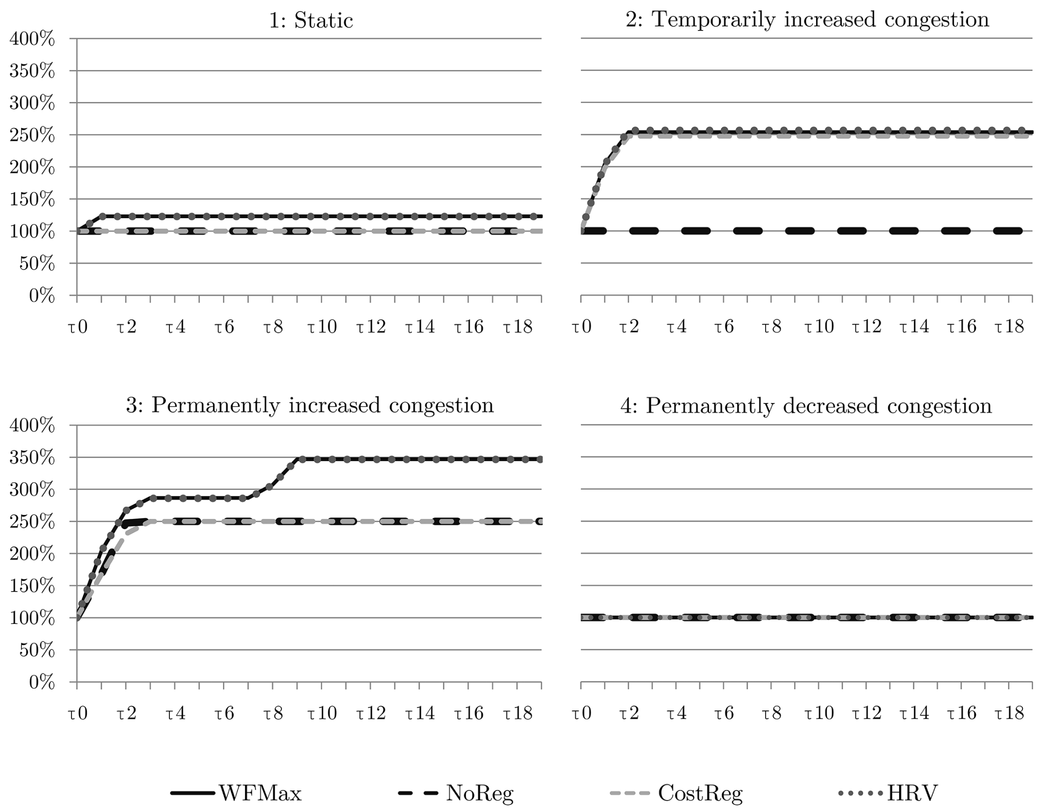

Figure 6.9: Line extension results (relative to initial capacity, ideal weights)

Ideal weights are quantities corresponding to the steady-state equilibrium and are analytically shown to grant convergence of incentive mechanisms to such equilibrium in just one period (Laffont et al., 1996). In the following simulation, we use quasi-ideal weights defined as the period-specific quantities of the welfare-optimal runs for each case.[102] Figure 6.9 confirms the theory of incentive regulation under renewable integration. The HRV incentive mechanisms nicely converge early to the welfare-optimal benchmark investment in all cases. Introducing the quasi-ideal weights isolates the investment incentives from the effects of the changing generation mix.

6.5.3 Welfare effects

As a consequence of the expansion results discussed above for each type of weight, we find the welfare results as summarized in Table 6.3. In the static case, the incentive regulatory scheme with Laspeyres weights leads to a welfare improvement close to the welfare-optimal benchmark, because transmission capacity converges to the optimum over time. Yet, in the other cases, this is no longer true due to overinvestment (cases 2 and 4) or delayed investment (case 3). The cost-regulatory case even leads to slightly better outcomes in these cases.

For Paasche weights, the incentive regulatory scheme, in the static case, leads to less extension-related welfare compared to the welfare-optimal benchmark, as a result of heavily diverging transmission overinvestment. The same is true for the other cases; except 3, in which the negative effect of slight overinvestment is more than compensated by quick expansion, compared to slower network upgrades in the Laspeyres case.[103] Cost-plus regulation still noticeable leads to better welfare outcomes in cases 1, 2, and 3. So, even though Paasche weights are easy to obtain for the regulator, they seem to be relatively inappropriate for incentive regulation in the context of a changing generation mix.

Combining Paasche weights with Laspeyres weights provides diverse outcomes. In the static case, the use of average Laspeyres-Paasche weights leads to welfare-optimal results. However, welfare effects are between Laspeyres and Paasche weights for cases 2 and 3, and similarly bad under Paasche weights in case 4. Incentive regulation under ideal weights, as expected, provides the best welfare results in all cases.

Thus, incentive regulation might still provide relatively adequate outcomes in terms of welfare convergence, as long as proper types of weights are used. Ideal weights always lead to convergence to the welfare optimum, but are not available to

[102] Ideal weights serve as benchmarks. In practice, they may not be available to the regulator as they cannot be observed from market outcomes. Compare Section 6.3.

[103] This feature of Paasche weights may be beneficial in the case of lumpy network investments.

Weights		Static congestion 1	Temporarily increased congestion 2	Permanently increased congestion 3	Permanently decreased 4
WFMax		0.29%	1.28%	11.62%	0.00%
NoReg		0.00%	0.00%	9.25%	0.00%
CostReg		0.00%	1.27%	9.22%	0.00%
HRV	Laspeyres	0.25%	1.01%	9.02%	-0.17%
	Paasche	-0.11%	0.38%	9.39%	-0.32%
	Average Lasp. -Paasche	0.29%	0.89%	9.21%	-0.32%
	Ideal	0.29%	1.28%	11.62%	0.00%

Table 6.3: Welfare changes relative to the case without extension

the regulator in complex networks. Accordingly, the regulator might actually choose the best practically available weights that can be observed from market outcomes under incentive regulation for each assumed congestion behavior:

- no exogenous change of network congestion: Average Laspeyres-Paasche weights provide the best results due to quick network expansion, but Laspeyres weights also work well;

- temporarily increased congestion: Laspeyres weights work best, average Laspeyres-Paasche weights fall somewhat short;

- permanently increasing congestion: Paasche weights work best, while average Laspeyres-Paasche weights provide the second best outcome;

- permanently decreasing congestion: Incentive regulation with anything other than ideal weights does not lead to desirable outcomes, as the Transco is rewarded for network investments that are obsolete in later periods (stranded investments).

Regarding questions of real-world renewable integration, cases 2 and 3 appear to be most relevant. Whereas Laspeyres weights work best in case 2 and Paasche weights are preferable in case 3, average Laspeyres-Paasche weights appear to be an appropriate choice in both cases. That is, the regulator may choose average Laspeyres-Paasche weights if it is not clear if the expected exogenous increase in network extension is a permanent or a transitory one.

6.6 Conclusion

In this chapter we address transmission investment in the context of a renewable integration process. That is, transmission capacity expansion is driven by the adoption of new and zero variable cost renewable generation, which is increasingly replacing conventional generation. We compare incentive price cap, cost-of-service, and non-regulated regulatory approaches in dynamic systems that assume different transformation paths toward a renewable-based system. In previous research, the complex issue of interaction between generation, transmission, and demand is not considered in the regulation of transmission expansion. In reality, transmission investment is not the only source of welfare change; another possible source is the shift toward renewables in the power plant fleet, which is considered exogenous here.

We consider two sources of welfare change: (i) network expansion; and (ii) the shift in generation technologies. In our stylized settings this means more wind and solar as opposed to conventional base load generation. Compared to the welfare-optimal solution, this, in turn, may translate into either (stranded) overinvestments or substantially delayed investments in the transmission network for incentive price cap (HRV) regulation if standard Laspeyres weights are used. This is due to the accumulation of excessive rents for the Transco, some of them purely originating from an exogenously changing generation mix. Cost-of-service regulation, on the other hand, can trigger investments close to the welfare-optimal levels. This suggests that, in order to reap the full benefits of incentive regulation, the regulator should seek to differentiate the changes in congestion rents, so as to efficiently guide the transmission expansion process and minimize welfare losses.

Under a renewable integration process the definition of appropriate weights that lead to welfare convergence with HRV regulation is the challenge for regulators. In our stylized application, Laspeyres weights only reflect the above mentioned non-differentiated sources on welfare, and therefore over-compensate the Transco that may over- or under-invest in network expansion. The complexities in real-world renewable integration would then need the regulator to precisely differentiate between the sources of welfare change in the transmission expansion process. In our simulations, the use of quasi-ideal weights (related to Laffont et al., 1996) achieves this goal and allows for early convergence in investment and welfare values of incentive regulation to the welfare-optimal benchmark. However, the actual implementation of ideal weights seems challenging in regulatory real-world practice.

The challenge would be finding a practically obtainable new type of weight that provides the required incentives under renewable integration. None of the evaluated weights (except for ideal ones) are able to incentivize welfare-optimal network investments. Yet our results indicate that different weights are favorable, depending on the permanent or transitory nature of exogenously increasing network congestion attributable, for example, to the build-up of renewable generation capacity. We conclude that average Laspeyres-Paasche weights may be an appropriate choice in case of an assumed exogenous increase in network congestion, the duration of which may not be known. In addition, these weights lead to earlier investments compared to Laspeyres weights, which may be beneficial if a requirement of substantial future network investment for renewable integration is anticipated, or if investments are lumpy. In any case, the choice of weights depends on the regulator's expectations on the exogenously driven development of congestion rents.

Our analysis thus provides a motive for further research on weight regulation aimed to characterize optimal regulation for transmission expansion under a transformation toward a renewable-based power system. This task may be more complex in the context of meshed, loop flowed networks, since the welfare effects from transmission expansion and a changing mix in generation technologies may be more difficult to isolate. Although our analysis is motivated by renewable energy integration, our findings may be interpreted in a more general context. Exogenous congestion changes may not only originate from renewable integration, as assumed here, but also from other developments in the generation mix, or from changes in power demand.

Chapter 7

European electricity grid infrastructure expansion in a 2050 context

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This chapter is based on:

European Electricity Grid Infrastructure Expansion in a 2050 Context.

Discussion Paper 1299, DIW Berlin, Egerer et al. (2013a).

Joint work with Clemens Gerbaulet and Casimir Lorenz.

It was presented at the 8th Conference on Energy Economics and Technology, 2013 (Dresden), at the 7th Annual Trans-Atlantic INFRADAY, 2013 (Washington D.C.), at the 10th International Conference on the European Energy Market, 2013 (Stockholm) where it is published in the IEEE conference proceedings, Egerer et al. (2013c), at the Annual Conference 2014 (Hamburg) of the Verein für Socialpolitik (German Economic Association), and at the Berlin Conference on Energy and Electricity Economics, 2015 (Berlin).

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European Electricity Grid Infrastructure Expansion in a 2050 Context

The Energy Journal 37(SI3): 101–124, Egerer et al. (2016a).

7.1 Introduction

The transformation process of the European electricity sector has increasingly become more dynamic in recent years. From a European perspective, the main political drivers are the integration of national markets into one internal energy market (EC, 2008b, Article 194) and the reduction of total greenhouse gas (GHG) emissions. Compared to emission levels of 1990, general reduction targets are: i) the 20-20-20 goals, setting national emission reduction targets with an overall reduction of 20% in 2020 (EC, 2008a) and ii) the long-term reduction target as stated by the European Commission (EC) in the Energy Roadmap 2050 with a reduction of 80–95% by the middle of the century (EC, 2011b). In 2014, the EC (2014a) has set a target of 40% for GHG reduction compared to 1990 with a renewable share of 27% for the European Union (EU) in 2030. The electricity sector plays a central role in the realization of these targets as its decarbonization is expected at a faster pace than that of the remaining economy.

On the contrary, energy policy remains a deeply national domain. National electricity systems historically rely on specific technologies and fuels in electricity supply for geographical and political reasons. It therefore comes as no surprise that the current transformation process varies strongly between individual member states. The national strategies and enthusiasm for the implementation of the 20-20-20 goals vary between member states in their design and ambition, as do national renewable support schemes. In addition, there are different points of view on nuclear power and carbon capture, transport, and storage (CCTS) as complementary options in a sustainable energy strategy. These challenges of combining national energy strategies and the vision of a European low-carbon electricity system with high renewable shares become apparent when raising the questions of market design and cross-border integration, with both depending on the physical exchange of electricity by the means of transmission infrastructure.

This chapter analyzes investments in the European high-voltage transmission network for different policy scenarios for electricity generation. A bottom-up electricity sector model assesses the cost-optimal network investments based on national generation portfolios which are disaggregated to a nodal representation of the electricity grid. The techno-economic mixed-integer linear problem (MILP) optimizes investments into voltage upgrades and line expansions in the existing high-voltage alternating current (HVAC) network and investments in additional point-to-point high-voltage direct current (HVDC) overlay lines in steps of ten years until 2050.

The analysis focuses on the effect of different policy scenarios for electricity supply with regards to i) the reduction of GHG emissions and ii) the technological preferences and their effect on the actual transmission investment needs using a European nodal electricity sector model. The data for the pathways the power sector might take is based on PRIMES results with a national resolution, which have been created during the EMF 28 study (Holz and Hirschhausen, 2013; Weyant et al., 2013).[104] PRIMES has provided official numbers for the Energy Roadmap 2050 of the European Commission (EC, 2011a) and has thus undergone a stakeholder process in all member states of the EU. The scenarios in this chapter are the reference scenario, with a target of 40% GHG reduction by 2050 without technology restrictions (40%DEF), and two 80% mitigation scenarios. The first mitigation scenario sees no technology constraints (80%DEF) while the second scenario has higher renewable shares and technology constraints on CCTS and nuclear power (80%GREEN).

The combination of both national and European legislation affects the low-carbon transformation of the electricity system. In this context, top-down energy system models are a suitable tool to determine the lowest-cost system development for a set of physical, economical, and political scenario assumptions and constraints. While energy system models are capable of representing the entire energy sector, their complexity limits them to an analysis on a national level. Due to spatial aggregation and the resulting simplification of the network topology, energy system models provide limited insights into future infrastructure requirements.

Several studies analyze the development of the European electricity system until 2050. Most studies, however, do not represent the transmission grid in detail but aggregate on a country level (see Capros et al., 2012a,b; DII, 2013; ECF, 2010; EURELECTRIC, 2010; Hagspiel et al., 2014).

Calculations for the EU Energy Roadmap 2050 are based on results from the PRIMES model and describe possible pathways for the EU to reach its decarbonization targets while ensuring competitiveness and security of supply. For several scenarios, potential developments are analyzed in all energy-related sectors such as electricity, transportation, industry, and heating. The PRIMES model approximates the European transmission grid, using a single node per country and applies the DC load flow linearization. Country nodes are interconnected by multiple cross-border lines with information (or assumptions, for new lines) on their thermal capacity and their line reactance. Investments in generation and transmission capacity are inter-temporally optimized under perfect foresight. The low spatial resolution of the aggregated transmission grid does not allow for transmission investment on national

[104] The Stanford Energy Modeling Forum (EMF) employs an international expert group. The objective is to improve the understanding of energy and environmental problems by comparing modeling approaches and results (`https://emf.stanford.edu/`). The EMF 28 addressed the effects of technology choices on EU climate policy.

levels or line-specific N-1 security considerations.[105] The model scope is limited to the EU. Potential imports and exports from and to North Africa are not taken into account (EC, 2011a,c,d). In the results, expanding the capacity of the transmission grid is seen as a no-regrets option to be able to “accommodate various power generation pathways” (EC, 2011b, p. 14).

The Grid Study 2030/2050 by Tröster et al. (2011) determines a more detailed transmission grid expansion for Europe in the years 2030 and 2050, representing the European grid with 224 nodes. It implements the DC load flow linearization and approximates N-1 security with a limit of 80% of the thermal line flow capacity. Fürsch et al. (2013) use the same grid model with the addition of endogenous investments into power plants. This allows for a better trade-off between investments into generation, storage, or transmission lines.

European Network of Transmission System Operators for Electricity’s (ENTSO-E) Ten-Year Network Development Plan (TYNDP) gives a detailed perspective on the planned grid expansions in Europe. These grid expansion plans are not solely based on model results but a combination of information provided by different institutions and stakeholders. Parts of the cost benefit analysis include the usage of power system models, including different levels of grid details (ENTSO-E, 2014a).

Compared to existing studies, this chapter implements a nodal resolution of the high-voltage transmission network allowing for a detailed spatial representation of load, generation, and electricity flows. The analysis of different exogenous scenarios for possible developments of national power plant portfolios disregards endogenous investment into generation capacity. We find that transmission expansion can be seen as a no-regrets option in the short term, as significant cross-border expansion takes place in all modeled scenarios. Furthermore, the overall investment structure is comparable to the investments described in the TYNDP. In the long term until 2050, the scenarios with high GHG mitigation targets require substantially more investments than those with a moderate target. The overall interconnector investments of 30bn–60bn EUR by 2050 determined in this chapter are generally lower than those specified in the Energy Roadmap 2050 (EC, 2011b). Even though the model allows for investments in an overlay HVDC grid, the majority of expansions take place in the existing HVAC network. By 2020, all scenarios suggest investments of about 16bn–19bn EUR. Thereafter, only the high-mitigation scenarios require large additional network investments. The statement of transmission as a no-regrets option is valid until 2020 with market integration being the main driver. In this period,

[105] N-1 Security (also called N-1 contingency) ensures that one element of the electricity grid can fail while leaving the system in a satisfactory state without causing any further failures such as line overloading. If another element of the electricity grid fails, load shedding or similar actions must be performed to return to the satisfactory state.

generation capacities are similar in all three scenarios due to the specific 20-20-20 targets. For the following decades, location and timing of transmission investments do not only depend on the GHG reduction target, but also on the choice of generation technologies. We find that the high-mitigation scenarios are more robust against changes in interconnector investment cost. Without sufficient information on system development, particularly on the power plant portfolio, flexible infrastructure development might not be possible or might run the risk of stranded transmission investments.

The remainder of this chapter is structured as follows: Section 7.2 introduces transmission investment decisions in electricity sector modeling and describes the methodology applied in this chapter. The data and scenarios are presented in Section 7.3. Section 7.4 discusses the quantitative results, and Section 7.5 provides the conclusion.

7.2 Mixed-integer transmission investment model

7.2.1 Introduction to modeling of transmission expansion planning

Models for transmission expansion planning in electricity networks have to consider many factors. They should include technical network aspects (e.g., flow distribution on lines, losses, and operational questions on network topology and reliability), investment options (e.g., lumpy investments, voltage levels, topology, and options for HVAC and HVDC technology), economic considerations (e.g., costs per investment option and power plant operation), uncertainty (e.g., development of load, generation capacity, and resource prices as well as short-term uncertainty in the system), and institutional and organizational aspects (e.g., market design, regulation, and cost-allocation). In the academic literature, publications focus on certain aspects of transmission expansion planning to reduce the model complexity and the size of the model scope.

The transmission expansion problem has not changed over time (Kaltenbach et al., 1970), but today's computational power allows for an increase of model complexity and optimization using larger datasets. Latorre et al. (2003) provide an overview of models and important aspects on transmission expansion planning. Still, from a modeling perspective, the planning problem has certain particularities that require non-linear constraints or integer variables. The most important ones are the representation of quadratic losses in electricity transmission, lumpy line investments in voltage upgrades and additional line circuits, new lines between previously unconnected nodes changing the topology, and the bi-linearity between endogenous variables for physical line parameters and for load flow. Including some of these important aspects into the optimization models drastically increases computation time and complicates the convergence to the global optimum compared to a linear optimization model. Different approaches to modeling transmission expansion planning can be found in Alguacil et al. (2003), Bahiense et al. (2001), Gunkel and Most (2014), Lumbreras et al. (2014), Tejada et al. (2015), and Torre et al. (2008).

7.2.2 Mathematical formulation of the extended ELMOD model

The model application in this chapter is an extension of ELMOD, a techno-economic electricity sector model developed at the Dresden University of Technology (Chair of Energy Economics), the Berlin University of Technology (Workgroup for Infrastructure Policy), and the German Institute for Economic Research (DIW Berlin, Department Energy, Transportation, Environment), see Leuthold et al. (2012). ELMOD is a large-scale spatial model of the European electricity market including both generation and the physical transmission network.[106] In this analysis, the model application is on infrastructure investments into the European high-voltage transmission network until 2050. Section 7.2.3 provides a critical discussion of model assumptions and limitations.

The model optimizes line investments for specific years. A rolling planning approach is used, so that the optimization is conducted consecutively for each decade, building on the results of the previous optimizations. The initial network for one year includes the initial network topology and all additional investments for the previous periods. The model has two decision levels, one for transmission investments and the other for generation dispatch. The assumption of perfect competition with a European central planner expanding the transmission network with the aim of minimizing total system costs reduces the two decision levels to one objective value. Total system costs in the objective function 7.1 include annualized fixed costs of network investments (variables i_l^{acup} are for an HVAC upgrade, i_l^{ac} for additional HVAC lines, and i_d^{dc} for additional HVDC lines) and variable generation costs of the generation g_{nit}^{tech} (i.e., costs for fuel and carbon emissions) for a set of hours which are scaled to one year (with the factor $\hat{y}$). Capital cost of existing infrastructure and of power plants is not taken into account. The model is a mixed-integer linear problem (MILP) to account for the lumpy nature of transmission investments. Investments are either represented with binary variables for upgrade decisions to a higher voltage level or with integer variables for additional lines. The applied methodology does not include

[106]ELMOD has been adjusted for various research questions: e.g., for market design (Weigt et al., 2010), for uncertainty and stochastic effects (Abrell and Kunz, 2015), for welfare distribution (Egerer et al., 2013b), for regulatory challenges (Egerer et al., 2015b; Rosellón and Weigt, 2011), and for integrated planning of the electricity system with investments in generation, storage, and transmission for the integration of renewable generation (Egerer and Schill, 2014b).

combined investments in generation and transmission, as the generation capacities are exogenous parameters provided by the results of an energy system model.

The model approximates the characteristics of power flows in meshed networks for the HVAC grid, following the DC load flow approach of Schweppe et al. (1988). In the typically meshed HVAC grids, the flow on a specific line cannot be controlled directly due to the existence of loop-flows. Line flows depend on all power injections and withdrawals at network nodes as well as the technical and topological configuration of all elements in the HVAC grid. This characteristic is represented by the DC load flow linearization which, however, neglects some technical grid characteristics such as reactive power.

HVDC lines are assumed to be point-to-point lines without meshed elements and implemented with transport flows in the model. Therefore, their operation is not part of the DC load flow approach. It can be determined freely within the given technical limits. The approach mimics modern HVDC connections where the operator is relatively free in deciding how much power to transfer.

Operation of the transmission grid must not be critically endangered by the failure of any one component, so-called N-1 security. This aspect is approximated in the expansion model by a reduction (transmission reliability margin) of the maximal power flow limit for every transmission line. An endogenous consideration of individual line failures to represent N-1 contingency is not possible due to the additional model complexity and the network size in the application (see Section 7.2.3 for a discussion).

$$\begin{aligned} \min c = &\sum_{nit} (g_{nit}^{\text{tech}} \hat{c}_{ni}^{\text{tech}}) \hat{y} \\ &+ \sum_{l} (i_l^{\text{acup}} \tilde{c}_l^{\text{acup}} + i_l^{\text{ac}} \tilde{c}_l^{\text{ac}}) \\ &+ \sum_{d} (i_d^{\text{dc}} \tilde{c}_d^{\text{dc}}) \\ &+ \sum_{nt} (ens_{nt} voll) \end{aligned} \tag{7.1}$$

In addition to the objective function for a specific year, which minimizes the combination of annual variable generation costs and annualized investment costs in the HVAC and HVDC network, Equations 7.2–7.3j describe the constraints of the model. The nodal energy balance 7.2 ensures that load q_{nt} is equal to supply at all nodes and in all hours. Combined nodal generation output of all conventional g_{nit}^{tech} and renewable r_{nit}^{tech} technologies plus in- and outflows on HVAC lines ni_{nt}^{ac} and HVDC lines ni_{nt}^{dc} determine nodal supply. Energy not served ens_{nt} is priced with the value of lost load *voll* in the cost balance.

Equation 7.3a limits conventional generation output per technology to the installed capacity $\overline{g}_{ni}^{\text{tech}}$ in each node. A similar time-dependent constraint exists for renewable generation per node with Equation 7.3b.

$$\sum_i (g_{nit}^{\text{tech}} + r_{nit}^{\text{tech}}) + ens_{nt} = q_{nt} + ni_{nt}^{\text{ac}} + ni_{nt}^{\text{dc}} \qquad \forall \quad n,t \tag{7.2}$$

$$
\begin{aligned}
g_{nit}^{\text{tech}} &\le \overline{g}_{ni}^{\text{tech}} && \forall \quad n,i,t && (7.3a)\\
r_{nit}^{\text{tech}} &\le \overline{r}_{nit}^{\text{tech}} av_{nit}^{\text{tech}} && \forall \quad n,i,t && (7.3b)\\
ni_{nt}^{\text{ac}} &= \sum_k b_{nk}\theta_{kt} && \forall \quad n,t && (7.3c)\\
pf_{lt}^{\text{ac}} &= \sum_n h_{ln}\theta_{nt} && \forall \quad l,t && (7.3d)\\
\theta_{\hat{n}t} &= 0 && \forall \quad t && (7.3e)\\
h_{ln} &= \hat{b}_l im_{ln}^{\text{ac}} && \forall \quad n,l && (7.3f)\\
b_{nk} &= \sum_l im_{ln}^{\text{ac}} h_{lk} && \forall \quad n,k && (7.3g)\\
|pf_{lt}^{\text{ac}}| &\le \overline{pf}_l^{\text{ac}} + i_l^{\text{acup}}\overline{pf}_l^{+\text{acup}} + i_l^{\text{ac}}\overline{pf}_l^{+\text{ac}} && \forall \quad l,t && (7.3h)\\
ni_{nt}^{\text{dc}} &= \sum_d pf_{dt}^{\text{dc}} im_{dn}^{\text{dc}} && \forall \quad n,t && (7.3i)\\
\left|pf_{dt}^{\text{dc}}\right| &\le \overline{pf}_d^{\text{dc}} + i_d^{\text{dc}}\overline{pf}_d^{+\text{dc}} && \forall \quad d,t && (7.3j)
\end{aligned}
$$

The flow on HVAC lines is restricted by constraints 7.3c and 7.3d of the linearized DC load flow approximation (Schweppe et al., 1988) and by the transmission capacity of each HVAC line in Equation 7.3h. Equation 7.3c determines the inflow or outflow for each node and hour depending on the phase angle θ_{nt} and network susceptance matrix b_{nk}. The power flow pf_{lt}^{ac} on each HVAC line is determined in Equation 7.3d, dependent on phase angle and network sensitivity matrix h_{ln}. As only the difference of phase angles is relevant in the determination of power flows, the phase angle is fixed to zero at one node (the slack bus, $\theta_{\hat{n}t}$) in each of the non-synchronized HVAC networks (Equation 7.3e). Equations 7.3f and 7.3g describe the calculation of the network sensitivity matrix h_{ln} and the network susceptance matrix b_{nk}, based on the series susceptance $\hat{b}_l$ of the HVAC lines. Point-to-point HVDC lines are implemented with directed flows in 7.3i that are only constrained by capacity in Equation 7.3j.

The main driver of infrastructure investment is the regional level of load in relation to the spatial availability and variable cost of generation. In the case of network congestion, it is not possible to operate the electricity system with the least-cost generation capacities. In this case, an incentive to invest in transmission capacity emerges. The imposed deviations from the least-cost merit order dispatch provide incentives to invest in transmission. The model allows for upgrades of lines with lower voltage levels than the common voltage level of 380 kV in Europe. For upgraded lines and those already operated at 380 kV, the model can invest in additional circuits of 380 kV, thereby maintaining the topology of the high-voltage transmission network. A second option is investment in a set of predefined point-to-point HVDC connectors. Investment in transmission relaxes the constraints of Equations 7.3h and 7.3j for line flows and can relieve congestion, allowing for a generation dispatch with lower variable generation cost. An overall reduction in system cost is reached if the cost savings in the power plant dispatch are higher than the equivalent annuity for the line investment.

Investment in the HVAC transmission system affects the series susceptance $\hat{b}_l$ of the line and thereby changes the flow pattern in the meshed HVAC network. An endogenous consideration of changing flow patterns in the DC load flow linearization requires bi-linear terms in the model constraints. b_{nk} or h_{ln}, which are multiplied by θ_{nt}, would become variables when considering the changing values of $\hat{b}_l$ as a result of line expansion. To remain in a linear model world, the applied linear model is solved iteratively for investment in transmission capacity, at first neglecting changes in $\hat{b}_l$ and in the flow patterns (see Figure 7.1). After each optimization, the b_{nk} and h_{ln} matrices are updated with the new series susceptances $\hat{b}_l$ to represent the new network configuration after the optimization. Before starting the next iteration, the model is run using the new lines and updated flow patterns but without additional network investments to calculate the system costs of the respective network configuration. Then the optimization is repeated in the next iteration whereas line investment of the previous iterations can be undone by reimbursing the investment costs. These steps are repeated until either i) the resulting grid expansion does not change between iterations anymore, or ii) identical configurations are observed twice, which indicates that the optimization enters a loop of repeating solutions. In both cases the grid configuration of all iterations with minimal total cost is used as the final solution.

This heuristic approach does not guarantee global optimality of the grid expansion configuration, but provides a very good approximation. During model development, this approach has been compared to a global search with aforementioned bi-linearities on small and medium-sized problems. Here, the results were either globally optimal, or the differences were relatively minor. The iterative optimization process reaches convergence for the conducted model runs after about ten iterations.

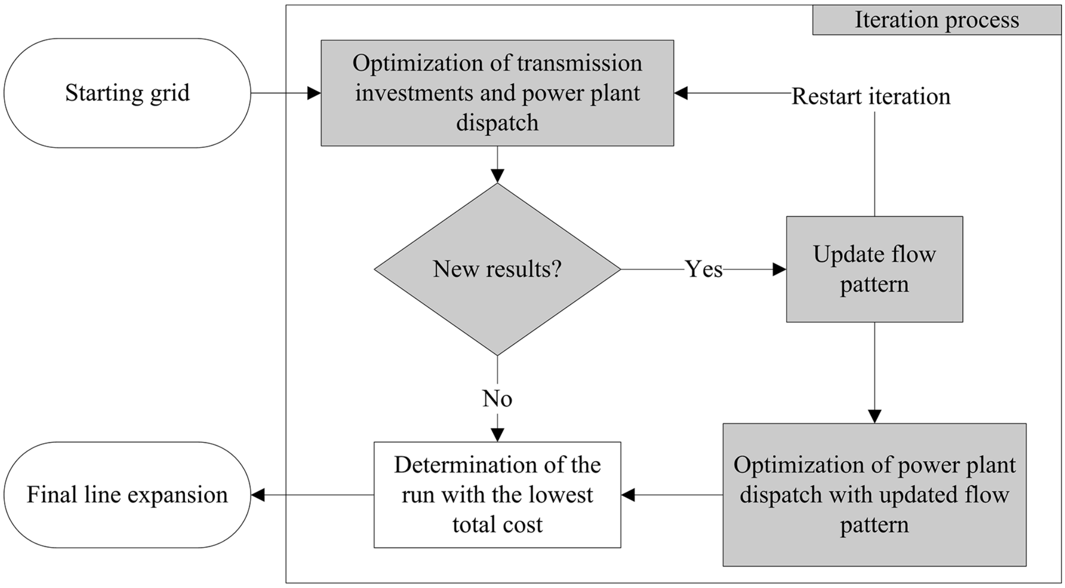

Figure 7.1: Iterative optimization process

Each optimization period accounts for ten years, using a rolling planning approach. The model optimizes the network topology consecutively for 2020, 2030, 2040, and 2050, corresponding to the data provided. The result for one period is the initial network configuration for the subsequent period. The size of the network and the number of hours require a limitation of the number of binary and integer variables before optimizing the entire model scope. This is done by solving the model for each single model hour separately. Every upgrade and expansion occurring in any of these separate runs remains in the solution space for the optimization with all model hours. This approach limits the model to only a certain set of available expansions. Its results have been compared to those of full enumeration for smaller problems. Here, the preselection using the reduced problems has provided a very good selection for the problem with all hours. Therefore, it can be expected that the preselection is no significant distortion for the results of the bigger problem.

7.2.3 Critical discussion of model assumptions and limitations

The network investment model has several main characteristics: i) the nodal network representation of the high-voltage transmission network, ii) the integer formulation for line investment of different type and technology, iii) the iterative optimization process for line investment to address changing flow patterns in the DC load flow linearization, and iv) the cost-minimizing formulation of the generation dispatch. Therefore, the approach allows for a cost-minimizing optimization of all line investments in the electricity system. The model is applied to the European transmission network and has a large number of integer variables (i.e., one binary variable per possible voltage upgrade, an integer variable per HVAC line, and an integer variable per HVDC line). Size and complexity of the model require the following model limitations which have to be regarded in the evaluation of the results.

In the generation dispatch, the model applies the same aggregation of generation technologies as the input data of PRIMES does. It abstracts from individual power plants by aggregating data on generation units to generation technologies at network nodes. Also, the temporal representation is limited to a small set of system states (i.e., load levels and availability of renewable energy sources). These limitations reduce the model complexity but do not allow for a detailed implementation of system stability in extreme conditions, inter-temporal constraints, and system flexibility, all being important aspects for renewable integration. However, network investment is only one option among several others to handle system transformation and the integration of renewables.

The limitations mostly suggest that the model results provide a lower bound for network investment. However, a more detailed implementation of the possible development of significant storage capacity or increased utilization of demand response could reduce the level of network investment.

In the network representation, the DC load flow linearization determines a flow distribution according to the network topology and physical line characteristics. The applied methodology takes changes of flow distributions into account which result from investments in HVAC lines. This is not done during the optimization itself, but in consecutive iterations of the iterative optimization process. An endogenous implementation in a single optimization would require non-linear model constraints.

Additional limitations of the expansion model are the preselection of HVAC investment options by model runs of every individual hour, the limitation of HVDC investment to a set of candidate lines, and the separate optimization for every ten years. The preselection of HVAC investment options might only lead to a locally optimal investment combination, as only the computation of the full model analyzes the interactions of all model hours. Lumbreras et al. (2014) suggest an automatic preselection of candidates for line expansion using benders decomposition, which allows for keeping the globally optimal combination in the solution space. The preselection algorithm used in this chapter provides an efficient combination between computational complexities and finding optimal solutions.

Restricting the set of available HVDC connections to 23 connections allows for a computationally more efficient implementation compared to a highly meshed HVDC candidate grid. This simplification possibly underestimates the benefits of HVDC lines and leads to less HVDC and more HVAC investment.

The consideration of line losses could make HVDC lines more attractive as an option for long-distance transportation. The trade-off between HVAC and HVDC technology is also sensitive to cost parameters for investment.

Last but not least, to keep the model calculations tractable, the model uses a transmission reliability margin of 20% for HVAC and HVDC lines. A detailed representation of N-1 contingency remains challenging in optimization models on transmission expansion planning for large networks. Using the reliability margin affects the results in several ways. HVAC lines are usually well interconnected. Here, the assumption of a reliability margin is more adequate for most lines, as a contingency can usually be accommodated by the surrounding grid. Following this argumentation, the reliability margin for HVDC lines would have to be higher as a contingency would lead to a steep decrease in transmission capacity along the HVDC corridor. The model limitations indicate the focus on cost-minimizing network optimization for different generation scenarios. The methodology applies a stylized representation of system security in the optimization as it does not explicitly model N-1 contingency and other stability criteria. A detailed N-1 consideration for every line is likely to result in additional investments in transmission lines. While a higher temporal resolution of system states could also increase transmission investment, the opposite effect could be expected by the inclusion of local line-specific cost factors for all lines such as additional external costs.

7.3 Input data and scenarios

7.3.1 Initial system data

The network topology consists of four non-synchronized high-voltage electricity grids (Central Europe, Scandinavia, Great Britain, and Ireland) with the voltage levels 150 kV, 220 kV, 300 kV, and 380 kV. Twelve HVDC cables connect these systems. The grid has a total of 3,523 nodes (substations) and 5,145 lines as shown in Figure 7.2. Egerer et al. (2014a) describe the European dataset of the ELMOD model in detail.

Each HVAC line is defined by the starting and ending node, its length, voltage level, and the number of installed circuits. Endogenous investment decisions include a binary decision for the voltage upgrade of lines to 380 kV and an integer decision for 380 kV lines to increase its number of circuits. HVDC lines are defined by a starting and an ending node, capacity, and length. The twelve existing HVDC lines are ten offshore connectors between the non-synchronized networks of Ireland, Great Britain, Scandinavia, and continental Europe, one cable between Greece and Italy, and one between Finland and Sweden. For investments in additional HVDC lines, the model only has the option to invest in lines of an overlay HVDC backbone grid, as outlined in Figure 7.2. The additional HVDC lines are exogenous options which include 23 individual point-to-point connections all over Europe. These network nodes have been chosen based on good interconnection in the HVAC network and distance to load/generation centers, where an HVDC end point could likely be built.

Investment costs in Table 7.1 are calculated for each individual line with regard to technology and type of investment. They include investment costs for two transformer stations per line and a cost factor for every kilometer of the transmission line. Transformer stations are more expensive for upgrades than for expansion, as additional transformers from 380 kV to 110/220 kV will become necessary.

[m EUR]	**Transformer stations**	**Line costs per km**	**Nominal capacity in MW**
HVAC expansion (per additional circuit)	4.0	1.4	1700
HVAC upgrade (per upgrade to 380 kV)	6.5	0.2	1700
HVDC expansion (per circuit)	260	1.4	2000

Table 7.1: Parameters for transmission investment

The spatial character of the model requires nodal shares for load and generation in each country. National load is spatially distributed based on the population of NUTS regions (EC, 2016).[107] The spatial distribution of conventional generation capacity is based on the PLATTS power plant database (Platts, 2012). Its power plants (including hydropower and biomass) have been geocoded and, aggregated by technology, allocated to the closest network node in the same country. The allocation of the national renewable capacity, that is, onshore wind, photovoltaics, and concentrated solar power (CSP), to the nodes in the network uses a combination of the technical potential and the size of NUTS 2 zones.[108,109] For each country the national share of the NUTS 2 zone's potential is determined and allocated evenly to all nodes within the respective zone. Nodal data for national offshore wind allocation reflects spatial information for the projection of future offshore wind capacities (OffshoreGrid, 2011).[110]

[107] Load is allocated corresponding to network nodes on NUTS 2 level. The nomenclature des unités territoriales statistiques (NUTS) is a geocode standard by the European Union for statistical purposes.

[108] ibid. EC (2016).

[109] Average wind speeds for onshore wind and the average radiation for photovoltaics and concentrated

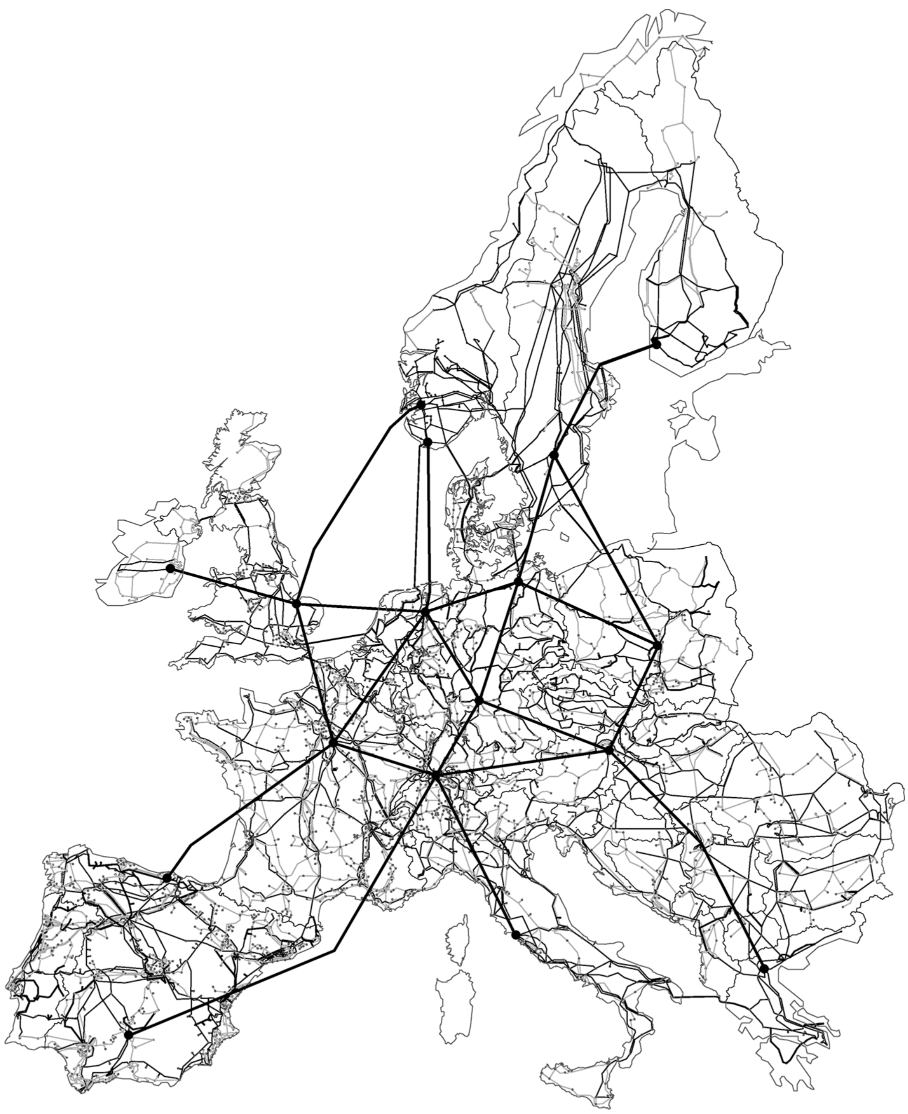

Figure 7.2: Initial network topology for Europe and HVDC overlay grid[111]

To account for the fluctuating characteristics of load and renewable energy sources, 18 model hours are generated. These hours describe two seasons (summer and winter), three times of the day (day, night, and shoulder hours), and three wind availability cases (high, mid, and low) as shown in Table 7.2. Different load factors are calculated for summer and winter as well as for day, night, and shoulder hours by an aggregation of national hourly load data for 2012 (ENTSO-E, 2013).

	Summer									**Winter**								
Solar & load	Day			Night			Shoulder			Day			Night			Shoulder		
Wind	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18

Table 7.2: Reference hours

For photovoltaics and CSP, 70% of the annual electricity generation is assumed to be generated in the summer and 30% during winter hours, which is further allocated to day and shoulder hours (Table 7.3). Due to shorter time with daylight, shoulder hours in the winter have a lower share than in the summer. For wind power, different shares between winter and summer are calculated for each country based on monthly electricity output levels. The allocation on high, mid, and low wind hours (Table 7.4) assumes more balanced generation levels for the winter than for the summer and for offshore wind compared to onshore wind. The factors do not distinguish between day, night, and shoulder hours.[112] Pumped-storage hydroelectric plants and reservoirs are modeled as run-of-river power plants with correspondingly adjusted availabilities.

Summer			**Winter**		
Day	Night	Shoulder	Day	Night	Shoulder
71%	0%	29%	83%	0%	17%

Table 7.3: Solar production energy share

solar power are provided on NUTS 2 level by Velte et al. (2009).

[110] Offshore grid: Deliverable 3.1 - inventory list of possible wind farm locations with installed capacity for the 2020 and 2030 scenarios.

[111] Annualized costs calculate by the investment costs and an assumption on the life time (40 years) and the interest rate (8%).

[112] The limited number of hours in the model only allows the representation of basic effects in the fluctuating generation pattern of solar and wind technologies. They include seasonal and daytime patterns for solar and seasonal and three output levels for wind. Therefore, the 18 hours allow for some temporal differentiation. The spatial correlations of wind and solar generation levels is neglected in the data.

	Summer			Winter		
	High	Mid	Low	High	Mid	Low
Onshore	70%	25%	5%	65%	25%	10%
Offshore	60%	30%	10%	55%	30%	15%

Table 7.4: Wind production energy share

7.3.2 Scenarios on the development of the electricity sector

In the analysis the results of three EMF 28 scenarios (Weyant et al., 2013) serve as input for the transmission investment model. The scenarios are distinguished by the two dimensions policy and technology. The policy measures define a certain mitigation level for GHG emission. The constraints on the availability of certain generation technologies depict different developments in the power plant portfolio. All three scenarios fulfill the 20% emission reduction target for Europe by 2020:

- The **40%DEF** scenario without progressive climate policy represents the reference scenario. No technology restrictions exist. CCTS technology for fossil power plants, nuclear power, renewable energy sources, and energy efficiency follow a reference pathway leading to a GHG reduction of 40% by 2050.

The two other scenarios assume a more progressive climate policy in Europe leading to a mitigation level of 80% by 2050:

- The **80%DEF** scenario sets no constraints on the use of nuclear power and CCTS technology. Hence it uses the same technology constraints as the 40%DEF scenario. It allows for a comparison of the additional infrastructure needs assuming progressive policy compared to the reference scenario.
- In contrast, the **80%GREEN** scenario constrains the usage of nuclear power and CCTS technology by technological availability as well as slightly increased fuel prices. While assuming a higher level for energy efficiency, RES capacities deliver most of the additional GHG reduction on the generation side. The electricity demand development is generally slightly lower, with a total demand in 2050 of 94% compared to the 80%DEF scenario. The comparison between the scenarios 80%DEF and 80%GREEN highlights the effect of technology choices on infrastructure requirements.

The top-down energy system models provide their results on a national level for the different policy scenarios. Input data for the infrastructure model is derived from results provided by the PRIMES model (Capros et al., 1998; EC, 2011a). This includes data on generation capacity, annual demand, annual renewable generation output, resource prices for gas and coal, and the CO_2 emission price. Figure 7.3 shows the aggregated generation capacities for all countries in the different scenarios.[113]

The initial nodal generation capacities of the model dataset are scaled to fit the national PRIMES data for each scenario and year. Assuming a brownfield approach for generation investment, the spatial distribution of generation capacity per technology does not change within one country over time. As the PRIMES output is only reported for EU27 countries, the power plant capacity of the PLATTS database is used for Croatia and non-EU27 countries (Switzerland, Norway, and non-EU countries in south-eastern Europe). For these countries, demand remains constant and only minor changes are assumed in the installed generation capacity over time. In Switzerland, existing nuclear generation capacity is decommissioned and replaced by combined cycle gas turbine plants by 2040. The installed hydro capacity in Norway increases by 10% by 2050.

7.3.3 Regional character of the scenarios

The scenarios presented in the section above not only differ in the total amount of installed generation capacities, but also in the distribution of these capacities among the countries. Therefore, the scenarios can also be characterized by their regional character and how robust the scenarios are concerning changes in transmission pricing.

In a transmission investments model, the point of minimal total cost does not represent the case of a congestion-free network in all periods, but a point where the cost of grid congestion (e.g., the constraints) and the investment cost into the grid are even (Kirschen and Strbac, 2004). Therefore, optimal infrastructure includes temporary congestion. Transmission investment costs can be a low-cost option compared to generation investments. If costs for transmission infrastructure were higher, the point of optimal transmission investments would include fewer investments in transmission and include higher generation cost.

Building on MISO (2010), we assume that national generation scenarios are more price-sensitive regarding the transmission investments than European scenarios. To test the sensitivity of this regional case we double the cost of cross-border investments and compare the results to the European case. The changes in line expansions in kilometers indicate the scenario's robustness and price-sensitivity.

[113]Due to contractual restrictions, the results of the PRIMES model cannot be stated on a national level. The data section is limited to an aggregated overview for key scenario data on European level and the description of the regionalization of the national PRIMES data.

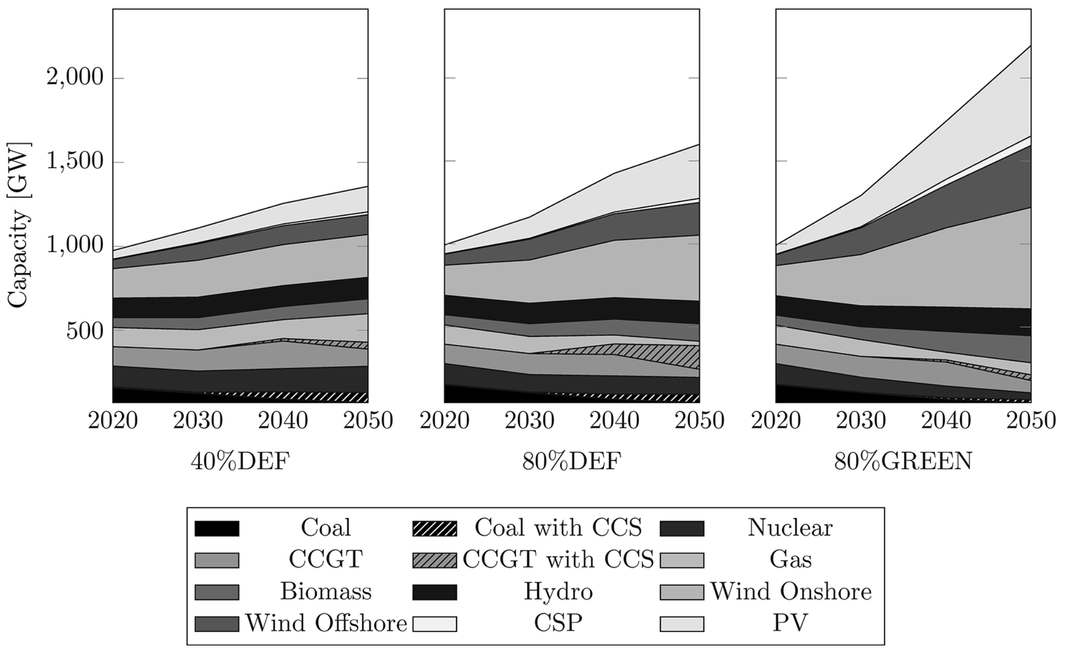

Figure 7.3: Aggregated PRIMES results for the development of the European generation capacity, 2020–2050

7.4 Results

The results section first, in Section 7.4.1, describes which lines are upgraded or built by the model, in physical terms, for example, HVAC or HVDC (in GW), and then, in Section 7.4.2, translates these physical investments into monetary terms (in EUR); we also look at the dynamics of network expansion over time. The following Section 7.4.3 characterizes the scenarios regarding their regional or European characteristics. Subsequently, Section 7.4.4 compares the results to other studies and those of the Energy Roadmap 2050 by the European Commission.

7.4.1 Transmission expansion in HVAC and HVDC technology

Tables 7.5 and 7.6 summarize the results of the model for physical expansion of the network, differentiated by technology, that is, HVAC and HVDC, as well as by time step and domestic versus cross-border lines. Table 7.5 reveals an interesting finding that is often ignored in aggregate analysis: domestic upgrades play an important role in all scenarios, and largely outweigh cross-border investments (over 2:1 in the 40%DEF scenario, and over 3.5:1 in the 80% scenarios). The total number of kilometers increases between the 40% scenario (27,978 km) and the 80% scenarios, but is almost identical within the 80% scenarios; it is even slightly lower in the

80%GREEN scenario (50,993 km) than in the 80%DEF scenario (52,424 km). The two 80% scenarios differ with respect to their distribution between HVAC and HVDC cross-border lines, as the 80%GREEN scenario has a higher share of HVDC cross-border lines.

[km]	**National**	**Cross-Border**		**Total**
	HVAC	HVAC	HVDC	
40%DEF	19,194	4,611	4,174	27,978
80%DEF	39,905	7,173	5,346	52,424
80%GREEN	39,798	4,138	7,057	50,993

Table 7.5: Network extension per line type

Table 7.6 provides details of the dynamic transmission expansion process by decade. Unsurprisingly, the level of network expansion is directly related to the generation investment in the underlying PRIMES scenario. Therefore, in the 40%DEF scenario, most transmission expansion occurs by 2020, and very little in 2020 to 2030. On the contrary, the expansion path in the 80%DEF scenario lies mainly in the 2030 to 2040 period, whereas in the 80%GREEN scenario it is in the 2040 to 2050 period, because the model suggests that the 80% CO_2-reduction target will only be achieved at a later stage. A look at the spatial distribution of the transmission investments confirms that the largest share is related to domestic lines, and that HVAC expansion clearly dominates HVDC grid expansion.

[km]		**2020**	**2030**	**2040**	**2050**	**Total**
40%DEF	HVAC	14,908	175	3,644	5,078	23,804
	HVDC	2,770	939	0	465	4,174
	Total	17,677	1,113	3,644	5,543	27,978
80%DEF	HVAC	15,036	2,443	17,510	12,090	47,078
	HVDC	3,629	472	778	467	5,346
	Total	18,665	2,915	18,288	12,556	52,424
80%GREEN	AC	12,802	2,804	8,216	20,114	43,936
	DC	3,629	1,250	1,245	933	7,057
	Total	16,431	4,054	9,461	21,048	50,993

Table 7.6: Total kilometers of upgrades or expansion

In the 40%DEF scenario, mainly local grid reinforcement measures are necessary with a focus on cross-border connections and network development in Central-Eastern Europe (Figure 7.4). The 80%DEF and 80%GREEN scenarios invest slightly more in cross-border lines (+3,700 km/+2,400 km) and significantly more in the HVAC network within countries (+20,700 km/+20,600 km), compared to the 40%DEF scenario. In the 80%GREEN scenario, the higher renewable share results in higher HVDC cross-border investments in the North and Baltic Seas region and additional HVAC lines as integration measures at the connection nodes of HVDC lines with the HVAC network (e.g., in Sweden, France, and Germany). On the contrary, the solar capacities in Southern Europe do not seem to generate a corresponding level of HVDC connections in Southern Europe. The 80%DEF scenario also requires some of the investments for the integration of increasing renewable generation. Yet, the renewable share is lower than in the 80%GREEN scenario as the scenarios allow for more CCTS technology and an overall constant level of nuclear power in the European electricity system. This combination of a lower renewable share and a shift in the spatial allocation of nuclear and coal power plants results in fewer investments in the North and Baltic Seas region and a more dynamic network development in Central-Eastern Europe.

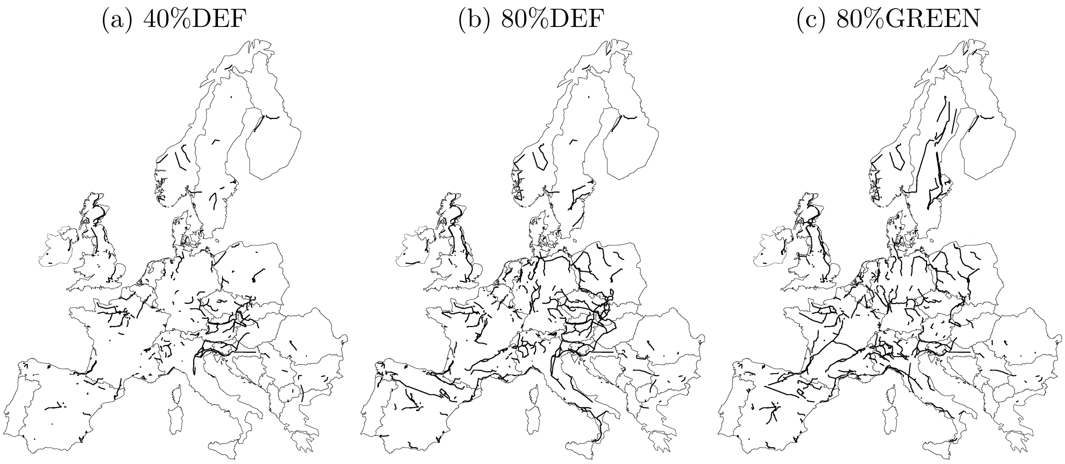

Figure 7.4: HVAC grid infrastructure investments

Figure 7.5 depicts the investments in HVDC lines, realized among the 23 options provided by the backbone architecture. Contrary to the common belief of pan-European electricity highways, the model only invests in the HVDC offshore cables between the non-synchronized networks of Ireland, Great Britain, Scandinavia, and continental Europe but not in the onshore HVDC cables, nor in any HVDC cable south of France (with one exception in the 80%GREEN scenario). Compared to the high-mitigation scenarios, the 40%DEF scenario has one additional cable, connecting Great Britain to Germany but one less connecting it to Norway. Sweden is linked to continental Europe by one additional cable in the 40%DEF scenario, two in the 80%DEF scenario, and three in the 80%GREEN scenario. Higher overall HVDC investments in the 80%GREEN scenario also indicate a stronger integration of the non-synchronized transmission systems around the North and Baltic Seas.

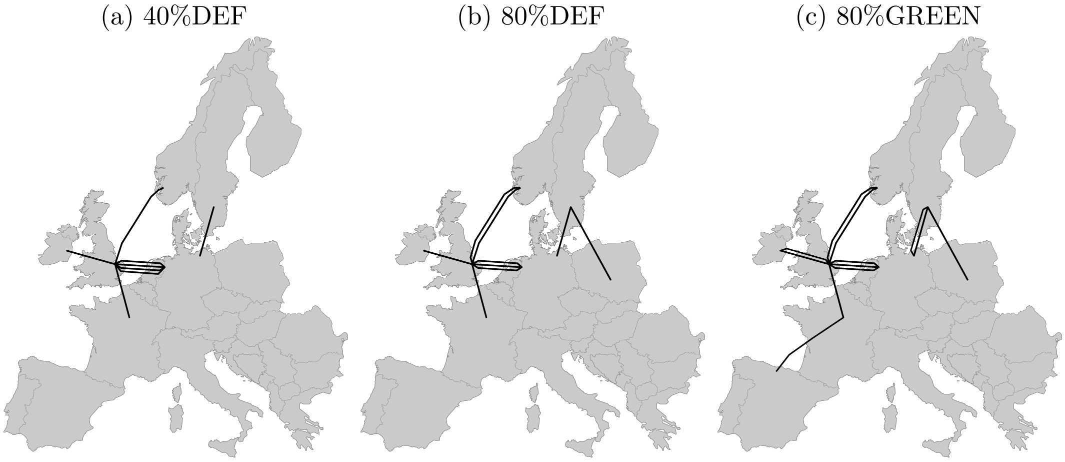

Figure 7.5: HVDC grid infrastructure investments

7.4.2 Total cost of investments

Table 7.7 translates the physical transmission upgrades and expansion into monetary investment values. Unsurprisingly, once again, investments are proportional to network length; the high fixed costs of HVDC line transformers somewhat modify this proportionality. While the 80% mitigation scenarios show higher investment figures than the 40%DEF scenario, they are identical to each other (57bn EUR); therefore, there is no difference in network expansion whether the decarbonization comes from renewable or conventional sources.

Considering the timing of investments, all scenarios have similar total investment costs by 2030. Investments for 2020 are driven by network expansion to resolve existing bottlenecks (where cost efficient),[114] by better cross-border market integration, and by the implementation of the European 20-20-20 targets. The transmission network sees a high expansion rate but a low variance of total expansion costs between the scenarios (16bn–19bn EUR). In the following decade, the transformation of the generation portfolio slows down. In the absence of strong commitments to climate targets on the European level between 2020 and 2030 in the PRIMES scenarios, the energy system model postpones investments in generation to later decades and predicts stagnating resource and carbon emission prices. With this model input, the

[114] The initial network topology is not free of congested lines in 2012, causing some network expansion in the first decade.

electricity sector model adds only few transmission lines in all scenarios. After 2030, transmission investments remain at a moderate level with an additional 12bn EUR in the 40%DEF scenario. In both high-mitigation scenarios they are ascending to about 34bn EUR due to the approaching 80% emission reduction target by 2050. In the 80%DEF scenario more investments occur in 2040 compared to 2050 (19bn EUR vs. 15bn EUR) while in the 80%GREEN scenario the larger share of investments is in 2050 due to the continuously strong growth in renewable capacities.

[m EUR]		**2020**	**2030**	**2040**	**2050**	**Total**
	HVAC	11,847	168	4,318	6,339	22,672
40%DEF	HVDC	5,178	1,834	0	911	7,923
	Total	17,025	2,002	4,318	7,250	30,595
	HVAC	12,224	3,397	17,321	14,154	47,096
80%DEF	HVDC	6,641	921	1,349	913	9,824
	Total	18,864	4,318	18,670	15,067	56,919
	HVAC	9,330	3,685	8,184	22,633	43,833
80%GREEN	HVDC	6,641	2,270	2,263	1,827	13,000
	Total	15,971	5,955	10,447	24,460	56,833

Table 7.7: Total investment costs for transmission capacity

7.4.3 Regional character

In addition to the total investment costs and kilometers built, the regional character and robustness of the scenarios is an important aspect to consider. We compare two cases; the first is the European case, which is identical to the results presented above. In the regional case, we assume double costs for cross-border infrastructure investment to mimic hurdles of international cooperation and increased transaction costs. As expected, we see fewer kilometers built in the regional cases (Table 7.8), especially HVDC investments, which are exclusively cross-border lines (see reduced investments in the regional cases). By comparing the three scenarios, it becomes apparent that the 80%GREEN scenario is least affected by the increased cross-border expansion cost but only for HVAC. For all scenarios, HVDC investments are more sensitive to the higher cost assumptions due to their cross-border character. The remaining level of HVDC investments is about 50% higher in 80%GREEN compared to the other scenarios. The overall relatively small change of line expansion in the 80%GREEN scenario is in line with the assumption that, with high renewable deployment, the spatially different availability of renewable capacity can be smoothed out overall, given a well-connected electricity transmission grid. Therefore, the 80%GREEN scenario can be interpreted as a robust European scenario.

In the 80%DEF scenario, the different mix in generation technologies seems to represent a more national scenario, as here the relative decrease in line expansion is highest.

[km]		National HVAC	Cross-border HVAC	Cross-border HVDC	Total
40%DEF	European	19,194	4,611	4,174	27,978
	Regional	18,860	4,207	3,243	26,310
		(-2%)	(-9%)	(-22%)	(-6%)
80%DEF	European	39,905	7,173	5,346	52,424
	Regional	36,132	6,808	3,194	46,135
		(-9%)	(-5%)	(-40%)	(-12%)
80%GREEN	European	39,799	4,138	7,057	50,993
	Regional	40,967	4,088	4,654	49,709
		(+3%)	(-1%)	(-34%)	(-3%)

Table 7.8: Total kilometers per line type in the European or Regional case (changes in parenthesis)

7.4.4 Comparison with the Energy Roadmap 2050 and other studies

We now turn to a comparison between our model results and those of the Energy Roadmap 2050, which is the roadmap for the European Union's decarbonization strategy (EC, 2011b) and of other studies introduced in Section 7.1. This comparison is possible for the Energy Roadmap 2050 as the reference scenario for the Impact Assessment of the Energy Roadmap 2050 (EC, 2011c) is very close to the 40%DEF scenario (with a similar 40% mitigation target), and the decarbonization scenarios include the diversified supply technologies scenario (comparable to 80%DEF) and the high RES scenario (comparable to 80%GREEN).

As described in Section 7.1, the PRIMES model diverges from our methodology due to its aggregated network representation. It also includes both, costs for new line investments and maintenance costs of the existing network, whereas our model does not consider maintenance costs. Overall, we find that both the structure of network expansion and the level of investment into cross-border lines differ significantly from those of the Energy Roadmap 2050. In particular, the Energy Roadmap 2050 sees much higher investments in the high-mitigation scenario (EC, 2011c, Table 29).

Other studies show lower cost than the Energy Roadmap as well (Table 7.9). The Grid Study 2030/2050 by Tröster et al. (2011) uses a similar scenario to 80%GREEN, by reaching 99% of renewable share in 2050 for the electricity sector. Fürsch et al. (2013) use a model similar to Tröster et al. (2011) but apply a more conservative scenario definition. By 2050, a GHG emission reduction of 80% is assumed for the electricity sector, compared to 1990. While the calculated costs are lower than the Energy Roadmap 2050, they remain two to three times higher than the costs proposed in this chapter. One explanation is that those studies use a reduced spatial resolution with cost markups to approximate the entire high-voltage network. Compared to their focus on cross-border lines, the results in this chapter highlight the importance of national transmission investments and network adaption requires less cross-border integration.

[bn EUR]	**Resolution**	**by 2030**	**2030–2050**	**Total**
Energy Roadmap 2050	by country	96.7–148.3	105.5–272.2	205.7–420.4
Tröster et al. (2011)	224 nodes	70–98	74–79	149–173
Fürsch et al. (2013)	224 nodes	70	144	214
This analysis	3,523 nodes	19–23.1	11.5–35	30.6–56.8

Table 7.9: Transmission cost comparison with other studies

[m EUR]	**before 2020**	**2021–2030**	**2031–2050**	**Total**
40%DEF	8,487	1,849	2,769	13,104
Reference	13,100	300	0	13,400
80%DEF	9,850	988	7,529	18,367
Diversified	21,900	9,700	600	32,200
80%GREEN	8,652	2,573	6,262	17,488
High RES	21,900	21,200	50,800	93,900

Table 7.10: Interconnector investments in the model results and in the Energy Roadmap 2050

Another point of divergence is the timing of investments: similar to the model results, network investment costs in the Energy Roadmap 2050 increase for the decarbonization scenarios in future decades and remain on the same level between 2030 and 2050. However, the numbers do not predict the large upfront investments by 2020 and the low investment levels between 2020 and 2030. For Tröster et al. (2011) and Fürsch et al. (2013), investment needs are higher between 2030 and 2050 than they are between 2010 and 2030, especially when North Africa is included.

The assessment of cross-border interconnector investment (Table 7.10) shows differences in the results between our model results and the Energy Roadmap 2050.[115] While results are quite similar in the 40%DEF scenario, they already diverge for the 80%DEF scenario, and particularly so for the 80%GREEEN scenario. As was

[115] No separate information on the investments in cross-border lines can be found in Tröster et al. (2011) and Fürsch et al. (2013). Therefore their results are not compared.

shown in the previous subsection, our model results indicate quite modest levels of HVAC and HVDC interconnectors, and focus primarily on the early period (before 2020). On the contrary, the European Roadmap 2050 not only has 2.5 times more investment in this period (21.9bn EUR), but this even increases to 50.8bn EUR for the period 2031 to 2050. In the high RES scenario of the Energy Roadmap 2050, 67.5 GW of investments in offshore connectors in the North and Baltic Seas region (2030 to 2050) are stated, that are determined by exogenous assumptions. In our model results of the 80%GREEN scenario, HVDC lines for offshore wind connection to the HVAC grid are not included and the the rather high interconnector investments of the Roadmap's high RES scenario are not observed.

In addition, the network architecture between the two models diverges significantly: while our results suggest only a very modest HVDC expansion, the Energy Roadmap 2050 sites HVDC lines all over Europe. This is in line with the results from Tröster et al. (2011) where investments in HVDC interconnectors are two to three times higher than in HVAC lines. In contrast, Fürsch et al. (2013) see equal investments in HVAC and HVDC lines.

In the results of this analysis, it is not clear whether renewables are really a main driver of (cross-border) network expansion; rather, it seems that the change in the spatial allocation of conventional generation technologies (i.e., nuclear and CCTS technology) is also a major driver of transmission investment.

Our findings show that in Europe transmission investment for renewable integration is only a fraction of generation investments. This must not be the case everywhere, as a recently conducted grid and investment project "CREZ" in Texas (US) shows. Even though our results show similar investment cost per line km, investment needs are different. The investments are mainly planned to integrate 11 GW of wind capacity in the north to load centers in central and east Texas (ERCOT, 2014). Approximating the investment cost for the wind turbine capacity at around 20bn USD, transmission investments make up nearly a third of the total cost. This difference could be explained in part by the fact that in Europe wind and solar potentials are much closer to the demand centers. Hence less distance has to be covered by the transmission grid.

7.5 Conclusion

In this chapter, we present a comprehensive model of the European electricity sector, with a focus on network expansion in different CO_2-mitigation scenarios. The specificity of the model is the spatial disaggregation of the European electricity system, represented by 3,523 nodes and 5,145 lines. The results are compared to the Energy

Roadmap 2050, the benchmark developed for and used by the European Commission

Our results diverge from most of the available literature, including the Energy Roadmap 2050, in that we find more intra-national HVAC transmission expansion, fewer cross-border interconnector lines, and a very modest level of HVDC transmission expansion. The high granularity of our model allows a differentiation between domestic and cross-border investment. It turns out that, in all scenarios, national investments are two to three times more important than cross-border interconnectors (in km). While national networks have the character of copperplates in the initial HVAC network, they require additional investments to adapt to the changing generation portfolios. Our model also suggests that transmission expansion should take place early (i.e., by 2020) and follow up with additional expansion in the high mitigation scenarios between 2030 and 2050. Overall, the investment levels are quite modest: even in the high-mitigation scenarios (80% CO_2 reduction), total investments do not exceed 57bn EUR, which corresponds to less than 2bn EUR per year Europe-wide. The model limitations mostly suggest that the model results provide a lower bound for network investment. However, considering other options for renewable integration like storage capacity or the utilization of demand response could also reduce the level of network investment.

Altering the cross-border transmission cost provides insights in the regional structure of the scenarios. In the case of higher cross-border transmission costs we show that the 80%GREEN scenario has a European character as investment levels in HVAC lines remain on a similar level. It is more robust than the 80%DEF scenario where the relative decrease in investment levels is highest (national character). HVDC investments are more sensitive to the higher cost assumptions due to their cross-border character.

A comparison with the Energy Roadmap 2050 shows significant differences in structural and financial terms: our model focuses on domestic upgrades and newbuilds, and our investments in interconnectors (17bn EUR) are less than one fifth of those in the Roadmap (94bn EUR). In addition, we find neither an overlay backbone HVDC network nor significant HVDC lines at all, but rather a few HVDC lines across the North Sea and the Baltic Sea. Finally, there seems to be no difference whether the low-carbon generation is from renewable or conventional capacity (e.g., nuclear and CCTS).

The chapter suggests that i) a spatial differentiation of the electricity sector improves the understanding of the nature of transmission expansion; and ii) while some transmission expansion is required for a low-carbon transformation, its importance is modest, in particular when compared to the huge efforts required for low-carbon electricity generation.

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Appendix to Chapter 2: GAMS code of ELMOD-DE

ELMOD-DE model: master execution file

```
$ontext
Electricity Model for Germany in 2012 (ELMOD-DE 2012).
Version 1.0, March 2016.
Written by Jonas Egerer.
This work is licensed under the MIT License (MIT).
For more information on this license, visit
http://opensource.org/licenses/mit-license.php.
Whenever you use this code, please refer to http://www.diw.de/elmod.
The model is documented in Egerer, J. (2016):
"Open source Electricity Model for Germany (ELMOD-DE)"
DIW Data Documentation 83
We are happy to receive feedback under je@wip.tu-berlin.de
$offtext

*------------------------------------------------------------------------*
*                            Global options                              *
*------------------------------------------------------------------------*

* Set star to either use excel or gdx dataload
$setglobal Excel_dataload "*"
$setglobal GDX_dataload ""


* Define start and end week for the loop with model runs (1-53)
Scalar
Wmin     Start model run at week number of Wmin         /  1 /
Wmax     Stop  model run at week number of Wmax         / 53 /
;
```

```
*------------------------------------------------------------------------*
*                            Solver options                              *
*------------------------------------------------------------------------*
options
reslim = 10000000 ,
lp = cplex ;

option
dispwidth = 15    ,
limrow    = 0           ,
limcol    = 0           ,
solprint  = off   ,
sysout    = off ,
threads   = 0     ;

$ONMulti

*------------------------------------------------------------------------*
*                              Execution                                 *
*------------------------------------------------------------------------*

*Include the following GAMS files
$INCLUDE setup.gms
$INCLUDE data.gms
$INCLUDE model.gms

**Definition of first and last hour of the first week in 2012 (So-Fr)
Low  =   1                                                           ;
High = 144                                                           ;

**Starting loop for weekly model runs
loop(w$(ord(w)>=Wmin and ord(w)<=Wmax),

**Define hours included in the weekly model run
         TT(t)=no                                                    ;
         TT(t)$TW(t,w)=yes                                           ;

**Data for hours of the weekly model run
         GMAX(p,t)  = input_gen(p,t)                $TW(t,w)         ;
         RMAX(n,t)  = sum(tech,input_res(n,tech,t)) $TW(t,w)         ;
         LOAD(n,t)  = input_load(n,t)               $TW(t,w)         ;
         EX(n,t)    = input_export(t,n)             $TW(t,w)         ;
         IM(n,t)    = input_import(t,n)             $TW(t,w)         ;
         MC(p,t)    = input_mc(p,t)                 $TW(t,w)         ;

**Fixing storage level to zero in first and last hour of week
         level.fx(s,t)$(ord(t)=TWL(w) or ord(t)= TWH(w)) = 0         ;
```

```
**Fixing other generation technologies to output level
         gen.fx(p,t)$(TT(t) and sum((cou,n,sta,dena,z6,fuel),
                Plant_con(p,cou,n,sta,dena,z6,'oth',fuel,'cap')))
                                 = GMAX(p,t)                        ;

****Solve and output*************************************************

         solve ELMOD_DE using lp minimizing cost                    ;

**Export data of model run
         result_price(n,t)       $TT(t) = energybalance.m(n,t)      ;
         result_conventional(p,t)$TT(t) = gen.l(p,t)                ;
         result_storage_gen(s,t) $TT(t) = storG.l(s,t)              ;
         result_storage_pump(s,t)$TT(t) = storP.l(s,t)              ;
         result_storage_lev(s,t) $TT(t) = level.l(s,t)              ;
         result_renewable(n,t)   $TT(t) = res.l(n,t)                ;
         result_voll(n,t)        $TT(t) = voll.l(n,t)               ;
         result_flows(l,t)       $TT(t) = pf.l(l,t) * MVABase       ;
         result_delta(n,t)       $TT(t) = delta.l(n,t)              ;
         result_cost(w)                 = cost.l                    ;
**Clear data of model run
         option clear=objective                                     ;
         option clear=generation                                    ;
         option clear=renewables                                    ;
         option clear=lineflow                                      ;
         option clear=linecap_pos                                   ;
         option clear=linecap_neg                                   ;
         option clear=slackfunct                                    ;
         option clear=energybalance                                 ;
         option clear=storage1                                      ;
         option clear=storage2                                      ;
         option clear=storage3                                      ;
         option clear=storage4                                      ;
         option clear=cost                                          ;
         option clear=pf                                            ;
         option clear=delta                                         ;
         option clear=gen                                           ;
         option clear=res                                           ;
         option clear=level                                         ;
         option clear=storG                                         ;
         option clear=storP                                         ;
         option clear=voll                                          ;
         option clear=GMAX                                          ;
         option clear=RMAX                                          ;
         option clear=LOAD                                          ;
         option clear=EX                                            ;
```

```
         option clear=IM                                                  ;
         option clear=MC                                                  ;
**Confirm that hours and week has been solved
         TR(t)$TT(t)  = yes                                               ;
         WR(w)        = yes                                               ;
);

* Solver options
$onecho > cplex.opt
lpmethod 4
threads 1
$offecho

execute_unload 'results_ELMOD_DE',
result_price
result_conventional
result_storage_gen
result_storage_pump
result_storage_lev
result_renewable
result_voll
result_flows
result_delta
result_cost
TR
WR    ;
```

ELMOD-DE model: setup file for scalars, sets, alias and parameters

```
*------------------------------------------------------------------------*
*                  SCALARS, SETS, ALIAS, and PARAMETERS                  *
*------------------------------------------------------------------------*

*------------------------------------------------------------------------*
*                                Scalars                                 *
*------------------------------------------------------------------------*

scalars
MVABase    Base for per unit calculation               /    500   /
kVBase1    Voltage level [380 kV]                      /    380   /
kVBase2    Voltage level [220 kV]                      /    220   /
TRM        transm. reliability margin [%]              /     20   /
VLL        value non-served (lost) load [EUR by MWh]   /   3000   /
;
```

```
*------------------------------------------------------------------------*
*                              Sets                                      *
*------------------------------------------------------------------------*
sets
****sets in model setup**************************************************
l          ac transmission lines
n          network nodes
p          power plant block
s          pumped-storage plant
t          hours

****sets for time blocks*************************************************
w          weeks included in model run           /   w01 *    w53  /
m          months                                /   m01 *    m12  /

****sets for data import*************************************************
node       nodal input data         / share_l, share_h,
                                      ror, pv, on, off, bio, geo
                                      long, lati                   /
net        network data             / resistance, reactance,
                                      power, voltage, circuits     /
con        conventional data        / cap, eff, co2, coal          /
psp        pumped-storage data      / cap, eff, sto                /
time       national time series     / nuc, lig, coal, ccgt, gas,
                                      oil, oth, was, ror, bio, geo /
ren        renewable technologies   / ror, bio, onW, ofW, pv, geo  /

****sets for output******************************************************
cou        country
sta        state
dena       DENA zones in Germany
z6         six reporting zones
tech       generation technology
fuel       generation fuel
;
*------------------------------------------------------------------------*
*                             Alias                                      *
*------------------------------------------------------------------------*

alias    (n, nn)
;
*------------------------------------------------------------------------*
*                        Defining Parameters                             *
*------------------------------------------------------------------------*
parameters
****for dataload*********************************************************
Node_data(n,cou,sta,dena,z6,node)            nodal input data
```

```
Grid_technical(l,net)                        line data
Grid_topology(l,n)                           line topology
Plant_con(p,cou,n,sta,dena,z6,tech,fuel,con) power plant data
Plant_psp(s,cou,n,sta,dena,z6,psp)           storage data
H_demand(t)                                  hourly demand DE
input_import(t,n)                            hourly nodal import
input_export(t,n)                            hourly nodal export
H_price(t,fuel)                              hourly fuel prices
H_co2(t)                                     hourly CO2 prices
H_con(t,tech)                                hourly availability tech
H_wind(t,dena)                               hourly availability wind
H_pv(t,dena)                                 hourly availability PV

****for time************************************************************
Low                     counter #1 for hours
High                    counter #2 for hours
TT(t)                   hours for model runs
TW(t,w)                 mapping hour to week
TM(t,m)                 mapping hour to month
TWL(w)                  first hour of week
TWH(w)                  last hour of week
TR(t)                   hours with model results
WR(w)                   weeks with model results
MR(m)                   months with model results
Hours_run               number of hours in results

****for demand**********************************************************
input_load(n,t)         demand in node n at time d and t
Share_H(n)              nodal demand share for peak hour
Share_L(n)              nodal demand share for off-peak hour
Load(n,t)               demand in node n at time d and t
Load_min                lowest hourly demand
Load_max                highest hourly demand
Demand_Function(n)      demand function for hourly nodal level

****for transmission ****************************************************
Resistance(l)           resistance of line l
Reactance(l)            reactance of line l
LineVoltage(l)          voltage level of line l (220 380)
Circuits(l)             number of parallel line circuits
PFLimit(l)              maximum of thermal line capacity
Incidence(l,n)          incidence matrix of the system
H(l,n)                  flow sensivity matrix
B(n,nn)                 network susceptance matrix
BVector(l)              line series susceptance
Slack(n)                reference node DC load flow
ZBase1                  base 1 (380 kV) for p.u. calculation
```

```
ZBase2                  base 2 (220 kV) for p.u. calculation
IM(n,t)                 fixed import flows in model run
EX(n,t)                 fixed export flows in model run

****for generation ******************************************************
input_gen(p,t)          all hourly data on conventional generation
input_res(n,tech,t)     all hourly data on renewable generation
input_mc(p,t)           all hourly data on marginal costs
GenN(p,n)               mapping of power plants and nodes
GMAX(p,t)               model input data on conventional generation
RMAX(n,t)               model input data on renewable generation
MC(p,t)                 model input data on marginal cost
StorN(s,n)              mapping of pumped-storage and nodes
StorC(s)                installed capacity (pumping and generation)
StorE(s)                available pumped-storage size
StorEff(s)              cycle efficiency of pumped-storage plant

****for reporting *******************************************************
result_price(n,t)
result_conventional(p,t)
result_storage_gen(s,t)
result_storage_pump(s,t)
result_storage_lev(s,t)
result_renewable(n,t)
result_voll(n,t)
result_flows(l,t)
result_delta(n,t)
result_cost(w)     ;
```

ELMOD-DE model: data upload and processing file

```
*------------------------------------------------------------------------*
*                          Loading Data                                  *
*------------------------------------------------------------------------*

****Excel upload*********************************************************

%Excel_dataload%$ontext

$call "gdxxrw Data_Input.xlsx @data_input.txt o=Data_input.gdx ";

$GDXin Data_input.gdx
$load n, p, s, l, t, cou, sta, dena, z6, tech, fuel
$load Node_data
$load Grid_technical, Grid_topology
```

```
$load Plant_con, Plant_psp
$load H_demand, input_import, input_export, H_price, H_co2
$load H_con, H_wind, H_pv

$ontext
$offtext

****GDX upload*************************************************************
%GDX_dataload%$ontext

$gdxin Data_input.gdx
$load n, p, s, l, t, cou, sta, dena, z6, tech, fuel
$load Node_data
$load Grid_technical, Grid_topology
$load Plant_con, Plant_psp
$load H_demand, input_import, input_export, H_price, H_co2
$load H_con, H_wind, H_pv
;

$ontext
$offtext

*------------------------------------------------------------------------*
*                          Data Processing                               *
*------------------------------------------------------------------------*
*------------------------------------------------------------------------*
*                              Time                                      *
*------------------------------------------------------------------------*
***Month*******************************************************************
TM(t,'m01')$(ord(t)<=744)=yes ;
TM(t,'m02')$(ord(t)>744  and ord(t)<=1440)=yes ;
TM(t,'m03')$(ord(t)>1440 and ord(t)<=2184)=yes ;
TM(t,'m04')$(ord(t)>2184 and ord(t)<=2904)=yes ;
TM(t,'m05')$(ord(t)>2904 and ord(t)<=3648)=yes ;
TM(t,'m06')$(ord(t)>3648 and ord(t)<=4368)=yes ;
TM(t,'m07')$(ord(t)>4368 and ord(t)<=5112)=yes ;
TM(t,'m08')$(ord(t)>5112 and ord(t)<=5856)=yes ;
TM(t,'m09')$(ord(t)>5856 and ord(t)<=6576)=yes ;
TM(t,'m10')$(ord(t)>6576 and ord(t)<=7320)=yes ;
TM(t,'m11')$(ord(t)>7320 and ord(t)<=8040)=yes ;
TM(t,'m12')$(ord(t)>8040 and ord(t)<=8784)=yes ;

***Weeks*******************************************************************
Low  =   1                                                                ;
High = 144                                                                ;

loop(w,
```

```
        TW(t,w)=no                                                    ;
        TW(t,w)$(ord(t)>=Low and Ord(t)<= High)=yes                   ;
        TWL(w)  = Low                                                 ;
        TWH(w)  = High                                                ;
        Low$(ord(w)=1)   = High + 1                                   ;
        High$(ord(w)=1)  = High + 168                                 ;
        Low$(ord(w)>1)   = Low  + 168                                 ;
        High$(ord(w)>1)  = High + 168                                 ;
        High$(High>8784)=8784                                         ;
);

*---------------------------------------------------------------------*
*                       Transmission Network                          *
*---------------------------------------------------------------------*
ZBase1 = (kVBase1 *1E3)**2 / (MVABase * 1E6)                          ;
ZBase2 = (kVBase2 *1E3)**2 / (MVABase * 1E6)                          ;

LineVoltage(l)    = Grid_technical(l,'voltage')                       ;
Circuits(l)       = Grid_technical(l,'circuits')                      ;

Resistance(l)     = Grid_technical(l,'resistance')
                    / ( ZBase1 $ ( LineVoltage(l) eq 380 )
                      + ZBase2 $ ( LineVoltage(l) eq 220 ) )
                      / Circuits(l)                                   ;

Reactance(l)      = Grid_technical(l,'reactance')
                    / ( ZBase1 $ ( LineVoltage(l) eq 380 )
                      + ZBase2 $ ( LineVoltage(l) eq 220 ) )
                      / Circuits(l)                                   ;

PFLimit(l)        = Grid_technical(l,'power')
                      * Circuits(l) * ( 1 - TRM / 100 )               ;

Incidence(l,n)    = Grid_topology(l,n)                                ;

BVector(l) = Reactance(l)
               / ( SQR( Reactance(l) ) + SQR( Resistance(l) ) )       ;

H(l,n)   = BVector(l) * Incidence(l,n)                                ;
B(n,nn) = SUM(l, Incidence(l,n) * H(l,nn) )                           ;

Slack('n235')     =  1                                                ;

option clear=Grid_technical                                           ;
```

```
*----------------------------------------------------------------------*
*                               Demand                                 *
*----------------------------------------------------------------------*
Load_Max = smax(t, H_demand(t))                                        ;
Load_Min = smin(t, H_demand(t))                                        ;

Share_H(n) = sum((cou,sta,dena,z6),
                            Node_data(n,cou,sta,dena,z6,'share_H') ) ;

Share_L(n) = sum((cou,sta,dena,z6),
                            Node_data(n,cou,sta,dena,z6,'share_L') ) ;

Demand_Function(n) = ( Share_H(n) - Share_L(n) )
                       / ( Load_Max - Load_Min )                       ;

input_load(n,t)    = ( Share_L(n) + ( H_demand(t) - Load_Min )
                       * Demand_Function(n) ) * H_demand(t)            ;

option clear=H_demand                                                  ;

*----------------------------------------------------------------------*
*                            Set Generation                            *
*----------------------------------------------------------------------*

****Conventional Plants***********************************************
GenN(p,n)
= yes$sum((cou,sta,dena,z6,tech,fuel),
                Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'cap') )      ;

loop(tech,
       input_gen(p,t)$sum((cou,n,sta,dena,z6,fuel),
                     Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'cap'))
       = H_con(t,tech)
         * sum((cou,n,sta,dena,z6,fuel),
                     Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'cap'))
);

loop(fuel,
      input_mc(p,t)$sum((cou,n,sta,dena,z6,tech),
                     Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'eff'))
                         = H_price(t,fuel)
      / sum((cou,n,sta,dena,z6,tech),
                     Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'eff'))
      + H_co2(t)
      * sum((cou,n,sta,dena,z6,tech),
                     Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'co2'))
```

```
      + sum((cou,n,sta,dena,z6,tech),
                     Plant_con(p,cou,n,sta,dena,z6,tech,fuel,'coal'))
);

option clear=H_price                                                   ;
option clear=H_co2                                                     ;

***Storage************************************************************
StorN(s,n) = yes$sum((cou,sta,dena,z6),
                              Plant_psp(s,cou,n,sta,dena,z6,'cap'))   ;
StorC(s)   = sum((cou,n,sta,dena,z6),
                              Plant_psp(s,cou,n,sta,dena,z6,'cap'))   ;
StorE(s)   = sum((cou,n,sta,dena,z6),
                              Plant_psp(s,cou,n,sta,dena,z6,'sto'))   ;
StorEff(s) = sum((cou,n,sta,dena,z6),
                              Plant_psp(s,cou,n,sta,dena,z6,'eff'))   ;

***Renewables*********************************************************
*Wind onshore and PV
input_res(n,'on',t)
  = sum((cou,sta,dena,z6),
                Node_data(n,cou,sta,dena,z6,'on') * H_wind(t,dena) ) ;

input_res(n,'pv',t)
  = sum((cou,sta,dena,z6),
                Node_data(n,cou,sta,dena,z6,'pv') * H_pv(t,dena) )   ;

*Wind offshore in North and Baltic Seas
input_res(n,'off',t)$sum((cou,sta,z6),
        Node_data(n,cou,sta,'21',z6,'OFF'))
      = sum((cou,sta,z6), Node_data(n,cou,sta,'21',z6,'OFF') )
                                                  * H_wind(t,'20')     ;
input_res(n,'off',t)$sum((cou,sta,z6),
        Node_data(n,cou,sta,'22',z6,'OFF'))
      = sum((cou,sta,z6), Node_data(n,cou,sta,'22',z6,'OFF') )
                                                  * H_wind(t,'20')     ;
input_res(n,'off',t)$sum((cou,sta,z6),
        Node_data(n,cou,sta,'81',z6,'OFF'))
      = sum((cou,sta,z6), Node_data(n,cou,sta,'81',z6,'OFF') )
                                                  * H_wind(t,'80')     ;

*Hydropower, biomass, and geothermal
input_res(n,'ror',t) = sum((cou,sta,dena,z6),
        Node_data(n,cou,sta,dena,z6,'ror') * H_con(t,'ror') )         ;
input_res(n,'bio',t) = sum((cou,sta,dena,z6),
        Node_data(n,cou,sta,dena,z6,'bio') * H_con(t,'bio') )         ;
input_res(n,'geo',t) = sum((cou,sta,dena,z6),
```

```
        Node_data(n,cou,sta,dena,z6,'geo') * H_con(t,'geo') )        ;

*Table: 1=Wind und 2=PV monthly installed capacity [%] end of 2012
Table Extend(m,*)
          c1      c2
 m01   0.935   0.779
 m02   0.940   0.786
 m03   0.946   0.823
 m04   0.952   0.834
 m05   0.958   0.842
 m06   0.964   0.897
 m07   0.970   0.914
 m08   0.976   0.924
 m09   0.982   0.954
 m10   0.988   0.973
 m11   0.994   0.986
 m12   1.000   0.997
 ;

input_res(n,'on',t)
               = input_res(n,'on',t) * sum(m$TM(t,m),Extend(m,'c1')) ;
input_res(n,'pv',t)
               = input_res(n,'pv',t) * sum(m$TM(t,m),Extend(m,'c2')) ;

option clear=H_wind                                                  ;
option clear=H_pv                                                    ;
option clear=H_con                                                   ;
```

ELMOD-DE model: setup file for model equations

```
*----------------------------------------------------------------------*
*                          MODEL SETUP                                  *
*----------------------------------------------------------------------*
*----------------------------------------------------------------------*
*                           Variables                                   *
*----------------------------------------------------------------------*
variables
cost                    dispatch cost in the system
pf(l,t)                 line flow on ac lines on line l and hour t
delta(n,t)              voltage angle difference at node n in hour t ;

positive variables
gen(p,t)                generation of plant block p in hour t
res(n,t)                renewable generation at node n in hour t
level(s,t)              energy content in storage s in hour t
```

```
storG(s,t)              generation of storage s in hour t
storP(s,t)              demand of storage s in hour t
voll(n,t)               unserved load at node n in hour t                ;

*----------------------------------------------------------------------*
*                              Equations                                *
*----------------------------------------------------------------------*
equations
objective               objective function
generation              conventional generation
renewables              renewable generation
lineflow                line flow on transmission lines
linecap_pos             upper limit (+) line flow
linecap_neg             lower limit (-) line flow
slackfunct              voltage angle fixed for slack bus
energybalance           balance of supply and demand
storage1                pumped-storage generation limit
storage2                pumped-storage pumping limit
storage3                pumped-storage storage limit
storage4                pumped-storage energy balance                    ;

*----------------------------------------------------------------------*
*Objective function                                          *Equation No
*                                                                  (1.1)
objective..

 cost =E= (sum((p,t)$(GMAX(p,t) and TT(t)), MC(p,t) * gen(p,t) )
                         + sum((n,t), voll(n,t) * VLL) )                 ;

**Energy balance                                                   (1.2)
energybalance(n,t)$TT(t)..

 sum(p$(GenN(p,n)*GMAX(p,t)), gen(p,t) )
  + res(n,t)$Rmax(n,t)
  + IM(n,t)
  + sum(s$StorN(s,n), storG(s,t) )
  + sum((nn)$B(n,nn), B(n,nn) * delta(nn,t) ) * MVABase

           =E=   Load(n,t)
                 - voll(n,t)$Load(n,t)
                 + EX(n,t)
                 + sum(s$StorN(s,n), storP(s,t) )                        ;


*Generation contraints                                             (1.3a)
generation(p,t)$(GMAX(p,t) and TT(t))..
```

```
 gen(p,t) =L= GMAX(p,t)                                               ;

*                                                                (1.3b)
renewables(n,t)$(Rmax(n,t) and TT(t))..

 res(n,t) =L= RMAX(n,t)                                               ;

**Pumped-storage hydroelectricity                                (1.4a)
Storage1(s,t)$TT(t)..

 storG(s,t) =l= StorC(s)                                              ;

*                                                                (1.4a)
Storage2(s,t)$TT(t)..

 storP(s,t) =l= StorC(s)                                              ;

*                                                                (1.4b)
Storage3(s,t)$TT(t)..

 level(s,t) =l= StorE(s)                                              ;

*                                                                (1.4c)
Storage4(s,t)$TT(t)..

 level(s,t+1) =e= level(s,t) + storP(s,t) * StorEff(s) - storG(s,t)  ;

*DC load flow representation                                     (1.5a)
linecap_pos(l,t)$TT(t)..

 pf(l,t) * MVABase =L= + PFlimit(l)                                   ;

*                                                                (1.5a)
linecap_neg(l,t)$TT(t)..

 pf(l,t) * MVABase =G= - PFLimit(l)                                   ;

*                                                                (1.5b)
lineflow(l,t)$TT(t)..

 pf(l,t) =E= sum( n$H(l,n), H(l,n) * delta(n,t) )                     ;

*                                                                (1.5d)
slackfunct(n,t)$(Slack(n)*TT(t))..

 Slack(n) * delta(n,t) =E= 0                                          ;
```

```
*------------------------------------------------------------------------*
*                         Model definition                               *
*------------------------------------------------------------------------*
model ELMOD_DE /
objective
generation
renewables
lineflow
linecap_pos
linecap_neg
slackfunct
energybalance
storage1
storage2
storage3
storage4
/;
```