Modeling an Integrated Energy Transformation of the Electricity Sector

An Open-source Analysis for Germany

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Technische Universität Berlin

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An Open-Source Analysis for Germany

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Abstract

This thesis addresses research questions and implications in the context of the German and European energy transformation and is comprised of three parts:

Part I starts with a chapter providing an introduction to the topic. Chapter 2 then focuses on the topic of "sector coupling" and the technical and economic challenges of coupling electricity, heat, and transportation, in order to further transform towards a system relying on renewables instead of fossil and fissil fuels as a primary source of energy. For Germany some practical quantitative scenarios for sector coupling until 2030 and 2050 are being discussed.

Part II deals with economic dispatch modeling. In Chapter 3, a five-fold approach to open science is introduced and the advantages of open energy models are being discussed. A fully open-source bottom-up electricity sector model with high spatial resolution using the Julia programming environment is then developed describing source code and a data set for Germany. Following the open approach, the entire model code and used data set are publicly available and open-source solvers like ECOS and CLP are used. The model is then benchmarked regarding runtime of building and solving against a representation in GAMS as a commercial algebraic modeling language and against Gurobi, CPLEX, and Mosek as commercial solvers. Chapter 4 examines the ongoing discussion about potential effects of introducing bidding zones in Germany. An electricity sector model with network representation is applied to analyze the system implications and the distributional effects of two bidding zones in the German electricity system in 2012 and 2015. Results show a modest decrease in cross-zonal re-dispatch levels, particularly in 2015. However, overall network congestion and re-dispatch levels increase in 2015 and also remain on a high level in case of two bidding zones. Results are very sensitive to more than two bidding zones and additional line investments, illustrating the challenge to define stable price zones in a dynamic setting. Chapter 5 investigates the impact of uncertain photovoltaic generation on unit commitment decisions. This is done for a market following the rolling planning procedure employing a large-scale stochastic electricity market model (*stELMOD*). A novel approach to simulate a time-adaptive intra-day photovoltaic forecast, solely based on an exponential smoothing of

deviations between realized and forecast values, is presented. Generation uncertainty is then incorporated by numerous multi-stage scenario trees that account for a decreasing forecast error over time. Results show that total system costs significantly increase when uncertainty of both wind and photovoltaic generation is included by a single forecast, with more frequent starting processes of flexible plants and rather inflexible power plants mainly deployed at part-load. Including the improvement of both wind and photovoltaic forecasts, the scheduling costs can be significantly reduced.

Part III shifts the focus to issues of the decentral energy transformation. In Chapter 6, the interdependencies between transmission line infrastructure and the electricity mix are being assessed. In particular, it is tested how an energy system based on 100 % renewable sources operates under different transmission regimes, for example, copper plate or more constrained network topologies. A stylized model of optimal generation and storage investment and operation for the German electricity system is being developed. The few cases of transmission congestion in the results suggest that a high share of renewables can be accommodated by modest grid expansions and a large amount of short-term and long-term storage capacities. Chapter 7 deals with local electricity markets. Implications of recently proposed market designs under the current rules in the German market are tested using a simplistic equilibrium model representing heterogeneous market participants in an energy community with their respective objectives. We find that these proposed designs are financially unattractive to prosumers and consumers under the current regulatory framework and they even cause distributional effects within the community when local trade and self-consumption are exempt from taxes. Therefore, a novel market design is being introduced that allows for ownership and participation of renewable technologies for all community members. The analysis shows that this design has the potential to mitigate both distributional effects and the avoidance of system service charges, while simultaneously increasing end-user participation.

The dissertation shows approaches and methodologies to overcome techno-economic challenges of the transformation towards renewable energy opening up even further research possibilities.

Keywords: German electricity market; decarbonization; renewable energy sources; sector coupling; electricity market design; distributional effects; congestion management; energy communities; power systems modeling; dispatch and investment cost modeling; DC power flow modeling; uncertainty; open source

Zusammenfassung

Diese Arbeit befasst sich mit Forschungsfragen und Implikationen im Kontext der deutschen und europäischen Energiewende und besteht aus drei Teilen:

Teil I beginnt mit einem einführenden Kapitel zur Anwendung mathematisch-quantitativer Methoden auf Strommärkte. Kapitel 2 konzentriert sich dann auf das Thema „Sektorenkopplung“ und die technischen und wirtschaftlichen Herausforderungen der Kopplung von Strom, Wärme und Verkehr, um die Transformation zu einem System voranzutreiben, das auf erneuerbare Energien statt auf fossile und fissile Brennstoffe setzt. Für Deutschland werden einige quantitative Szenarien für die Sektorenkopplung bis 2030 und 2050 diskutiert.

Teil II befasst sich mit der ökonomischen Dispatch-Modellierung. In Kapitel 3 wird ein fünfdimensionaler Ansatz zur offenen Wissenschaft vorgestellt und die Vorteile offener Energiemodelle diskutiert. Anschließend wird ein Bottom-up-Stromsektormodell mit hoher räumlicher Auflösung unter Verwendung der Programmiersprache Julia entwickelt. Dem offenen Ansatz folgend, sind der gesamte Modellcode und der verwendete Datensatz öffentlich verfügbar, und es werden Open-Source-Solver wie ECOS und CLP verwendet. Das Modell wird dann hinsichtlich der Erstellungs- und Lösungslaufzeit mit einer Darstellung in GAMS als kommerzielle algebraische Modellierungssprache und mit Gurobi, CPLEX und Mosek als kommerzielle Solver verglichen. Kapitel 4 untersucht die Diskussion über mögliche Auswirkungen der Einführung von Preiszonen in Deutschland. Ein Stromsektormodell mit Netzdarstellung wird angewandt, um die Systemauswirkungen und Verteilungseffekte von zwei Preiszonen im deutschen Stromsystem in den Jahren 2012 und 2015 zu analysieren. Die Ergebnisse zeigen einen kleinen Rückgang der zonenübergreifenden Redispatchmengen. Allerdings nehmen die Netzengpässe und Redispatchmengen insgesamt im Jahr 2015 zu und bleiben auch im Falle von zwei Preiszonen auf einem hohen Niveau. Die Ergebnisse reagieren sehr empfindlich auf mehr als zwei Preiszonen und zusätzliche Leitungsinvestitionen. Dies veranschaulicht die Herausforderung, stabile Preiszonen in einem dynamischen Umfeld zu definieren. Kapitel 5 untersucht die Auswirkungen einer unsicheren Photovoltaik-Erzeugung auf Unit-Commitment-Entscheidungen. Dies geschieht für einen Markt nach

dem rollierenden Planungsverfahren unter Verwendung eines stochastischen Strommarktmodells (*stELMOD*). Ein neuartiger Ansatz zur Simulation einer zeitadaptiven untertägigen Photovoltaik-Prognose wird vorgestellt. Die Erzeugungsunsicherheit wird dann durch zahlreiche mehrstufige Szenariobäume berücksichtigt, die einen abnehmenden Prognosefehler im Laufe der Zeit simulieren. Die Ergebnisse zeigen, dass die Systemkosten erheblich steigen, wenn die Unsicherheit sowohl der Wind- als auch der Photovoltaik-Erzeugung in einer einzigen Prognose berücksichtigt wird. Werden die Verbesserung beider Prognosen berücksichtigt können die Kosten erheblich gesenkt werden.

Teil III verlagert den Schwerpunkt auf Fragen der dezentralen Energiewende. In Kapitel 6 werden die Interdependenzen zwischen der Übertragungsleitungsinfrastruktur und dem Strommix bewertet. Insbesondere wird getestet, wie ein Energiesystem, das zu 100 % auf erneuerbaren Energien basiert, unter verschiedenen Übertragungsregimen funktioniert. Es wird ein Modell der optimalen Investition und des optimalen Betriebs von Erzeugung und Speicherung für das deutsche Elektrizitätssystem entwickelt. Die wenigen Fälle von Übertragungsengpässen in den Ergebnissen deuten darauf hin, dass ein hoher Anteil erneuerbarer Energien durch geringe Netzausbauten und eine große Menge an kurz- und langfristigen Speicherkapazitäten bewältigt werden kann. Kapitel 7 befasst sich mit lokalen Strommärkten. Es werden die Implikationen vorgeschlagener Marktgestaltungen unter dem derzeitigen deutschen Marktdesign getestet. Die Analyse wird durch ein vereinfachtes Gleichgewichtsmodell durchgeführt. Die Ergebnisse zeigen, dass die Designs für Prosumenten und Verbraucher unter dem gegenwärtigen Regulierungsrahmen finanziell unattraktiv sind und sogar Verteilungseffekte innerhalb der Gemeinschaft verursachen können. Daher wird ein neues Marktdesign eingeführt, das den Besitz und die Teilnahme an erneuerbaren Technologien für alle Gemeindemitglieder ermöglicht. Die Analyse zeigt, dass dieses Design das Potenzial hat, sowohl Verteilungseffekte als auch die Vermeidung von Systemdienstleistungsentgelten zu mildern und gleichzeitig die Beteiligung der Endnutzer zu erhöhen.

Die Dissertation zeigt Ansätze und Methoden zur Bewältigung der techno-ökonomischen Herausforderungen der Transformation hin zu erneuerbaren Energien auf, die weitere Forschungsmöglichkeiten eröffnen.

Schlagwörter: deutscher Strommarkt; Dekarbonisierung; erneuerbare Energien; Sektorenkopplung; Strommarktdesign; Verteilungseffekte; Engpassmanagement; Energiegemeinschaften; Energiesystemmodellierung; Einsatz- und Investitionskostenmodellierung; DC-Lastflussmodellierung; Unsicherheit; quelloffen

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From now on, everything will change—and some things will get better...

Overview

Contents

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List of Acronyms

AC . . . . alternating current

AC . . . . air conditioning

ACER . . . . European Agency for the Cooperation of Energy Regulators

BCE . . . . base case exchange

BEV . . . . battery electric vehicle

BMWi . . . . German Federal Ministry of Economic Affairs and Energy

BNetzA . . . . German Federal Network Agency

CCGT . . . . combined cycle gas turbines

CCOT . . . . combined cycle oil turbines

CCTS . . . . carbon capture, transport, and storage

CCU . . . . carbon capture and utilization

CHP . . . . combined heat and power

CM . . . . congestion management

CO_2 . . . . carbon dioxide

COMPET . . . . European Competitiveness Council

CSS . . . . closed-source software

CWE . . . . Central Western Europe

DA . . . . day-ahead

DC . . . . direct current

EEG . . . . Erneuerbare-Energien-Gesetz

EEX . . . . European Energy Exchange

EnWG . . . . Energiewirtschaftsgesetz

EU ETS . . . . EU Emissions Trading System

FBMC . . . . Flow-Based Market Coupling

FC(E)V . . . . fuel cell (electric) vehicle

GAMS . . . . General Algebraic Modeling System

GW . . . . gigawatt

GWh . . . . gigawatt hours

HEV . . . . hybrid electric vehicle

HVDC . . . . high-voltage direct-current

ICT . . . . information and communication technology

ID . . . . intra-day

IEM . . . . Internal Energy Market

IP . . . . integer problem

IPCC . . . . Intergovernmental Panel on Climate Change

IPP . . . . independent power producer

JMM . . . . Joint Market Model

JuMP . . . . Julia for Mathematical Programming

KKT . . . . Karush-Kuhn-Tucker condition

kV . . . . kilovolt

kWh . . . . kilowatt hour

kWp . . . . kilowatt peak

LCOE . . . . levelized cost of energy

LCOS . . . . levelized costs of storage

LEM . . . . local electricity market

lib . . . . lithium-ion battery

LMP . . . . locational marginal pricing

LP . . . . linear program

MaStR . . . . Markstammdatenregister

MCP . . . . mixed complementarity problem

MDG . . . . Millenium Development Goal

MILP . . . . mixed-integer linear problem

mio. . . . . million

MIP . . . . mixed-integer program

Mt . . . . megaton

MW . . . . megawatt

MWh . . . . megawatt hour

NDP . . . . network development plan

NGO . . . . non-governmental organization

NGV . . . . natural gas vehicle

NTC . . . . net transfer capacity

NUTS2 . . . . Nomenclature of Territorial Units for Statistics, Level 2

OCGT . . . . open cycle gas turbines

OCOT . . . . open cycle oil turbines

OPSD . . . . Open Power System Data

OR . . . . operations research

OSS . . . . open-source software

P2P . . . . peer-to-peer

PHES . . . . pumped hydroelectric energy storage

PHEV . . . . plug-in hybrid electric vehicle

PJM . . . . Pennsylvania-New Jersey-Maryland Interconnection

PSP . . . . pumped-storage plants

PTDF . . . . power transmission distribution factors

PtG . . . . power to gas

PtH . . . . power to heat

PtL . . . . power to liquid

PV . . . . photovoltaic

pv-open . . . . open-space photovoltaics

pv-roof . . . . rooftop photovoltaics

RES . . . . renewable energy sources

rfb . . . . redox flow battery

RMSE . . . . root-mean squared error

RoR . . . . run-of-river

SDG . . . . Sustainable Development Goal

stELMOD . . . . stochastic Electricity Market Model

TRM . . . . transmission reliability margin

TSO . . . . transmission system operator

TTC . . . . total transfer capacity

TWh . . . . terawatt hour

TYNDP . . . . Ten-Year Network Development Plan

UC . . . . unit commitment

UN . . . . United Nations

VSS . . . . value of stochastic solution

wind-off . . . . offshore wind

wind-on . . . . onshore wind

Part I

Introduction

Chapter 1

Operations Research and Modeling Electricity Markets and Grids

"Though this be madness, yet there is method in 't."

(William Shakespeare, Hamlet, Act 2, Scene 2, 205)

1.1 Motivation

In the ninth grade I was supposed to give a talk in my geography class. At the time I came across an article describing the idea of a silicon-based economy developed by a German chemist.[1] *Using renewable energy from solar and wind power, mainly in the North African desert, silicon dioxide (SiO_2)—the main component of sand—was to be split in its components silicon and oxygen. The silicon was then to be transported, for example, via ships, to Europe where it would be burnt together with nitrogen (N) in special power plants or even cars. The whole idea was sparked by an effect observed in a chemical plant in Burghausen some years ealier: Aside from releasing energy, the only residues from this reaction are quartz (SiO_2) and silicon nitride (Si_3N_4)—a substance used for the production of ammonia (NH_3), itself needed for the fabrication of azotic fertilizer. The ammonia could also be used for obtaining hydrogen in order to fuel an alternative future transportation system.*

In a nutshell, sand from the desert could be used to transport energy from areas with very high solar irradiation to load centers in Northern Europe, where solar power would be less efficient. Motorists would just need to return bags of sand to the gas station when refilling their silicon tanks. The whole process was still quite callow and extremely inefficient. But it was the year 2000 and the groundbreaking German renewable energies law Erneuerbare-Energien-Gesetz (EEG) had just come into force some months earlier, decreeing a system of long-running feed-in tariffs for renewable power plants. Having visited the Philippsburg nuclear power station with my father when I was a child, I was fascinated by the topic and decided to give my talk about a renewables based energy system.

Some years later the idea of using solar power from the North African desert was revived by the Trans-Mediterranean Renewable Energy Cooperation (TREC) on initiative of the Club of Rome—this time using high-voltage direct-current (HVDC) interconnections, a concept that later became widely known as Desertec. I learned about this during my studies at TU Berlin—it was even the topic of my final oral exam in my energy and resources focus courses when I was asked to deliberate on the question of ownership of the sun. During my studies I decided that I wanted to become an active part in the energy transformation and started to build solar panels on rooftops. When I finished my studies, I got the chance to further delve into the topic of a sustainable energy system and this dissertation is one step of that adventure.

[1] Manfred Dworschak. 2000. "Asche zu Asche, Sand zu Sand." *Der Spiegel* 46/2000:250–252.

1.1.1 Development of Fossil and Renewable Energy Systems

While hydro and wind power have been around for many hundred years, the first "solar cell" was only formed in the 19th century by Edmond Becquerel when he discovered the photo-voltaic effect (Becquerel 1839). At the time, the majority of industrialized countries' energy demand was covered by hard coal. From the mid-19th century until the beginning of the 20th century, hard coal even served 95 % of the demand in England and Wales (Kander, Malanima, and Warde 2014). This only changed because of the increased use of oil. Renewable sources other than large-scale hydro in some regions did not play any significant role since the beginning of the industrialization.

In 1883 the inventor Charles Fritts developed a first functioning photovoltaic (PV) cell (Fritts 1883) and installed a small array on a New York rooftop in 1884. He states the price to be \$ 100 per cell[2], although the capacity is not defined. The physics behind the effect were not understood at the time and only the idea of light quanta or photons by Albert Einstein (Einstein 1905) led to a new updraft in research on the photo-voltaic effect. PV cells became a viable product in 1954, when scientists at the Bell Laboratory discovered the advantages of silicon over selenium as the base material—which is still the standard today—and presented the first commercially viable product with an efficiency of 6 % or 60 W per square meter up from 0.5 % of the then available products (Chapin, Fuller, and Pearson 1954).[3] The first serious application of this kind of panels were NASA's satellites that needed an autarkic energy supply in space.

This invention came right at a time when more and more research suggested that a rise in the CO_2 concentration in the earth's atmosphere would lead to a rise in global average temperatures (Weart 2008). While first hints of this "greenhouse effect" were already found by the end of the 19th century (Arrhenius 1896), it took until the mid-20th century until this idea manifested. By the 1970s it became clear that the burning of fossil fuels significantly increases CO_2 concentration, leading to a man-made increase in global temperatures accompanied by further effects on the earth's climate ("global warming"). In its special report (IPCC 2018), the Intergovernmental Panel on Climate Change (IPCC) lays out the impacts of a global warming above 1.5° C. This limit is even less than the "well below" 2° C agreed upon in the Paris Agreement (United Nations 2015) and what the 195 signatories promised to pursue efforts towards. The results imply that a rapid decrease of anthropogenic emissions is

[2]This corresponds to \$ 2,561.17 in 2020, inflation-adjusted by the Consumer Price Index (CPI) of the U. S. Bureau of Labor Statistics (BLS).

[3]Today's commercially available panels have reached an efficiency of up to 20 % or 200 W per square meter with research prototypes reaching almost double that number.

necessary in order to prevent potentially catastrophic climate-related risks for nature and humankind.

In his pioneering article *"Energy Strategy: The Road Not Taken?"* Amory Lovins (1976) sketches a possible future energy system dependent on so-called "soft energy technologies". These are described to have five properties: to be renewable, diverse, flexible and relative low-tech, and matched to the energy end-use needs in scale and quality. By decoupling economic growth in terms of GDP from the growth of energy use—believed to be directly linked at the time—he puts a strong focus on energy efficiency and energy conservation, mostly by rather low-hanging fruits like technical fixes. The proposed "soft energy path" would lead to a 100 % renewables powered U. S. economy by the year 2025. The energy system would move away from heavily centralized and presumably inefficient structures towards a decentral supply structure with local and domestic generation and storage.[4] He discusses the positive societal implications and the increased social function on a community level. Even a wholly solar economy for the U. S. is mentioned to be possible. To a large extent this work describes an energy system we are envisioning today for the year 2030 or 2050, depending on local potentials and political ambitions.[5] In his pathway he also mentions (fossil-fuel based) transitional technologies that are needed in order to buy the time required for the transition until 2025—a mere five years from today. One very important point he makes is about "rebottling that genie" of nuclear power and proliferation by making the shift towards these "soft energy technologies". By the year 2020 research has proven in many articles (e.g. Brown et al. (2018a), Jenkins, Luke, and Thernstrom (2018), Hansen, Breyer, and Lund (2019), and Kemfert, Breyer, and Oei (2020)) that an energy system based on 100 % renewables is not only technically possible but also more economic, sustainable, and has numerous positive effects in other fields like social development and energy access.

In the year 2000, the United Nations (UN) declared a set of eight so-called Millenium Development Goals (MDGs) (UN General Assembly 2000), mostly focusing on poverty, health, and education, but also on sustainability. By 2015, this effort was in large part successful across the globe with remaining shortfalls in some regions. Driven by this success, 17 new Sustainable Development Goals (SDGs) (UN General Assembly 2015) were agreed upon that are set to be reached by the year 2030. Among them are affordable and clean energy (SDG 7), sustainable cities and communities (SDG 11), responsible consumption and

[4]Chapters 6 and 7 in Part III address issues of a decentral energy transformation.

[5]Chapter 2 gives a detailed outline of an integrated energy transformation in line with the agreed-on climate targets.

production (SDG 12), life below water (SDG 14) and on land (SDG 15), as well as climate action (SDG 13)—topics directly affecting and being affected by the world's energy system (Fuso Nerini et al. 2018; McCollum et al. 2018). This calls for a large number of associated research questions, some of which I address in my dissertation.

1.1.2 Topic of This Dissertation

The overarching topic of this dissertation—*"Open Source Modeling for an Integrated Energy Transformation"*— touches on the tools and methodologies needed in order to gain insights into the energy and more specifically the electricity system and applies them to some concrete research questions:

- What are the technical and economic challenges of "sector coupling", that is, coupling electricity, heat, and transportation, in an attempt to advance the low-carbon transformation by a further shift from fossil fuels as a primary source of energy to renewable ones and what are the concrete quantitative scenarios for Germany until 2030 and 2050?
- What are the benefits of openness in electricity sector modeling? How can a fully open-source bottom-up electricity sector model with high spatial resolution look like and how does it benchmark regarding runtime of building and solving against a representation in a commercial algebraic modeling language and against commercial solvers?
- What are the potential effects of introducing bidding zones in the German electricity market in terms of system implications and distributional effects?
- What are the impacts of uncertainty like PV generation on unit commitment decisions for the German rolling planning procedure and how can a time-adaptive intra-day photovoltaic forecast be simulated?
- What are the interdependencies between transmission line infrastructure and the electricity mix? In particular, how does an energy system based on 100 % renewable sources operate under different transmission regimes?
- What are the implications and effects of local electricity market designs for energy communities under Germany's current tariff mechanism? And, how can we adjust the existing concepts of local electricity markets in order to ensure a fair distribution of costs between all participants?

The coherencies and interdependencies of such complex systems call for advanced analytical tools, such as numerical modeling using the theory and methods of operations research (OR). The contribution of this dissertation to the literature is twofold. On the one hand, methods and models are further developed and on the other hand policy-relevant implications are drawn from numerical results.

The remainder of this chapter is structured as follows: Section 1.2 gives an introduction to the methods of OR used in this dissertation, Section 1.3 provides an overview over the field of electricity modeling, Section 1.5 sketches the outline of the dissertation and its contributions, and Section 1.6 concludes with an outlook on future research.

1.2 Operations Research

In this dissertation different numerical optimization methods from the field of operations research (OR) are applied. This section introduces linear programming and integer programming (Section 1.2.1), stochastic programming (Section 1.2.2), and mixed complementarity programming (Section 1.2.3).

1.2.1 Linear Programming & Integer Programming

A linear program (LP) has the objective to find values for a vector x such that the value of a linear function, called the objective function and containing a vector c of the cost parameters, reaches its optimum (Equation (1.1a)). This is the case, when the maximum or minimum possible value—depending on the direction of optimization—is reached. x is therefore called the vector of decision variables. The values x can take are restricted by an additional linear function containing the matrix A of multipliers and limited by a parameter b. This equation is called a constraint (Equation (1.1b)). These constraints form the feasible region in which the optimal combination of x can be searched for. The values of x are further bounded by a non-negativity condition (Equation (1.1c)).

One standard solution technique for such a problem is the simplex algorithm developed by George Dantzig in 1947. An extensive introduction to linear programming can be found in Dantzig (1963).

$$\min_{x} \quad c^T \times x \tag{1.1a}$$

$$s.t. \quad A \times x = b \tag{1.1b}$$

$$x \geq 0 \tag{1.1c}$$

Replacing the non-negativity constraint by a condition $x \in \mathbb{N}$ turns the problem into an integer problem (IP). The solution of such problems is more complex, requiring additional methods, most notably the branch-and-bound algorithm. When only some of the decision variables in x are limited to integer or binary variables, the problem type turns into a mixed-integer program (MIP).

1.2.2 Stochastic Programming

In reality the assumption of perfect information and foresight oftentimes does not apply. In those cases the methods of stochastic programming are useful in order to make decisions under uncertainty. A prerequisite for this methodology is a known probability distribution for returning events—unquantifiable uncertainties cannot be modeled. The outcome of the problem in this case is not only affected by the decision made in a first stage as represented in Section 1.2.1 but there is a second stage or (multiple stages) in that corrective decisions have to be made depending on the decision taken in the first stage and some random variables. Equation (1.2) depicts such a two-stage stochastic program with recourse.

$$\min_{x} \quad c^T \times x + E_\xi \times Q(x, \xi) \tag{1.2a}$$

$$s.t. \quad A \times x = b \tag{1.2b}$$

$$x \geq 0 \tag{1.2c}$$

Here, $Q(x,\xi) = \min\left\{q^T \times y \mid Wy = h - Tx,\;\; y \geq 0\right\}$ is the second stage problem with E_ξ being the mathematical expectation with respect to ξ. This second problem with decision variable vector y and multiplier q has own constraints consisting of the recourse matrix W, the right-hand side h and the technology matrix T, determining the effect on the first-stage decision variable vector x. Birge and Louveaux (2011) present a comprehensive introduction to stochastic programming.

1.2.3 Mixed Complementarity Programming

A general complementarity problem consists of a function $F(z)$ (Equation (1.3a)) and a variable vector z (Equation (1.3b)) with $z \in \mathbb{R}^n$ and $F : \mathbb{R}^n \to \mathbb{R}^n$. They are connected via the condition in Equation (1.3c), implying that either the function value or the variable value have to be zero, that is, they are complementary to each other. A common notation for this is the perpendicular operator $\perp$. If $F(z)$ is a linear function, the problem becomes a linear complementarity problem (LCP).

$$F(z) \geq 0 \tag{1.3a}$$

$$z \geq 0 \tag{1.3b}$$

$$F_j(z) \times z_j = 0 \quad \forall \quad j = 1, ..., n \tag{1.3c}$$

When there is a lower bound other than zero and/or there is an additional upper bound, the problem becomes a mixed complementarity problem (MCP). Equation (1.4) shows the general form, implying that not only inequality constraints (Equations (1.5a) and (1.5c)), but also equality constraints (Equation (1.5b)) are possible.

$$F(z) \quad \perp \quad l \leq z \leq u \tag{1.4}$$

$$\text{if } z_j = l_j, \quad \text{then } F_j(z) \geq 0 \tag{1.5a}$$

$$\text{if } l_j < z_j < u_j, \quad \text{then } F_j(z) = 0 \tag{1.5b}$$

$$\text{if } z_j = u_j, \quad \text{then } F_j(z) \leq 0 \tag{1.5c}$$

In order to find an optimal solution to a MCP with regard to an objective function, the first order conditions have to be satisfied. These are also called the Karush-Kuhn-Tucker conditions (KKTs). KKTs are sufficient for optimality if the maximizing objective function is concave (or the minimizing objective function is convex), inequality constraints are continuously differentiable convex functions and equality constraints are affine functions. In other cases the conditions are necessary but not sufficient and need to be amended by further conditions. Solving a MCP with multiple players (combining their KKTs) leads to a Nash equilibrium—a solution from which none of the players desires to deviate, as the optimal decisions of the others are already taken into account. Gabriel et al. (2013) provide an extensive introduction to complementarity modeling for energy markets.

1.3 Electricity Modeling

1.3.1 Purpose of Modeling

Electricity sector models are usually large-scale, complex techno-economic models describing the behavior of an electricity system in operation. These models have been around for a long time for assessment and optimization of operation and investment decisions but also to generate insights for policy making. The rapid change of the electricity sector, driven by vast extensions of renewable installations and an increase in sector coupling with heat and transportation, make them even more relevant in the present and coming years.

While the process of formulating and coding such a model frankly speaking is already a spark of joy by itself, Hamming (1962) elaborates on the famous motto of his book *"The purpose of computing is insight, not numbers"* as follows (Hamming 1973, 3):

> «The choice of the particular formula, or algorithm, influences not only the computing but also how we are to understand the results when they are obtained. The way computing progresses, the number of iterations it requires, or the spacing used by a formula, often sheds light on the problem. Finally, the same computation can be viewed as coming from different models, and these different views often shed further light on the problem. Thus computing is, or at least should be, intimately bound up with both the source of the problem and the use that is going to be made of the answers—it is not a step to be taken in isolation from reality. »

He elaborates on this in the famous Chapter N+1 "The Art of Computing for Scientist and Engineers". In the context of statistical models, Box (1979, 201-202) comments under the equally famous caption *"All models are wrong but some are useful"*:

> «Now it would be very remarkable if any system existing in the real world could be exactly represented by any simple model. However, cunningly chosen parsimonious models often do provide remarkably useful approximations. [...] For such a model there is no need to ask the question "Is the model true?". If "truth" is to be the "whole truth" the answer must be "No". The only question of interest is "Is the model illuminating and useful? »

Both points are equally true for energy and electricity sector models. The scope and features of the models have to be carefully selected in order to be able to gain the insights desired while at the same time keep the model simple enough for it to be computed but complex enough for the outcomes still to be useful and applicable to the real world problem examined.

Silvast et al. (2020) found in their ethnographic study that the choice of the model design is directly influenced by the epistemic qualities modelers want to address (e.g. the impact of certain policies). Models are not seen as perfectly accurate representations of real systems but as approaches and approximations. Modelers viewed their models as being of high quality, though, when they had direct impacts in policy making.

Several meta studies describe the current questions and challenges of electricity and energy sector modeling (Pfenninger, Hawkes, and Keirstead 2014; DeCarolis et al. 2017; Grimm et al. 2017). An overview of existing proprietary electricity sector models can be found in Foley et al. (2010) and Fernandez Blanco Carramolino et al. (2017). The website of the openmod initiative[6] provides an overview of open energy models.

Section 1.3.2 outlines taxonomies for the classification of models and model features and Section 1.3.3 describes the properties of solar PV as one example of uncertainties to be approached in an electricity system model.

1.3.2 Model Taxonomy

Ventosa et al. (2005) distinguish models in general by their mathematical structure: there are optimization models with a single-firm optimization problem as described in Section 1.2.1 and equilibrium models simultaneously optimizing problems of multiple firms as described in Section 1.2.3—both applied in this dissertation—as well as simulation models like agent-based models that are similar to equilibrium models but can be used when the underlying problem is too complex for the formulation of an equilibrium problem.

For electricity market models they introduce the seven classifications degree of competition, time scope, uncertainty modeling, interperiod links, transmission constraints, generating system modeling, and market modeling with different manifestations (see Table 1.2a). Interperiod links are, for example, storage constraints tracking the level of a storage or intertemporal constraints of thermal generating units, replicating their technical behavior like ramping or minimum up and down times. One focus is set on the modeling of the electricity transmission system that reaches from a simple single node model without any transmission modeling up to a very detailed and complex non-linear AC model.

In their review article Hall and Buckley (2016) develop a taxonomy for the broader class of energy systems models comprising 14 classifications in the three categories purpose of the model, technological detail, and mathematical description. The purpose of the model could be forecasting, exploring, or backcasting. The structure contains internal and external assumptions of the model. The scope of a model is comprised of geographical and sectoral coverage as well as time horizon and time steps. The technological details describe the technology features of the model like the included renewable and storage technologies or

[6] wiki.openmod-initiative.org/wiki/Open_Models

the demand inclusion (which sectors) and cost inclusion (investment, operating, emission costs). Finally, the mathematical description distinguishes between a top-down, bottom-up, hybrid, or other analytical approach, classifies the underlying methodology (optimization, equilibrium, simulation, or other methods like econometrics), and states the mathematical approach. One important point are the data requirements: qualitative, quantitative, monetary, aggregated, and disaggregated. See Table 1.2b for an overview.

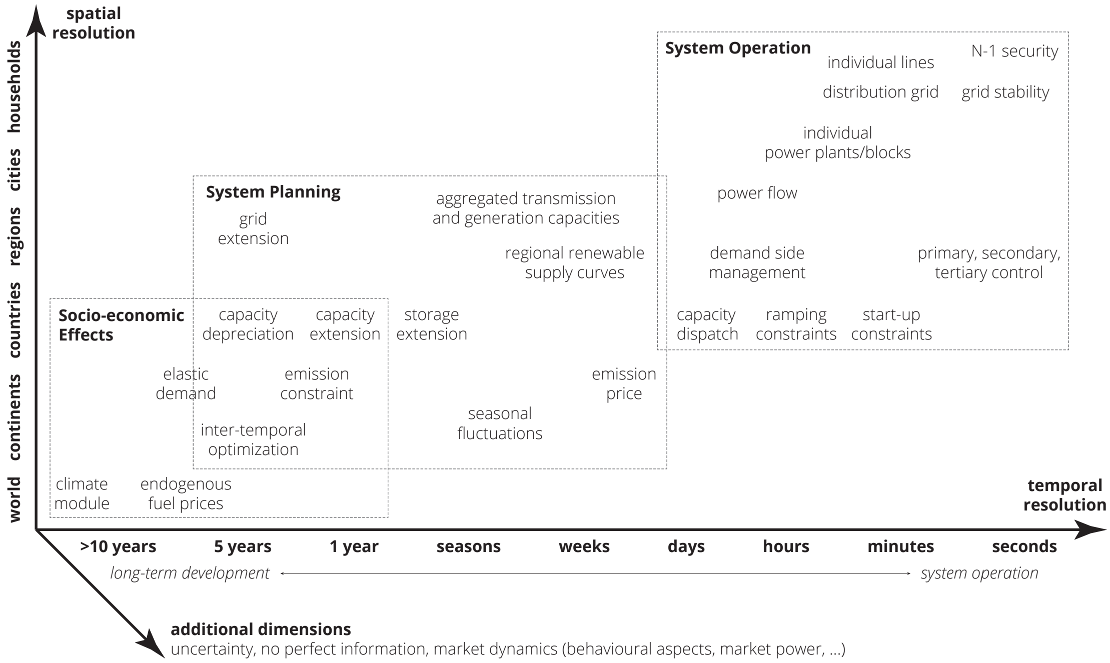

Figure 1.1: Classification of model features for energy and power system models.

Source: own depiction based on Schaber (2014).

Haller (2012) and Schaber (2014) categorize the concrete model features of energy and power system models by their spatial resolution and temporal resolution. Additional dimensions could be uncertainty, no perfect information, or market dynamics (e.g. behavioral aspects and market power). Figure 1.1 shows typical features of such models classified by their spatial resolution between the whole world and single houses and by their temporal resolution between more than ten years and seconds. Additionally, the features are grouped by the most long-term and spatially aggregated category of global welfare, the most short-term and spatially disaggregated category of system operation, and the medium-term and spatially medium aggregated category of system planning. This dissertation focuses on all three categories but does not touch on all the mentioned features.

Table 1.1: Classification of models.

(a) Classification of electricity market models.

Classification	Manifestation
degree of competition	perfect competition oligopoly monopoly
time scope	long-term medium-term short-term
uncertainty modeling	deterministic probabilitic
interperiod links	intraperiod constraints interperiod constraints
transmission constraints	single node model transshipment model DC model AC model
generating system modeling	aggregated capacities individual generator intertemporal contraints
market modeling	exogenous price imperfect market equilibrium single-firm residual demand

Source: own depiction based on Ventosa et al. (2005).

(b) Classification of energy systems models.

Category	Classification
purpose of the model	purpose structure geographical coverage sectoral coverage time horizon time step
technological detail	renewable technology inclusion storage technology inclusion demand characteristic inclusion cost inclusion
mathematical description	analytical approach underlying methodology mathematical approach data requirements

Source: own depiction based on Hall and Buckley (2016).

Yet, not only the appropriate choice of features and the mathematical formulation of the problem is crucial for the quality and relevance of research, but also the type of data and software used is a significant factor. Here, the topic of openness plays an important role. Section 1.4 gives a short introduction to the topic of open science and open source, to be enlarged upon in Chapter 3.

1.3.3 Uncertainty Modeling of Solar Power

One example of the uncertainties in an electricity system is the forecast and realization of solar PV production and the resulting forecast error. This section[7] gives a short introduction into the relevant characteristics of PV as an energy source and hence the challenges that arise when modeling the uncertainty of PV.

Solar power differs in many aspects from wind power.[8] Starting with the obvious, the source of energy for PV is the solar irradiation of the sun. PV power performance is first and foremost strictly determined by the sun's positioning. Thus, the production pattern has a strong diurnal dependency with forecast errors exclusively occurring during daylight hours. The daily course of the sun must therefore be adequately reflected models. Due to the quadratic shape of diurnal generation, the highest absolute errors mainly occur during mid-day hours when solar irradiation is most intense.

Figure 1.2 illustrates the monthly *absolute* errors as the difference of forecasted and realized values in Germany for the year 2016 on a normalized scale. Each line represents a day of the month. The absolute error structure itself almost follows the diurnal course of the sun. In order to incorporate the effects of seasonality into the forecast simulation methodology, error terms of quarter years are merged. The considered quarter years each comprise three consecutive months, starting in January. In the first and fourth quarter the absolute error terms are relatively small due to a smaller energy production in absolute terms (Lorenz et al. 2011). In contrast, with increasing energy production, the second quarter shows stronger deviations in both positive and negative directions, that is, the PV production is over- or underestimated by the day-ahead forecast, respectively. The third quarter has small absolute error terms compared to the high PV production during these summer months. Thus, absolute day-ahead forecast errors of solar power show a strong seasonal dependency.

However, the seasonal dependency reverses when looking at *relative* error patterns as

[7] This section was originally published as an appendix to Zepter and Weibezahn (2019).
[8] Please refer to Abrell and Kunz (2015) for details on the introduction of uncertainty of wind generation.

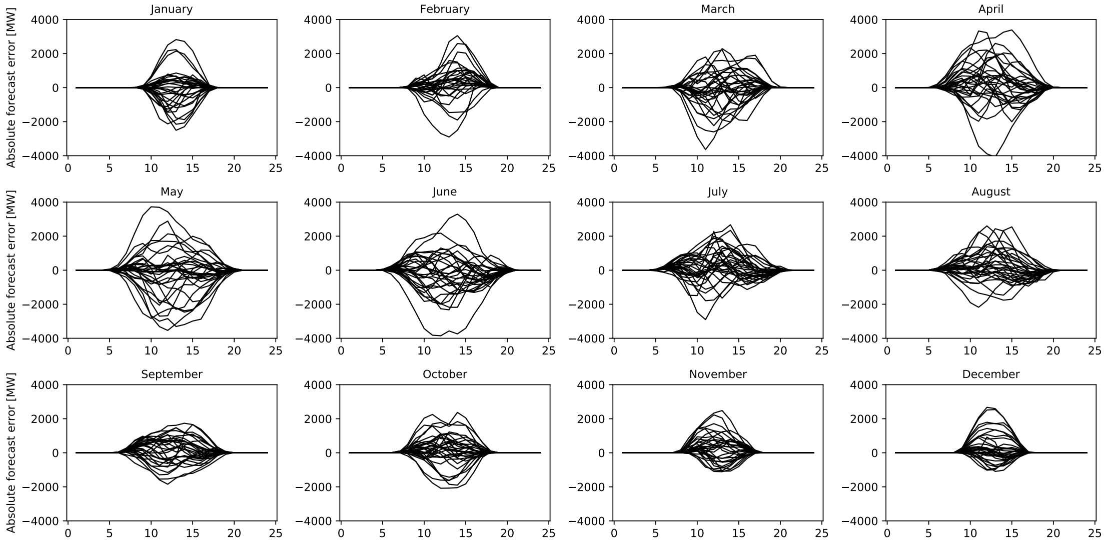

Figure 1.2: Daily absolute error patterns by month for Germany in the year 2016; each line represents a pattern over the course of one day (24 hours).

Source: own depiction.

illustrated in Figure 1.3. The first and fourth quarter report high ratios of relative error terms of the hourly energy production. In the second and third quarter, forecast errors are by contrast significantly lower relative to realized values. Due to a higher intermittent cloud situations in general (Pierro et al. 2016), the forecast errors in spring, autumn, and winter are greater compared to summer months that are relatively more predictable since there is significantly less cloud coverage. The autoregressive components in the error time series of solar power, indicating how much weight is put on previous errors, must be valued according to these seasonal changes (Pierro et al. 2016).

In general, the forecast errors for PV tend to be smaller than for wind (Wu et al. 2015), having a smaller root-mean squared error (RMSE). In the case of Germany for the examined data sets of the year 2016, the RMSE for PV is found to be 1.4 % of overall installed PV capacity, whilst the RMSE for wind onshore and offshore are 2.6 % and 6.3 % of overall installed capacities, respectively. Due to spatial averaging effects, the RMSE for the whole of Germany is much smaller than for minor zones, as for example the control zones of transmission system operators (TSOs). In the literature, the error distribution for PV is often assumed to be normally distributed (Lorenz et al. 2009; Hayashi, Shimoo, and Wakao 2015). Following the characteristics of the RMSE , the distributions are much tighter than for wind,

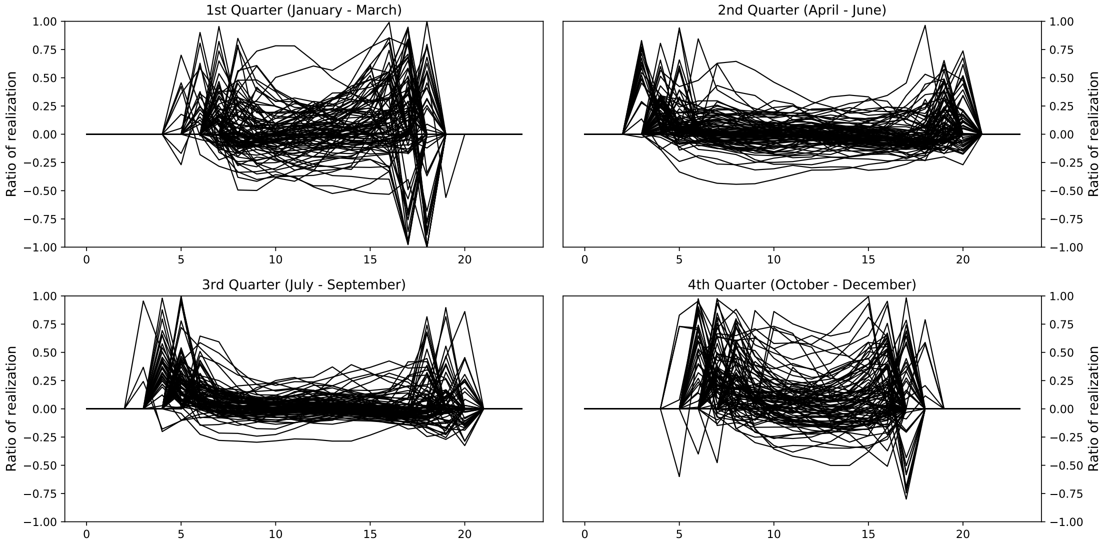

Figure 1.3: Monthly relative error patterns for months in the considered seasons for Germany in the year 2016; each line represents a pattern over the course of one day (24 hours).

Source: own depiction.

implying that the forecasts are generally more accurate and precise with fewer extreme divergences.

At short-term timescale, the PV power production is—for the greatest part—depending on the global solar irradiance (Lorenz et al. 2009). Solar irradiance is influenced either by environmental factors or performance degrading weather conditions. The former is comprised of: (1) the angle of incidence of the sun which is the most significant but also completely predictable; (2) cloud coverage, causing the most variance; and (3) haze, dust and smoke particles. The latter represents soiling, snow and ice as well as high winds (Lorenz et al. 2011). At short-term, these confounding factors cause divergences from the predicted production and can hence induce a variable and uncertain PV power production. These two terms are generally distinguished by their time horizon. Variability occurs sub-hourly, uncertainty is meant in hourly time steps (Ela et al. 2013). While the daily and annual orbiting of the sun is considered to be deterministic, the weather dependent factors cause the most fluctuations in intraday operation (David, Diagne, and Lauret 2012). Thus, they are considered to be stochastic.

The correlation of meteorological parameters and PV power output is assumed to be quasi-linear (David, Diagne, and Lauret 2012).[9] It is hence legitimate to consider PV power as a source of uncertainty (Lorenz et al. 2009), in contrast to wind power, where the final power production has an exponential relationship to wind speed as source of energy. In the method presented in Chapter 5, the stochasticity of changing cloud coverage situations is directly incorporated into the aggregated power generation. Moreover, regional differences in solar power production are neglected due to spatial averaging effects (Lorenz et al. 2009; Mills et al. 2010).

1.4 Open Science and Open Source

> *«Knowledge is the only good that increases when shared.»*
>
> Marie Freifrau von Ebner-Eschenbach (1830–1916)

In recent years the term "open science" has become increasingly used in the scientific community. It considers different aspects of knowledge creation and dissemination in research. According to the literature review of Fecher and Friesike (2014), five schools of open science can be distinguished: The *democratic school* advocates for open access of knowledge. The *pragmatic school* assumes that the creation of knowledge becomes more efficient if researchers work together, for example by opening up their data and code. The *infrastructure school* focuses on the increase of research efficiency by the provision of collaboration tools. Chapter 3 focuses on the aspects of these three schools. In addition, the *public school* addresses the topic of citizens science—involving the public in research—and the *measurement school* discusses impact measurements for scientific results alternative to the traditional metrics of citations and impact factors.

Chapter 3 introduces five key dimensions in detail that are a prerequisite of fully open energy science. These are open data, open-source programming and modeling languages, open-source model code, open-source solvers and open-access publications.

In the past most energy models were closed-source and did not release their data. Until recently, even the model used by the European Commission to produce European climate strategies (European Comission 2018) was not available to the public (Müller, Weibezahn, and Wiese 2018). The reasons for this reluctance of the academic world to open up are multifarious. Today more and more voices are advocating for open source and open access in energy research and energy system modeling (Pfenninger et al. 2017).

[9] Quasi-linearity refers to the (almost) direct dependency between power production and solar irradiance.

Wilkinson et al. (2016) introduce the principal of FAIR data that should be applied. It demands data to be findable (data has an persistent identifier and is clearly described by metadata), accessible (data can be retrieved by an open communication protocol), interoperable (metadata follows a language for knowledge representation), and reusable (data comes with detailed provenance and is accessibly licensed). Over the last few years, stakeholders in the electricity sector started to open up and publish data online. Nevertheless, while many of those data sources can now be openly viewed, it is—according to copyright law and licensing—mostly not legally possible to use, process, and redistribute this data why more and more initiatives are calling for improved legislation (Morrison, Brown, and De Felice 2017) and the legal aspects of open data for power system models are being discussed in the community (Hirth 2020).

The major advantage of proprietary software in the context of the used modeling language is the ease of use. Usually the software comes as an out-of-the-box solution with an IDE, ready to be used. The software is being maintained on a regular basis and everything should work reliably including the links to the solvers to be used. On the contrary, it is less customizable for example for the usage of alternative solver packages. Only supported solvers can be used with the proprietary software. Furthermore, established open-source software (OSS) solutions like Python with a long history and a substantial developer community come with at least the same level of reliability.

The model formulation of assessment models should not be a 'black box'. Bazilian et al. (2012) and Pfenninger et al. (2017) and Pfenninger (2017) all argue that energy scientist must show what happens 'under the hood' of their models. This transparency is the only way other researchers, but also the general public, can replicate and validate the results and fully understand and challenge the models in the peer-review of publications but also in the context of policy advice. This is also the only way to fulfill the standards of open science. Furthermore, it increases the quality of models since developers are forced to decrease the number of errors or at least errors can be found by others. The models therefore become more robust. Especially when it comes to the usage of model results as arguments for certain policy implications or recommendations, the credibility and legitimacy of those results increases significantly if everyone is able to check them and to see the underlying assumptions.

Last but not least, publishing models according to open standards grants access to anyone and therefore also to stakeholders with less financial means like non-governmental organizations or developing countries, enabling them to produce their own analyses. It also fosters the interoperability of different models (Pfenninger, Hawkes, and Keirstead 2014).

Pfenninger et al. (2018) supply a guideline of strategies on how to open models up, while Hülk et al. (2018) provide a transparency checklist for models. Several meta studies describe the current questions and challenges of electricity and energy sector modeling (Pfenninger, Hawkes, and Keirstead 2014; DeCarolis et al. 2017; Grimm et al. 2017).

For numerically solving large-scale problems commonly known solver packages are the commercial CPLEX Optimizer and Gurobi can be used. Open-source solvers can be an alternative. The advantages in those cases are similar to the ones for the modeling tool: publicly available and therefore controllable source-code as well as cost savings for license fees. Standard open-source solvers for linear programs are CLP and GLPK. Currently, the performance of CLPEX and Gurobi in solving problems is usually multiple times better than for the open-source alternatives.

A good example of the advantages of open-source software in science is the first image of a black hole that was made possible by *Matplotlib*, a plotting library for Python (Nowogrodzki 2019). While Steve Ballmer, former CEO of Microsoft, called Linux "a cancer" in 2001, today Microsoft heavily invests in open source topics. By November 2019, 100 % of the 500 largest supercomputers use one or another distribution of Linux as their operating system.[10] This speaks to just how superior the customizability of open source software is, as all of these computers are in a way unique and have a need for very specific solutions. Morgan and Finnegan (2007) describe that IT managers in the examined business found that—next to low costs—access to the source code facilitates innovation, increases collaboration, and prevents vendor lock-in.

The advantages and disadvantages of OSS versus closed-source software (CSS) can be described using the categories customizability and control, security, reliability, and maintenance.

In terms of security, open source means that also hackers have access to the source code, facilitating the exploitation of security flaws—on the other hand, more eyes on the code will be able spot those flaws before they can be exploited (Swire 2004). This is more relevant in the context of operating or control systems and not so much with electricity sector models. The counter-argument is often times quoted under the catchphrase "security by obscurity", meaning that a hidden closed source code prevents attackers from finding an entrance point. A number of security problems in commercial software has shown the weakness of this viewpoint.

Concerning reliability and performance, this can also be formulated as an advantage of

[10]www.top500.org/statistics/list

OSS, described by Linus' Law: "Given enough eyeballs, all bugs are shallow" (Heron, Hanson, and Ricketts 2013). A bigger number of developers in a crowd-sourced project can contribute more expertise to the project than a closed development team in a company (Mockus, Fielding, and Herbsleb 2002; Morgan and Finnegan 2007). However, this argument only holds for large and widely used software. Small OSS communities do not have this advantage just like very young ones, who might overcome this shortfall when growing over time.

A similar advantage can be described for the maintenance of a software (Heron, Hanson, and Ricketts 2013): A big open source community will find and fix bugs in software packages and will be able to develop new features that they feel are needed. At the same time this can be a problem when it comes to poor documentation and compatibility issues but sometimes also a lack of development roadmaps, giving users a certainty of future releases. In general it can be stated that the more people are using an open-source solution, the more efficient it becomes.

Famous examples of OSS are Linux, the GNU Project, Android, Mozilla Firefox, and Open Office in a broader context, Python as an established programming language, Julia as a rather new programming language, and OSeMOSYS (Howells et al. 2011) as an energy sector model. Infamous examples of CSS, on the other hand, are Windows, the Internet Explorer, GAMS as an algebraic modeling language, and PRIMES (E3MLab 2016) as an energy sector model.

While open-source tools—aside from numerical solvers—are already today capable of the tasks, still a lot of challenges remain (Müller, Weibezahn, and Wiese 2018) including the need for collaboration, poor data quality, and the issue of licensing to be able to re-use data and code. The costs related to proprietary software like GAMS do not seem to be a driver in the game. In times of fast-moving topics touching so many aspects of society like the *Energiewende*, openness becomes even more important. Citizens want to comprehend the necessities of an integrated transformation and are increasingly interested in the results of scientists—to a great extent sparked by movements like Fridays4Future. The differences in model results need to be communicated and explained—transparency is the key to acceptance in the population.

1.5 Outline and Contributions of this Dissertation

1.5.1 Overview of the Dissertation

The dissertation is comprised of three parts:

- **Part I Introduction** includes this introduction (Chapter 1) as well as a general introduction to the topic of sector coupling (Chapter 2), including a literature review and evidence from case studies on the German energy sytem.
- **Part II Economic Dispatch Modeling** continues with three papers on the dispatch modeling of the German power market. Chapter 3 introduces the economic dispatch model Joulia.jl, a deterministic LP model depicting the day-ahead (DA) market and discusses the benefits of different dimensions of openness in the field of energy modeling. Chapter 4 extends this model by incorporating a feature for congestion management (CM). It simulates a hypothetical zonal pricing and analyzes the market implications and distributional effects of price zones within the German electricity market. Chapter 5 moves on to a stochastic MIP further extending the simulation by an intra-day (ID) market. It examines the topic of unit commitment (UC) in a stochastic electricity market model and develops a methodology to incorporate the uncertainty of PV generation.
- **Part III A Decentral Energy Transformation** shifts the focus towards decentral aspects of the energy transformation. In Chapter 6 the model functionality is extended by an investment module and the impact of different transmission system extensions on the spatial distribution of capacity investments is evaluated. Chapter 7 scrutinizes decentral transformation via local electricity market (LEM) settings within the existing electricity system. It investigates distributional effects of suggested market designs for those local balancing mechanism and suggests a new market design for a fairer allocation of costs and benefits.

Table 1.2 gives an overview of the scopes (dispatch and investment as well as the markets DA, ID, CM, and LEM) and types of models (deterministic or stochastic as well as LP, MIP, or MCP) developed in Parts II and III and the programming and modeling languages used. The following sections summarize each chapter as a synopsis.

Table 1.3 at the end of this section gives an overview of the pre-publications for each chapter of the dissertation and states detailed information on individual contributions of the co-authors.

Table 1.2: Overview of models used.

Chapter	Model Scope	Model Type	Language
	Part II Economic Dispatch Modeling		
3	Dispatch Model: DA	deterministic LP	Julia
4	Dispatch Model: DA, CM	deterministic LP	GAMS
5	Dispatch Model: DA, ID, CM	stochastic MIP	GAMS
	Part III A Decentral Energy Transformation		
6	Dispatch and Investment Model: DA	deterministic LP	Julia
7	Dispatch Model: LEM	deterministic MCP	Julia

1.5.2 Chapter 2: Sector Coupling for an Integrated Low-Carbon Energy Transformation

While the first phase of the German *Energiewende*, focusing on the electricity sector, was largely successful (Hirschhausen 2018), the second phase needs to focus on all energy usage, especially heat, transportation, and usage as feedstock in the chemical industry. In that context, intensified "sector coupling" will be required, accompanied by a further shift from fossil fuels as a primary source of energy to renewable ones.

This chapter provides an overview of the upcoming challenges in the next phase of the *Energiewende*, by focusing on the technical and economic challenges of coupling electricity, heat, and transportation, in an attempt to advance the low-carbon transformation. I apply the concepts to the ongoing *Energiewende* in Germany. By intensifying the links between the sectors, one can harvest "low-hanging fruits" in terms of flexibility and fuel switching from fossil to renewable energies. This is a precondition to attain the ambitious targets of the *Energiewende* with respect to carbon dioxide (CO_2) emission reductions. While this chapter focuses on Germany, the technical and economic arguments are valid at a broader scale, and apply to other transformation processes as well.

Section 2.2 describes the basic idea of "sector coupling", until recently a widely unknown concept, including a schematic stylized scheme. In Section 2.3, I describe how sector coupling might evolve in the transportation and heating sectors, and that far-reaching electrification is at the core of the process. Section 2.4 provides some concrete quantitative scenarios for sector coupling for the case of Germany until 2030 and 2050, based on a rapidly growing body of recent literature. While there is consensus on the feasibility of reaching ambitious decarbonization targets, different models suggest different pathways to achieve them. For instance, the role of synthetic fuels (domestic and/or imported) is controversially discussed. Section 2.5 concludes.

1.5.3 Chapter 3: Illustrating the Benefits of Openness

In this chapter a five-fold approach to open science is introduced comprised of open data, open-source software (that is, programming and modeling tools, model code, and numerical solvers), as well as open-access dissemination. The advantages of open energy models are discussed.

A fully open-source bottom-up electricity sector model with high spatial resolution using the Julia programming environment is then developed, describing source code and a data set for Germany. This large-scale model of the electricity market includes both, generation dispatch from thermal and renewable sources in the spot market as well as the physical transmission network, minimizing total system costs in a linear approach. It calculates the economic dispatch on an hourly basis for a full year, taking into account demand, infeed from renewables, storage, and exchanges with neighboring countries.

Following the open approach, the entire model code and used data set are publicly available and open-source solvers like ECOS and CLP are used. The model is then benchmarked regarding runtime of building and solving against a representation in GAMS as a commercial algebraic modeling language and against Gurobi, CPLEX, and Mosek as commercial solvers.

With this chapter I demonstrate in a proof-of-concept the power and abilities as well as beauty of open-source modeling systems, but also its shortcomings. This openness has the potential to increase the transparency of policy advice, leading to higher acceptance and to empower stakeholders with fewer financial possibilities.

After an introductory Section 3.1, Section 3.2 describes the aspects of the underlying open concept. Section 3.3 provides a short introduction into the benefits of the Julia programming language and the algebraic modeling language JuMP. Section 3.4 explains the model and gives an overview of the used input data. In Section 3.5 the implementation in Julia and the results of the benchmark tests are discussed. The chapter then concludes with a discussion in Section 3.5.3 and an outlook in Section 3.6.

1.5.4 Chapter 4: Two Price Zones for the German Electricity Market

There is an ongoing discussion about the potential effects of introducing bidding zones in Germany. This chapter applies an electricity sector model with network representation to analyze the system implications and the distributional effects of two bidding zones in the German electricity system in 2012 and 2015.

In this chapter I discuss the implications of two price zones (i.e., a northern and a southern bidding area) on the German electricity market. In the northern zone, continuous increases in capacity with low variable costs cause large regional supply surpluses in the market dispatch, while in the southern zone conventional capacity decreases. As the spatial imbalance of supply and load is increasing, the current single bidding area more often results in technically infeasible market results, requiring curative congestion management measures.

Results show a modest decrease in cross-zonal re-dispatch levels, particularly in 2015. However, overall network congestion and re-dispatch levels increase in 2015 and also remain on a high level in case of two bidding zones. Results are very sensitive to more than two bidding zones and additional line investments, illustrating the challenge to define stable price zones in a dynamic setting. With two bidding areas, model results show increased prices in the southern zone and decrease in the northern zone. The average price deviation rises from € 0.4 per megawatt hour (MWh) in 2012 to € 1.7 per MWh in 2015, with absolute values being significantly higher in hours when price differences occur. Stakeholders within zones are exposed to the price deviations to a different extent. Distributional effects are surprisingly small compared to the wholesale price or different network charges.

After an introductory Section 4.1, Section 4.2 reviews the relevant literature on the discussion of zonal and nodal pricing. Section 4.3 introduces the two consecutive model stages of the spot market dispatch and the adjustments by re-dispatch. Section 4.4 presents and discusses the model results for two bidding zones in the German electricity system. The last Section 4.5 summarizes the numeric analysis and concludes with policy implications.

1.5.5 Chapter 5: Unit Commitment under Imperfect Foresight

This chapter investigates the impact of uncertain photovoltaic (PV) generation on unit commitment (UC) decisions for the German rolling planning procedure employing a large-scale stochastic UC electricity market model (stochastic Electricity Market Model (stELMOD)).

A novel approach to simulate a time-adaptive intra-day (ID) photovoltaic forecast, solely based on an exponential smoothing of deviations between realized and forecast values, is presented. Generation uncertainty is then incorporated by numerous multi-stage scenario trees that account for a decreasing forecast error over time.

Results show that total system costs significantly increase when uncertainty of both wind and photovoltaic generation is included by a single forecast, with more frequent starting processes of flexible plants and rather inflexible power plants mainly deployed at part-load. Including the improvement of both wind and photovoltaic forecasts by a scenario tree of possible manifestations, the scheduling costs can be significantly reduced in representative weeks for spring and summer. In general, stochastic representations increase the need for congestion management (CM) as well as more frequent use of storage in the model, leading to a more realistic depiction of the markets.

Following an introductory Section 5.1, Section 5.2 gives an overview of pertinent advancements in the field of stochastic unit commitment modeling under uncertainty of renewable infeed. Section 5.3 describes the main contribution of this chapter, the novel modeling approach used to incorporate uncertainty of PV generation in stochastic market models. Exemplary results of the analysis for the German power system are presented in Section 5.4. Section 5.5 discusses the results and concludes with further research opportunities.

1.5.6 Chapter 6: The Impact of Transmission Development on a 100% Renewable Electricity Supply

In this chapter, I analyze the interdependencies between transmission line infrastructure and the electricity mix, applied to the case of Germany today and in the future. In particular, I am interested in how an energy system based on a high share of distributed renewable sources operates under different transmission regimes, for example, copper plate or more constrained network topologies.

I develop a stylized model of optimal generation and storage investment and operation, under different transmission expansion scenarios (current state, 2035 with and without HVDC lines, and copper plate). I take real data of the German electricity system, characterized by a particularly high share of distributed renewables, and select an extreme value for the future, that is, 100 % renewable.

Results suggest that the system can accommodate the high share of renewables, by installing a large amount of short-term and long-term storage capacities. Renewable electricity capacity investment is inversely related to the state of transmission expansion, and so is storage investment. The high level of granularity of the model also allows for a spatial allocation of renewable capacities, where wind is placed mainly in the north and solar PV rather in the south. The few cases of transmission congestion suggest that by expanding the grid modestly, a high share of renewable can be accommodated. The chapter ends with a discussion of model constraints and further research ideas.

Following the introductory Section 6.1, Section 6.2 analyzes current literature concerning distributed resources and their effects on transmission requirement. Section 6.3 provides a description of the investment and dispatch model that is developed to compare the different locations of renewables, the data, and the scenarios. Section 6.4 provides the results of the scenario runs and discusses them, and Section 6.5 concludes.

1.5.7 Chapter 7: On Distributional Effects in Local Electricity Market Designs

Decentral engagement by entrepreneurs and environmentalists has motivated academia to focus research on design and trading concepts of local electricity markets. The European Commission has picked up the issue and has launched a general call to create energy communities. Literature provides a wide range of conceptual ideas and analyses on the technical and economic framework of single market features such as peer-to-peer trading. The successful, system-wide integration of energy communities into existing market structures requires, however, a set of legal adjustments to national regulation.

In this chapter I test the implications of recently proposed market designs under the current rules in the German market. The analysis is facilitated by a simplistic equilibrium model representing heterogeneous market participants in an energy community with their respective objectives.

I find that, on the one hand, these proposed designs are financially unattractive to prosumers and consumers under the current regulatory framework. On the other hand, they even cause distributional effects within the community when local trade and self-consumption are exempt from taxes.

To this end, I introduce a novel market design—*Tech4all*—that counterbalances these effects. With only few legal amendments, it allows for ownership and participation of renewable technologies for all community members independent of their property structure and affluency. The analysis shows that this design has the potential to mitigate both distributional effects and the avoidance of system service charges, while simultaneously increasing end-user participation.

The chapter opens with an introduction in Section 7.1. Section 7.2 presents recent literature on the development of local electricity markets and introduces the methodology of mixed complementarity problems (MCPs). In Section 7.3, the MCP model is introduced. Section 7.4 presents the case study, its data as well as the results and Section 7.5 concludes on the performance and points towards further research possibilities.

Table 1.3: Chapter origins and own contribution.

Chapter	Pre-publications & Own Contribution
2	**Sector Coupling for an Integrated Low-Carbon Energy Transformation: A Techno-Economic Introduction and Application to Germany**
	This chapter is the accepted version of the following publication: Jens Weibezahn. 2018. "Sector Coupling for an Integrated Low-Carbon Energy Transformation: A Techno-Economic Introduction and Application to Germany." In *Energiewende "Made in Germany": Low Carbon Electricity Sector Reform in the European Context,* edited by Christian von Hirschhausen et al., 217–237. Cham, Switzerland: Springer. doi: 10.1007/978-3-319-95126-3_9.
	Single-author original research article.
3	**Illustrating the Benefits of Openness: A Large-Scale Spatial Economic Dispatch Model Using the Julia Language**
	This chapter is the accepted version of the following publication: Jens Weibezahn and Mario Kendziorski. 2019. "Illustrating the Benefits of Openness: A Large-Scale Spatial Economic Dispatch Model Using the Julia Language." *Energies* 12 (6): 1153. doi: 10.3390/en12061153.
	Joint work with Mario Kendziorski. J. W. and M. K. both curated the data and developed the model and methodology. J. W. initiated the research, wrote the paper, and managed the review and editing process.
4	**Two Price Zones for the German Electricity Market — Market Implications and Distributional Effects**
	This chapter is the accepted version of the following publication: Jonas Egerer, Jens Weibezahn, and Hauke Hermann. 2016. "Two price zones for the German electricity market — Market implications and distributional effects." *Energy Economics* 59:365–381. doi: 10.1016/j.eneco.2016.08.002.
	Joint work with Jonas Egerer and Hauke Hermann. The model builds upon ELMOD-DE (Egerer 2016). J. E. and J. W. jointly extended the model and implemented it in GAMS. J. E. had the lead in the joint effort of writing and editing the manuscript.

Chapter origins and own contribution (continued).

Chapter	Pre-publications & Own Contribution
5	**Unit Commitment under Imperfect Foresight — The Impact of Stochastic Photovoltaic Generation**
	This chapter is the accepted version of the following publication: Jan Martin Zepter and Jens Weibezahn. 2019. "Unit commitment under imperfect foresight — The impact of stochastic photovoltaic generation." *Applied Energy* 243:336–349. doi: 10.1016/j.apenergy.2019.03.191.
	Joint work with Jan Martin Zepter. The authors contributed equally to this work: conceptualization, methodology, investigation, visualization, writing—original draft preparation, writing—review and editing.
6	**The Impact of Transmission Development on a 100 % Renewable Electricity Supply — A Spatial Case Study on the German Power System**
	This chapter is the accepted version of the following publication: Jens Weibezahn et al. 2020. "The Impact of Transmission Development on a 100% Renewable Electricity Supply — A Spatial Case Study on the German Power System." In *Transmission Network Investment in Liberalized Power Markets,* edited by Mohammad Reza Hesamzadeh, Juan Rosellón, and Ingo Vogelsang, 453–474. Lecture Notes in Energy 79. Cham, Switzerland: Springer. doi: 10.1007/978-3-030-47929-9_15.
	Joint work with Mario Kendziorski, Hendrik Kramer, and Christian von Hirschhausen. J. W., M. K., and H. K. contributed equally to this work: conceptualization, methodology, investigation, visualization, writing—original draft preparation, writing—review and editing. C. v. H. supervised the research and contributed to the conceptualization.
7	**On Distributional Effects in Local Electricity Market Designs — Evidence from a German Case Study**
	This chapter is the accepted version of the following publication: Alexandra Lüth, Jens Weibezahn, and Jan Martin Zepter. 2020. "On Distributional Effects in Local Electricity Market Designs — Evidence from a German Case Study." *Energies* 13 (8): 1993. doi: 10.3390/en13081993.
	Joint work with Alexandra Lüth and Jan Martin Zepter. The authors contributed equally to this work: conceptualization, methodology, investigation, visualization, writing—original draft preparation, writing—review and editing.

1.6 Conclusion and Research Outlook

In this dissertation numerous contributions to the literature of energy and electricity modeling have been made tackling the research questions posed in Section 1.1. New open-source models and modeling methodologies were developed and data sets generated. Since research will never be in a completed state, while offering a number of answers to the posed research questions, each of the chapters also leaves issues unaddressed and commences new pathways to be taken in future projects.

1.6.1 Sector Coupling

Further research is required to translate sector coupling into practical policy instruments, to accompany and steer the process. It is clear that a stronger carbon price helps the general trend, but more specific instruments are needed to electrify transportation and heating, and to internalize the adverse environmental effects of fossil fuels in all three sectors (Bach et al. 2020). The models developed in this dissertation include some very limited aspects of sector coupling, yet the topic needs to be widely addressed. For example, future changes in magnitude and temporal and spatial shifts of electricity demand due to the advancement of electrification in other sectors but also in the new flexibility options opened have to be considered. The scenarios and methodologies we developed in the H2020 project "Optimal System-Mix Of Flexibility Solutions for European Electricity" (OSMOSE)[11] together with 32 partners from academia and industry across nine European countries are an ideal foundation for this work. One example of the challenges is the increased complexity of models, integrating several sectors in an energy system model while at the same time keeping the necessary level of detail in the representation of the electricity sector. A promising approach is the integration of two types of frameworks—covering energy systems or purely the electricity sector—in a graph-based system like anyMOD (Göke 2020). Extending this framework by stochastic elements and applying methods like Bender's decomposition allows for the needed representation of complexity in order to solve even large scale models.

1.6.2 Networks and Congestion Management

The model *Joulia.jl*, based on the programming language Julia and presented in this dissertation, will be extended by some additional modules in order to deliver a comparable scope of functionality like other open-source power sector models, for example *PyPSA* or *oemof*

[11] www.osmose-h2020.eu

written in Python. In the next steps, DC transmission lines will be included and *Joulia.jl* will be developed from a LP model towards the integration of unit commitment decisions in a MIP variant for a better technical representation of power plants. Also, the use of heat generated from turbines will be included with a detailed representation of combined heat and power (CHP) plants. The model will also be extended by a congestion management module. Some of these modules have already been developed in preceding GAMS models and need to be transferred.

Regarding the topic of zonal pricing for the German electricity market analyzed in this dissertation, additional system and distributional implications with neighboring countries have not been addressed. For example, 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 that zone. Hours with scarcity and higher prices in southern Germany, on the other hand, could reduce exports to southern Europe. These effects may be important in the context of the European discussion on bidding zones. Therefore, future research will extend the analysis to a fully European level, in particular the extension of the model *Joulia.jl* to the context of the Central Western Europe (CWE) region and adjacent countries.

Several developments will increase regional system imbalances in the medium-term. Among 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 and nuclear power plants (2022). 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.

The gradual introduction of Flow-Based Market Coupling (FBMC) in CWE also changes the market procedures with transfer capacities being allocated in parallel to market clearing (instead of ahead of market clearing), requiring new methodologies in electricity network modeling. Schönheit, Weinhold, and Dierstein (2020) develop a novel approach for an accurate representation of FBMC in power system models.

1.6.3 Uncertainties in Power Systems

Future research into the stochastic representation of the German rolling-planning market scheme of day-ahead, intra-day market, and congestion management is intended. Due to the complexity and run-time of the stochastic calculations in this dissertation, assumptions had to be made disregarding minimum on- and offtimes of conventional power plants as well as part-load efficiencies, which could influence the solution since many plants are not operating at full-load in the stochastic cases. In order to further investigate the impact of comprehensive uncertainties in power systems, future research should address those issues and could furthermore include load forecasting errors into the rolling planning procedure. Improving renewable forecasts in the coming years in the interplay with increasing shares of renewable generation and flexibility options with differing response rates should also be analyzed. The influence of increased dispatch frequency is another potential research topic and can be used to optimize the market design with respect to comprehensive uncertainty of RES production present in today's power system.

More recent works apply chance constraints to stochastic dispatch models, even in robust approaches (Lubin, Dvorkin, and Backhaus 2016) and developing stochastic electricity market designs (Dvorkin 2020). This methodology is very promising for systems with high shares of renewable generation and potentially uncertain probability distributions.

1.6.4 Local Electricity Markets

Furthermore, the topic of local electricity markets and expedient system designs for such set-ups holds numerous open research questions to be tackled—especially regarding the design of the taxes and duties system (Schittekatte, Momber, and Meeus 2018). In further studies, the system design proposed in this dissertation needs to be tested with a larger and more representative data set as well as a greater variety of market participants. It needs to be embedded into the larger power and energy system in order to capture changes in tax and duty revenues for the whole system or sensitivities thereof. The MCP allows for the introduction of additional players that could represent a business provider for a local sharing mechanism in order to fully analyze the impact of all associated features.

Another interesting question is the long-term remuneration of renewable generation capacities in the realm of the current energy-only market when subsidy schemes have faded out and the system is dominated by renewables. In this setting capacity instruments might become an interesting alternative (Beckers and Hoffrichter 2014).

Some of these issues will be addressed in the upcoming research project "Modeling of (de-)centralized energy transitions: interdependencies, coordination and approaches from a system-oriented perspective" (MODEZEEN), funded by the German Federal Ministry of Economic Affairs and Energy (BMWi).

Chapter 2

Sector Coupling for an Integrated Low-Carbon Energy Transformation: A Techno-Economic Introduction and Application to Germany

"We will [. . .] advance the integration of the heat, mobility and electricity sectors in conjunction with storage technologies."

(Coalition Agreement for the 19th Legislative Period of the German Bundestag, March 14, 2018 (CDU, CSU, and SPD (2018), Authors' translation, p. 72))

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2.1 Introduction

The previous chapters have shown that the first phase of the *Energiewende*, focusing on the electricity sector, was largely successful. In fact, it was relatively easy to increase the share of renewables in electricity, now almost 40 %, and to close down nuclear power plants, albeit at the cost of temporarily high CO_2 emissions. Yet, in order to reach the climate goal of a 55 % reduction in greenhouse gases by 2030 and an 80 to 95 % reduction in the coming decades until 2050 (base year 1990, BMWi and BMUB (2010)), the second phase needs to focus on all energy usage, especially heat, transportation, and usage as a raw material in the chemical industry. In that context, intensified "sector coupling" will be required, accompanied by a further shift from fossil fuels to renewable ones.

This chapter provides an overview of the upcoming challenges in the next phase of the *Energiewende*, by focusing on the technical and economic challenges of coupling electricity, heat, and transportation, in an attempt to advance the low-carbon transformation. We apply the concepts to the ongoing *Energiewende* in Germany. By intensifying the links between the sectors, one can harvest "low-hanging fruits" in terms of flexibility and fuel switching from fossil to renewable energies. This is a precondition to attain the ambitious targets of the *Energiewende* with respect to CO_2 emission reductions. While this chapter focuses on Germany, the technical and economic arguments are valid at a broader scale, and apply to other transformation processes as well.

The chapter is structured in the following way: The next section describes the basic idea of "sector coupling", until recently a widely unknown concept, including a schematic stylized scheme. In Section 2.3 we describe how sector coupling might evolve in the transportation and heating sectors, and that far-reaching electrification is at the core of the process. Section 2.4 provides some concrete quantitative scenarios for sector coupling for the case of Germany to 2030 and to 2050, based on a rapidly growing body of recent literature. While there is consensus on the feasibility of reaching ambitious decarbonization targets, different models suggest different pathways of reaching them. The role of synthetic fuels (domestic and/or imported) is controversially discussed. Section 2.5 concludes.

2.2 The Basic Idea of "Sector Coupling"

In 2016, Germany had a total primary energy demand of more than 3,700 terawatt hours (TWh). About 93 % of this primary energy is consumed by the energy sector. Usage as a raw material, mainly in the petrochemical industry, accounts for 7 %. 34 % of primary energy come from oil, 23.6 % from coal (12.3 % hard coal and 11.3 % lignite), 22.6 % from fossil gas, 6.9 % from nuclear, and 12.6 % from renewable sources.[1] The largest source of CO_2 emissions is coal (lignite and hard coal), accumulating to a share of 41 % in 2016, followed by mineral oil with 34 %, and fossil gas with 22 %, based on total emissions of 751.7 megatons (Mt).[2] Due to conversion and other losses, only 68 % of the primary energy is used as final energy. Although precise differentiation between sectors is difficult, it is estimated that about half the energy is used for heat, one third for fuels, and only one fifth for electricity (Agora Energiewende 2018).

The first conclusion from this statistic is that increasing energy efficiency and halving primary energy usage until 2050 (compared to 2008, BMWi and BMUB (2010)) will be one of the critical success factors of the low-carbon energy transformation. The second conclusion is that due to the limited potentials for solar thermal and geothermal energy, biomass, and biofuels, the increased use of renewable power from wind and PV is the predominant strategy to further decrease greenhouse gas emissions in all energy sectors. However, this strategy requires an increased coupling of energy sectors and is the corner stone for an integrated energy transformation.

The basic idea of sector coupling is to facilitate a more sustainable use of different types of energy across sector boundaries, that is, electricity, heat, and transportation. In addition, the objective of sector coupling is to substitute fossil fuels by renewables, both electricity and fuels. Thus, sector coupling targets a more rational use of energy, in the techno-economic sense, and lower greenhouse gas emissions. In addition, sector coupling can activate additional degrees of freedom in the energy system, and therefore introduce more flexibility into the system — facilitating the further integration of intermittent renewable energy sources like wind or solar (Wietschel et al. 2018).

As such, the coupling of sectors is nothing new and has been practiced for a long time, for example, by means of CHP plants or electricity used in rail transport. Advanced coupling can be achieved by different technology options, with the most efficient one being the direct usage of electricity in battery electric vehicles (BEVs), rail transportation, trolley trucks and buses in the transportation sector, and power to heat (PtH) and heat pumps in the heat sector. The indirect (and therefore less efficient) usage of electricity is via a conversion into synthetic fuels (power to gas (PtG) and power to liquid (PtL)). Also other synthetic

[1] AGEB. 2017. *Auswertungstabellen zur Energiebilanz für die Bundesrepublik Deutschland 1990 bis 2016.* Technical report. Berlin, Germany: AG Energiebilanzen e. V.

[2] BMWi. 2018. *Gesamtausgabe der Energiedaten - Datensammlung des BMWi.* Technical report. Berlin, Germany: Bundesministerium für Wirtschaft und Energie.

fuels produced from biomass are conceivable, yet not mature for commercial applications. Figure 2.1 shows a schematic overview of a coupled energy system, primarily based on electricity from wind and solar PV. Consequently, the distinct energy sectors coalesce and have to be assessed in an integrated way.

One of the benefits of a decarbonized and integrated energy sector are new business models for energy utility companies, service providers, and new market players. Additional economic value will be added within Europe and Germany, decreasing commodity dependence from other parts of the world.

2.3 Sectors

The different sectors in sector coupling can be delimited in different ways, yet most of the literature agrees on the definition of three sectors: electricity, heating and cooling, and transportation. Within the sectors a further distinction can be made, mostly into industrial, commercial and service, and household consumers. The following subsections provide a more detailed view on the transportation and heating/cooling sectors, their current energy consumption (see Figure 2.2) and the technology options for direct or indirect electrification. It concludes with the intersectoral interdependencies with the electricity sector.

2.3.1 Transportation

The German transportation sector accounts for a final energy consumption of about 750 TWh/year. Currently, 94 % is based on mineral oil while only 2 % is based on electricity (mostly rail transportation, not necessarily from renewable sources) and 4 % on renewable energy, mainly biofuels as addition to gasoline; fossil gas has a negligibly small share (see Figure 2.2). While the German government foresees a reduction of consumption by 10 % in the year 2020 and 40 % in 2050 compared to 2005 levels (BMWi and BMUB 2010), the actual energy demand and consequently also greenhouse gas emissions in the transportation sector are steadily growing. This is mostly due to the fact that the transportation demand for goods and passengers is increasing year by year. At the same time, CO_2 emissions increased to 165 Mt in 2016 despite emission standards for vehicles being tightened and the first driving bans in place or planned in Hamburg and Stuttgart in the light of the emissions scandal.

The adverse trend in the transportation sector requires a definite low-carbon transformation strategy, resting on at least two pillars: (i) the transformation of mobility behavior,

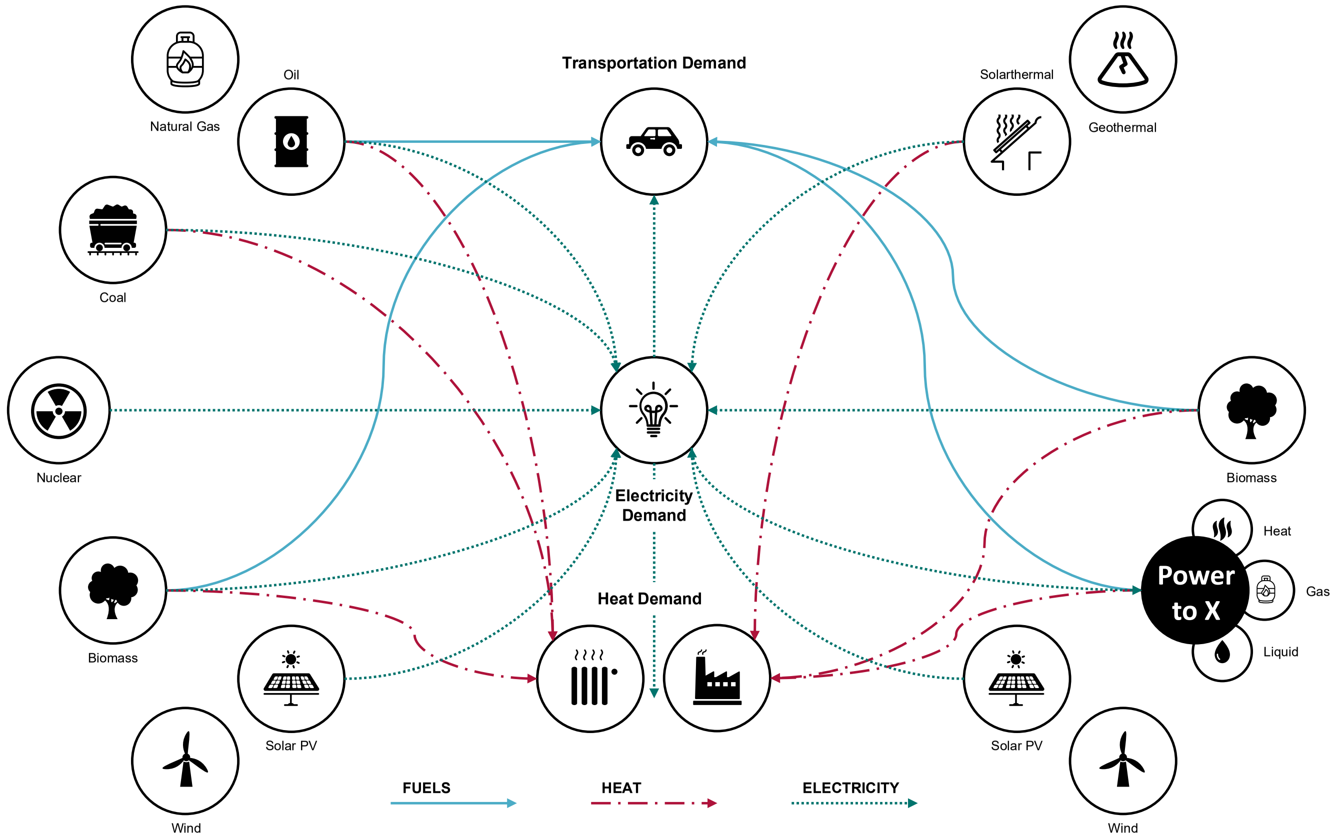

Figure 2.1: Schematic overview of the shift towards a decarbonized energy sector.

Source: own depiction based on SRU (2017).

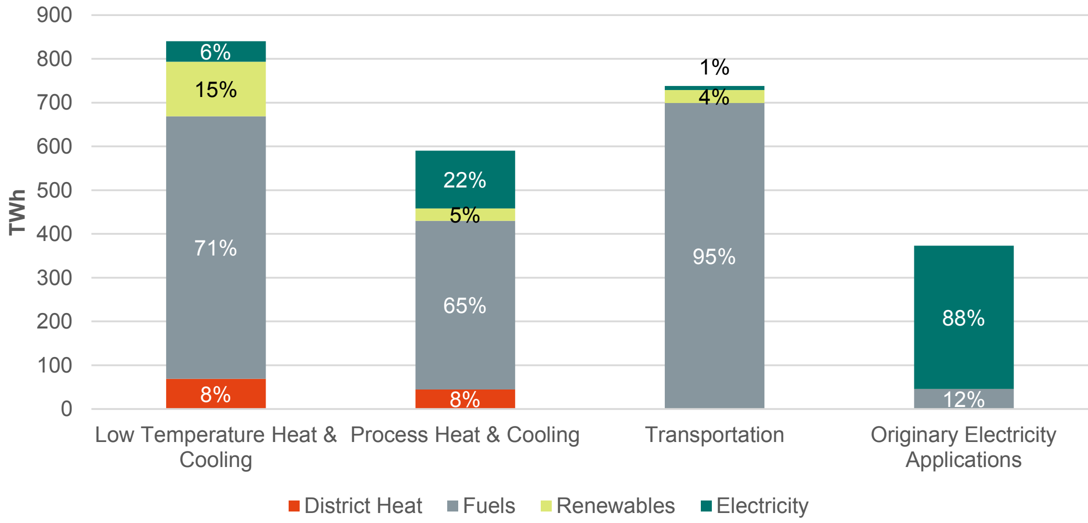

Figure 2.2: Final energy usage by application and energy carrier.

Source: own depiction using data from AGEB (2018), based on acatech, Leopoldina, and Akademienunion (2017).

leading to a shift in the modal split and (ii) the transformation of the fuel mix towards more renewables. While a future decrease in passenger kilometers of transportation demand seems unrealistic, the current trend towards urbanization and digitalization could be used to increase the share of public transportation (local and long-distance) and bikes in the modal split. Significant investments in infrastructure from bike lanes to high-speed rail lines in combination with digital solutions would be necessary to incentivize this shift. Additionally, nudges like subsidies for public transportation season passes and congestion charges for cars and parking could be supporting measures. A side effect of this strategy is an increase in the quality of life in cities due to less air pollution from fine particles, nitric oxide, and airborne gases as well as noise pollution. As aforementioned, "efficiency first" has been declared to be the leading principle by the German government (BMWi 2016).

Cars To decarbonize the transportation sector, different technological options are available or are currently being developed. The most prominent are probably battery electric vehicles (BEVs), directly electrifying passenger transportation and thereby increasing efficiency compared to conventional combustion engines. Assuming an efficiency factor of about 30 % for internal combustion engines compared to about 80 % for electric engines, the final energy usage for passenger road transportation could be reduced from about 400 TWh to 150 TWh (acatech, Leopoldina, and Akademienunion 2017). In 2016, the share of electric vehicles of all new registrations in Germany was less than 0.4 %. In absolute values they account for less than 12,000 out of 3.5 million newly registered vehicles[3] and less than 35,000 in total stock[4]. Other countries like Norway and China have higher shares in registrations and stock, mostly thanks to generous subsidies or regulations. The German subsidies of up to € 4,000, shared by the government and as discounts by the manufacturers, appear to not provide sufficient incentives, which is why the reserved public funds of € 600 million for this program have not been exhausted (less than € 120 million distributed between May 16, 2016 and April 30, 2018 for roughly 66,000 vehicles[5]).

A technology that has caught on in Germany on a larger scale than BEVs are hybrid electric vehicles (HEVs). By January 1, 2017, there were already more than 165,000 hybrid vehicles in stock[6] with almost 50,000 new registrations in 2016 alone[7]. HEVs have a combustion engine combined with an electric engine with battery so their range is considerably extended compared to BEVs, thus they are to date still fueled completely by fossil fuels. plug-in hybrid electric vehicles (PHEVs) on the other hand have the additional option to be charged directly with electricity. Some BEVs are also equipped with so-called range extenders, an additional combustion engine that is activated when the battery power is exhausted.

Fuel cell (electric) vehicles (FC(E)Vs) use electric engines powered by hydrogen fuel cells. Their advantage is the faster refueling process and a longer range due to the higher energy concentration of a hydrogen tank. Although their development is ongoing for many years already, the technology is still not available for mass production, making them more expensive. Since hydrogen needs to be produced from electricity by electrolysis and then converted back into electricity, the whole process suffers from significant conversion losses in the order of 50 %.

Natural gas vehicles (NGVs) use fossil gas as a fuel (emitting CO_2) or can be powered by bio methane from biogas or synthetic methane. Both alternatives have a lower energy content. The advantage of NGVs is the already existing (yet sparse) infrastructure of gas stations across Germany.

The last option is the replacement of conventional diesel or petrol by biofuels or syn-

[3] Kraftfahrt-Bundesamt (KBA). 2017b. *Neuzulassungen von Pkw im Jahr 2016 nach ausgewählten Kraftstoffarten.*

[4] Kraftfahrt-Bundesamt (KBA). 2017a. *Bestand an Pkw am 1. Januar 2017 nach ausgewählten Kraftstoffarten.*

[5] BAFA. 2018. *Elektromobilität (Umweltbonus): Zwischenbilanz zum Antragstand vom 30. Juni 2018.* Technical report. Eschborn, Germany: Bundesamt für Wirtschaft und Ausfuhrkontrolle.

[6] Kraftfahrt-Bundesamt (KBA). 2017a. *Bestand an Pkw am 1. Januar 2017 nach ausgewählten Kraftstoffarten.*

[7] Kraftfahrt-Bundesamt (KBA). 2017b. *Neuzulassungen von Pkw im Jahr 2016 nach ausgewählten Kraftstoffarten.*

thetic fuels with similar properties that could be distributed via the existing, well permeated network of gas stations and can be burned in only slightly retrofitted internal combustion engines. The major drawback of this process is the additional conversion step for synthetic fuels. While a BEV has an approximate overall energy efficiency (from electricity generated by renewable sources to wheel) of 69 %, FC(E)Vs only reach about 26 %. Yet, this is still a higher efficiency rate compared to the 13 % of power to liquid processes (acatech, Leopoldina, and Akademienunion 2017). Translated into a km per kilowatt hour (kWh) scale (comparable to the “miles per gallon” concept in the US) a conventional internal combustion engine can reach about 1.5 km/kWh from mineral oil, while a fully electric car will yield 5 km/kWh. Power to liquid and power to gas concepts with a combustion engine or with an electric engine achieve 1 km/kWh and 2 km/kWh, respectively. It is essential to use the most efficient technology options available since additional electricity demand from the transportation sector alone would amount to more than 1000 TWh per year if fossil fuels were mostly substituted by synthetic fuels. Neglecting the rivalry with food production, a rough estimate shows that the current energy demand from the transportation sector could also not be supplied from biofuels produced only on agricultural sites within Germany, even if the entire available agricultural area in Germany was used for fuel production only. (Quaschning 2016)

One of the key success factors of BEVs and PHEVs, aside from the currently prohibitively expensive price, is the availability of a sufficient charging infrastructure with an adequate level of standardization and interoperability so that vehicles are able to use a high number of charging stations. However, current infrastructure does not yet suffice to provide for a large number of potential users, predominantly for those living in apartment buildings with no access to a charger connection in their own garage.

While BEVs are an option for short-range transportation, mostly in urban areas where they are being used already, heavy-duty and long-range transportation reverts to different technology options. This is due to the undue weight of batteries and high time consumption of charging processes needed for these high capacities. One option that is been tested in different pilot projects are trolley trucks, using a contact wire along their route, which could be used along major transportation corridors. To avoid the need to transship for the first and last mile, those vehicles would need to be equipped with additional short-range batteries or hybrid solutions or fuel cell engines. Assuming a subsidized introduction phase for the infrastructure on German highways, studies show that about 80 % of heavy-duty trucks could be converted to trolley trucks in an economic viable way, only requiring about

30 % of the German national highways to be equipped with contact wires.[8] A shift towards more freight traffic on electrified rail corridors can further alleviate the problem.

Aviation and Maritime Transportation A special case is air and maritime transportation. Fully battery electric airplanes are not very likely to achieve market maturity within the next decades since the specific energy content of currently available batteries is too low and their weight is too high. Also, planes depend on short turn-around times at the airports since they are very capital intense assets and only earn money while airborne, which would be prevented by long recharging cycles. Hydrogen is, due to its comparatively low energy content, also not a probable option. Therefore, liquid fuels with a high specific energy content will still be needed. Instead of using fossil fuels, they could be synthetic or of organic nature like algae (Adeniyi, Azimov, and Burluka 2018). Likewise, maritime transportation can at least partially been switched to biofuels.

In all cases, the degree of decarbonization ultimately depends on the electricity mix present in the system. In order to achieve a reduction in greenhouse gas emissions, renewable energy capacities need to be tremendously expanded. Otherwise, coal or fossil gas capacities will be used to power vehicles, only lowering local emissions and improving the quality of life of the local population, but adversely affecting the climate.

2.3.2 Heating and Cooling

In the heating and cooling sector, two major issues can be distinguished: on the one hand there is space heating and cooling and the provision of warm water, all at comparably low temperatures, on the other hand there is process heating and cooling for industrial and commercial purposes at extremely high or low temperatures. In 2016, the German heating and cooling sector used about 1430 TWh of final energy (Figure 2.2).[9] Figure 2.3 shows the technical options of providing heat using renewable energies.

Space Heating, Cooling, and Warm Water Space heating, cooling, and warm water accounts for 33 % or about 840 TWh of the final energy consumption (Figure 2.2). According to political objectives, the energy usage of buildings is supposed to be reduced by 20 % by

[8] Martin Wietschel et al. 2017. *Machbarkeitsstudie zur Ermittlung der Potentiale des Hybrid-Oberleitungs-Lkw.* Studie im Rahmen der Wissenschaftlichen Beratung des BMVI zur Mobilitäts- und Kraftstoffstrategie. Karlsruhe, Germany: Fraunhofer ISI, Fraunhofer IML, PTV Transport Consult, TU Hamburg-Harburg, M-Five.

[9] AGEB. 2018. *Anwendungsbilanzen für die Endenergiesektoren in Deutschland in den Jahren 2013 bis 2016.* Technical report. Berlin, Germany: AG Energiebilanzen e. V.

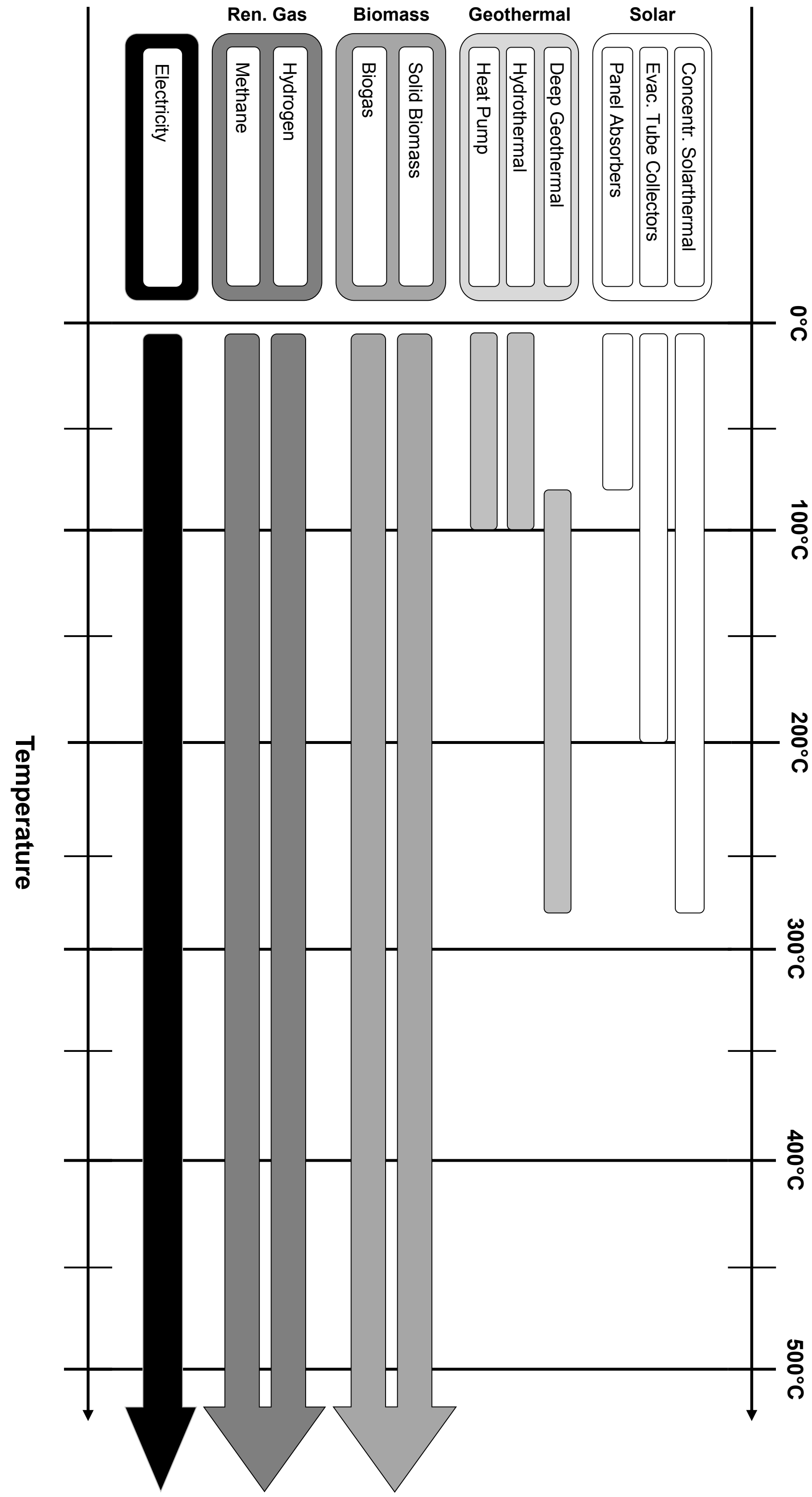

Figure 2.3: Obtainable heat levels by renewable sources.

Source: own depiction based on Naegler et al. (2015) and Naegler et al. (2016).

2020 compared to 2008, while until 2050 all buildings are set to be “climate neutral” (BMWi and BMUB 2010). One way to achieve this and limit the energy usage and carbon emissions of buildings is to enhance insulation. Since there are technical and economic limitations in this field, carbon emissions of the used energy need to be lowered as well. Modern condensing boilers have reached a yield level for the calorific value of burned fuels that cannot be increased any further through innovation (acatech, Leopoldina, and Akademienunion 2017), which is why only combined heat and power units could increase the efficiency. Consequently, a fuel switch towards either organic or synthetic fuels or renewable energies is necessary.

Using rooftop solar thermal panels for heat generation is one option to achieve this switch. Those panels however can only contribute a limited share of the required heat (mostly for warm water generation) since there is a seasonal offset between high supply in the summer and high heat demand in the winter. Geothermal heat generation is another option, yet there is a very limited potential in Germany (acatech, Leopoldina, and Akademienunion 2017).

Replacing the natural gas used in gas boilers by biogas or gas from power to gas processes can serve as a bridging technology for houses that have not yet been refurbished with other technologies. Electric heat pumps are more efficient in generating heat, though so far this technology is not very prevalent and mostly used in newly built or renovated single-family homes. One of the reasons are the still very high investment costs compared to a gas boiler and, compared to natural gas or heating oil, high consumer prices for electricity. Heat pumps have a higher efficiency with lower final temperatures which means that underfloor heating systems using low temperature levels are most efficient. However, warm water in apartment buildings, which—for sanitary reasons—needs to be at a minimum temperature of 60°C, is more difficult to supply. Therefore, also hybrid systems or biogas fired heat pumps or communal heating and power stations will be required for applications where heat pumps are not technically or economically viable options.

Currently, the modernization rate of German buildings amounts to about 1 % annually, while most studies suggest a necessary rate of at least 2 % in order to reach climate targets. Otherwise, the refurbishment of heating systems will not advance fast enough. At the same time, about 3 % of all home renovations each year lack any energy improvements. Thus, there is a potential for an increased rate of energy related modernization, but it needs to be promoted by suitable political measures. (SRU 2017)

District heating systems will still play a certain role in the future, provided sufficiently dense demand. A centralized provision of heat, distributed via a low-temperature heat grid in densely populated areas, has tremendous efficiency advantages over decentralized heating systems. Power to heat technologies (Bloess, Schill, and Zerrahn 2018), that is, generation of heat from excess electricity, for instance in times of high renewable production, can be used in those facilities. At the same time, waste heat from industrial processes can be used in the residential sector. In combination with large-scale (and long-term) heat storages based on water or salt, this system would provide a lot of flexibility to the overall energy system.

Space cooling currently has a neglectable share, mostly already being generated from electricity. Due to rising temperatures in the wake of climatic change, and to more extreme summers to be expected, the demand for air conditioning (AC) is likely to rise significantly.

Process Heating and Cooling Process heating and cooling for industrial and commercial purposes account for 23 % or about 590 TWh of the final energy consumption in Germany (Figure 2.2). More than 90 % thereof is from process heat, mostly generated from fossil natural gas and coal. Only industrial demand is of relevance here, since the commercial demand and the demand from households is already mostly generated directly from electricity (e.g. cooking). The industrial demand for process heat can be split into the high-temperature range above 500°C, mid-range temperatures and the low-temperature range below 100°C. The low-temperature range accounts for only about 25 % of the heat demand, while the high-temperature range has the largest share of more than 57 % (Naegler et al. 2015).

Whereas the low-temperature range could mostly be replaced by efficient heat pum"-ps, temperatures above 200°C cannot be achieved by this technology. In these processes fossil fuels need to be replaced by biomass or synthetic fuels or they should be directly electrified wherever possible (see Figure 2.3). Certain processes require very high temperatures above 1,500°C that are hard to reach using electricity as energy carrier. Moreover, currently used energy carriers might have additional purposes within the process. Coke in blast furnaces for example provides the necessary stability of the materials in the furnace (acatech, Leopoldina, and Akademienunion 2017).

Again, a rise of process efficiency is crucial to achieve the energy transformation in the industry sector. However, the energy used for many processes in the basic substance industries is thermodynamically required for physical phase transitions or chemical conversions and constitute an elementary component of the final product (e.g. glass, ceramics, and plastics), which cannot be replaced. In addition, the electrification of some processes might be a lot less efficient than the current methods. Hence, process optimization potentials are limited in a twofold manner: minimizing heat losses and waste heat being used for space heating in the companies' buildings or redirected into neighboring district heating networks.

Increasing the quota of recycled materials in the German economy would yield a further decrease in energy demand from industrial processes since the recycling of raw materials like glass, paper, plastic, aluminum, or steel is usually less energy intensive compared to new production. Yet, many of today's recycling technologies lead to a so-called "down cycling", reusing the material in a lower quality form. Plastic water bottles for example are down cycled into fibers for clothing production or park benches. With those proceedings, the need for new high-quality plastic is not being reduced. These emissions can only be abated by switching to a different production process.[10]

Another important aspect is the formation of CO_2 as a byproduct. For example, major emissions come from burning in the cement production. These emissions can only be abated by switching to a different production process. Alternatively, the CO_2 can be separated and deposited with carbon capture, transport, and storage (CCTS) technologies or used as a base material in other processes, for example, carbon capture and utilization (CCU). Neither of the two is sufficiently developed to yield promising results, and it is likely that the *Energiewende* will have to do without them.

In conclusion, the decarbonization of the industrial sector including heating and cooling is a challenge compared to the other sectors. Only a minor part is already electrified, a major increase in electricity demand can be expected and for some processes, there is currently no alternative to the usage of synthetic fuels.

2.3.3 The Electricity Sector in the Core of Interdependencies

The lower-carbon sector coupling is likely to evolve around the electricity sector. In fact, the fuel switch from fossil fuels to electricity of the described sectors transportation, heat, and industry has wide-ranging consequences for the electricity sector. These sectors are highly dependent on efficiency gains, but also on the flexibility options those sectors provide for the system and the assumed scenarios and pathways for sector coupling. The overall goal of decarbonization leads to a high demand for renewable energy from competing sectors and applications. In general, a large number of options for sector coupling are available and conceivable. Figure 2.4 provides a detailed overview of the possibilities to

[10] One example of a new binder with significantly reduced energy usage and CO_2 emissions is Celitement, developed at Karlsruhe Institute of Technology (KIT): www.celitement.de.

couple transportation, heat, and industry via the electricity sector.

When shifting towards a higher degree of electrification, the decarbonization of the electricity system is the key success factor. Otherwise, the current CO_2 emissions from other sectors would only be shifted to an electricity generation from fossil fuels, implying only a locally emission free energy use. Fluctuating and intermittent renewable energy sources can be employed for power production, using photovoltaics (PV), onshore and offshore wind generation, biomass or geothermal technologies, in combination with storage. Via the electricity transportation and distribution grid, the electricity can be directly used in all sectors or be stored in long-term storages like pumped hydro storages or short-term storages like batteries. An advance in sector coupling will further increase the needs for flexibility in the system.

For applications where no direct electrification is possible, indirect electrification is an option, using synthetic fuels produced with the help of electricity. This path can also be used for a long-term chemical storage of energy. As mentioned above, synthetic fuels are a viable replacement for some cases in the transportation sector but also for the substance-based use of primary energy.

Heat can be directly produced from electricity, via so-called power to heat (PtH) applications (Bloess, Schill, and Zerrahn 2018). Those can be small-scale or large-scale electric boilers or heat pumps. The generated heat can then be used directly for heating buildings, warm water generation, or in industrial applications. It can also be generated centrally and transported via district heating networks. Heat storages in homes or at a larger scale can decouple supply from demand.

The advantages of synthetic fuels are low costs of refurbishing (cutover costs) of the existing technology. Most applications like gasoline and diesel cars could be easily adapted to synthetic fuels. Yet, synthesizing fuels using electricity is an additional conversion step in the value chain, thus lowering the overall efficiency of the used energy and therefore increasing the amount of additional electricity required. This exacerbates the competition between sectors for renewably generated electricity even further. In the long term, the costs for new technologies and infrastructure necessary for a direct electrification might therefore outweigh the increased costs of electricity due to the higher demand.

The dimensions and cost of the energy system are also highly dependent on the flexibility present in the system, that is, of electricity generation, of electricity and heat storages, and of electricity load. The cost of energy provision is directly related to gains in efficiency and the flexibility of the whole system. Sector coupling increases the flexibility in the system in many ways but is also associated with an increased need for flexibility due to the higher

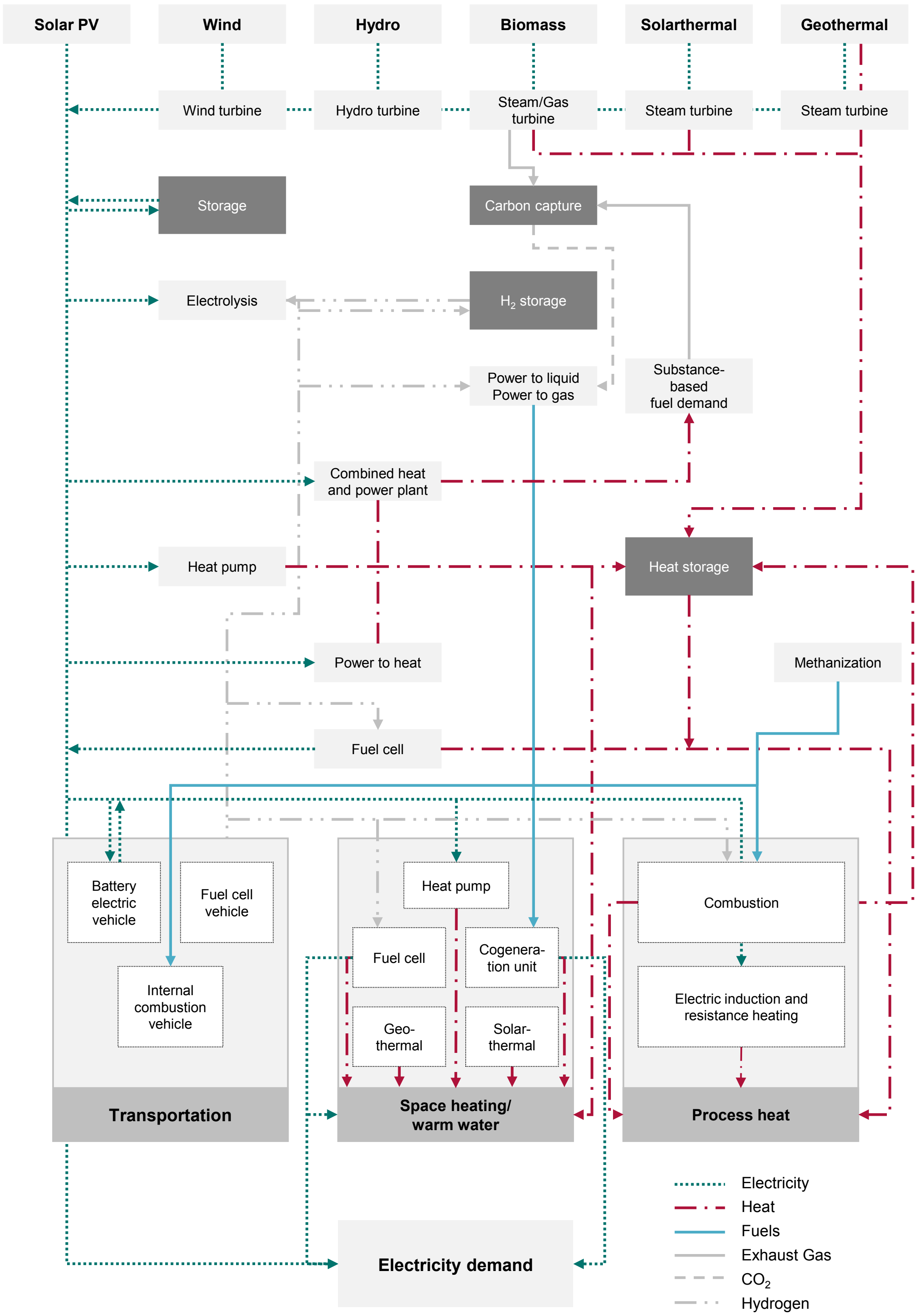

Figure 2.4: Options for sector coupling in a decarbonized energy system.

Source: own depiction based on SRU (2017).

electricity demand.

A more flexible demand for electricity lowers the amount of required generation capacities and storage technologies by peak-load shaving and load shifting options. This can be achieved by flexible heat pumps for space heating and warm water production or a regulated charging of electric vehicles. The achieved savings can compensate the higher costs associated with these demand side flexibility technologies. Inflexible demand on the other hand would lead to a larger necessary dimensioning of generation and storage capacities to absorb the associated high load peaks. This would add to the costs of electricity generation, also via the need to generate the additional renewable energy at less favorable and therefore more expensive locations.

A key factor is flexibility from industrial processes in energy intensive sectors, especially when they are electrified. To date most production processes are optimized to run on a steady basis without any flexibility. A so-called "flex-efficiency" production (Agora Energiewende 2018), increasing efficiency and adding flexibility to the system, is necessary for a successful integration. Incentives for energy optimized production processes will be a prerequisite for businesses to adapt them.

Power to X technologies provide further flexibility and storage options for electricity in other forms. Power to heat allows the production of heat from electricity via heat pumps or boilers. Power to gas and power to liquid can be used for the generation of synthetic gas and fuels from electricity, utilizable in the above-mentioned fields and most notably as long-term and seasonal chemical energy storages (see Buttler and Spliethoff (2018) for an overview). The production of those synthetic gas and fuels could also happen in North Africa or the Middle East, providing oil- and gas-exporting countries with new non-fossil-based business models (Agora Energiewende and Agora Verkehrswende 2018).

Newly developed inexpensive storage technologies like Carnot batteries can help to store large amounts of electricity over a longer period. Those batteries use high temperature heat pumps to generate heat that is then stored in water or salt storage tanks. Electricity can be regenerated from the heat via thermal engines. Alternatively, the heat can be directly dispensed for heating and cooling. Researchers predict a cycle efficiency of 75 % for this technology.[11]

The choice of technologies in one sector has therefore implications on the flexibility needs and selection of energy carriers in the other coupled sectors. The possibility to shift loads between the sectors in conjunction with high flexibility lowers the need for demand side

[11] "DLR arbeitet an Gigabatterie." VDI nachrichten, May 3, 2018. www.vdi-nachrichten.com/Technik/DLR-arbeitet-an-Gigabatterie.

flexibility. In many cases there is a trade-off between flexibility and efficiency, for example between direct and indirect electrification. Coupling of the sectors increases the degrees of freedom of the overall system, shifting the attention to the efficiency of the system components.

2.4 Some Model-based Evidence

Although the discussions about far-reaching sector coupling are only emerging, some detailed studies already provide some evidence of the potential effects: SRU (2017) and Ausfelder et al. (2017) provide an overview of the most prevalent analyses for Germany. Brown et al. (2018b) extend the literature for the European case. Although these studies vary in the set boundaries of the energy system, they concur that a far reaching decarbonization (80 to 95 %) of all the regarded sectors until 2050 is technically and economically feasible via a comprehensive electrification.

2.4.1 Electrification is Key

Most studies assume an increase in energy efficiency and additional electricity demand from the transportation, heat, and industry sectors. By 2050, the final electricity demand will grow to about between 780 TWh and 1,450 TWh, that is, an up to twofold increase compared to today's values. Some studies even reach about 3,000 TWh, assuming no efficiency gains or a demand fully supplied by domestic generation, see Quaschning (2016). The calculated yearly peak demands do not differ much from today's: 60 gigawatts (GW) to 80 GW. Only one study reaches 110 GW. The storage demand varies between 8 GW and 15 GW with an outlier at 75 GW. This flexibility demand is mostly met by batteries or the storage technology is not further specified.

The different growth rates in electricity demand also yield different installed renewable capacities depending on the transformation path (Figure 2.5. For 2030 the studies assume a photovoltaic capacity between 68 GW and 109 GW, onshore wind capacities between 51 GW and 97 GW, and offshore capacities between 11 GW and 22 GW, while for 2050 a photovoltaic capacity between 75 GW and 290 GW, onshore wind capacities between 64 GW and 204 GW, and offshore capacities between 15 GW and 70 GW are being calculated. Electricity imports and exports do not exceed 50 TWh per year, limiting the possibilities to shift emissions to neighboring countries.

While electricity could be generated to a large extent in Germany, synthetic fuels might

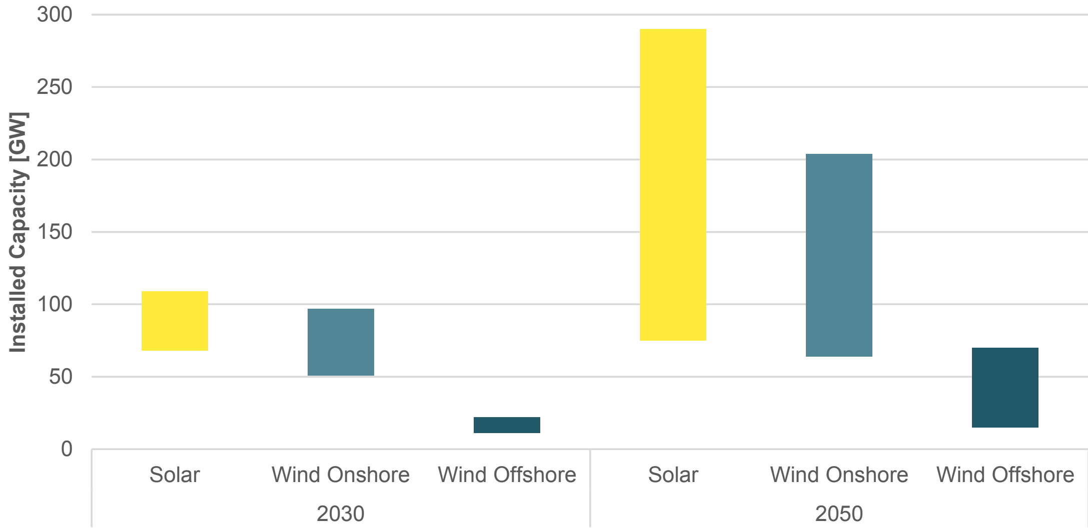

Figure 2.5: Range of installed capacities in Germany from study scenarios.

Source: own depiction based on SRU (2017).

be supplied in part from abroad, between 20 TWh and 1,200 TWh. Necessary generation capacities and the area required is shifted outside the country's borders.

2.4.2 "Efficiency First"

Thus, the consumption of electricity will rise significantly with an increasing level of sector coupling and electrification of loads. A multifold increase in capacity expansion of renewable generation technologies is key for decarbonization. Otherwise the sectors would be electrified but for example electric vehicles—perceived to be clean means of transportation—would only shift their greenhouse gas emissions to an electricity production from gas and coal (Schill and Gerbaulet 2015). Since renewable energy sources are in fact limited domestically or come with increasing marginal costs of capacity additions due to the need to draw on less favorable production sites, even renewably generated electricity has to be used as efficiently as possible. The principle "efficiency first" (Agora Energiewende 2018) with all conceivable process improvements applies to all sectors—every kilowatt-hour not consumed is a kilowatt-hour saved.

The energy concept of the federal government therefore also states ambitious efficiency goals for electricity: 10 % less final energy use in 2020 and 25 % less in 2050 compared to the year 2005 (BMWi and BMUB 2010). Efficiency gains in the electricity sector will be eaten up entirely by the mentioned increase in demand from heat and transportation. At the same time the increased need for flexibility that comes with a higher share of and higher generation amounts from renewables have to be considered when deciding for specific decarbonization pathways for the sectors in question. The concept of flex-efficiency (Agora Energiewende 2018) therefore needs to be implemented: energy savings in times of low renewable generation is especially valuable. Efficiency is extended by a temporal component.

2.4.3 Role of Synthetic Fuels Uncertain

While the verdict is clear on the role of electrification, the role of synthetic fuels is discussed more controversially. Synthetic fuels may become essential for a deep decarbonization of the energy sectors (Agora Energiewende and Agora Verkehrswende 2018). While space heating and cooling can be supplied directly from electricity using heat pumps, high-temperature applications in industrial processes are not flexible enough for direct electrification. In the interplay with the need for synthetic fuels in industry for substance-based usage and applications that cannot be directly electrified due to chemical or physical reasons, the deployment of synthetic or organic fuels might contribute to the flexibility needs. Furthermore, the chemical energy storage capabilities of synthetic fuels could help to bridge phases of so-called "dark doldrums", when there is not enough electricity generation from photovoltaics and wind power over a longer period of time (i.e. a couple of days up to two weeks) and where shortfalls in electricity and heat supply might coincide. The higher energy costs of those fuels, coming from the lower efficiency of additional conversion steps, could be outweighed by the lower need for generation capacities and storages to cushion those periods that do not occur often but would need to be anticipated. Efficient combined heat and power plants could be fired with those synthetic fuels and gases to produce electricity and heat. The same level of security of supply therefore can be reached with less installed capacities.

While synthetic fuels may play a certain role in industry and the electricity sector, their relevance is controversial for the transportation sector. Only applications where a very high specific energy content is essential should rely on indirect electrification. Those are namely air transportation and, in part, maritime transportation. Still, the transportation sector can contribute significantly to the flexibility of the system by offering demand side flexibility from controlled charging processes of electric vehicles.

2.4.4 Digitalization and Smart Infrastructure

Aside from the big picture of necessary electrification and investments in renewables and flexibility, some other aspects will play a role in a successful sector coupling. The energy sector needs to increase the level of its digitalization, moving towards a smart, efficient use of infrastructure. An increasingly decentralized structure of "prosumers", customers who are producers of energy or electricity at the same time, relies on an interconnected system using new technologies (Agora Energiewende 2018). Smart markets with real-time smart metering of electricity will give incentives to customers to offer flexibility for the system. Regional price mechanisms can enhance an efficient utilization of distribution and transmission grids. Taxes and levies may not overlay those price effects.

Smart homes will be able to optimize the energy usage in buildings in combination with rooftop PV generation, battery storages, flexible heat pumps, and electric vehicle charging. Smart mobility will offer new concepts of transportation, avoiding unnecessary trips and increasing the efficiency of the transportation infrastructure. Following the trends for example in the information and communication technology (ICT) industry, more and more products will be offered "as-a-service", such as mobility-as-a-service in shared mobility concepts, calling for a change in consumer mentality. New business models will arise around sector coupling and the digital energy industry—enhancing a more flexible and intelligent use of energy in general.

Electricity transmission networks will be expanded to a certain degree. Yet, an efficient utilization should limit the amount of required capacity expansions. Due to the progressing decentralization and higher energy demands in homes from heat pumps and electric vehicles, load profiles and flows in the distribution grids will change drastically, possibly leading to the need for further investments.

District and local heat networks will still play a role especially in densely populated areas. Due to the improvements in building insulations, heat demand will decrease. Grids should gradually be retrofitted to decentralized low-temperature networks, accommodating waste heat from industrial processes and biogas plants, geothermal generation, heat pumps, and other power to heat applications.

2.4.5 Other Issues: Fossil Gas, Transportation, and Market Design

The demand for natural fossil gas will gradually decrease with the switch to renewable generation technologies. While gas fired power plants can act as very flexible back-up capacity with comparably low CO_2 emissions, in a fully decarbonized energy world there is no CO_2

budget available for converting fossil gas into electricity anymore. The natural gas grid infrastructure will therefore shrink, with a possible withdrawal from sparsely populated areas. Still, the gas grids can be retrofitted and used for transportation and distribution of synthetic green gases like hydrogen and methane that will be used in the industry sector. It can also support the energy sector with additional flexibility.[12] An alternative to this are biofuels.

In the transportation sector the electrification and expansion of rail networks should be expedited. A sufficient charging infrastructure for fast-charging electric vehicles along major transportation corridors and in densely populated cities needs to be established to facilitate the switch to electric mobility, especially for longer trips and for people not living in single-family homes. Heavy-duty freight transportation could be taken over by hybrid trolley trucks, requiring a major infrastructure implementation of overhead contact systems along major highways.

An adapted market design, coherent in pricing and taxation for all sectors and fuels, will be the foundation of a coupled energy sector, accompanied by investment incentives like public technology funding and regulatory frameworks. Consistent and sufficiently high CO_2 prices will facilitate the shift towards renewables in all sectors. The EU Emissions Trading System (EU ETS) could be advanced accordingly or a tax on CO_2 emissions could be introduced to speed up the development on a national level. Pricing CO_2 has the advantage of being a technology neutral policy measure, promoting the most cost efficient abatement options, avoiding lock-in effects, and anticipating not yet known new technologies (acatech, Leopoldina, and Akademienunion 2017). Other emissions have to be considered as well.

2.5 Conclusion

The low-carbon transformation of the German energy system (but also of others) has so far focused on the electricity sector. As described in the previous chapters, it was relatively easy to attain, and even to surpass, the goals on renewables, and taking nuclear plants from the grid, while the reduction of greenhouse gas emissions and the phasing out of coal will take somewhat more time than expected. However, as the *Energiewende* enters the next phase, even more efforts are required to work towards the large-scale introduction of renewables, which is required in all sectors in order to attain the decarbonization targets.

[12] Frontier Economics et al. 2017. *Der Wert der Gasinfrastruktur für die Energiewende in Deutschland.* Technical report. Köln, Germany: Vereinigung der Fernleitungsnetzbetreiber (FNB Gas e. V.)

In this chapter we have provided a broad survey of "sector coupling", that is, the combination of technical and economic interdependencies between electricity, transportation, and heat, accompanied by a larger share of renewables. Both elements are necessary (though not sufficient) to succeed the *Energiewende*: without technical interdependencies, transportation and heating are likely to remain largely fossil, whereas introducing renewables into electricity alone is insufficient, too. We observe and describe a rapidly growing literature on sector coupling: while ambitious targets are agreed upon, they can be reached, concretely for the German case, by deepening sector coupling.

Further research is required to translate sector coupling into more concrete policy instruments, to accompany and steer the process. It is clear that a stronger carbon price helps the general trend, but more specific instruments are needed to electrify transportation and heating, and to internalize the adverse environmental effects of fossil fuels in all three sectors, which are the very reason for this exercise. SRU (2017) and Ausfelder et al. (2017) include early suggestions of targeted policy instruments, but they need to be deepened to translate the rather abstract idea of sector coupling into real life.

Part II

Economic Dispatch Modeling

Chapter 3

Illustrating the Benefits of Openness: A Large-Scale Spatial Economic Dispatch Model Using the Julia Language

> "There's no company called Linux, there's barely a Linux road map. Yet Linux sort of springs organically from the earth. And it had, you know, the characteristics of communism that people love so very, very much about it. That is, it's free. [. . .] And we could either say, hey, Linux is going to roll over the world, but I don't see that happening. That's not what's going on right now."
>
> *(Steve Ballmer, CEO at Microsoft's annual Financial Analyst Meeting on July 27, 2000[1])*

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3.1 Introduction

In the wake of the strenuous efforts to reduce the effects of climate change, electricity systems worldwide have undergone profound transformations over the last decades from mostly centralized conventional power generation using carbon-intense fossil fuels towards more decentralized renewable power plants. Nevertheless, the goals of climate protection demand for further action and massive changes in the upcoming decades. In order to achieve a better comprehension of electricity systems, assess and optimize operation and investment decisions, but also to generate insights for policy making, electricity sector models are being used. These models are usually large-scale, complex techno-economic models describing the behavior of an electricity system in operation. The rapid change of the electricity sector, driven by vast extensions of renewable installations and an increase in sector coupling with heat and transportation, make them even more relevant for a consistent energy transition in the present and coming years.

Historically, most of these models have acted as proprietary black-box solutions, written in commercial systems and operated by organizations without the opportunity for other researchers to reproduce and validate results and for the public to fully understand and use these models, leading to a lack of transparency in the modeling community. One example is the European Commission's strategic long-term vision for a climate neutral economy by the year 2050. The policy package laid out here is based on insights gained using an energy sector model that cannot be directly reproduced since neither the model source code nor the data sets have been published.

Against this backdrop, more and more voices are advocating for open source, open data, and open access in energy system modeling (Pfenninger et al. 2017). Some initiatives already have published their models for an open-source use.[2]

With this chapter we are presenting a new tool set for electricity and energy system modeling: the rather new programming language Julia, developed at MIT specifically for the needs of scientific computing, in combination with its algebraic modeling library JuMP. In a benchmark study with a proof-of-concept (PoC) for a fully 'open' electricity system model we are presenting a quantitative comparison with regard to computation time of the new

[1]Quoted after Jennifer Helene Maher. 2016. "Software Evangelism and the Rhetoric of Morality - Coding Justice in a Digital Democracy". New York: Routledge.

[2]Examples are the energy modeling system OSeMOSYS (Howells et al. 2011) or the power system analysis tool PyPSA (Brown, Hörsch, and Schlachtberger 2018) and the open energy modeling framework (oemof, www.oemof.org), both written in Python. Those two models can be used fully open source, oemof even provides a library for output visualization.

Julia/JuMP with the conventional proprietary General Algebraic Modeling System (GAMS).

We argue that using an open-source language like Julia, the modeler's efficiency and productivity can even be enhanced, since the whole modeling workflow from data pre-processing to visualization can be implemented within the same system at only very low start-up costs. Embedded into a broader open concept, this would lead to an increase in transparency but also to a strengthening of the modeling community.

On the other hand our benchmark study also shows one deficit of open-source tools: for the time being at least very complex models are still dependent on proprietary software in the form of the numerical solvers required since open-source alternatives can mostly not keep pace with their commercial counterparts.

With this chapter we also introduce *Joulia.jl*, an open-source package for large-scale spacial economic dispatch problems written in Julia/JuMP, solely using open data and—where complexity allows—making use of open-source numerical solvers.

The remainder of this chapter is structured as follows: Section 3.2 describes the benefits of open science. Section 3.3 provides a short introduction into the Julia programming language and the algebraic modeling language JuMP. Section 3.4 explains the model and gives an overview of the used input data. In Section 3.5 the implementation in Julia/JuMP and the results of the benchmark tests are discussed. The chapter then concludes with a summary and outlook in Section 3.6.

3.2 The Benefits of Openness

In their manifesto[3], the Open Energy Modeling Initiative (openmod) advocates for more openness in energy modeling:

> «Energy models are widely used for policy advice and research. They serve to help answer questions on energy policy, decarbonization, and transitions towards renewable energy sources. [...] We believe that more openness in energy modeling increases transparency and credibility, reduces wasteful double-work and improves overall quality. This allows the community to advance the research frontier and gain the highest benefit from energy modeling for society.»

[3]www.openmod-initiative.org/manifesto

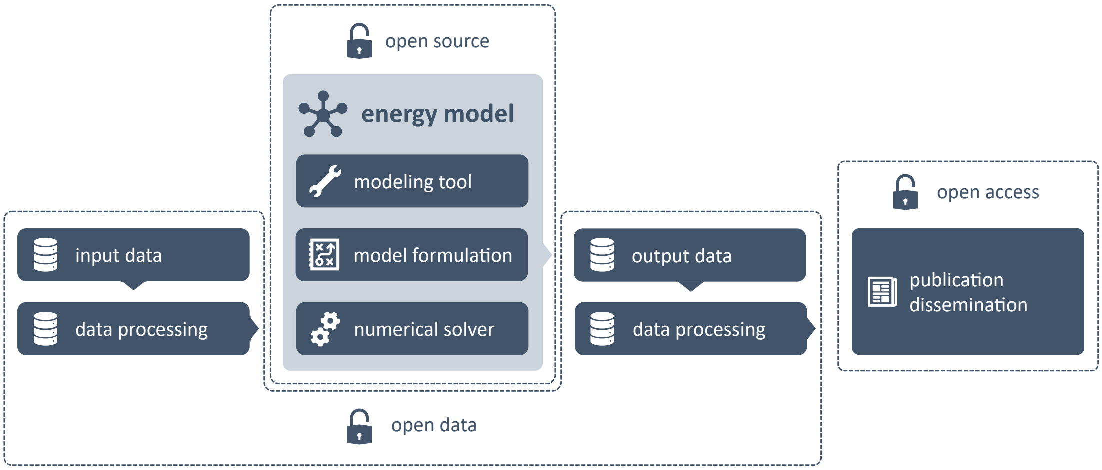


Figure 3.1: Schematic workflow and dimensions of openness in the energy modeling process.

Source: own depiction based on Müller, Weibezahn, and Wiese (2018).

The Open Definition 2.1[4] states: "Knowledge is open if anyone is free to access, use, modify, and share it — subject, at most, to measures that preserve provenance and openness." More specifically, the openness of a modeling project can affect different dimensions. We define five dimensions of openness that will be described in the following section: open data, an open-source modeling language, open-source model code, open-source solvers, and finally open-access publications. This follows recommendations by DeCarolis, Hunter, and Sreepathi (2012) and Morrison (2018). These dimensions can be aggregated to three major topics: the availability and usage as well as publication of input and output data, the software part, and the scientific publications. See Figure 3.1 for a schematic overview of the workflow and the dimensions of openness in the energy modeling process.

The difference between OSS and CSS generally lies in the availability of the source code to the general public. OSS, as promoted by the Open Software Initiative (OSI)[5], comes with a license with minimal or no restrictions on the (re-)distribution, use, and modification of the software. The Free Software Foundation (FSF)[6] and the GNU Project promote a rather similar approach:

> «The word "free" in our name does not refer to price; it refers to freedom. First,

[4] www.opendefinition.org
[5] www.opensource.org
[6] www.fsf.org

> the freedom to copy a program and redistribute it to your neighbors, so that they can use it as well as you. Second, the freedom to change a program, so that you can control it instead of it controlling you; for this, the source code must be made available to you.»[7]

CSS or proprietary software, on the other hand, is always distributed under a very restrictive license and as a 'black box' with no possibility to view the source code in order to determine the functionality.

The advantages and disadvantages of OSS vs CSS can be described using the categories customizability and control (is the software a 'black box' or can the user check what it does 'under the hood'?; can the user change the source code in order to adapt the software to her specific needs?), security (can the software be corrupted by hackers?), reliability (does the software do what it promises? does it come with a huge number of bugs?), and maintenance (will bugs be fixed with a short lead time? will new features be implemented?).

Famous examples of OSS are Python as an established programming language, Julia as a rather new programming language, and OSeMOSYS (Howells et al. 2011) as an energy sector model. Infamous examples of CSS, on the other hand, are GAMS as an algebraic modeling language, and PRIMES (E3MLab 2016) as an energy sector model.

3.2.1 Open Data

Energy sector models in general and electricity sector models in particular are mostly not rocket science[8] but are largely data-driven (hence: 'large-scale models'). In the past, most of this data was not available to the general public, hidden in commercial databases or not accessible at all due to trade secrets and matters of 'national security'. Over the last few years, stakeholders in the electricity sector started to open up and publish data online, in most cases because of legislation obligating them to a certain transparency. Nevertheless, while many of those data sources can now be openly viewed, it is—according to copyright law and licensing—mostly not legally possible to use, process, and redistribute this data why more and more initiatives are calling for improved legislation (Morrison, Brown, and De Felice 2017). Nevertheless, there is and always will be a certain portion of data that will not be available to the public.

Another aspect is the structure of publication and quality of the published data. Pro-

[7] GNU's Bulletin Volume 1 No. 1, 1986

[8] To quote an expert in the field: "The whole world can be modeled as linear programs!"

jects like Open Power System Data (OPSD)[9] (Wiese et al. 2019) try to tackle this issue by providing Python scripts to download and pre-process commonly needed power system data for modelers. This also increases the productivity of modelers since not everyone has to go through the same tedious process of data collection and pre-processing again (Pfenninger et al. 2017).

3.2.2 Open-Source Programming & Modeling Tool

An algebraic modeling language is a modeling tool to formulate an optimization (or simulation) problem in a high-level language and then pass the generated matrix on to a so-called solver—an independent software—for calculating the numerical solution to the problem rather than writing the input directly in low-level code.

When it comes to the decision what modeling tool should be used for a project, there is a quasi standard at least for the academic and industry energy community: GAMS, the General Algebraic Modeling Language. Aside from this, AMPL can be used but there is also a whole range of viable open-source alternatives with major advantages over their commercial competitors. One of them is R, a language originally designed for statistical computing. A more general solution is Python in combination with Pyomo as an optimization library, which could be considered to be the open source standard. In this chapter we propose the usage of the Julia Language in combination with the optimization package JuMP. For details on Julia and JuMP see Section 3.3.

The major advantage of proprietary software in the context of the used modeling language is the ease of use. Usually the software comes as an out-of-the-box solution with an IDE, ready to be used. The software is being maintained on a regular basis and everything should work reliably including the links to the solvers to be used. On the contrary, it is less customizable for example for the usage of alternative solver packages. Only supported solvers can be used with the proprietary software. Furthermore, established OSS solutions like Python with a long history and a substantial developer community come with at least the same level of reliability.

Table 3.1 gives an overview of the software considered in this chapter and some of its characteristics.

[9] www.open-power-system-data.org

Table 3.1: Considered software packages and their characteristics.

Software	Functionality	Type	Website
GAMS	Algebraic modeling language (AML)	CSS	www.gams.com
AMPL	Algebraic modeling language (AML)	CSS	www.ampl.com
Python	Programming language	OSS	www.python.org
Julia	Programming language	OSS	julialang.org
R	Programming language	OSS	www.r-project.org
Pyomo	Algebraic modeling library (Python-based)	OSS	www.pyomo.org
JuMP.jl	Algebraic modeling library (Julia-based)	OSS	www.juliaopt.org
lpSolve	Algebraic modeling library (R-based)	OSS	lpsolve.r-forge.r-project.org
CPLEX	Solver	CSS	www.cplex.com
Gurobi	Solver	CSS	www.gurobi.com
MOSEK	Solver	CSS	www.mosek.com
CLP	Solver	OSS	www.coin-or.org/Clp
GLPK	Solver	OSS	www.gnu.org/software/glpk
ECOS	Solver	OSS	www.embotech.com/ecos

3.2.3 Open-Source Model Formulation

The most important part of the process is the model formulation in the form of source code. Assessment models should not be a 'black box', just delivering numbers as results that are used for policy implications and that might on the way become perceived as facts by policymakers. Bazilian et al. (2012) and Pfenninger et al. (2017) and Pfenninger (2017) all argue that energy scientist must show what happens 'under the hood' of their models.

This transparency is the only way other researchers, but also the general public, can replicate and validate the results and fully understand and challenge the models in the peer-review of publications but also in the context of policy advice. This is also the only way to fulfill the standards of open science. Furthermore, it increases the quality of models since developers are forced to decrease the number of errors or at least errors can be found by others. The models therefore become more robust.

Especially when it comes to the usage of model results as arguments for certain policy implications or recommendations, the credibility and legitimacy of those results increases significantly if everyone is able to check them and to see the underlying assumptions.

Last but not least, publishing models according to open standards grants access to anyone and therefore also to stakeholders with less financial means like non-govern"-mental organizations or developing countries, enabling them to produce their own analyses. It also fosters the interoperability of different models (Pfenninger, Hawkes, and Keirstead 2014).

Pfenninger et al. (2018) supply a guideline of strategies on how to open models up, while Hülk et al. (2018) provide a transparency checklist for models. Several meta studies describe the current questions and challenges of electricity and energy sector modeling (Pfenninger, Hawkes, and Keirstead 2014; DeCarolis et al. 2017; Grimm et al. 2017).

3.2.4 Open-Source Numerical Solver

For numerically solving large-scale problems—like electricity sector models—usually commercial solvers are the product of choice for most modelers. Commonly known solver packages are the CPLEX Optimizer by IBM and Gurobi by Gurobi Optimization but also less well-known products like MOSEK by Mosek ApS can be used. For academics at universities these products are usually free of charge under academic licenses, while research institutes, government agencies, non-governmental organizations, and commercial users must purchase commercial licenses.

Open-source solvers can—under certain circumstances—be an alternative. In this chapter we are benchmarking a number of open projects against the commercial ones. The advantages in those cases are similar to the ones for the modeling tool: publicly available and therefore controllable (no 'black box') source-code as well as cost savings for license fees. Standard open-source solvers for linear programs are CLP by COIN-OR and GLPK by the GNU Project. Another promising product is ECOS by embotech, a spin-off of ETH Zurich.

Since CLPEX and Gurobi are, by now, well established products with high license fees and therefore bigger resources than open projects, their performance in solving problems is usually multiple times better. Nevertheless we wanted to use open-source solvers as a proof-of-concept: it is possible and—depending on the size of the project—worthwhile to cover the complete modeling workflow with open solutions. This point is especially important for users or stakeholders with very little budget like non-governmental organizations or even developing countries.

3.2.5 Open-Access Publications

Last but not least the outcome of a model should be freely available to stakeholders and the interested public as open-access publications (like this one is). Due to the coersions of the established valuation system, many academics are still publishing their works in commercial journals, available to others only by means of paying high subscription or usage fees. Most of the published research has been funded by taxpayer's money and results should therefore be available to all citizens and the general public free of charge. The publication of open-access articles—most favorably in fully open-access journals—should be the academic standard. According to the European Competitiveness Council (COMPET), all publicly funded scientific papers should be published open-source by 2020. Already today, collaborators in EU Horizon 2020 research projects have the obligation to publish open access. In October of 2018 OpenAIRE, funded by the European Commission since 2008, has been established as a non-profit organization democratizing the research life-cycle, by assisting the transition of how research is performed and knowledge is shared".[10] They for example support and offer services and infrastructure like the Zenodo repository service[11] for publishing research data.

In this section we have introduced five key dimensions that are a prerequisite of fully open energy science. These include open data, open-source programming and modeling languages, open-source model code, open-source solvers and open-access publications. While open-source tools—aside from numerical solvers—are already today capable of the tasks, still a lot of challenges remain (Müller, Weibezahn, and Wiese 2018). One of them is practical knowledge of the stakeholders. Others include the need for collaboration, poor data quality and the issue of licensing to be able to re-use data and code. The costs related to proprietary software like GAMS do not seem to be a driver in the game.

3.3 The Julia Language & JuMP.jl

The model described in this chapter is written in the Julia programming language (Bezanson et al. 2017) and uses the package *JuMP.jl* (Dunning, Huchette, and Lubin 2017) as algebraic modeling library in combination with several packages serving as links to the examined solvers. The integration of the algebraic modeling language directly into high-level programming languages comes with the major advantage that other functionalities of the language like data pre- and post-processing as well as visualization can be used, representing the full modeling workflow (compare Figure 3.1) within the same code. This methodology is comparable to the more established combination of Python as a programming language with Pyomo as its algebraic modeling library.

Julia is a high-level, high-performance dynamic programming language for numerical computing. It is the ideal combination of practical, yet rather slow high-level dynamic languages like Python, R, or Mathematica and efficient but statically typed languages like C

[10] www.openaire.eu
[11] www.zenodo.org

and Fortran. With its sophisticated type system, just in time compilation, and other measures it combines the productivity and efficiency of both worlds. Libraries for Julia can be written entirely in the Julia language itself. Julia is fully open source and has a rapidly growing community of users and developers (more than 500 contributors and more than 1,200 packages available) (Bezanson et al. 2017) with a very open-minded, diverse and welcoming community. In August 2018, after six years of development, the official version 1.0 has been released, leading to a steep growth in number of users and popularity. By the end of 2018, the GitHub repository containing the core language had more than 19,000 'stars', that is, GitHub users who follow the repository. It is listed among the top 50 programming languages according to the Tiobe index. Yet, given the short history of the language, it has not reached the same level of maturity as Python. The same holds true for *JuMP.jl*, which is currently available in version 0.18 with a major transition coming up with version 0.19 in March of 2019.

Julia can be used in a REPL (read-eval-print loop) on a console, in Jupyter notebooks, and in IDEs like the Atom text editor. Since data pre- and post-processing, modeling, and visualizations can be written all within Julia, the complete workflow of a modeler can be represented within the system boundaries (as in Python). The package *JuMP.jl* (Julia for Mathematical Programming) provides the user with a very efficient and fast algebraic modeling language. It builds upon the existing syntax of Julia and uses code-generating macros to describe variables, objectives, and constraints. The necessary code is therefore compact and legible.

Since Julia needs some time for the first compilation, there is a start-up cost to be accounted for. Running the same or similar models in loops brings down the time of model generation significantly. Benchmarking JuMP against other open-source and commercial languages shows that is is significantly faster than the open-source solutions like Pyomo and, depending on the problem, in the same range or better than commercial solutions like GAMS (Dunning, Huchette, and Lubin 2017; Lubin and Dunning 2015). Hence, one of the main advantaged of Julia is speed, which this chapter is testing for an application in electricity sector modeling.

3.4 Model Description

The model used in this chapter replicates an electricity market by solving an economic dispatch problem—that is, minimizing total system generation costs—including power flows on a high-voltage transmission network. Therefor, supply and demand are held in balance

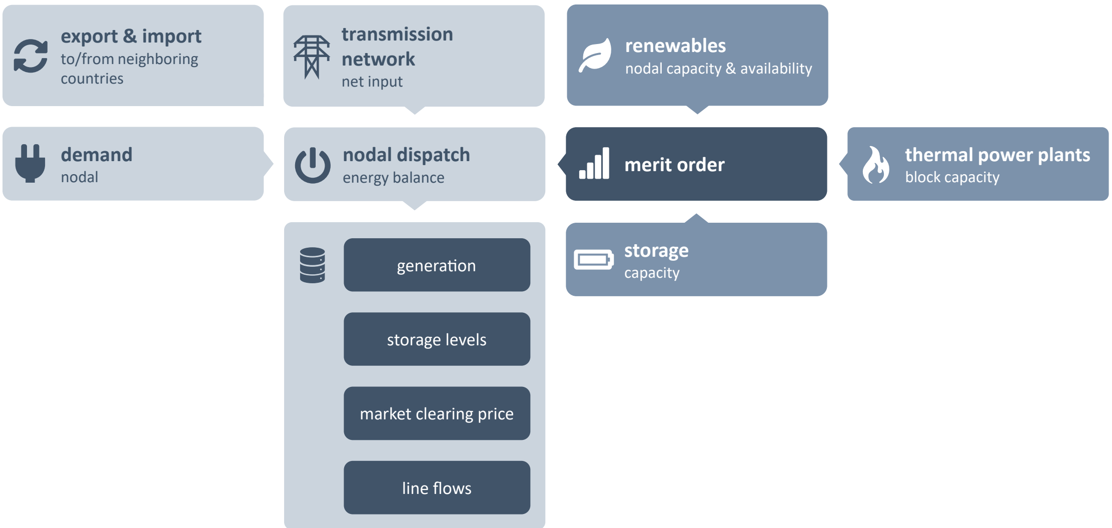


Figure 3.2: Schematic representation of *Joulia.jl*.

Source: own depiction.

on a nodal basis. Supply is represented by a hourly merit order of thermal and renewable power plants as well as the possibility or energy storage. Exports and imports from neighboring countries (or market zones) are also taken into account. As results the model outputs the production levels of generation units, the filling level of storages, nodal market clearing prices, as well as power flows on transmission lines—all on an hourly basis. Figure 3.2 gives an overview of the model structure. Section 3.4.1 outlines the used data, Sections 3.4.2 to 3.4.6 describe the equations the model is comprised of. Please refer to Appendix A.1 for a declaration of the used symbols.

In this chapter we are comparing the implementation of this model as linear programs (LPs) in two different modeling tools or languages. For the implementation in GAMS we use ELMOD-DE, developed by Egerer (2016) for the German electricity market. The source code is published open source[12] (together with a reference data set for the year 2012), which is why we decided to use this implementation in our benchmarking test for the sake of replicability. ELMOD-DE is based on the original version of ELMOD, an European electricity market model developed by Leuthold, Weigt, and Hirschhausen (2012). For the implementation in Julia we use *Joulia.jl*, introduced in Section 3.5.1.

[12] www.diw.de/elmod

3.4.1 Input Data

The model in both implementations uses the same reference data set for the German electricity market for the year 2015 (Kunz et al. 2017b, without gas and heat). Details of the data set are described in the accompanying data documentation (Kunz et al. 2017a, ch. 2). The data set is composed of the following parameters:

- 724 high voltage **transmission lines** with their geographical information, voltage levels, and transmission limits (see Figure A.1)
- 450 **network nodes** with their geographical information and installed renewable capacity
- 707 conventional **power plant blocks** with their geographical information, technology, fuel, installed capacity, efficiency, emissions, and (if applicable) transportation costs for hard coal
- **electricity demand** time series for each node
- **import and export** time series for electrical neighbors
- **availability factors** for **conventional** generation capacity by technology
- **availability time series** for **renewable** generation capacity by technology

Some relevant details of the data set are listed in Appendix A.2. Figure A.1 shows a map of the transmission lines considered in the model. Table A.4 gives an overview of the aggregated installed capacity in the German market for the model. Table A.5 shows the annual average of fuel costs for conventional generation capacities as well as their carbon intensity and annual average price of emission allowances.

It is obvious that the complexity of the model (and therefore the runtime) is mostly driven by the size of the electricity system analyzed. Section 3.5.2 illustrates the correlation.

3.4.2 Objective

The objective of the model is to deterministically minimize total system costs in terms of generation costs by a benevolent planner with perfect foresight. Hence, the objective function is to minimize the sum of all hourly conventional generation $G_{p,t}$, multiplied by the associated specific variable costs $vc_{p,t}$ of the specific power plant block (Equation (3.1)). Renewables are assumed to have zero marginal costs.

$$\min_{G,R,phesG,phesD} \text{cost} = \sum_{p,t} (G_{p,t} \times vc_{p,t}) \tag{3.1}$$

3.4.3 Energy Balance

Equation (3.2) describes the nodal energy balance. Generation from conventionals $G_{p,t}$, renewables $R_{n,s,t}$, and pumped hydro storages $phesG_{phes,t}$ connected to the node as well as the netinput $\sum_{nn}(\theta_{nn,t} \times b_{n,nn})$ from the transmission grid and possible exchanges with neighboring market zones $ex_{n,t}$ have to be in balance with electricity demand $d_{n,t}$ and demand from pumped hydro storages $phesD_{phes,t}$ at all network nodes and at all times (hourly resolution) in order to satisfy all demand and keeping the system stable. Nodal market clearing prices are derived from the dual variables of the energy balance.

$$\sum_{p} G_{p,t} + \sum_{s} R_{n,s,t} + \sum_{phes} phesG_{phes,t} + \sum_{nn} (\theta_{nn,t} \times b_{n,nn}) + ex_{n,t}$$
$$= d_{n,t} + \sum_{phes} phesD_{phes,t} \quad \forall \quad n,t \qquad (3.2)$$

3.4.4 Generation

The generation $G_{p,t}$ from each block p of a conventional power plant is limited by the maximum installed capacity $\overline{g}_p$ which is reduced by an availability factor $avag_{p,t}$ (Equation (3.3a)). Equation (3.3b) for generation from intermittent renewable sources $R_{n,s,t}$ works analogously, only that the installed capacity $\overline{r}_{n,s}$ is aggregated by network node n and technology s and multiplied by a weather dependent availability time series $avar_{n,s,t}$.

$$G_{p,t} \leq \overline{g}_p \times avag_{p,t} \qquad \forall \quad p,t \qquad (3.3a)$$
$$R_{n,s,t} \leq \overline{r}_{n,s} \times avar_{n,s,t} \qquad \forall \quad n,s,t \qquad (3.3b)$$

3.4.5 Storage

The model considers pumped hydroelectric energy storage (PHES) in Equation (3.4). The inter-temporal constraint in Equation (3.4a) links the filling level $phesLevel$ at time t to the level at time $t-1$, considering generation $phesG_{phes,t}$ and pumping $phesD_{phes,t}$ from the PHES. Due to losses in the storage cycle, the PHES demand is multiplied by an efficiency factor eff_{phes}. Equations (3.4b) and (3.4c) limit the generation and pumping from a PHES unit to the maximum installed capacity $\overline{gsto}_{phes}$, while Equation (3.4d) limits the storage filling level to the maximum energy content $\overline{lsto}_{phes}$ of a PHES. For reasons of parallelization, the model assumes each PHES to be empty at the beginning and end of each model week in order to avoid a hard link between weeks.

$$\begin{aligned}
phesLevel_{phes,t} &= phesLevel_{phes,t-1} \\
&\quad + eff_{phes} \times phesD_{phes,t} - phesG_{phes,t} && \forall \quad phes, t && (3.4a)\\
phesG_{phes,t} &\leq \overline{gsto}_{phes} && \forall \quad phes, t && (3.4b)\\
phesD_{phes,t} &\leq \overline{gsto}_{phes} && \forall \quad phes, t && (3.4c)\\
phesLevel_{phes,t} &\leq \overline{lsto}_{phes} && \forall \quad phes, t && (3.4d)
\end{aligned}$$

3.4.6 Transmission Network

The transmission network is represented using the DC load flow approach (Schweppe et al. 1988, pp. 313) (Equation (3.5)). Only considering the real power flow and assuming small differences in voltage angles θ and voltage levels, this linearization of AC power flows provides an—for this application—acceptable level of accuracy.[13]

The modulus of the power flow $PF_{l,t}$ on a line l is limited by the maximum power flow $\overline{pf}_l$ for this line (Equation (3.5a)). This maximum power flow accounts for N-1 security, applying a transmission reliability margin, and is determined by its voltage level and number of circuits. This power flow $PF_{l,t}$ is calculated summing up the multiplications of the voltage angle $\theta_{n,t}$ of a node with the corresponding entry of the adjacency (node-to-line) matrix $h_{l,n}$ for this line (Equation (3.5b)). The $netinput_{n,t}$ used in the nodal energy balance is calculated with the same scheme, only this time summing up the multiplications of the voltage angle $\theta_{nn,t}$ with the network susceptance matrix $b_{n,nn}$ for all other nodes nn in the network (Equation (3.5c)). Finally, Equation (3.5d) defines a slack bus $\hat{n}$ with a voltage angle of zero to be the reference point of the network.

$$\begin{aligned}
|PF_{l,t}| &\leq \overline{pf}_l && \forall \quad l, t && (3.5a)\\
PF_{l,t} &= \sum_{n} (\theta_{n,t} \times h_{l,n}) && \forall \quad l, t && (3.5b)\\
netinput_{n,t} &= \sum_{nn} (\theta_{nn,t} \times b_{n,nn}) && \forall \quad n, t && (3.5c)\\
\theta_{\hat{n},t} &= 0 && \forall \quad t && (3.5d)
\end{aligned}$$

[13] This methods is accurate on average but there can be significant flow errors on certain lines, see Milano (2010, ch. 6) for details.

3.5 Implementation & Results

3.5.1 Joulia.jl

An overview of existing proprietary electricity sector models can be found in Foley et al. (2010) and Fernandez Blanco Carramolino et al. (2017). With GenX, the MIT Energy Initiative contributed an extensive model written in Julia (Jenkins and Sepulveda 2017), but the source code is not publicly available. With *Joulia.jl* we want to contribute to the community an energy sector model fulfilling the criteria of all five dimensions of openness according to Section 3.2. It should be easily usable for everyone, the first one written in the cutting-edge Julia language, providing all the tools for the entire modeling pipeline and coming with open data ready to be used.

Joulia.jl is a package provided within the JuliaEnergy organization on GitHub[14], easily to be imported to the Julia environment. It uses the library JuMP as an algebraic modeling tool or language. The package provides the user with generic functions that together constitute the electricity market model described in Section 3.4.

Depending on further packages, any desired data set can be read in from .csv files or binary files. *Joulia.jl* hereby uses a generic, technology-neutral and extendable data framework in order to be able to extend the future functionality. The model functions can then be called with the data set, generating the actual full model code thereof and passing it on to a desired solver. Results from the solver are being collected and used to produce visualizations, profiting from the plot packages of Julia. Even dynamic plots are possible.

Joulia.jl can be used for a number of research questions, for example the impact of nodal prices and of different configuration of price zones (see Egerer, Weibezahn, and Hermann (2016) for a possible application). It can be used to analyze the impact of investment decisions into generation or transmission capacities on generation levels by technology, line flow patterns, as well as price levels. Using different data sets, the geographic scope of the model can be extended for example to the whole of Europe or to any other region like developing countries in order to assess policy changes in their markets.

Figure 3.3 shows a code example representing Equation (3.2).[15] JuMP's `@constraint` macro adds an equality constraint called `market_clearing` to the model named `m` for each $n \in N$ and $t \in T$. Figure 3.4 juxtaposes the same equation in its GAMS implementation. Here, the equation has to be declared and defined first, using the `EQUATION` keyword be-

[14] www.github.com/JuliaEnergy

[15] In order to capture possible lost generation or load, a dummy variable is introduced into the equation.

```
@constraint(m, market_clearing[n=N, t=T],

sum(G[p,t] for p in map_n_p[n])
+ sum(R[s,n,t] for s in RES)
+ sum(PHES_G[phes,t] for phes in map_n_phes[n])
+ ex[n,t]
+ mvabase * sum(b[n,nn] * THETA[nn,t] for nn in N if b[n,nn] != 0)
- LOST_GENERATION[n,t]

==

demand[n,t]
+ sum(PHES_D[phes,t] for phes in map_n_phes[n])
- LOST_LOAD[n,t]
)
```

Figure 3.3: Example code for market clearing/energy balance constraint in Julia/JuMP.

fore it can be initialized in a second step following the `..` operator. Using the `sum` operator the set over which the summation should be executed can be limited by the `$` operator. The same effect can be generated in Julia using in-line for loops. Another difference is the assignment of equations to models. In GAMS the model can be defined at the very end of the code and initialized with a list of equations. In JuMP, a variable or an equation is directly linked to a model initialized in the beginning. Nevertheless different models are possible, consisting of the same variables and equations only written out once if the model is generated using functions. It can be stated that in general models in JuMP are more compact then their counterparts in GAMS, as illustrated by an example in Dunning, Huchette, and Lubin (2017).

```
EQUATION
market_clearing                balance of supply and demand
;

market_clearing(n,t)..

sum(p$map_n_p(p,n), G(p,t))
+ sum(s, R(n,s,t))
+ sum(phes$map_n_phes(phes,n), PHES_G(phes,t))
+ ex(n,t)
+ mvabase * sum((nn)$b(n,nn), b(n,nn) * THETA(nn,t))
- LOST_GENERATION(n,t)

=E=

demand(n,t)
+ sum(phes$map_n_phes(phes,n), PHES_D(phes,t))
- LOST_LOAD(n,t)
;
```

Figure 3.4: Example code for market clearing/energy balance constraint in GAMS.

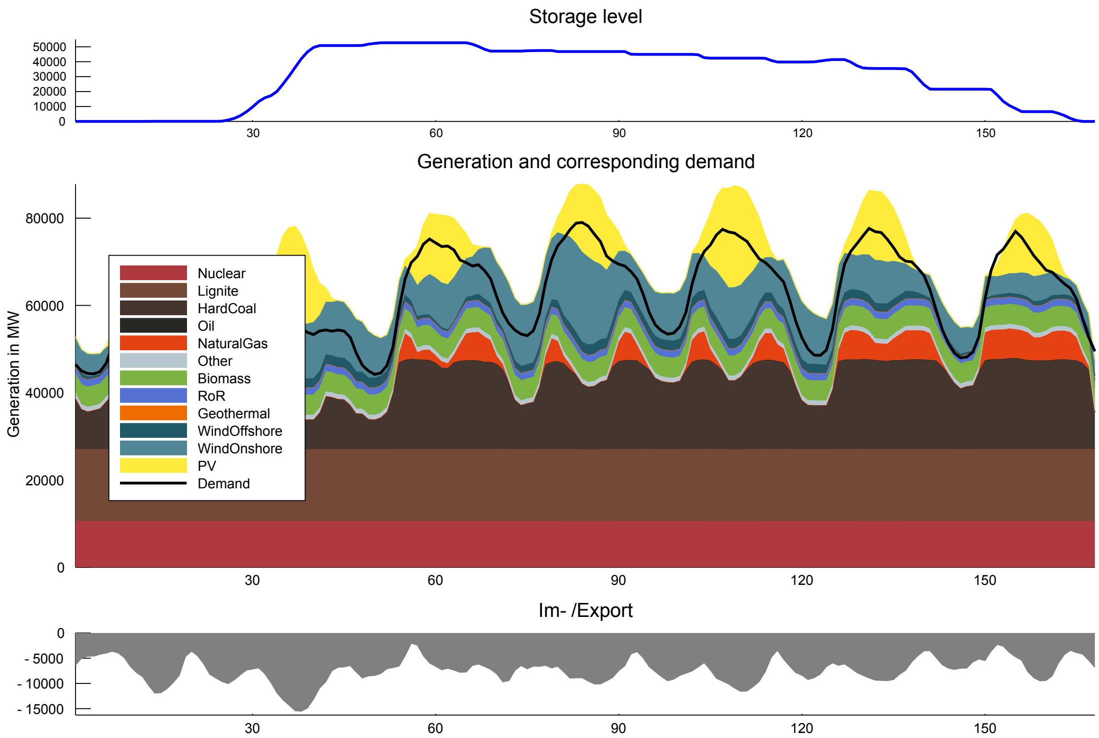


Figure 3.5: Example of a dispatch graph for one week (168 hours) in summer, showing generation, demand, storage, and import/export.

Source: own depiction.

Figure 3.5 shows an example of the resulting cumulative dispatch for each hour in one week in summer, broken down by fuel and renewable source, respectively. The black line shows electricity demand while imports and exports are represented by the gray area in the bottom subplot and the filling level of pumped hydroelectric storages is mapped in the top subplot in dark blue.

Since the transmission system is also available with its geographical information, the utilization of the lines and the calculated nodal prices in the model can be visualized as in Figure 3.6.

3.5.2 Benchmark Test

In a benchmark test we are comparing the implementation of the model in GAMS (*EL-MOD-DE*), solved with the three commercial solvers CPLEX, Gurobi, and Mosek with the

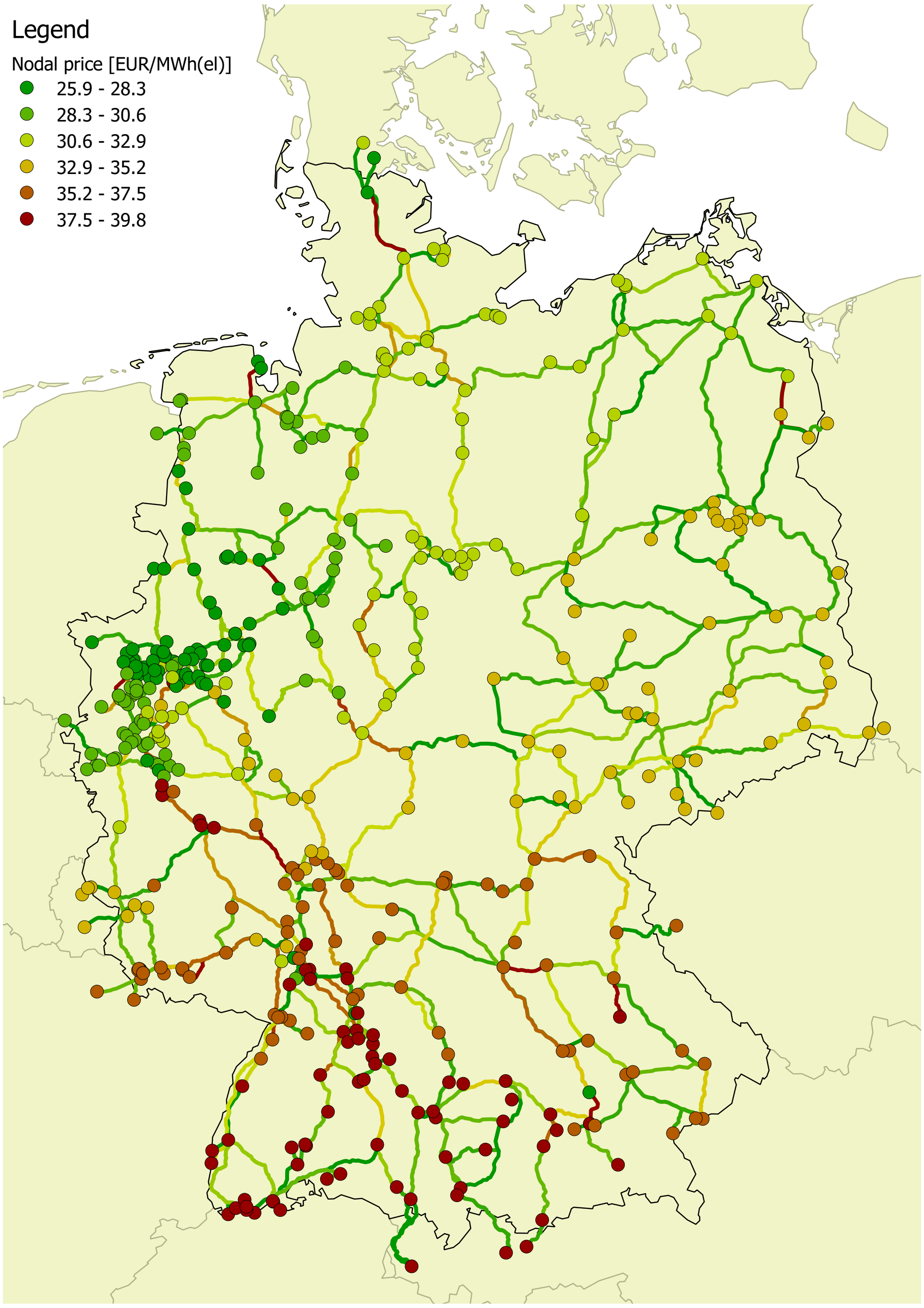
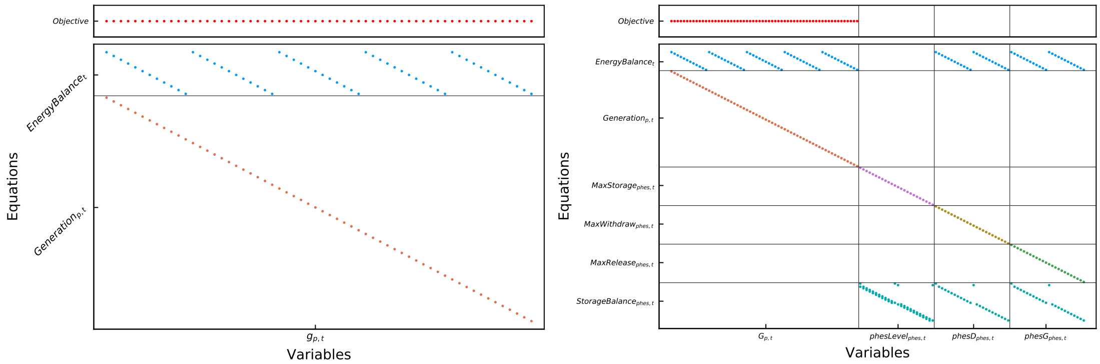


Figure 3.6: Example of a graph showing calculated average nodal prices and the average utilization of transmission lines in the German transmission system. Green represents utilization below 40 %, yellow between 40 % and 70 % and red above 70 %. Data for November 27, 2015, 7 pm.

Source: own depiction.



(a) Simple case.

(b) Medium case.

Figure 3.7: Illustration of the structure and complexity of the three cases as the sparsity pattern of the constraint coefficient matrices.

Source: own depiction.

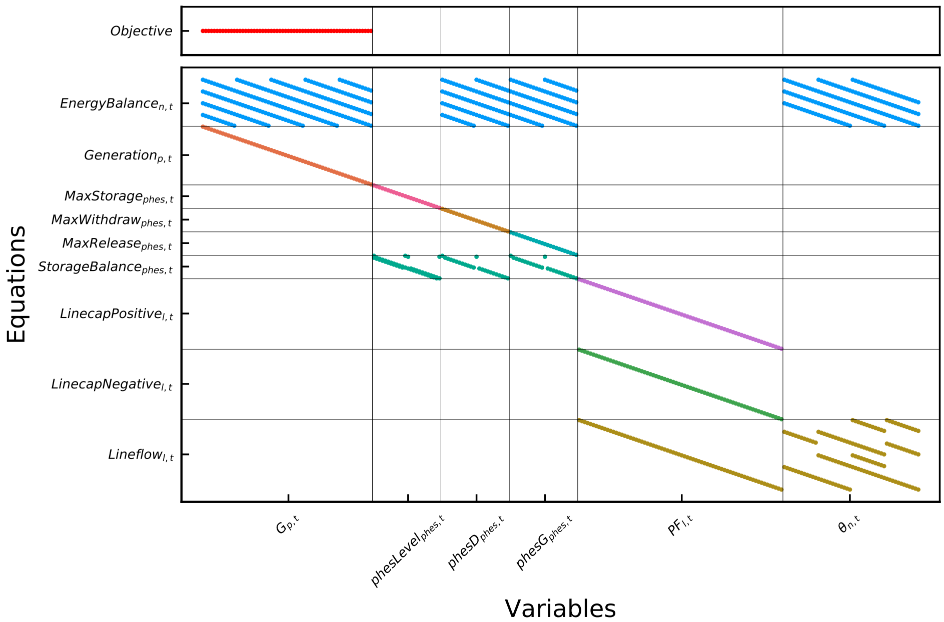


Figure 3.8: Illustration of the structure and complexity of the three cases as the sparsity pattern of the constraint coefficient matrices, hard case.

Source: own depiction.

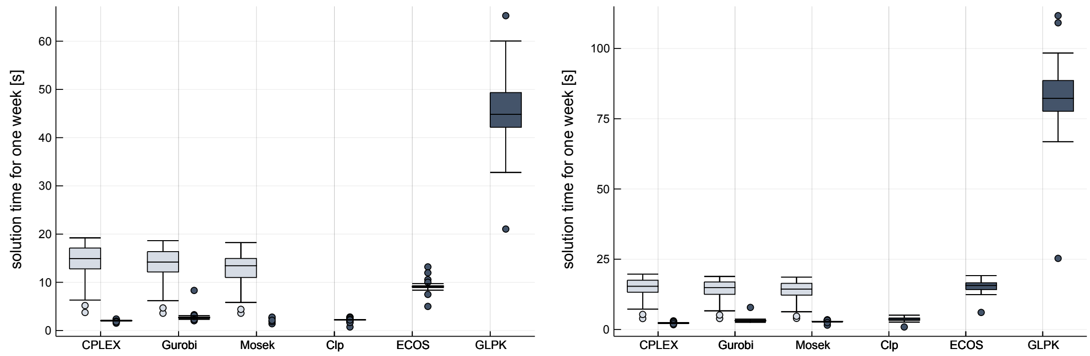
implementation in Julia/JuMP (*Joulia.jl*), solved with the same three solvers plus the additional two open-source solvers ECOS and CLP not available in GAMS. In order to visualize the impact of the complexity of the problem on the runtimes we distinguished three cases: (i) a simple case for dispatch without storage (and hence no intertemporal constraints) and no transmission grid (only Equations (3.1), (3.2), and (3.3)), (ii) a medium case, adding storage (Equations (3.4)), and (iii) a hard case, adding the transmission grid (Equations (3.5)).

In order to illustrate the difference of these three cases, the constraint coefficient matrix of the problems can be analyzed. Since the original problem is too expansive to be plotted, we generated a sample problem consisting of only five power plant blocks, four network nodes, six network lines and three storage units. This problem only calculates the dispatch for twelve time slices. Figure 3.7a shows the resulting matrix of the simple case. Each dot in the graph represents the occurrence of the variable $G_{p,t}$ in one of the equations, that is, a non-zero element of the matrix. Each increase in t or p expands the matrix accordingly. In Figure 3.7b the resulting matrix for the medium case is shown. The top left corner contains the matrix of the simple problem. The additional variables and constraints for the storages expand the matrix to the right and downwards, quadrupling the size of the matrix. Again, each increase in t or $phes$ expands the matrix additionally. Adding the power flow constraints of the transmission network, the matrix results in Figure 3.8. The matrix of the medium case is included in the top left corner again, representing only one quarter of the full matrix. Now, an increase in n or l would expand the matrix additionally. This simple example shows how the hard problem is already 16 times larger than the simple problem.

Now, taking into account the actual sizes of the used sets according to Section 3.4.1, the numbers are put into perspective: The *Joulia.jl* simple problem consist of 308,112 rows, 308,280 columns and 616,224 non-zeros, the medium problem of 329,616 rows, 324,408 columns and 664,608 non-zeros, and the hard problem of 770,112 rows, 673,008 columns and 1,729,056 non-zeros. The GAMS problem structure is almost—but not perfectly—identical due to minor differences in building the LP files. This has no significant influence on the benchmarking test, though.

Figures 3.9 and 3.10 show box plots of the total run time of solutions for all the weeks of one year with the named combinations and the three cases. Table 3.2 summarizes the solve statistics for the hard case. For reasons of comparability, the total time for building the model and solving it is being used since GAMS and Julia are using different metrics in that regard. The calculations were made with Julia version 1.0.2, JuMP version 0.18.5, GAMS version 25.1.3, CPLEX version 12.8, Gurobi version 8.1, and Mosek version 8.1.

Obviously, the size and complexity of the model to be solved totally depends on the



(a) Simple case. (b) Medium case.

Figure 3.9: Comparison of total runtimes for combinations of GAMS and Julia/JuMP with different solvers. The runtimes of all weeks of the model year are being displayed.

Source: own depiction.

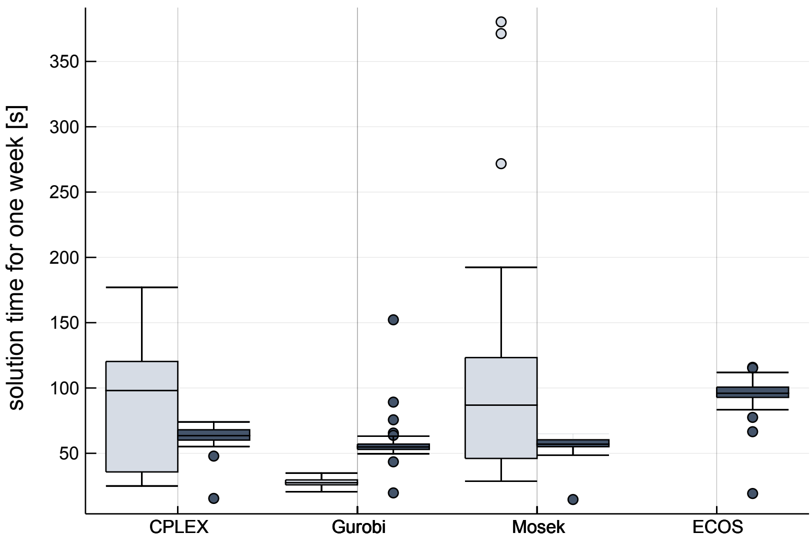


Figure 3.10: Comparison of total runtimes for combinations of GAMS and Julia/JuMP with different solvers, hard case. The runtimes of all weeks of the model year are being displayed.

Source: own depiction.

Table 3.2: Total runtime statistics for solving all weeks of one year in the hard case with combinations of GAMS and Julia/JuMP with different solvers.

Language	**Solver**	**Average** [sec]	**Minimum** [sec]	**Minimum** full weeks [sec]	**Maximum** [sec]
GAMS	CPLEX	85	25	25	177
	Gurobi	28	21	21	35
	Mosek	101	29	38	380
Julia	CPLEX	63	15	55	74
	Gurobi	57	20	50	152
	Mosek	57	15	53	65
	ECOS	95	19	77	116

extent of the data used. Therefor, benchmarking tests on optimization problems can only give an indication on the proportions and magnitudes but cannot easily be generalized. Yet, the literature for similar benchmarking tests involving commercial and open-source solvers shows that commercial solvers are always the faster alternative, while open-source solvers cannot match their performance but—depending on the problems tested—capable ones are available if the commercial alternatives are not a viable option.

Meindl and Templ (2012) give an overview of existing open-source as well as commercial solvers for linear problems. They conduct a case study solving 200 instances of the secondary cell suppression problem. These instances can be divided into an easier and a harder group. Generally, they find that both tested commercial solvers CPLEX and Gurobi perform better than the open-source solvers CLP, GLPK and LP_solve. However, when solving the group of easier instances GLPK and CLP were only 9 and 13 times slower than the fastest solver (CPLEX). The gap widened between the solvers as CLP took 2823 times the run time of CPLEX in the harder cases. Also, Gurobi performed much worse only being a bit faster than GLPK.

Jablonský (2015) benchmarks the three commercial solver CPLEX, Gurobi, and FICO XPRESS on a set of 361 mixed integer problems. The results vary between the different instances of problems but overall Gurobi performed best in most cases.

Gearhart et al. (2013) test the four open-source linear programming solver CLP, GLPK, LP_solve, and MINOS against the commercial solver CPLEX. Firstly, they use a set of 180 linear problems which is considered as "easy". In this run CLP was almost as fast as CPLEX. GLPK also showed a good performance with only being about 9 times slower compared to CPLEX. The other two had considerably worse solution times. In the second test they benchmark only the CLP solver against CPLEX with a set of 21 "hard" problems. With CPLEX generally being better, CLP was faster in some of these instances.

In an ongoing benchmarking project by Mittelmann (2018)[16] several open-source and commercial solvers are tested using the Simplex and the Barrier algorithm for linear problems. Results indicate that Gurobi is the fastest and most reliable solver in both cases closely followed by XPRESS. Also, CLP is almost as fast as CPLEX in the Simplex algorithm comparison.

Especially CLP is named in the literature as a very fast open-source solution with GLPK coming in second. While we found that CLP can solve our problem, it did so in an more than 50-fold increase in average time compared to Gurobi as the fastest commercial solver and a more than 40-fold increase compared to CPLEX for the hard case. GLPK was not able to produce a solution in an acceptable amount of time for this case and showed significant shortfalls also for the simple and medium cases. The open-source solver that was able to keep pace with its competitors is ECOS with only a less than twofold increase in average time compared to the fast commercial solutions. This solver is not covered by any of the common benchmark tests.

Comparing across platforms, Julia produces on average faster results than GAMS using CPLEX and Mosek, but is a little slower for Gurobi. What is interesting is the difference for the minimum runtime for one week and the minimum runtime for full weeks only, since weeks 1 and 53 are trunk weeks with less hours. Julia is significantly faster here than GAMS. This is illustrated by the lower outliers in the box plot for Julia. Another interesting observation is the higher variability between weeks for solution times for Mosek and CPLEX with GAMS compared to Julia. Since GAMS is proprietary software, the differences cannot easily be explained.[17] Julia/JuMP seems to have a more efficient model generation and, in part, faster links to the solvers. Since the underlying *MathProgBase.jl* as low-level interface will be replaced by the novel *MathOptInterface.kl* starting from version 0.19 of JuMP, further increases in performance can be expected.

We also tested other non-commercial solvers that are compatible with JuMP—Bonmin, Couenne, Ipopt, and SCS—but none of those were able to either solve the problem at all

[16] plato.asu.edu/bench.html

[17] Since this chapter focuses on an application in the electricity sector modeling, it is out of the scope of the chapter to explain the differences in efficiency based on the low-level differences between GAMS and JuMP.

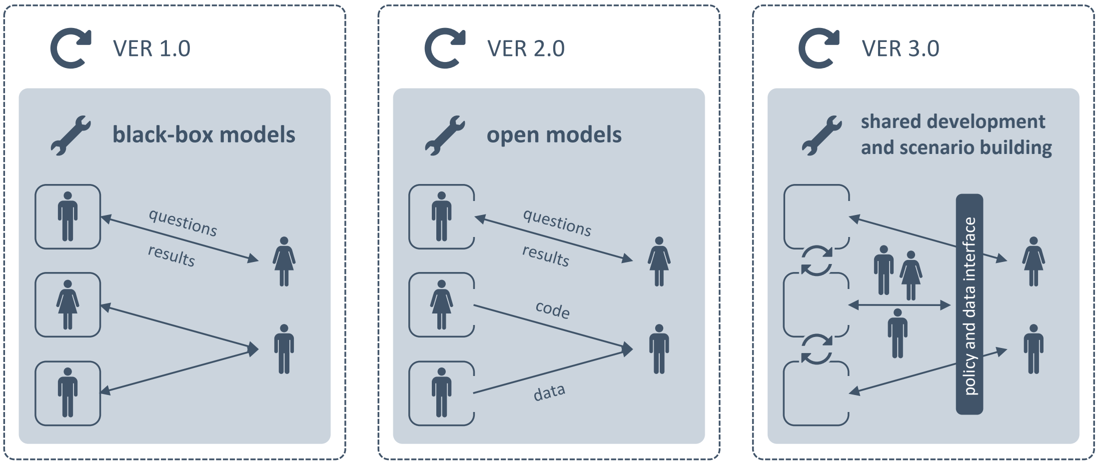


Figure 3.11: Third generation energy system modeling.

Source: own depiction based on DTU and RLI (Müller, Weibezahn, and Wiese 2018).

or to solve it in a runtime close to the solvers shown in Table 3.2.

3.5.3 Discussion

In order to deliver a comparable scope of functionality like other open-source power sector models, for example PyPSA (Brown, Hörsch, and Schlachtberger 2018) or *oemof* written in Python, further research in the field is necessary. In the next steps, DC transmission lines will be included and *Joulia.jl* will be developed from a LP model towards the integration of unit commitment decisions in a mixed-integer program (MIP) variant for a better technical representation of power plants. Also, the use of heat generated from turbines will be included with a detailed representation of CHP plants. The model will also be extended by a congestion management module. Future research into the stochastic representation of the German rolling-planning market scheme of day-ahead, intra-day market, and congestion management as well as the possibility for endogenous investment decisions is intended.

Joulia.jl is intended for the open-source community with the possibility for interoperability with existing models but also for a future further development by the community, following the proposition of DTU and RLI for the third generation of energy system modeling with shared model development and scenario building (see Figure 3.11).

3.6 Conclusion

In this chapter we introduce the Julia package *Joulia.jl*, providing a modeling framework for electricity system models, implementing the modeling workflow from processing input data, building and solving the model, and finally producing visualizations of the results. It is open source and free to use for everyone as a package on GitHub, written in and for the cutting-edge Julia language and hence providing all the tools for the entire modeling pipeline. It also comes with a free and open data set that can be used for analysis.

In order to benchmark the new modeling tool Julia as an open-source programming language in combination with its algebraic modeling library JuMP we compare the performance of the tool in terms of runtime against an implementation of the same model in GAMS as a proprietary tool. One of the aspects examined is the possibility to use open-source numerical solvers that comes with JuMP. We have shown that the use of such open-source alternatives like ECOS is possible for the given model, with runtimes within the same order of magnitude as commercial solvers—even though the linear program can be solved a little faster using the commercial Gurobi or CPLEX. With growing complexity of models, commercial solvers are increasingly playing out their advantages of speed with open-source solvers falling behind. Yet, comparing across platforms, open-source tools like Julia/JuMP or Python/Pyomo provide a more than viable alternative to the commercial tool GAMS, coming with other additional advantages like a modern syntax and tools for data processing as well as visualization. A little drawback is the persistent dependency on commercial numerical solvers.

Chapter 4

Two Price Zones for the German Electricity Market — Market Implications and Distributional Effects

"Properly defined price zones are a core element of the European electricity market model. As they may need to be adjusted over time to ensure a functioning market, Regulation (EU) 2015/1222 on 'Capacity Calculation and Congestion Management' (CACM-Regulation) established a coordinated process to review the current price zone configuration and to propose changes in case it turns out to be inefficient (Art. 32-24)."

(European Commission[1])

This chapter is the accepted version of Energy Economics 59, 365–381 (Egerer, Weibezahn, and Hermann 2016) and based on DIW Berlin Discussion Paper No. 1451 (Egerer, Weibezahn, and Hermann 2015). Findings and policy implications are published in DIW Wochenbericht 9/2015 "Energiewende und Strommarktdesign: zwei Preiszonen für Deutschland sind keine Lösung" (Egerer et al. 2015). Appendix B contains the original appendix to this publication.

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4.1 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 (European Commission (EC) 1996, 2003, 2009) but it is implemented through national regulation. This process mostly resulted in national bidding zones with no additional regional price signals.[2] 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 line specific network capacities, the zonal representation defines larger bidding areas while aggregating internal and cross-zonal network constraints to NTCs with neighboring bidding zones. Preventive congestion management is possible to some extent with the calculation of the cross-zonal NTCs. Still, a market dispatch can be infeasible in the physical transmission system, requiring curative congestion management, mainly re-dispatch measures. The mostly national bidding zones in effect, as of 2015, are under scrutiny at the European level according to the framework guidelines and the Network Code on Capacity Allocation and Congestion Management (European Commission (EC) 2014; Transmission System Operators for Electricity (ENTSO-E) 2014). 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

[1] Answer in reply to parliamentary question E-001929/2017, given by Mr Arias Cañete on behalf of the European Commission on June 28, 2017.

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

other transmission lines, that is, 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, 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.[3] 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 recently built or under construction – are located in northern Germany.[4] 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-Württemberg), which have to pay for long inland transport from the North Sea harbors. Combined cycle gas turbines (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, Gerbaulet, and Hirschhausen 2013).[5]

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 per

[3]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 (AGEB 2015). The installed capacity has been about 35 % of peak demand for each technology.

[4]The border between northern and southern Germany depends on the context. In this chapter, 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.

[5]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.

year in 2009 (BNetzA 2010), to €165m, €113m, and €185m per year in the years 2012 to 2014, respectively (BNetzA 2015b). 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.[6]

This discussion is attracting increasing attention in Germany (Monopolkommission 2015; Wissenschaftlicher Beirat beim BMWi 2014; Frontier Economics and Consentec 2011, 2013) and in Europe (ACER 2014; Berg Skånlund et al. 2013; CEPS et al. 2012).[7] 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 2015a). The annual German grid development plans (50Hertz Transmission GmbH et al. 2016) translate into the law on national requirements ("Bundesbedarfsplan") which includes the specific extension projects (BBPlG 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 it 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 (Löschel et al. 2013; ACER 2014).

Bidding zones require the integration of a cross-zonal net transfer capacity (NTC) in the market and result in market splitting and diverging electricity prices within Germany in hours this NTC becomes a binding constraint.[8] Consequently, the geographic scope of bidding zones and NTC levels auctioned into the market are the relevant parameters determining

[6]This chapter 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.

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

[8]This chapter 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.

the effectiveness of zonal price differentiation as well as gains and losses of stakeholders in the zonal market. Applying an electricity sector model, this chapter elaborates on such a change in the congestion management scheme for 2012 and 2015 scenarios, including sensitivities on network extension and four bidding zones, 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.[9]

The remainder of the chapter is structured as follows: Section 4.2 reviews the relevant literature on the discussion of zonal and nodal pricing. Section 4.3 introduces the two consecutive model stages of the spot market dispatch and the adjustments by re-dispatch. Section 4.4 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.

4.2 Literature Review

Compared to zonal pricing with mostly coordinated market coupling in Europe, some markets have implemented a nodal pricing scheme.[10] Nodal pricing is often considered as 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, Neuhoff, and Newbery (2005) and Rubio-Oderiz and Perez-Arriaga (2000) suggest that nodal pricing (and complementary capacity charges) also 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 considered. Holmberg and Lazarczyk (2015) compare the efficiency of three ex-

[9]This chapter focuses on the German discussion and abstracts from system and distributional implications on European level. The model scope is limited to the German electricity sector.

[10]The most prominent example is the Pennsylvania-New Jersey-Maryland Interconnection (PJM) in the north-eastern part of the US.

isting 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, Jørnsten, and Pignon (2003) also look at the possibility of 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 hours 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 in the case of 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, providing wrong pricing information for market participants under some circumstances. Internal congestion with a high and due to loop-flows not always directly comprehensible 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, Hobbs, and Newbery (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. Plancke, De Jonghe, and Belmans (2016) apply a numerical spot market model on two bidding zones in Germany. They discuss price effects in Germany and neighboring countries for a 2020 scenario. 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, Seeger, and Moser (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 separate Germany in at least one northern and one southern zone. Some scenarios split the northern zone even further between west and east (Burstedde 2012; Breuer, Seeger, and Moser 2013; Breuer and Moser 2014).

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 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 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 factorss (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, Bucksteeg, and Weber (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 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 chapter extends 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.

4.3 Numerical Optimization Models

4.3.1 General Modeling Approach

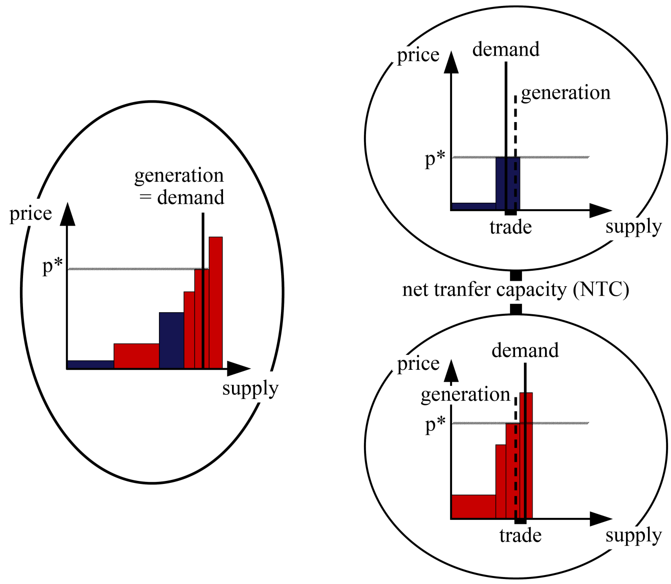
This chapter applies a bottom-up electricity sector model, separately optimizing the two consecutive steps of market settling in the spot market (Figure 4.1) and for re-dispatch (Figure 4.2). A single bidding area with a uniform hourly electricity price is compared to a market design with two bidding zones.[11]

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), it is the only constraint that electricity generation has to settle hourly load. 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 not to be technically feasible for implementation in the transmission network.

[11] Section 4.3.2 discusses simplifications and limitations of the model approach and relates it to other publications. The detailed mathematical description of the model equations follows in Section 4.3.3 and 4.3.4 and input data of the model in Section 4.3.5. The nomenclature is summarized in Section B.1.

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:

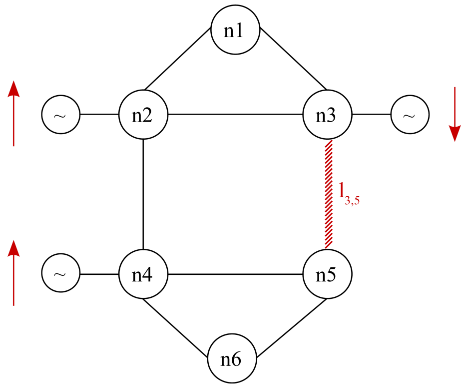
- Spot market price by bidding zone
- Generation level for each generating unit
- Generation level for each renewable technology
- Operation of pumped-storage hydroelectric plants
- Trade flows between bidding zones

Figure 4.1: Spot market models with weekly runs of 168 hours.

Source: own depiction.

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 hydro-electric plants)

Hourly model results:

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

Figure 4.2: Hourly re-dispatch model for adjustments of spot market dispatch.

Source: own depiction.

Thus, in a second step, it can become necessary to alter the market result in the nodal re-dispatch model. 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.[12] The nodal re-dispatch model uses results of the spot market model for hourly

[12] The model only considers re-dispatch required to prevent network flows exceeding the thermal limits of

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. The spot market allows for inter-zonal trade but only to a certain degree, the so-called NTC, which accounts for limited physical transmission capacity. In hours where this trade limit becomes a binding constraint, market results of the zonal case diverge from those of uniform pricing. The market dispatch sees a shift of generation 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 for the case of uniform pricing but can have a different initial point for hourly generation levels of power plants. In these hours, when spot market results diverge between uniform and zonal pricing, 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 lowest-cost generation dispatch in the nodal model for different bidding zone configurations in the spot market.

4.3.2 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.

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transmission lines. Other causes of re-dispatch (e.g. regional voltage stability) are not included as they require more technical model approaches.

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 to address possible issues of strategic behavior and market power. This chapter 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. 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 bidding 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 2012). 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.[13] In 2015, regulation requires generating units with more than 10 megawatt (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 have comparably high variable costs and the model hardly uses them for re-dispatch. Still, the barrier of 10 MW has been recently lowered from previously 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 of pumped-storage operation is excluded in the re-dispatch model.[14] Implications of not including pumped-storage in re-dispatch on model results are not straight forward due to the intertemporal optimization. The pumped-storage capacity in Germany is located partly in the middle and in the south of Germany. 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 market dispatch of uniform and zonal pricing has on re-dispatch. The linear structure of the model results in a similar dispatch as nodal pricing. The limitations for pumped-storage plants prevent equal results. Thus, the model formulation for re-dispatch is closer to required adjustments of the spot market dispatch to reach the benchmark of nodal pricing than to a more restricted re-dispatch, as conducted by TSOs, which only has to obtain feasibility. It is important to remember this mechanic of the re-dispatch model for the discussion of the model results.

[13] 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.

[14] 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 2012).

Bidding Zone Delimitation and NTC Calculation

There are several methods for the delimitation of bidding zones (see Section 4.2). 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). For the case of Germany mostly two zones are being discussed: one zone with high wind generation in the north and one zone with high demand and decreasing conventional generation 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.[15] This chapter focuses on the zonal setting with one northern and one southern border. It is the most discussed option in the political arena, represents most of the congested lines in 2012, and provides an alternative in case of stalled progress of network expansion (BMWi 2015a).

The optimal level of net transfer capacity (NTC) is difficult to determine.[16] 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.[17]

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 2015b). 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

[15]In an additional sensitivity run, we examine a possible four zone scenario by separating the northern zone into the three described regions. The rational for this zonal division might change in the future as open cast mining and firing of lignite will be in the decline over the next years due to the government's climate goals in the light of the Paris agreement. Also, additional wind capacity in coastal regions with permanently changing regional wind availability is likely to increase internal congestion in the northern zone and makes the definition of additional zonal borders less clear than the division between northern and southern Germany.

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

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

zones in Germany. The selected level is based on considerations of the calculations explained above.[18]

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 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 of transit flows. These effects are not included in the model analysis of this chapter.

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. They deviate, in the highly meshed networks of Central Europe, 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. Changes of cross-border flows as a result of two bidding zones are not included of course.

4.3.3 Mathematical Formulation of the Spot Market Model

The spot market model determines the power plant dispatch with the cost-minimizing objective function (Equation (4.1)) for total variable generation costs ($costs^{sp}$) of conventional generating units in the respective hours t. Variable generation costs C_p 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 have variable generation costs of zero. For this application the spot market model optimizes power plant operation in weekly blocks of 168 hours.[19]

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

[19] In the weekly runs pumped-storage hydroelectric plants have inter-hourly constraints on the charging level (Equation (4.2c)). 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.

The model constraints of the supply side account for conventional generation (Equation (4.2a)), renewable generation (Equation (4.2b)), and pumped-storage hydroelectric plants (Equation (4.2c)–(4.2e)). Hourly conventional generation output $g_{p,t}$ is limited for every generating unit to its hourly available generation capacity. This parameter calculates by installed turbine capacity $\overline{G}_p$ adjusted by a seasonal availability factor $AVG_{p,t}$. Maximal hourly renewable generation $r_{n,s,t}$ of each technology s at the respective network node n is determined by aggregated generation capacity $\overline{R}_{n,s}$ and hourly availability level $AVR_{n,s,t}$. The three constraints for the representation of pumped-storage hydroelectric plants e include: an inter-hourly constraint on the charging level of each plant $pslevel_{e,t}$, cycle efficiency of 75 %, limitation of pumping $\overleftarrow{ps}_{e,t}$ and generation $\overrightarrow{ps}_{e,t}$ to the turbine rating $\overline{PS}_e$, and an upper bound $\overline{LS}_e$ for the charging level $pslevel_{e,t}$. Both cases, uniform and zonal pricing, have the same objective function and generation constraints.

$$\min_{\substack{g,r,\overleftarrow{ps},\overrightarrow{ps}\\ pslevel}} \text{costs}^{\text{sp}} = \sum_{p,t} (g_{p,t} C_p) \tag{4.1}$$

$$\begin{aligned}
\text{s.t.} \quad g_{p,t} &\leq \overline{G}_p AVG_{p,t} && \forall \quad p,t && \text{(4.2a)}\\
r_{n,s,t} &\leq \overline{R}_{n,s} AVR_{n,s,t} && \forall \quad n,s,t && \text{(4.2b)}\\
pslevel_{e,t} &= 0.75\overleftarrow{ps}_{e,t} - \overrightarrow{ps}_{e,t} + pslevel_{e,t-1} && \forall \quad e,t && \text{(4.2c)}\\
\overrightarrow{ps}_{e,t} + \overleftarrow{ps}_{e,t} &\leq \overline{PS}_e && \forall \quad e,t && \text{(4.2d)}\\
pslevel_{e,t} &\leq \overline{LS}_e && \forall \quad e,t && \text{(4.2e)}
\end{aligned}$$

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 (4.3) including all generation $g_{p,t}, r_{n,s,t}, \overrightarrow{ps}_{e,t}$, fixed hourly cross-border flows for imports $IM_{n,t}$ and exports $EX_{n,t}$ with neighboring countries, as well as load $Q_{n,t}, \overleftarrow{ps}_{e,t}$ in each hour. Marginal values on the hourly energy balance represent hourly electricity prices in the spot market.

In the case of two bidding zones, each bidding zone z has its own energy balance Equation (4.4a). Hourly supply, demand, and cross-border flows aggregate to one of the two zones. Inter-zonal trade $zf_{z,y,t}$ is limited by the NTC level $\overline{NTC}_{z,y}$, an aggregated zone-to-zone trade capacity in the spot market in Equation (4.4b). 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.

$$\sum_p g_{p,t} + \sum_n \left(\sum_s r_{n,s,t} - Q_{n,t} + IM_{n,t} - EX_{n,t} \right) + \sum_e \left(\overrightarrow{ps}_{e,t} - \overleftarrow{ps}_{e,t} \right) = 0 \quad \forall \quad t \tag{4.3}$$

$$\sum_{p \in z} g_{p,t} + \sum_{n \in z} \left(\sum_s r_{n,s,t} - Q_{n,t} + IM_{n,t} - EX_{n,t} \right) \tag{4.4a}$$
$$+ \sum_{e \in z} \left(\overrightarrow{ps}_{e,t} - \overleftarrow{ps}_{e,t} \right) + \sum_y zf_{z,y,t} = 0 \qquad \forall \quad z,t$$
$$|zf_{z,y,t}| \leq \overline{NTC}_{z,y} \qquad \forall \quad z,y,t \tag{4.4b}$$

4.3.4 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 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 of minimizing generation costs ($costs^{rd}$, Equation (4.5)). Increasing output of conventional generation $g^+_{p,t}$ causes variable generation costs. Decreasing generation levels $g^-_{p,t}$ save variable costs, on the other hand. 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 on the national level. It does not restrict cross-zonal re-dispatch between the two bidding zones.[20]

$$min_{g^+,g^-,r^+,r^-} costs^{rd} = \sum_{p,t} \left(g^+_{p,t} C_p \right) - \sum_{p,t} \left(g^-_{p,t} C_p \right) \tag{4.5}$$

[20] 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.

The re-dispatch model guarantees line flows not exceeding the lines' maximum flow capacity $\overline{P}_l$ in Equation (4.6f).[21] Changes in the output levels of power plants affect the network input $ni_{n,t}$ and the line flows $pf_{l,t}$ which are calculated using the linear approximation of the DC load flow approach in Equations (4.6g)–(4.6i). The voltage angle $\theta_{n,t}$ is fixed to zero for one node which is defined as slack bus. Network transfer matrix $H_{l,t}$ and network susceptance matrix $B_{n,k}$ combine information on network topology and line susceptance. Generation output of conventional units can maximally be increased by the difference between the hourly available power plant capacity and the scheduled output level $g^0_{p,t}$ in Equation (4.6a). The scheduled output level of the market dispatch can be decreased to zero in Equation (4.6b). The same holds for renewable capacity $r^0_{n,s,t}$ in Equations (4.6c) and (4.6d). At the same time the energy balance Equation (4.6e) 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 4.3.2).

$$
\begin{aligned}
\text{s.t.} \quad & g^+_{p,t} \leq \overline{G}_p AVG_{p,t} - g^0_{p,t} && \forall \quad p,t && \text{(4.6a)}\\
& g^-_{p,t} \leq g^0_{p,t} && \forall \quad p,t && \text{(4.6b)}\\
& r^+_{n,s,t} \leq \overline{R}_{n,s} AVR_{n,s,t} - r^0_{n,s,t} && \forall \quad n,s,t && \text{(4.6c)}\\
& r^-_{n,s,t} \leq r^0_{n,s,t} && \forall \quad n,s,t && \text{(4.6d)}\\
& \sum_{p\in n}\left(g^0_{p,t} + g^+_{p,t} - g^-_{p,t}\right) + \sum_{s}\left(r^0_{n,s,t} + r^+_{n,s,t} - r^-_{n,s,t}\right) && && \\
& -Q_{n,t} + IM_{n,t} - EX_{n,t} + \sum_{e\in n} ps^0_{e,t} + ni_{n,t} = 0 && \forall \quad n,t && \text{(4.6e)}\\
& |pf_{l,t}| \leq \overline{P}_l && \forall \quad l,t && \text{(4.6f)}\\
& ni_{n,t} = \sum_{k}\left(\theta_{k,t} B_{n,k}\right) && \forall \quad n,t && \text{(4.6g)}\\
& pf_{l,t} = \sum_{n}\left(\theta_{n,t} H_{l,n}\right) && \forall \quad l,t && \text{(4.6h)}\\
& \theta_{n^{slackbus},t} = 0 && \forall \quad t && \text{(4.6i)}
\end{aligned}
$$

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

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

4.3.5 Model Data for 2012 and Scenarios for 2015, and Line Extension

This chapter uses the dataset for the German electricity sector with data of 2012 which is published in the detailed data documentations and only relies on public sources.[22] 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 kilovolt (kV) and 380 kV (Figure 4.3). The re-dispatch model requires line specific network data, that is, maximum power flow $\overline{P}_l$, line susceptance, and starting and ending node.[23] 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).

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 gigawatt hours (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).[24] The aggregation of the 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 4.1).

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

[23]The network transfer matrix $H_{l,n}$ and network susceptance matrix $B_{n,k}$ are derived with start and end node and line susceptance (Leuthold, Weigt, and Hirschhausen 2012). Physical properties of transmission lines are approximated by their length and voltage level with assumptions on specific technical parameters for overhead power lines.

[24]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.

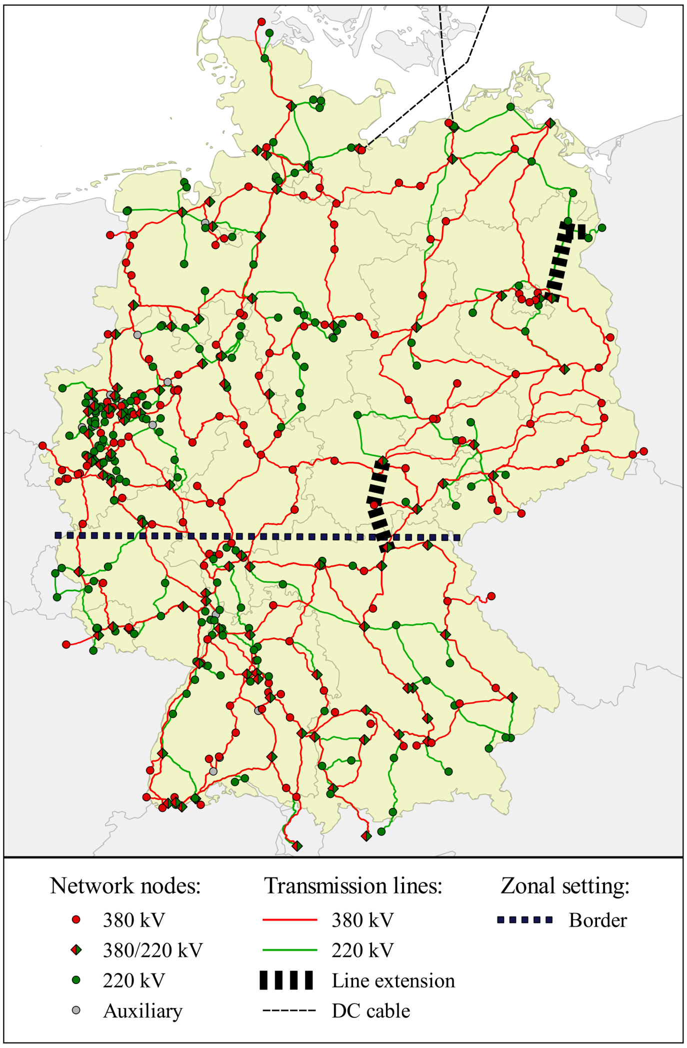

Figure 4.3: High-voltage network in 2012, two bidding zones, and additional lines in the transmission extension scenario.

Source: own depiction.

Temporal input data uses hourly time series with 8,784 hours for the year 2012.[25] Hourly national load levels and the nodal distribution key lead to hourly nodal demand $Q_{n,t}$. Installed capacity of conventional thermal power plant units $\overline{G}_p$ together with a seasonal availability factor $AVG_{p,t}$ calculates hourly available capacity. Maximum available renewable

[25]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.

power generation adjust installed capacity $\overline{R}_{n,s}$ with regional hourly availability factors for wind and photovoltaics $AVR_{n,s,t}$ provided by German TSOs. Compared to the previous ten years, 2012 was, by and large, an average wind and solar year in Germany (BMWi 2015b). Only wind generation in coastal regions was lower than average in the second half of the year (IWR 2013) while photovoltaics output was a few percentage points above average.[26] 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 $IM_{n,t}$ from and export flows $EX_{n,t}$ 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 4.2), regional cost factors for inland transport of hard coal increasing towards the south of Germany between € 2-20 per t[27], and the price for CO_2 emission allowances of € 7.94 per t.

The 2015 scenario tests the sensitivity of the 2012 model results by adjusting regional generation capacities (Table 4.1) 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 and additional peak capacity (-1.3 GW) retires. Solar PV 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 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 "Uckermarkleitung", allowing for better wind integration north-east 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 2015b).[29] Both lines are approved or under

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

[27]Transport costs in the variable costs range between € 0.7-7.4 per MWh depending on location and efficiency of the hard coal power plant block.

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

[29]In 2009, the EnLAG law (EnLAG 2009) has taken effect which outlines the facilitated implementation of 24

Table 4.1: Generation capacities and peak load for 2012 and change in 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[28]	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			

construction at the end of 2015 (BNetzA 2015a).

The regional characteristics of the input data are illustrated in Figure 4.4 with an aggregation of nodal data on state level for demand, conventional power plants, and renewable generation capacities. Also, Table 4.1 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 of the northern zone (357 TWh per year) is significantly higher than in the southern zone (194 TWh per year) but demand in the northern zone is concentrated in the west. Also, input data assumes different spatial allocation of load in peak and

extension projects (EnLAG projects) in the German high-voltage transmission system.

Table 4.2: Fuel prices for conventional thermal power plants.

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

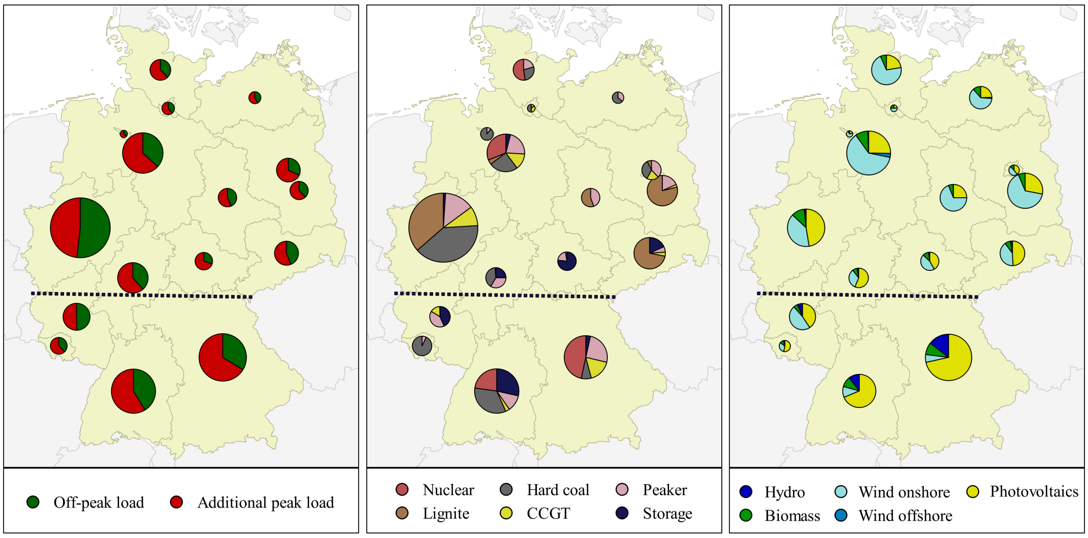

Figure 4.4: Spatial electricity data by state for the German electricity sector in 2012.

Source: own depiction.

off-peak hours. Conventional capacity illustrates the historical role of nuclear (north-west 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.[30] Most conventional generation capacity following nuclear power in the merit order (i.e. lignite and hard coal) is located in the northern bidding zone.[31] The southern

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

[31] 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 coast 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

part of Germany sees large additional renewable generation in hours of 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 lowest-cost generation dispatch for many hours.

4.4 Results

The results section distinguishes between the effects two bidding zones have on the market dispatch (4.4.1), on re-dispatch levels (4.4.2), and on distributional implications (4.4.3). Sensitivity runs present the effect of limited network investment reinforcing the German transmission network and of a setting with four bidding zones (4.4.4).

4.4.1 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 4.5 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.

plants have lower variable generation costs than modern gas-fired CCGT plants.

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).

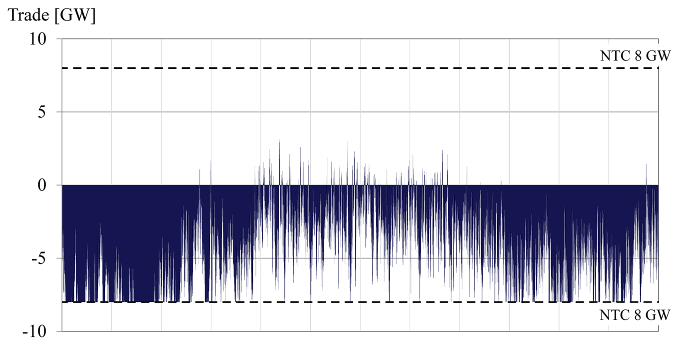

Figure 4.5: Hourly trade flows north to south (-) and south to north (+) over the year 2015 (Jan-Dec).

Source: own depiction

The average annual electricity price differential between the northern and southern zone for an NTC of 8 GW is rather low with € 0.4 per MWh in 2012 and grows to € 1.7 per MWh in 2015.[32] 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 per MWh and an average difference of € 6.9 per MWh. Many hours with a significant price difference occur in January and February, at price levels in the spot market of about € 50 per MWh in the northern zone, with more frequently deviating zonal prices in hours with high wind power generation. 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 smaller extent (see Figure B.1 in Appendix B.2).

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 4.6 deviate in 1,455 hours of the year for an NTC level of 8 GW with a maximum difference of € 50.5 per MWh and an average difference of € 10.2 per 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 per MWh) as well as with high wind

[32]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. Berg Skånlund et al. (2013) predicts a price differential of € 3.8 per MWh for an NTC of 7 GW in 2012 in a market study on two price zones in Germany, which decreases to € 1.5 per MWh for 10 GW.

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 6 GW NTC).

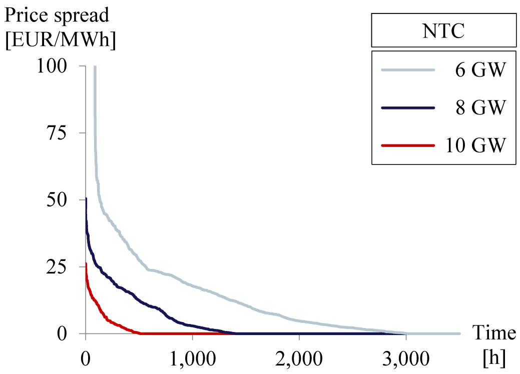

Figure 4.6: Price mark-ups in the southern zone compared to the northern zone in 2015.

Source: own depiction.

The implementation of the NTC between the two bidding zones affects the power plant dispatch in the spot market (Table 4.3). 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 smaller 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.

Table 4.3: Zonal generation by fuel for two price zones and difference compared to one price zone (in parentheses).

[TWh/year]		**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

4.4.2 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 4.7 illustrates the change in annual zonal re-dispatch levels for different NTC values in 2012 and 2015.

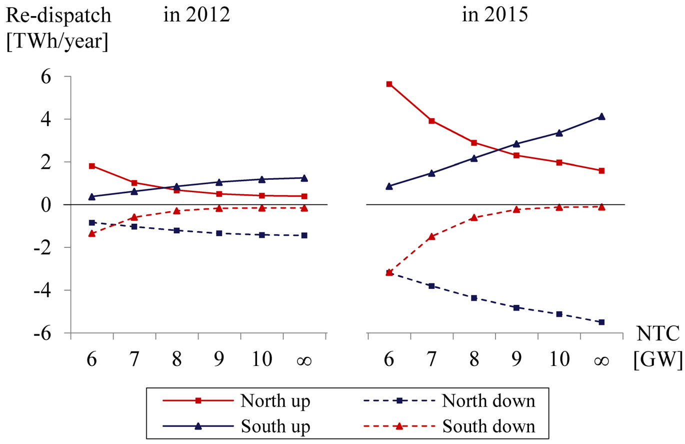

Figure 4.7: Re-dispatch for different NTC levels with up- and down-regulation.

Source: own depiction.

For very high NTCs, zonal pricing becomes ineffective as the dispatch in the spot market converges to the levels 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 increases output in the northern zone (+399 GWh). 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, an NTC of 8 GW has the lowest re-dispatch levels.[33] However, the implementation of two bidding zones only allows a limited reduction of

[33]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.

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.[34] 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 %).[35]

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 4.4, Figures 4.8–4.9), resulting in an overall reduction of cross-zonal re-dispatch of almost 1,500 GWh. In the northern bidding zone, down-regulation decreases not 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.[36]

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. 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

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

[35] 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.

[36] 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, this 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.

Table 4.4: Zonal re-dispatch levels per technology with up-regulation (+) and down-regulation (-).

[GWh/year]		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
[GWh/year]		**Zonal pricing** (NTC 8 GW)		
		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

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 (see Figures 4.8–4.9) down-regulates both, (1) 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 (2) 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, (1) hard coal plants and some gas capacities in western Germany for re-dispatch in order to create a technically feasible generation dispatch[37] which are (2) 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.

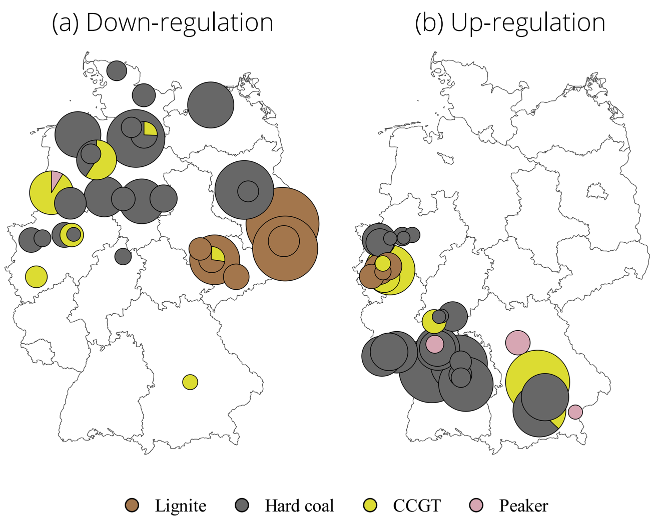

Figure 4.8: Re-dispatch for single price zones in 2015.

Source: own depiction.

4.4.3 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

[37]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.

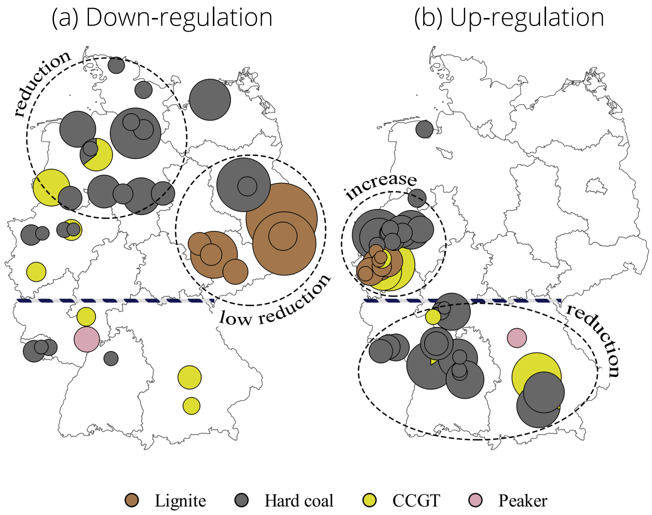

Figure 4.9: Re-dispatch for two price zones (NTC 8 GW) in 2015.

Source: own depiction.

same in 2012 and 2015. Yet, the level of redistribution increases by the same magnitude as does the price differential (€ 0.4 per MWh in 2012 and € 1.7 per 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 of 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 4.5). In 2012, the total redistribution between consumers and producers is limited to about € 50m in both zones. In 2015, distributional effects increase, as consumers see their payments increase by € 275m in the south and a reduction of € 163m in the north.

At the same time redistribution for generation increases to about € 200m. In the north, renewables (-€ 79m), followed by lignite (-€ 66m), hard coal (-€ 39m), and nuclear plants (-€ 15m) are the generation technologies that lose the most profits in 2015. On the contrary, in the south, nuclear (+€ 74m), renewables (+€ 57m), hard coal (+€ 55m), and CCGT plants (+€ 13m) are the biggest profiteers. The auctioning of trade capacity in the spot market provides scarcity rents to the TSO, increasing from € 25m in 2012 to € 119m in 2015.

Breaking down the total redistribution in Table 4.5 to values per MWh in Table 4.6 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.[38] 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: (1) exogenous seasonable availability factors are higher in the winter than in the summer months and (2) 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, that is, 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.

Table 4.5: Change in payments and rents for two bidding zones.

[m €]		**Consumer**	**Producer profits**		**Revenue**	**Congestion**
		rents	Conv.	Ren.	**trade flows**[39]	**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	

[38] 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.

[39] Zonal pricing also affects changes in payments for import and revenues from exports with neighboring countries. Table 4.5 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 chapter does not discuss the results in detail, as cross-border flows are fixed and neighboring markets not modeled endogenously.

Table 4.6: Effect of two price zones on average prices, demand, and producers.

[€/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

4.4.4 Additional Sensitivity Analysis

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 4.3 between the northern and southern bidding zone, provides 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 4.10, overall re-dispatch levels decrease from 5,720 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 per MWh. Price differentials occur in 556 hours with a maximum price difference of € 26.2 per MWh and an average price difference of € 5.7 per MWh. Distributional effects are in the range of the 2012 results. Thus, the importance of the analyzed bidding zones on network congestion and re-dispatch levels decreases with network investment.

Case with Four Bidding Zones

The high level of internal re-dispatch in the northern zone in 2015 motivates a sensitivity with more than two bidding zones. In a four zone case, the former northern zone is further divided into the coastal regions with 60 % of German onshore wind, all offshore wind, and

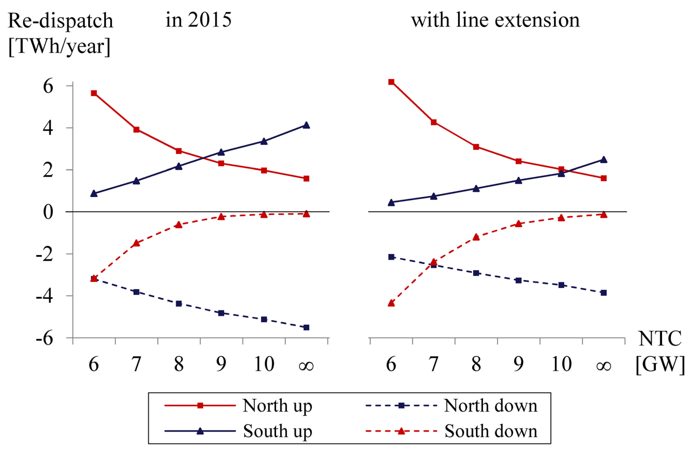

Figure 4.10: Implication of line extension on zonal re-dispatch.

Source: own depiction.

large hard coal capacity, the western zone with large demand centers and conventional capacity, and the eastern zone with low demand and excess in lignite capacity (see Table 4.7 and Figure 4.11). The assumed NTC levels between the new zones are 7 GW (north-west) and 2.5 GW (north-east and west-east). The NTC of the two zone case (8 GW north-south) is shared with 6 GW (west-south) and 2 GW (east-south).

The results in Table 4.8 show the highest zonal average price differences of €2.7 per MWh between the south and the east/north. It is about €1 per MWh higher than for two price zones as prices show an additional increase of about €0.2 per MWh in the southern zone and an additional decrease of about €0.8 per MWh in the northern/eastern zones. The average price in the western zone slightly increases compared to uniform pricing (+€0.2 per MWh) whereas it decreases in the two zone case as part of the northern zone (-€0.5 per MWh).

An equal electricity price for all four zones {NWES} prevails in 6,827 hours (77.7 %). Thus zonal prices deviate in about 500 hours more than in the two zone case. The four zone case results less frequently in a uniform price in all zones except for the southern zone (i.e. {NWE}{S} in Table 4.8) than the two zone case (583 hours compared to 1,455 hours). More frequent are equal zonal prices of the north and the east {NE} with different ({W}{S} in 538 hours) and equal ({WS} in 384 hours) prices between the west and the south. Different zonal prices in all four bidding zones ({N}{W}{E}{S}) only occur in 128 hours and mark the case with highest average price differences (between -€13.4 and +€9.7 per MWh).

Four bidding zones allow for a reduction of re-dispatch from 5,720 GWh (uniform pric-

Table 4.7: Generation capacities in the four zone case in 2015 (selected technologies).

	North	West	East	South
Technology	[GW]			
Nuclear	4.1			6.7
Lignite	0.5	10.5	9.9	
Hard coal	8.9	9.9		7.7
CCGT	2.5	3.1	0.6	3.2
Gas	3.2	2.9	1.1	3.8
Wind	22.6	5.0	6.6	3.5
Photovoltaics	9.6	6.5	5.3	19.9
Peak demand	21.3	26.0	7.3	31.4

ing) and 5,071 GWh (two price zones) to 3,962 GWh. Compared to the two north-south bidding zones, four zones reduce down regulation in the north (-920 GWh of mostly hard coal generation) and the east (-1,000 GWh of lignite generation) and up regulation in the west (-1,125 GWh hard coal and -450 GWh lignite) and the south (-330 GWh mostly hard coal). The additional zonal constraints exclude some generation from the dispatch in the north and the east which would be in the lowest-cost nodal market dispatch. The optimization approach for re-dispatch schedules this generation, that is, 600 GWh of mostly hard coal in the north and 200 GWh of lignite in the east, into the market by replacing 800 GWh of mostly hard coal in the west.

Four bidding zones, compared to two bidding zones, are better able to address the several temporally occurring bottlenecks, which follow regional wind availability and become more frequent with additional wind capacity. The structural bottlenecks between the northern and the southern bidding zone can be addressed by both two and four bidding zones.

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

Table 4.8: Zonal average price differences compared to uniform pricing for four zone case in 2015.

	North	West	East	South	Time
Zonal setting	[€/MWh]				[%]
{NWES}	0.0	0.0	0.0	0.0	77.7
{NWE}{S}	-2.4	-2.4	-2.4	+6.8	6.6
{NE}{W}{S}	-9.2	+0.8	-9.2	+9.1	6.1
{NE}{WS}	-4.6	+2.6	-4.6	+2.6	4.4
{NWS}{E}	+0.9	+0.9	-3.2	+0.9	2.2
{N}{W}{E}{S}	-12.5	+4.3	-13.4	+9.7	1.5
{N}{E}{WS}	-6.5	+5.9	-8.2	+5.9	1.3
{N}{WES}	-6.8	+0.6	+0.6	+0.6	0.1
{NW}{E}{S}	+0.1	+0.1	-4.7	+6.8	0.1
Average all hours	-1.2	+0.2	-1.3	+1.4	

model results for two and four bidding zones, imbalances with strong regional price differences occur in a limited number of hours. These prices can provide valuable 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 in 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 2015a). The proposed AC and DC 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 chapter, has to consider the regional dynamics of the German energy transition.

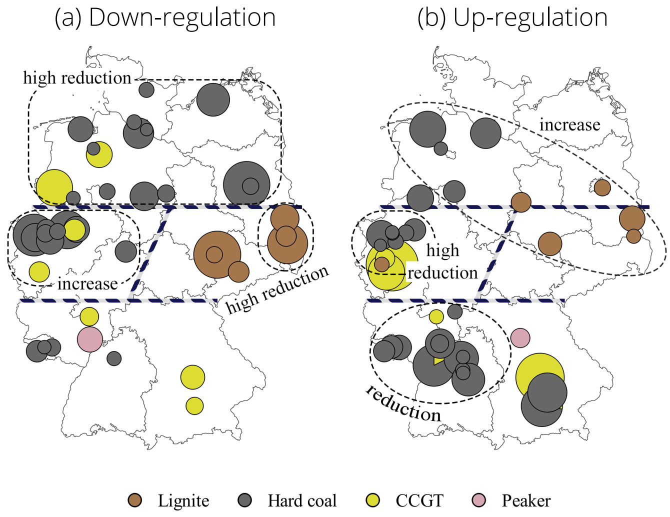

Figure 4.11: Re-dispatch and evaluation in 2015 for four bidding zones.

Source: own depiction.

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.

4.5 Conclusion

This chapter analyzes some potential effects of the creation of one northern and one southern bidding zone for the German electricity market in 2012 and 2015. Additional scenarios with network extension in 2015 and with four bidding zones are 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. The sensitivity with four bidding zones shows the potential of further dividing the northern bidding zone. In hours of strong regional imbalances, one observes price differences at significant levels, 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 per 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 the 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. Among 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 5

Unit Commitment under Imperfect Foresight — The Impact of Stochastic Photovoltaic Generation

"There is no certainty, but only different degrees of uncertainty."

(Anton Pawlowitsch Tschechow, 1860-1904)

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5.1 Introduction

The German Power System Over the last decade there has been a fundamental policy-driven restructuring of the German power sector towards a low-carbon energy system, incentivizing an extensive deployment of sustainable and clean energy sources. This process is likely to endure the next 20 to 30 years, since political plans envision an annual share of renewable electricity generation of 80 to 95 % by 2050.[1] Wind and PV energy sources form the cornerstone of the so-called German '*Energiewende*' (Agora Energiewende 2013) with a strong increase in deployment over the last years: In 2010, RES only accounted for a share of 36 % of the overall installed capacity. By the end of 2017, their share has risen to more than 55 %, with 50.47 GW on- and 5.41 GW offshore wind and 42.39 GW of solar power (UBA 2018). While wind energy has been deployed in large-scale already for quite some time, energy from PV installations has only been highly expanded particularly in the last years, mainly due to sinking investment costs and financial incentives by the government (UBA 2018; Fraunhofer ISE 2015). Unlike conventional thermal power plants, the generation of wind and PV power plants is volatile and non-dispatchable, that is, the availability is solely dependent on exogenous weather conditions and therefore uncertain, making short-term system operations more challenging. Despite of steadily increasing environmental and geopolitical costs of conventional technologies with respect to international agreements to reduce carbon emissions (for example the Paris Accord[2]) thermal power plants still dominate Germany's electricity generation with a share of almost 64 % of overall annual production (UBA 2018). Due to technical and economic reasons, thermal power plants are limited in reacting to a fluctuation in the residual load[3]. Hence, if deviations in the generation of RES are not comprehensively anticipated in short-term scheduling decisions, this might lead to a non-optimal use of the power system. High carbon and fuel costs as well as energy exports of excessive power to neighboring countries at small or even negative spot prices can arise as a consequence (Wirth 2019). In the short-term, UC decisions as well as the flexibility needs of the power system are depending on forecasted generation values of RES. Thus, optimal and efficient UC decisions rely on the accurate evaluation of both wind and PV infeed.

[1] cf. §1(2) *EEG*—Renewable Energy Sources Act

[2] cf. European Commission COM/2016/0110

[3] Residual load denotes the portion of load not served by RES and therefore to be covered by thermal generation.

Stochastic Modeling In general, the forecasting of power outputs aims to make a statement about the future output level of generation units. For thermal power plants, future states of production can be adjusted to a given demand within a power plant's technical and organizational/economic scope. Hence, the production is determined by the maximum capacity of generation, by ramping constraints of the generators as well as on- and offline time restrictions. The dispatch of conventional power plants can therefore be expressed by a deterministic optimization approach, where all input parameters are previously known with negligible uncertainty about the future state of realization. For RES, the power output depends on stochastic parameters and is therefore difficult to predict on point (Graeber 2014). Additionally, it can only be narrowly adjusted, for example through curtailment of single generators. Due to the stochasticity of their availability, RES leave a fluctuating residual load to be met by mostly inert thermal power plants. Despite spatial averaging effects counterbalancing deviations in single sites through a decentralized distribution of generation, rising shares of RES challenge system operations. This implies a change in the appropriate modeling approach: in order to minimize total system costs, particularly high operational costs of frequent scheduling of thermal plants, the intermittency of RES power output must be anticipated in the optimization process. Stochastic modeling techniques[4] provide the tools to allow for multiple possible manifestations in the future with assigned probabilities. Thus, uncertainty is incorporated by comprehensively accounting for prediction errors of volatile, non-dispatchable generation technologies.

stELMOD Abrell and Kunz (2015) developed a stochastic unit commitment model (stELMOD) for Germany in the context of the European electricity market in order to investigate the impact of intermittent wind generation on optimal scheduling decisions, reserve needs and system costs. Incorporating stochastic wind power availability with a multi-period scenario-tree, they find that short-term scheduling costs can be significantly reduced by anticipating uncertainty in the optimization process. According to their results, the flexibility of the power system is achieved by either using flexible generation plants or by flexibilizing the generation pattern of mostly inert thermal power plants. Yet, Abrell and Kunz solely considered wind generation as a possible source of uncertainty, neglecting the impact of PV generation.

[4]An introduction into stochastic programming techniques can be found in Birge and Louveaux (2011).

Objective This chapter investigates the impact of intermittent PV generation on unit commitment decisions in the German power system. By extending and updating the aforementioned stELMOD, it is to be examined how far the gradual convergence of PV forecasts and hence, the decreasing uncertainty of PV generation over time have to be taken into account, in order to comprehensively assess scheduling costs and flexibility needs of the German power system. We introduce a novel approach to simulate PV forecasts to be used in electricity market models, comprising the following methodological steps: (i) a time-adaptive intra-day forecast is simulated, building on an exponential smoothing of previous deviations between the realized and day-ahead forecast value; (ii) hourly scenario trees are generated from the time series of residuals between the constructed forecast and the actual realization; (iii) uncertainty of PV generation is incorporated into stELMOD by extending the existing scenario tree for wind accordingly.

Structure The remainder of this chapter is structured as follows: Section 5.2 gives an overview of pertinent advancements in the field of stochastic unit commitment modeling under uncertainty of renewable infeed. Section 5.3 describes the main contribution of this chapter, the novel modeling approach used to incorporate uncertainty of PV generation in stochastic market models. Exemplary results of the analysis for the German power system are presented in Section 5.4. Section 5.5 discusses the results and concludes with further research opportunities. In Section 1.3.3 the relevant characteristics of PV and the challenges in modeling arising are presented. Appendix C.1 describes the data used, relevant data adjustments, as well as included assumptions.

5.2 Insights from Literature and Recent Developments

Over the last years, unit commitment models have been adopted accordingly to account for the increasing variability and uncertainty in power systems. In the field, a vast amount of literature has been published, differing in the used methodology and the applied definition of uncertainty. Different parts of a power system can be considered as uncertain: outages of thermal power plants, load profiles, and power generation of intermittent RES. The latter is, particularly for large-scale integration of wind and PV, the most severe (Wangdee 2014).

Brouwer et al. (2014) examine the effect that integrating intermittent RES has on the power system and its thermal power plants with respect to reserve requirements and resulting efficiency of thermal power plants. They conclude that the influences are already sizeable for a medium penetration level of 20 % of the annual power generation (which has been exceeded considerably in Germany). While mainly focusing on high penetration of wind energy, the authors come to the conclusion that the stochastic impact of large-scale solar power needs further investigation. Thus, stochastic optimization is becoming more and more prevalent. A technical overview on the recent state-of-the-art in stochastic optimization of optimal-power-flow-based problems for power systems with a high level of uncertainty is given by Alqurashi, Etemadi, and Khodaei (2016).

Due to atmospheric turbulences, the stochastic influence of wind generation on unit commitment decisions is in general assumed to be stronger compared to the effects of uncertainty in PV generation. This is reflected by the amount of studies performed to assess the influence of volatile wind power on scheduling decisions in UC models (see Wang, Shahidehpour, and Li 2009 or Ruiz, Philbrick, and Sauer 2009). However, most of these studies target optimal UC decisions only in the DA market[5]. The underlying market structure of a subsequent hourly ID[6] and balancing CM market[7] clearing is often neglected.

Such a rolling planning procedure has been included in the Joint Market Model (JMM) by Weber et al. (2009) within the framework of the WILMAR project.[8] Most European countries employ a three-step market regime consisting of a day-ahead, an intra-day and a real-time balancing market. This structure influences the power system operation planning and scheduling decisions since different levels of uncertainty prevail in each market caused by different time frames of clearing. The day-ahead market is cleared at noon for the following day. It subserves the intention of grid integration. Optimizing trading quantities based on RES forecasts made 12 or 36 hours in advance might lead to high inaccuracies between

[5]In the DA market, the system operator agrees upon hourly trading quantities of electricity for the subsequent day. The clearing is set for 12 pm on the previous day, that is, the trading quantities are contracted for 36 hours. The expected infeed of intermittent renewable energy sources like wind and PV power is based on day-ahead forecasts. These predictions already take meteorological conditions into account. However, the forecasts can, particularly in the most distant hours of the contracted quantities in the day-ahead market, significantly differ from the actual realization of the infeed.

[6]The ID market builds upon commitment decisions made in the day-ahead market which it uses as initial values for solving. It is a market for short-term trading actions up to 15 minutes prior to real-time. The possible liquidity of the market decreases with continually declining time horizons since thermal power plants generally have technical and organizational restrictions with respect to ramping or on- and offline hours (Graeber 2014). Due to new information on the infeed of intermittent renewable energy sources, the system operator has the possibility to adjust the bids and thereby the unit commitment decisions for the whole system. Hence, the ID market represents the center stage for trading electricity produced by RES.

[7]Real-time balancing is used for CM, determining the actual flows in the transmission network and regulating exceeding flows in order to respect physical network restrictions imposed by the system.

[8]Wind Power Integration in Liberalized Electricity Markets, for further information please refer to www.wilmar.risoe.dk

contracted and realized quantities. The intra-day market enables participants to refine their trading bids with more accurate short-term forecasts of RES. It is cleared every hour. Afterwards, the real-time balancing market handles the congestion management, using reserved energy in order to regulate power transactions and to maintain network stability. Yet, last-minute power balancing is linked with high costs. The stochasticity of wind generation and inherent forecast errors are examined in Boone (2005) and are included in the JMM of Weber et al. (2009) and in the extension of the JMM by Tuohy et al. (2009). In order to pursue the integration of the underlying market regime, Abrell and Kunz (2015) additionally take a physical transmission network into account. Hence, the authors combine the fundamental market structure with a detailed representation of the German high-voltage transmission system provided by Leuthold, Weigt, and Hirschhausen (2012). However, these publications explicitly focus on the stochastic nature of wind power, neglecting additional effects by uncertain PV generation.

An approach to include both intermittent wind and PV generation into stochastic unit commitment has been proposed by Quan et al. (2015). Their findings imply the importance of including comprehensive uncertainty into unit commitment problems. Yet, they focus on optimal day-ahead scheduling decisions, abstracting from a rolling planning procedure. Abedi et al. (2011) employed a risk-constrained UC model, modeling the impact of both uncertain PV and wind power with the probabilistic method of confidence intervals. Using a class of multilayer perceptrons, the authors derive estimates of the generation level of wind and PV, achieving a reliable day-ahead commitment of thermal units by including dependable generation of wind and PV. In the end, their analysis reduces to solely obtain optimal day-ahead scheduling decisions of dispatchable units. For microgrid systems, the influence of stochastic solar uncertainty has been investigated by Hytowitz and Hedman (2015). Using a stochastic MIP to account for day-ahead uncertainty of PV generation, the scheduling decisions are assessed in a small-scale system that is interconnected with the main-grid to allow for energy tradings or reserve allocation. Uncertainty of PV generation is incorporated by solar scenarios based on statistical analysis of historical solar data. Araujo et al. (2015) formulate a small-scale stochastic UC approach to accommodate the estimation error of PV generation using a similar stochastic scenario approach. They explicitly consider conventional thermal generators as dispatchable and PV as non-dispatchable source of energy. The benefits of this approach are tested on a modified version of the IEEE 30-bus system[9], investigating only day-ahead dispatch strategies. Furukakoi et al. (2018) showcase

[9]The IEEE 30-bus system simulates a small share of the Midwestern American electric power system. For data and further information, please refer to www2.ee.washington.edu/research/pstca.

a multi-objective unit commitment model for minimizing the forecast error of PV power. Their algorithm is tested on an IEEE-6 bus system, and their results imply a reduction in system operating costs and improvement of stability. A systematic framework similar to the European market regime consisting of day-ahead commitment, hour-ahead scheduling and real-time balancing, was proposed by Wu et al. (2015). They investigate the impact on operating as well as integration costs by incorporating sub-hourly variability and hourly uncertainty of PV generation. In a case study for the Southwestern United States the authors find that high photovoltaic penetrations lead to operational challenges with an increased need for a flexible power system. Ming et al. (2018) propose a novel hierarchical solving structure that is applied to a hydroelectric unit commitment model in the presence of uncertain large-scale PV generation. With their method, the authors can reduce the dimension of the optimization while adequately solving the unit commitment problem.

However, the impact of stochastic PV availability has not been studied extensively for the German electricity market since the impact of PV in large-scale models seems to be mostly neglected. This chapter performs a comprehensive evaluation of both uncertain wind and PV generation, though mainly focusing on the additional impact of PV.[10] 1.3.3 decribes the fundamentals of uncertainy in PV generation. As a novel approach, the time-dependent forecast error of PV is explicitly implemented into the rolling planning procedure of the German electricity market.

5.3 Modeling Approach

This section provides insights into the methodological procedure of implementing uncertain photovoltaic generation into UC models. The novel methodology for the simulation of intra-day forecasts and its transformation into scenario trees, as well as the final implementation of uncertain PV production is described in detail. It also comprises a brief description of the used model, as well as the cases of uncertainty used for the analysis.

The analysis in this chapter uses stELMOD[11], a large-scale stochastic unit commitment electricity market model. It is written as MIP in the General Algebraic Modeling System (GAMS) and solved with the solver CPLEX Optimization Studio[12].

[10] For the sole impact of wind, see Abrell and Kunz (2015).

[11] The open-source model version can be found on www.diw.de/elmod, together with the model documentation (Abrell and Kunz 2015) and an application on cross-border congestion management (Kunz and Zerrahn 2016).

[12] see www.ibm.com/analytics/cplex-optimizer

The multi-market regime is integrated into a rolling planning procedure that solves the DA model first, obtaining unit commitment decisions for the next 36 hours. In a subsequent rolling planning procedure the ID and CM models are solved alternatingly for each hour. At 12 pm, the DA model is solved again for the following day. This procedure is integrated into a loop and is repeated for the time horizon set.

Due to the enormous computational effort of the model, some adjustments had to be made in order to keep the runtime for the stochastic case within acceptable limits. Therefore we neglect maximum ramping rates and minimum offline times of thermal power plants, leading to a relatively high and therefore less realistic frequency of startups and shutdowns of generation units. However, the results are—in relation—consistent with previous findings. Further documentation of model specifics can be found in Abrell and Kunz (2015). The used data set for this chapter is described in detail in Appendix C.1.

5.3.1 Implementation of Uncertain Photovoltaic Generation

Day-ahead forecasts play an essential role in power system operations since they are a prediction of the infeed of RES for the next day based on meteorological simulations. The inclusion of day-ahead forecast errors generally has a strong influence on system costs. However, in order to anticipate uncertainty of RES infeed in intra-day operation, that is, up to six or seven hours in advance, short-term power predictions need to be simulated. This section provides insights into how the fitted intra-day forecast for solar power is generated and implemented in stELMOD in this chapter (Figure 5.1): (1) an exponential smoothing of realized and day-ahead forecast values is carried out (Section 5.3.1); (2) based on that, an intra-day forecast is simulated (Section 5.3.1) and (3) scenario trees are constructed and reduced (Section 5.3.1). Finally, the steps of attaching these scenario trees to the existing implementation for wind power in stELMOD are described (Section 5.3.1).

Exponential Smoothing of Day-ahead Forecast Errors

Assume Y_t to be the realization of the generated PV power at any time $t \in T$ and X_t the day-ahead forecast value that has been predicted earlier in time for the time slice t in question. Here, T constitutes the time horizon, for our case hourly values. Let $\alpha_t \in \mathbb{R}$ denote the percentile discrepancy between the forecasted and the realized amount of power harvested from solar energy, then

$$Y_t = (1 + \alpha_t) \cdot X_t \qquad \forall t \in T, \tag{5.1}$$

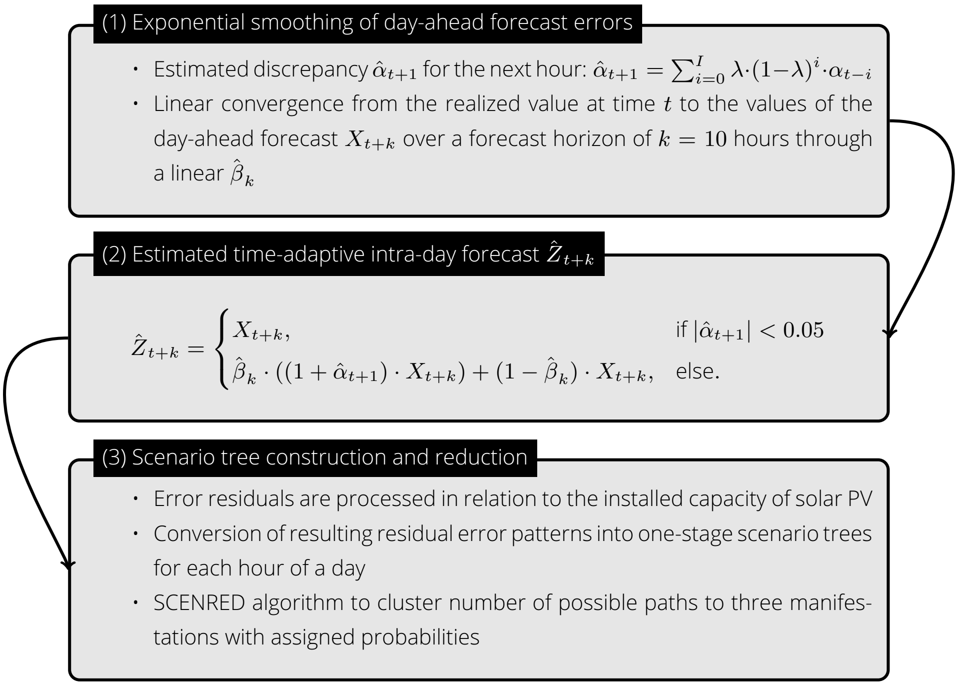


Figure 5.1: Schematic representation of the methodology.

Source: own depiction.

which can be rewritten as

$$\alpha_t = \left(\frac{Y_t}{X_t}\right) - 1 \qquad \forall t \in T. \tag{5.2}$$

This discrepancy—or error term—α_t in time slice t can therefore be represented by the ratio of the realized value to the forecasted value at time $t-1$. To avoid strong discrepancies in early (and late) hours of the day, where the ratio of realized to forecasted value might be relatively high even though the actual difference is small, the realization $Y_{\bar{t}}$ is set to the forecast value $X_{\bar{t}}$ at time $\bar{t}$. Here, $\bar{t} \in T$ denotes those times for which the realization of solar power is smaller than 1 % of the installed capacity. Thereby it is additionally ruled out that the ratio is undefined for any time $\bar{t} \in T$ when the realization $Y_{\bar{t}}$ is greater than zero while the forecast $X_{\bar{t}}$ is (still or already) zero.

The variable $\hat{\alpha}_{t+1}$ represents a factor around zero in order to up- or downscale the forecasted value X_t at time t for the next hour $t+1$. This error term $\hat{\alpha}_{t+1}$ for the next hour is based on previously observed discrepancies, following an exponential smoothing, such that for all $t \in T$

$$\begin{aligned} \hat{\alpha}_{t+1} &= \lambda \cdot \alpha_t + \lambda \cdot (1-\lambda) \cdot \alpha_{t-1} + \lambda \cdot (1-\lambda)^2 \cdot \alpha_{t-2} + ... + \lambda \cdot (1-\lambda)^I \cdot \alpha_{t-I} \\ &= \sum_{i=0}^{I} \lambda \cdot (1-\lambda)^i \cdot \alpha_{t-i}, \end{aligned} \tag{5.3}$$

with

$$\sum_{i=0}^{I} \lambda \cdot (1-\lambda)^i = 1, \tag{5.4}$$

where I is the number of previously realized values to be influencing the parameter and $0 < \lambda \leq 1$ the smoothing parameter controlling at which rate the weights for previous observations are decreasing: For a small λ, discrepancies earlier in time are relatively more weighted in determining the following estimated error term, while for a λ close to one, discrepancies closer in time to t are influencing the parameter relatively more with a steeper decline of weights for discrepancies earlier in time. $\lambda = 1$ would result in a persistent forecast, such that $\hat{\alpha}_{t+1} = \alpha_t$.

Following practical reasons, the number of considered past discrepancies for this chapter is set to $I = 3$. A larger number of discrepancies does not result in significant improvements in determining the discrepancy of solar power realization and day-ahead forecast due to fast changing cloud coverage or other confounding factors. Thus, the higher computational effort related with an increasing I would not be justified.

The values for λ are optimized with respect to minimizing the variance of the absolute error terms over a quarter year. Hence, the sum of the quadratic deviations of all hourly values is lowest for the depicted values of λ for each quarter year in Table 5.1. The sum of the weights for each discrepancy adds up to one (Equation (5.4)).

Table 5.1: Selection of smoothing parameter λ for each quarter year.

Months	**January - March**	**April - June**	**July - September**	**October - December**
λ	0.34	0.41	0.32	0.54

Now, consider β_t to be a parameter representing a linear convergence from the realized value at time $t \in T$ to the values of the day-ahead forecast over a total forecast horizon of 10 hours. Here, $k \in K \subset T$ denotes the forecast horizon starting from time step $t \in T$.

The values for $\hat{\beta}_k$ are determined by

$$\hat{\beta}_k = \begin{cases} 0 & \forall k \in K_{>10}, \\ -\left(\frac{k}{10}\right) + 1, & \text{else.} \end{cases} \tag{5.5}$$

In terms of the sum over all absolute errors over time, a linear convergence to the day-ahead forecast is found to yield more precise results than quadratic or exponential declining convergence schemes.

Intra-day Forecast Simulation

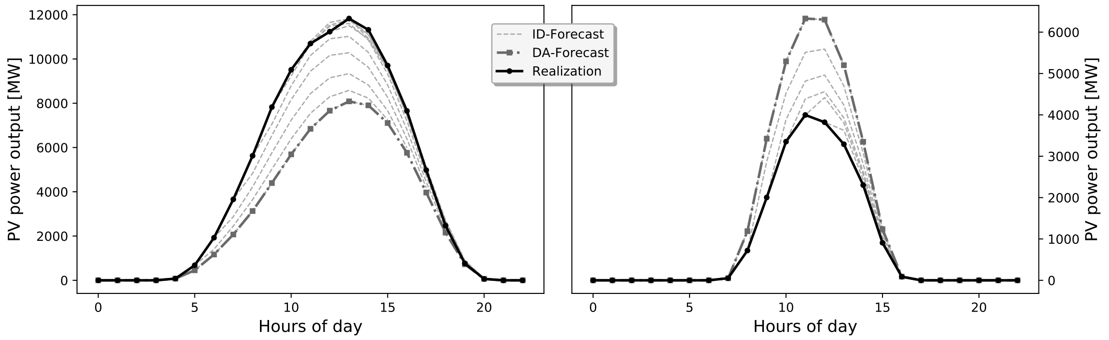
The resulting generated intra-day forecast $\hat{Z}_{t+k}$ follows a simple but effective structure that is represented as follows:

$$\hat{Z}_{t+k} = \begin{cases} X_{t+k}, & \text{if } |\hat{\alpha}_{t+1}| < 0.05, \forall t \in T, k \in K, \\ \hat{\beta}_k \cdot ((1 + \hat{\alpha}_{t+1}) \cdot X_{t+k}) + (1 - \hat{\beta}_k) \cdot X_{t+k}, & \text{else}, \forall t \in T, k \in K. \end{cases}$$

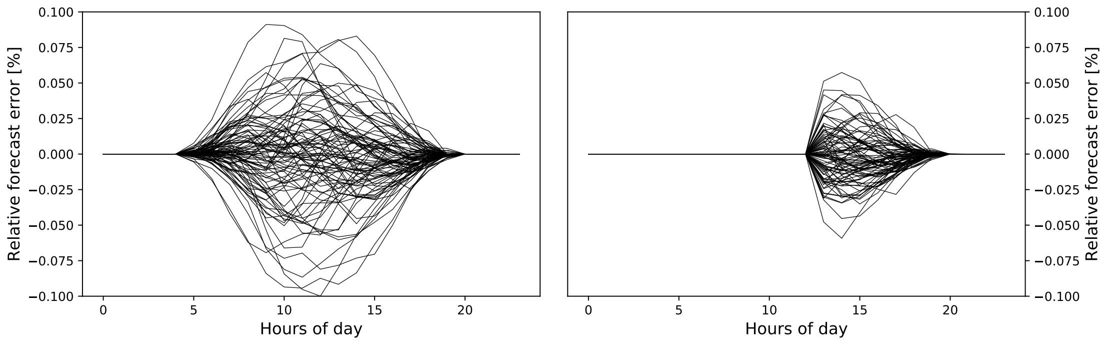
Thus, the estimated intra-day forecast $\hat{Z}$ is based on day-ahead forecast values X, as well as the ratio α of realized and forecasted values up to time t. This forecast linearly converges to the day-ahead forecast at time $t + k$, taking new realized values into account with proceeding time steps. Errors based on relatively small discrepancies, that is, for all $|\hat{\alpha}_{t+1}| < 0.05$, are ruled out by fitting the estimated forecast directly to the day-ahead forecast.

Figure 5.2a illustrates the simulated ID forecasts for two exemplary days. Note the differences in scale. On the left, June 21, 2016 is depicted where the actual realization is underestimated by the DA forecast. On the right, November 22, 2016 is illustrated as an example of an overestimation of the final realization. Both figures show the improvement of the hourly generated intra-day forecasts with respect to the day-ahead forecast. The time-adaptive character of the simulated ID forecast is clearly visible, providing an increasing improvement over the DA forecast.

Subsequently, the fitted ID forecasts are subtracted from the time series of the realized values for the year 2016 to receive the absolute errors of the ID forecast with respect to the final realization. These errors are divided by the installed capacity of solar power in Germany. This yields a time series of error residuals relative to the installed capacity in Germany such that a comparison of the error terms between days is possible. At 1.24 % of the installed capacity, the RMSE of the generated time series is significantly smaller than



(a) Improvement of simulated ID forecast from DA forecast to final realization for two exemplary days.



(b) Decreasing forecast error over a day in the second quarter of 2016 at 12 am (left) and 12 pm (right).

Figure 5.2: Decreasing solar forecast error.

Source: own depiction.

the RMSE of the DA forecast. Hence, the residuals are processed in a way that the error terms for each quarter year overlap in order to account for the seasonality of solar PV.

The relative residuals are displayed in Figure 5.2b from exemplary time points in a day for the second quarter. Through the generated ID forecasts, the relative error terms get significantly smaller with proceeding time steps compared to the DA forecasts, resulting in decreasing forecast errors over the course of the day. Especially strong deviations of the DA forecast and the actual realization from the beginning of the day are thereby removed and additionally updated by improved ID forecasts. Moreover, the error terms in the right illustration are more concentrated around zero, implying that the forecast errors are likely to be smaller once the first actual realizations of the day are known.

Scenario Tree Construction and Reduction

The generated residual time series described in the section above need to be converted into scenario trees for each hour of the day to provide the necessary data input for the model. Thus, the residuals are transformed into scenario trees with three branches that are not interconnected except for the root node. Each possible path has its own probability annotated. As a one-stage tree, the development of error terms may only take three different paths from the root node. In order to construct such a so-called fan, each time series of errors for a day in a quarter year represents a branch of the initial scenario tree, resulting in a tree of 91 or 92 branches.

Table 5.2: Sets and parameters for scenario tree construction and reduction.

Sets	
$t \in T$	time periods
$n \in N$	nodes in the scenario tree
$l \in L \subset N$	leaf nodes in the scenario tree
$s \in S \subset N \times T$	stage mapping of nodes and time periods
$a \in A \subset N \times N$	ancestor relation between nodes
Parameter	
poc(n)	probability of occurrence of a node $n \in N$

For the following setting, consider Table 5.2. First of all, it is necessary to construct a matrix that assigns the existence of a node $n \in N$ to a certain time period $t \in T$, where N denotes the set of nodes n in the scenario tree and T the set of time periods. The element $s \in S$ is a positive Boolean entry if a node $n \in N$ exists in a certain time period $t \in T$. The root node is fixed to time period one. Let $\tilde{x}$ denote a function that returns the index of an element $x \in X$ starting from one. Also, let $\overline{\overline{X}}$ represent the total number of elements $x \in X$. Now, for all other nodes in the scenario tree the following equation holds:

$$s(n,t) = \begin{cases} \text{YES}, & \text{if } \frac{\tilde{n}-1}{\overline{\overline{L}}} \leq \tilde{t}-1 \text{ and } \frac{\tilde{n}-1}{\overline{\overline{L}}} > \tilde{t}-2 \quad \forall t \in T, n \in N \\ \text{NO}, & \text{else.} \end{cases} \tag{5.6}$$

Subsequently, the ancestor relation for each node is determined. Again, the elements $a \in A$ are positive Boolean entries if a relation between the nodes $n \in N$ and $nn \in N$ exists. The numbering of nodes in the tree is, for our case, determined to be from top to bottom for each time period, starting in the root node n_0. The relation of all other nodes to their predecessors is given as

$$a(n, nn) = \begin{cases} \text{YES}, & \text{if } \tilde{n} = \tilde{nn} + \overline{\overline{L}} \quad \forall n, nn \in N \\ \text{NO}, & \text{else.} \end{cases} \tag{5.7}$$

Each node in the scenario tree has a probability of occurrence depending on the number of leaves in the tree with equally weighted paths. Naturally, the root node has the probability one. The resulting probabilities for all other nodes, meaning for stage two onwards, are determined by the number of leaves in the scenario tree as follows

$$\text{poc(n)} = \frac{1}{\overline{\overline{L}}} \quad \forall n \in S_{>1} \tag{5.8}$$

The resulting fan comprises a certain number of scenarios with nodes that have equal probabilities of occurrence and unique predecessors except for the root node.

Once the initial tree is constructed, it is filled with the values of the time series of forecast errors obtained from the procedure above such that each branch in the scenario tree represents the error profile of exactly one day of the examined quarter year. In order to manage complex computations with redundant cases, the GAMS tool SCENRED is applied. This tool requires a tree structure of given data and assigned nodal probabilities, which are reduced with a clustering algorithm from the initial setting of 91 or 92 days to fewer remaining scenarios. The process of reduction is an optimization problem in itself, requiring the user to predefine the desired number of reduced scenarios as well as the favored reduction method and accuracy.[13]

The envisaged number of reduced paths is set to three which corresponds to the original setting for wind power in stELMOD. A backward reduction method has been applied since it provides optimal expected performance in terms of running time and accuracy for extensive scenario trees (Abedi et al. 2013). Due to the characteristics of decreasing forecast

[13]SCENRED interprets the nodes as stochastic variables and applies probability measures to these paths. These are altered by an optimization to contain as little variation in the results as possible, such that the probability measure is stable. Furthermore, the distance of probability measures plays an important role. The algorithm determines measures that have a comparatively small distance to each other and to a certain scenario. These branches are deleted and their probability is added to the scenario in question. For further documentation of SCENRED see Heitsch and Römisch (2009) and Gröwe-Kuska, Heitsch, and Römisch (2003). The tool is easy to handle but might return non-optimal values when it comes to the reduction of error terms of renewable energies. Mere distance clustering of characteristic values of RES error terms at a certain time step is likely to be deficient as no time dependency is considered. However, for the framework of this chapter, the tool is considered to be the most effective method of clustering the produced scenarios.

errors over the day with proceeding time steps, hourly scenario trees have been generated for each quarter year. For the purpose of visualization, one resulting scenario tree for the third quarter from midnight for the next 24 hours is depicted in Figure 5.3.

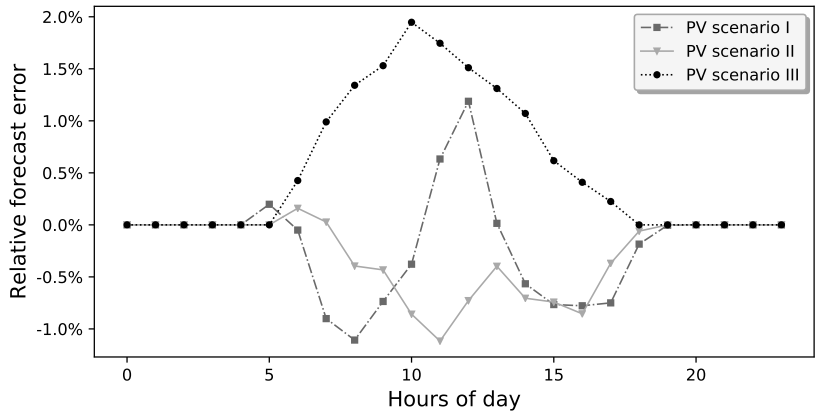


Figure 5.3: Scenario tree at midnight in the third quarter.

Source: own depiction.

Photovoltaic Forecast Error Implementation

In order to explain the incorporation of the forecast error for PV into stELMOD, we consider the existing implementation for wind generation as follows: The stochasticity of wind has been incorporated into the ID market in stELMOD using a one-stage scenario tree as depicted in Figure 5.4. The tree is structured such that nodes n_1 to n_{35} constitute the first branch, nodes n_{36} to n_{70} the second branch, and nodes n_{71} to n_{105} the third branch. Each branch of the one-stage tree represents a possible outcome of a forecast error for wind generation. The assigned probabilities for the wind scenarios I through III are 0.5, 0.3 and 0.2, respectively. The forecast errors[14] are given relative to the installed capacity of wind power in Germany. With the highest probability, wind scenario I accounts for no deviation from the final realization. Wind scenarios II and III consider positive and negative deviations of the final realization, respectively.

[14]The forecast error of wind generation is based on wind speed errors and hence transformed to power capacity factors via mean power curves of prevalent turbines. Since these are not exactly time dependent as they do not follow for example a diurnal pattern, the scenario tree for wind generation is assumed to be stable, implying no time-dependency of forecast errors.

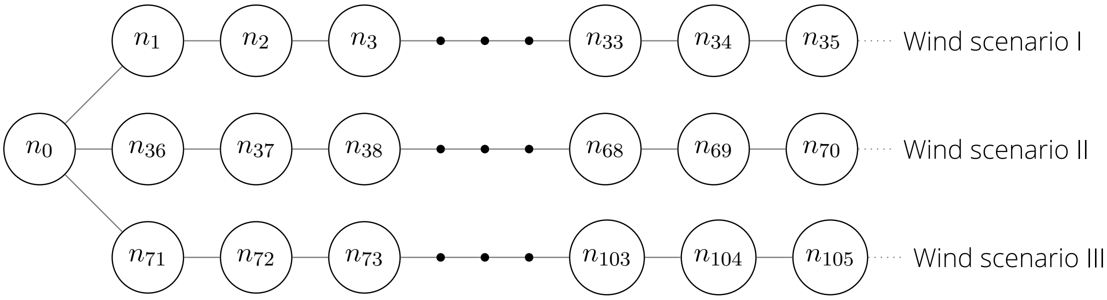


Figure 5.4: Scenario tree of stochastic wind implementation in the original model.

Source: own depiction.

Subsequently, the generated hourly scenario trees for PV, as summarized in Section 5.3.1, are incorporated into the original scenario tree structure by extending the tree as follows. In order to respect both the uncertainty of wind and PV generation, the number of included scenarios triples. For every possible outcome of wind generation, there are another three possible outcomes for PV generation. Thus, the respective probabilities need to be multiplied, leading to a sizable tree with smaller individual probabilities for each scenario. The sum of all scenarios equals one. The probabilities for the generated PV scenarios are determined by the SCENRED clustering algorithm and are changing over time, that is, they are dynamic.

Figure 5.5 illustrates the resulting tree structure with the respective wind and PV scenario for each branch. For reasons of clarity of the visualization, only a few node numbers are indicated. However, the structure follows the same pattern as indicated in Figure 5.4. As the error structure for PV changes over the course of the day, 24 scenario trees are integrated into the data set of the model. Each tree is the representation of a specific error structure viewed from a certain hour of a day, comprising forecast errors as well as nodal probabilities. Thus, the use of the correct scenario tree is incorporated into the iteration structure of the ID market model such that exactly one specific scenario tree is chosen at a specific time in the model run. Moreover, the error structure changes according to the daily structure when the model proceeds. Hence, an updated forecast is considered in every new hour of the iteration.

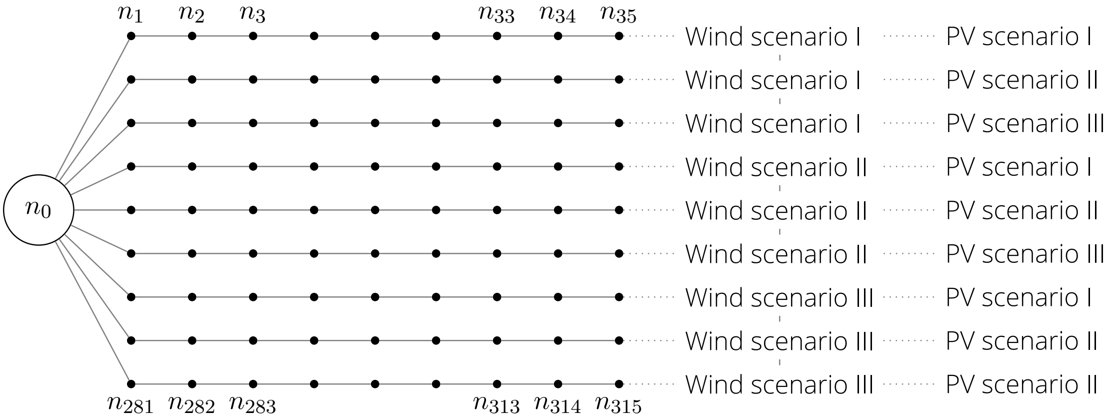


Figure 5.5: Scenario tree of both stochastic wind and PV implementation in the model extension.

Source: own depiction.

5.3.2 Implementation of Uncertainty Cases

In order to comprehensively assess the impacts of fluctuating renewable generation, different cases of stochastic RES infeeds are considered.

The deterministic case (DET) can be seen as reference case for the model evaluation without considering any uncertainty while employing the rolling planning approach. The generation from intermittent RES is set to the realized and thus previously known amounts in all markets and is known to the model for the subsequent 36 hours. Hence, new information is revealed every hour. As a result, the supply of RES is certain both in the DA as well as in the ID market.

The stochastic case (STO) optimizes the power plant dispatch over the whole setting of a scenario tree, taking into account different manifestations of RES with their assigned probabilities. In the DA market, the supply of RES equals the ID forecast. Stochasticity is implemented in the ID market by multiple scenario trees. As the rolling planning procedure proceeds onward, the forecast error decreases due to improved information on RES supply with decreasing forecast length and converges to the final realization. While the scenario tree is stable for wind generation, for PV it is strongly dependent on the hour of the day as well as on the season. By optimizing over a possible set of manifestations with assigned probabilities, the uncertainty of PV and wind production is comprehensively anticipated by the model, influencing unit commitment decisions towards a more flexible solution.

To be able to quantify the value of this stochastic solution (VSS, see Birge and Louveaux

2011), a third case with a single changing forecast (CHF) is used. In this case a single generation forecast for wind and PV is used in the model, expressing the current state of RES infeed. The DA market uses this single day-ahead forecast as in case of stochasticity. This single forecast is constructed by using the probability weighted mean (expected value) of the nodes in the reduced scenario tree for wind and PV for specific time periods.

Since a stochastic solution will always be more expensive than a deterministic one (because uncertainty is taken into account), subtracting the STO case from the CHF case will reveal the value of stochastic solution (VSS), that is, the improvements of the solutions that can be achieved from the stochastic programming approach.

While Abrell and Kunz (2015) focus on those three cases as representations of wind infeed, this chapter combines different representations of wind and PV generation in five cases to examine the impact of photovoltaic generation (see Table 5.3). Since an intermittent renewables infeed is closer to reality, a case CHF-CHF includes both a stochastic wind and PV input by a single forecast. By extending the scenario tree, case STO-STO incorporates uncertainty of both wind and PV generation. The comparison of cases STO-DET with STO-CHF as well as STO-CHF with STO-STO will signify the sole impact of stochastic PV generation on unit commitment decisions in Germany. The cases STO-STO, STO-DET and STO-CHF therefore explicitly depict the value added in this chapter: The case STO-STO signifies a complete stochastic representation of the renewables infeed of both wind and PV. The comparison of this case to the cases STO-DET and STO-CHF points out the impact of stochastic PV generation on a theoretical and realistic basis, respectively, making it possible to quantify the value of the stochastic solution.

Table 5.3: Cases of intermittent RES implementation.

	Case	**Wind**	**PV**
A	DET-DET	deterministic	deterministic
B	CHF-CHF	changing forecast	changing forecast
C	STO-STO	stochastic	stochastic
D	STO-DET	stochastic	deterministic
E	STO-CHF	stochastic	changing forecast

Source: own depiction based on Abrell and Kunz (2015)

5.4 Results

In this section, we assess the impact of stochastic PV generation on unit commitment decisions for the German rolling planning procedure by incorporating uncertainty of PV generation in the optimization model stELMOD. The results of the model are analyzed with respect to cost structures, generation portfolio, redispatch transactions and carbon emissions.

The results show an increasing need for flexibility of the German power system in order to cover uncertain changes of both wind and PV generation. The results are consistent with the findings of Abrell and Kunz (2015), but are differently intensified by the type of uncertainty incorporation. Updating information on both wind and PV generation with a single forecast leads to significant higher total system costs and a tremendous increase in scheduling actions. The impact of stochastic PV generation by different discrete scenarios leads to a further decrease of scheduling actions, at the cost of higher balancing actions and more carbon emissions.

Five cases are studied, differing in the amount of uncertainty considered. Case DET-DET reflects no uncertainty about wind or PV generation, case CHF-CHF incorporates both uncertain wind and PV generation by a single forecast, and case STO-STO implements the stochastic programming approach using a scenario tree with more than one possible manifestation. While STO-STO comprises both uncertain wind and PV generation, STO-DET only accounts for stochastic wind availability and STO-CHF uses the scenario tree for wind but a singe forecast for PV.

By comparing the results of cases DET-DET, CHF-CHF, and STO-CHF to STO-STO and STO-DET, the theoretical impact of stochastic PV generation is examined. The comparison of case STO-STO to STO-CHF hereby yield the VSS for PV generation. The latter incorporates uncertainty about PV generation by a single forecast, whereas the stochasticity of forecast errors of wind generation is included by a scenario tree. The results are additionally investigated for four different weeks to reflect the influence of seasonality.

5.4.1 Costs of the German Power System under Uncertainty

The costs of the power system in million (mio.) euros are illustrated in Table 5.4 for the different cases of the examined weeks. The weeks are solved for the same time horizon and data set. Total system costs comprise marginal costs of production, consisting of carbon and fuel costs, as well as startup costs for the plants. Throughout all seasons, case CHF-CHF shows the highest total system costs. Compared to the deterministic approach of

Table 5.4: System cost components in mio. Euros for analyzed weeks and cases.

Cases	**DET-DET**	**CHF-CHF**	**STO-STO**	**STO-DET**	**STO-CHF**
Week in January					
Total costs	152.24	153.61	152.67	152.24	152.26
Carbon costs	38.03	37.94	37.86	37.99	38.01
Startup costs	3.56	4.68	3.45	3.29	3.37
Fuel costs	110.65	110.99	111.377	110.96	110.89
Week in April					
Total costs	154.54	157.92	154.85	153.96	154.04
Carbon costs	40.18	40.171	40.22	38.48	38.48
Startup costs	1.97	4.57	1.41	2.99	3.09
Fuel costs	112.40	113.18	113.21	112.49	112.48
Week in July					
Total costs	138.20	140.46	138.68	138.28	138.29
Carbon costs	36.89	37.02	36.94	36.91	36.91
Startup costs	2.56	3.55	1.99	2.02	2.05
Fuel costs	98.76	99.88	99.74	99.36	99.32
Week in October					
Total costs	145.81	147.18	146.11	146.07	145.94
Carbon costs	38.17	38.10	38.01	38.07	38.11
Startup costs	2.92	4.16	2.75	2.31	2.38
Fuel costs	104.73	104.93	105.35	105.68	105.44

case DET-DET, total costs of case CHF-CHF increase by 2.18 % for a week in spring, followed by a cost increase of 1.6 % in summer, 0.94 % in autumn, and 0.9 % in winter. But most important to recognize, the cost structure differs. The increase of total system costs in case CHF-CHF is mainly caused by an increase of startup costs. Yet, the carbon costs in January, April, and October are reduced, albeit by insignificantly small amounts of 0.093 mio. euros, 0.01 mio. euros, and 0.07 mio. euros, respectively. Comparing the stochastic case STO-STO that incorporates uncertainty of both wind and PV with a scenario tree, with the deterministic case DET-DET, only slight increases of 0.28 %, 0.20 %, 0.29 %, and 0.21 % result for the weeks of January, April, July, and October, respectively. The further investigation of the cost structure shows that startup costs throughout the weeks are significantly reduced in the stochastic case STO-STO. Fuel costs increase, whereas carbon costs are reduced or remain at approximately constant levels.

The impact of PV on system costs is examined by a comparison of cases STO-STO and STO-DET, as well as cases STO-STO and STO-CHF. It is important to emphasize the distinction of the considered cases. STO-DET is an exception, as it includes the stochasticity of wind, whereas cases CHF-CHF, STO-STO and STO-CHF additionally incorporate the uncertainty of PV generation. Thus, the comparison of the respective cases points out the sole impact of including uncertainty of PV into the optimization process. The juxtaposition of case STO-STO to STO-DET gives the impact of stochasticity on a rather theoretical basis, whereas the comparison of STO-STO to STO-CHF leads to a more realistic contrast. Total system costs for case CHF-CHF are—throughout the examined weeks—higher than for case DET-DET. Except for a reduction of carbon costs, all other cost components (startup and fuel costs) increase. The biggest difference is apportioned to startup costs. With an increase of 31 % in the week of January, 39 % in the week of July, 42 % in the week of October, as well as 131 % in April, the cost addition is significant. Yet, compared to total system costs, it is small in absolute terms. As a result, incorporating uncertainty about the supply of both wind and PV with a single forecast leads to an increase of almost all cost components. However, looking at the differences between cases STO-STO and STO-DET, this increase diminishes. While in the week of January a carbon cost reduction counterbalances small increments in startup and fuel costs, for all other cases a significant decrease in startup costs reduces overall system costs. In the week of April, the impact of stochastic PV on startup costs is eminent, leading to a decrease of 54 %, 53 %, and 28 % compared to cases STO-CHF, STO-DET, and DET-DET, respectively.

5.4.2 Generation Portfolio in the German Case

In order to asses the impact of stochastic PV generation in more detail, the generation portfolios of the respective cases are analyzed. Table 5.5 depicts the overall unit commitment decisions for the examined weeks and cases. Throughout the cases, the average number of committed plants is at a constant level and varies only a little throughout the weeks. Spring reports the highest number of operating plants, ranging from 225 to 234 in cases STO-DET and STO-STO, respectively. The lowest average number of online plants occurs in the week of July, ranging from 215 in case CHF-CHF to 224 in case STO-STO. With respect to the included uncertainty in the system, the differences are remarkable. The impact of stochastic

PV incorporation is clearly visible, as the highest average throughout the seasons occurs in case STO-STO, where the most comprehensive uncertainty is included. Yet, the number of startups and shutdowns of plants are significantly reduced in stochastic case STO-STO, particularly in the weeks of spring and summer. Case CHF-CHF shows by contrast the highest frequency of startup and shutdown processes as the way of incorporating uncertainty differs from case STO-STO. In general, mainly coal- and gas-fired power plants account for the high number of startups and shutdowns, absorbing uncertainty of the system in different ways. Open cycle gas turbines (OCGT) plants are used particularly frequently in case CHF-CHF throughout all weeks. The number is significantly smaller in case STO-STO, where the average of committed plants is consistently higher with more plants deployed at part-load.

Table 5.5: Averaged number of operating plants, number of startups/shutdowns for examined weeks and cases.

Cases	**DET-DET**	**CHF-CHF**	**STO-STO**	**STO-DET**	**STO-CHF**
Week in January					
∅ plants online	222.62	220.05	225.26	224.78	224.60
# startups	477	640	253	314	305
# shutdowns	425	624	240	309	306
Week in April					
∅ plants online	231.19	228.17	234.07	225.00	225.78
# startups	420	724	126	303	308
# shutdowns	406	708	129	324	325
Week in July					
∅ plants online	218.35	215.35	224.42	222.04	221.66
# startups	513	649	154	240	267
# shutdowns	527	675	171	253	284
Week in October					
∅ plants online	219.73	220.13	225.6	225.01	223.62
# startups	507	767	192	272	306
# shutdowns	505	760	179	273	305

For reasons of clarity, the further investigation of generation portfolios focuses on cases

STO-STO, STO-DET, and STO-CHF, as those three cases represent the theoretical and realistic impact of stochastic PV generation by comprehensively accounting for forecast errors. Hence, the examination of their differences in generation pattern gives insights about the decisions made due to uncertain PV generation. Table 5.6 depicts the difference between generation in cases STO-STO and STO-DET. Thus, positive numbers represent a higher production in case STO-STO, negative numbers signify a higher production in case STO-DET.

Table 5.6: Difference in GWh in generation between cases STO-STO and STO-DET.

	Week in January	**Week in April**	**Week in July**	**Week in October**
RES	0	−232.71	0	0
Lignite	0.48	60.14	−5.85	7.03
Waste	0.03	0.35	−0.12	0
Nuclear	0.79	1.51	−0.10	0
Hard Coal	−21.23	216.70	11.62	−21.43
CCGT	15.68	−105.22	4.42	4.69
OCGT	3.31	0.91	−1.76	−0.32
OCOT	0.33	0.78	0.12	−0.42
OilSteam	−0.01	−0.01	0	0.02
PSP	0.64	57.52	−8.31	10.43

In general, RES are equally used throughout the seasons in both cases at maximum output except for the week in spring. To absorb this difference, production from hard coal is much higher in case STO-STO than in case STO-DET in this week. The production from lignite varies throughout the weeks with only small differences in winter, a positive deviation of 60.144 GWh in spring and 7.033 GWh in autumn, as well as a negative deviation of -5.847 GWh in summer. Remarkable are the differences in the use of hard coal and CCGT: In the weeks of spring and summer, the production from hard coal is higher in case STO-STO than in case STO-DET, whereas the generation from CCGT is decreasing in the week in April in case STO-STO and increasing in the weeks in January and July. The two cases also significantly differ in the use of storage facilities. The amount of electricity generation from pumped-storage plants (PSP) in case STO-STO exceeds the production in case STO-DET by 57.522 GWh in the week in April, while generation is decreased in the week in July. However, in the week in April PSP is more frequently used in case STO-DET with generation or storage in 149 hours. For case STO-STO, the frequency amounts only to 121 hours. In the other weeks, the frequency of the use of PSP is higher in the stochastic case STO-STO than in case STO-DET.

Table 5.7 depicts the difference between generation in cases STO-STO and STO-CHF, signifying the impact of stochastic PV incorporation on a more realistic basis. Again, positive numbers represent a higher production in case STO-STO, negative numbers signify a higher production in case STO-CHF.

Table 5.7: Difference in GWh in generation between cases STO-STO and STO-CHF.

	Week in January	**Week in April**	**Week in July**	**Week in October**
RES	0	−232.71	0	0
Lignite	−1.28	58.60	−8.53	6.31
Waste	0.06	0.24	−0.11	0
Nuclear	0.66	3.67	−0.15	0
Hard Coal	−23.23	219.81	14.12	−29.49
CCGT	17.76	−105.87	1.90	12.61
OCGT	3.34	0.72	0.06	−0.31
OCOT	0.44	0.72	−0.02	−0.32
OilSteam	0.01	−0.02	0	−0.01
PSP	2.27	54.84	−7.30	11.20

The difference of case STO-STO to STO-CHF shows that lignite and hard coal-based production is reduced in the case with stochastic representation of PV infeed. In the weeks in winter and summer, production from lignite is higher in case STO-CHF by 1.28 GWh and 8.53 GWh. The generation from hard coal is reduced in the winter and autumn weeks, and increased during spring and summer weeks. Gas-fired power plants have a higher production in the stochastic case, except for the week in April. The curtailment of RES production leads, as in the comparison above, to an increase in production from hard coal and lignite. However, less electricity from lignite- and more from hard coal-fired power plants was produced compared to the juxtaposition of cases STO-STO and STO-DET. Except for the week in spring, the storage and production from PSP is again more frequent in the stochastic case than in case STO-CHF.

Significant needs of congestion management are found for case STO-STO, particularly in the weeks in April and July with high PV infeed present in the system. In the former week, a total amount of 12.619 GWh is redispatched by decreasing production from lignite

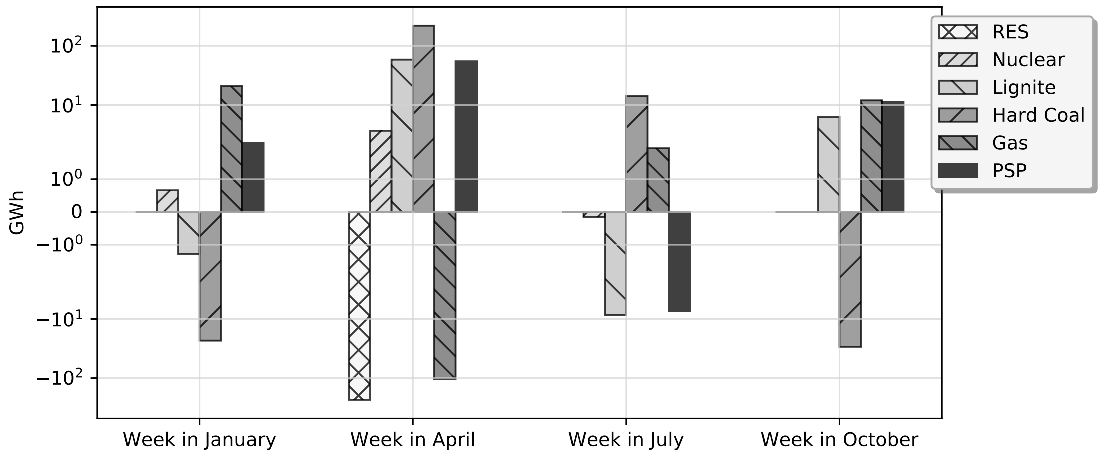


Figure 5.6: Difference in GWh in generation between cases STO-STO and STO-CHF.

Source: own depiction.

and nuclear by 9.617 GWh and 3.002 GWh, respectively. The decrease is mainly substituted by generation from hard coal with 7.32 GWh and OCGT with 3.584 GWh. The remaining amount is generated by CCGT and open cycle oil turbines (OCOT). In total, redispatch transactions reduce carbon emissions by 1,551 t CO_2. In the latter week, a total amount of 13.078 GWh is balanced. Coal, CCGT, OCGT and OCOT power plants increase their production by 7.457 GWh, 2.306 GWh, 2.896 GWh, and 0.422 GWh, respectively, in order to regulate a decrease of 11.242 GWh, 0.325 GWh, and 1.511 GWh in production from lignite, waste, and nuclear, respectively. This results in a reduction of carbon emissions of 3,040 t CO_2. The volumes traded on the CM market are, in general, higher in case STO-STO than in other cases. In terms of total carbon emissions, the impact of uncertain PV generation is significant in the week in spring due to the high increase of production from lignite and hard coal. Total carbon emissions add up to 5.07 mio. euros, increasing by 4.5 % compared to case STO-DET. Throughout the other weeks, the level of total carbon emissions remains at a constant level.

5.5 Discussion and Conclusion

Due to technical and economical constraints, UC decisions for thermal power plants need to anticipate the inherent uncertainty of RES infeed in the power system. In this chapter, the impact of uncertain PV generation on scheduling decisions in the German rolling planning procedure is investigated. By employing the stochastic electricity market model stELMOD, the influence of decreasing uncertainty of PV generation over time is examined with respect to total system costs and the power output of thermal power plants. A time-adaptive intra-day forecast based on an exponential smoothing of deviations between realized and day-ahead forecast values is constructed. The resulting residual time series between simulated intra-day forecast and realization are transformed into scenario trees, accounting for the relative forecast errors of PV production. The model stELMOD is extended by three additional cases in order to assess the impact of uncertain PV generation in the system. Four non-consecutive weeks are examined to account for differences due to seasonality.

Incorporating uncertainty of both wind and PV by a single forecast, the power system scheduling actions intensify to absorb the comprehensive uncertainty. The total system costs increase significantly throughout all weeks compared to the results for the sole impact of wind generation. The biggest difference is apportioned to startup costs due to a tremendous increase in scheduling frequency of rather flexible gas-fired power plants. Thus, the influence of stochastic PV generation on costs is significant when included by a single forecast.

Incorporating uncertainty with a scenario tree, the results report smaller differences than in case of a changing forecast with respect to total system costs. However, the cost structure shows small effects of seasonality. With lower relative forecast errors of PV generation, the scheduling costs are reduced—even by 52.84 % in the spring week compared to the sole stochastic incorporation of wind energy (case STO-DET). The influence of the stochastic case on scheduling actions is eminent. The power system requires significantly lower amounts of startup and shutdown actions compared to cases STO-DET and STO-CHF. The additional uncertainty in the system is, hence, absorbed by using more thermal power plants at part-load. Comprehensive uncertainty of both PV and wind generation increases the volumes traded on the congestion management market, as well as the frequency in use of storage. Moreover, effects of seasonality can be seen in the difference of the generation portfolio for cases STO-STO and STO-DET as well as for cases STO-STO and STO-CHF. In spring and summer, with lower uncertainty of PV generation present, more inert thermal power plants are used. For winter and autumn, case STO-STO reports a higher use of more flexible gas-fired power plants.

In conclusion, incorporating forecast errors for PV generation is an important contribution. The impact of stochastic PV generation differs in magnitude with respect to how uncertainty is incorporated in the model. This effect can be used to quantify the value of this stochastic programming approach (value of the stochastic solution). However, some aspects could not be incorporated into the model. Due to the complexity and run-time of the calculations, assumptions had to be made disregarding minimum on- and offtimes of conventional power plants as well as part-load efficiencies, which could influence the solution since many plants are not operating at full-load in the stochastic cases. In order to further investigate the impact of comprehensive uncertainties in power systems, future research should address those issues and could furthermore include load forecasting errors into the rolling planning procedure. Improving renewable forecasts in the coming years in the interplay with increasing shares of renewable generation and flexibility options with differing response rates should also be analyzed. The influence of increased dispatch frequency is another research possibility and can be used to optimize the market design with respect to comprehensive uncertainty of RES production present in today's power system.

Part III

A Decentral Energy Transformation

Chapter 6

The Impact of Transmission Development on a 100 % Renewable Electricity Supply — A Spatial Case Study on the German Power System

"In order to make sure our electricity supply remains secure and affordable, we need several thousand kilometers of new power lines. This is the only way to ensure that electricity from renewable energy sources actually reaches every power socket in Germany. The electricity grid is therefore the backbone of a successful energy transition."

(Peter Altmaier (German Federal Minister for Economic Affairs and Energy)[1])

This chapter is the accepted version of Chapter 15 (Weibezahn et al. 2020) of the book "Transmission Network Investment in Liberalized Power Markets" (Hesamzadeh, Rosellón, and Vogelsang 2020). Appendix D contains the original appendix to this publication.

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6.1 Introduction

The role of electricity transmission infrastructure for an energy system has, is, and continues to be an issue of greatest importance, and of controversy, too. Traditionally, the structure of transmission networks have followed the pattern of generation and load, serving mainly as a backup service in cases of larger discrepancy, or connecting power plants to the grid that had been planned without consideration to "optimal" location, such as nuclear power plants (usually far away from load centers). Thus, in the old days, transmission planning was considered to be fuel-neutral, and the role of the transmission network was limited to fuel-neutral backup service. Foci of research were incentives in transmission planning, for example, high- or low-powered incentives (Olmos and Pérez-Arriaga 2009; Hogan, Rosellón, and Vogelsang 2010; Rosellón and Kristiansen 2013), and financing, for example, merchant vs. regulated financing (Joskow and Tirole 2005, 2006; Gerbaulet and Weber 2018).

However, with the need to phase out fossil generation, and the arrival of massive amounts of distributed renewable energy, the assessment of the link between the electricity mix and the transmission requirements has fundamentally changed. The technology shift from carbon intense conventional power plants towards largely renewable technologies has strong implications for the power system's operation and investment decisions. A crucial characteristic of RES is their increased distributed structure, amongst others due to the smaller power ratings of such technologies. In particular, it has become evident that transmission planning is *not* neutral vis-à-vis the electricity mix, but that there is a direct link between the design of the transmission system and the resulting electricity flows, be they driven by carbon-intense, nuclear, or renewable generation. Thus, it is now commonly agreed that in a carbon-intense electricity system, transmission expansion leads to *more* carbon emissions: Transmission expansion does affect the electricity mix, and leads to rising CO_2 emissions in the European context, for example, in the thesis by Brancucci Martínez-Anido (2013) and the theory-based numerical assessment of Abrell and Rausch (2016).

Transmission expansion cannot be analyzed independently from the specific institutional context in which it takes place, that is, the form of regulation, financing, etc. In this chapter, we focus on the German case, a typical case in which transmission planning was considered to be a "standard" activity given to the transmission companies until recently, but where the interdependence with the electricity fuel mix has come out clearly once the *Energiewende*, the no-carbon, no-nuclear transformation of the energy system, has taken off. In the old days of vertical integration and regional monopolies, the transmission companies assured a

[1] www.bmwi.de/Redaktion/EN/Dossier/grids-grid-expansion.html

congestion-free network with ample overcapacity, which is, by the way, the basis why transmission constraints are not really binding until today (Kunz, Gerbaulet, and Hirschhausen 2013; Gerbaulet 2018). After vertical unbundling (in 1998) and first targets for renewables in the network development plan (2005), TSOs adapted a rhetoric of linking the share of renewables to additional transmission expansion, even though the real level of congestion was, and still is, negligible. As generously rate-of-return regulated companies with a significant information advantage vis-à-vis the regulator, TSOs tried to maximize expansion plans at the cost of economic efficiency (Kemfert, Kunz, and Rosellón 2016).

On top of this restructuring, the objective of the energy reform (*Energiewende*) in Germany puts additional stress onto the system. As part of the larger package, the *Energiewende* includes strict greenhouse gas reduction targets (-80 to -95 % by 2050, basis 1990), over 80 % of electricity from renewables (by 2050), the disconnection of nuclear power plants by 2022, and strict targets for economy-wide and sectoral energy efficiency (Hirschhausen 2018). The impact of the *Energiewende* on transmission planning was discussed controversially, with two major issues. TSOs continue their quest for large-scale transmission expansion, whereas from a climate perspective, it had become clear that, given the carbon-intense fuel mix, this would still mainly benefit the coal plants in East Germany (Mieth et al. 2015a). The few hours of network congestion were indeed correlated to high use of coal plants, mainly lignite in East Germany. In 2015, the network regulator integrated carbon constraints in network planning for the first time, and has tightened these since (Mieth et al. 2015b). Today, there is a general consensus on phasing out coal in the 2030s (Göke et al. 2018).

Thus, TSOs are in a key position not only to determine the amount of network expansion, but also to affect the electricity mix indirectly. Based on the assumption of massive network congestion, renewables expansion was linked to an "appropriate" level of transmission expansion, particularly large-scale transmission lines between the North/East of Germany and the South/West, in the national Ten-Year Network Development Plans (TYNDPs) (50Hertz Transmission GmbH et al. 2018); the plan also included several HVDC lines. With the rate-of-return on capital of over 6 % (and interest rates of about 0 %), no wonder TSOs tried to maximize expansion plans. On the other hand, our own work has confirmed the detrimental effect of transmission expansion in a fossil-fuel basin, that is, the lignite basin in East Germany (Lusatia), on the dispatch of lignite plants in the region: when expanding the East-South high-voltage corridor, about 30 GWh of additional lignite would be produced, corresponding to almost the entire electricity deficit of Bavaria.

While this conversation is still ongoing, it seems necessary to look ahead and consider the longer term, that is, when the objective of the low-carbon, no-nuclear *Energiewende* will be attained, including a largely renewables-based electricity generation. That is why we adopt a different perspective in this chapter, analyzing the link between the electricity mix, with a focus on centralized and distributed renewables, and the nature of the transmission system. Our hypothesis is that the geographical distribution of the renewable electricity mix interacts with different transmission architectures. To test this hypothesis, we develop a stylized model of transmission and generation investment, and operation, based on the traditions of electricity network modeling (Leuthold, Weigt, and Hirschhausen 2012; Weibezahn and Kendziorski 2019), but add a high degree of technical and spatial detail in the spirit of the DIETER model (Zerrahn and Schill 2015).

The remainder of this chapter is structured as follows: Section 6.2 analyzes current literature concerning distributed resources and their effects on transmission requirement. Section 6.3 provides a description of the investment and dispatch model that is developed to compare the different locations of renewables, the data, and the scenarios. Section 6.4 provides the results of the scenario runs and discusses them, and Section 6.5 concludes.

6.2 Literature Review

Many studies analyze optimal renewable power plant siting in electricity distribution grids. Abdmouleh et al. (2017) assess the literature published on the optimal placement of renewable energy sources, discuss the drivers of increased interest and compare different optimization approaches. They state that most studies focus on distribution grids for a given network setup without considering network extension. Besides renewable power plant placement and sizing, optimization studies also focus on system flexibility to integrate RES, such as storage systems (Lund et al. 2015). Sophisticated models such as written by Kayal and Chanda (2015) consider secure grid operation and different weather conditions, but treat the transmission network as static.

Fewer studies are performed to assess cost optimal capacity extension of wind and PV power plants in combination with transmission network extension options. Schlachtberger et al. (2017) propose a cost minimizing optimization problem. A case study for Europe is elaborated. In one scenario, no energy exchange between countries is allowed, whereas in another scenario the effect of international electricity trade is highlighted. They conclude that it is important to consider spatial and temporal scales when performing research on the integration of high shares of renewable power in the given grid infrastructure.

Likewise, Grams et al. (2017) show that spatial deployment of wind power over a large region allows minimizing renewable energy output variability. For Europe they conclude that large-scale spacial deployment could be a strategic response to the multi-day volatility challenge of the common weather regimes on the European continent. Based on a nodal approach, Abrell and Rausch (2016) point out that increased inter-European cross border transmission capacities allow for more renewable power usage. Furthermore, the European climate targets could be reached at cheaper cost, if national climate mitigation plans and thus their view on transmission adequacy would be matched more in a cooperative fashion. On a national scale, Drechsler et al. (2017) conclude that a spatially even mix of wind and solar power is preferable for the German national electricity system. They highlight that the current tender mechanism for wind power plant subsidies incorporate a regional correction factor to support regional distribution to some extent, whereas such a factor is missing for PV tender auctions. This so called reference yield model (*Referenzertragsmodell*) balances wind power over the whole territory of Germany, based on geographical characteristics defined for each postal code. It neither considers present network infrastructure information nor distance to regions of high electricity demand. Back in 2010 in Germany, strategic planning and support of erecting wind turbines was absent, such that investors faced obstacles to install wind power plants at the most beneficial locations (Ohl and Eichhorn 2010). Likewise, Ohlhorst (2015) found that federal state government targets for wind and PV power plants are not in line with national top-down climate mitigation ambitions. In particular, the current energy policy is characterized by a separated planning approach of grid infrastructure extension and power generation dispatch planning, resulting in higher total cost. An integrated approach combining both aspects would result in welfare gains (Kemfert, Kunz, and Rosellón 2016). Clearly in the case of Germany, there are incentives for overinvesting into transmission infrastructure.

There are no simple answers to resolve the issue of “optimal” transmission planning for a largely renewables-based electricity system. Clearly, the higher the oversupply of transmission, the easier it is to feed in surplus renewables, but this holds for surplus fossil fuel electricity, too—as currently practiced in Germany, which has a 50 TWh export surplus, mainly based on coal and lignite sources. Thus, while Fürsch et al. (2013) favor grid extension to integrate RES, there needs to be a compromise between different flexibility options, in particular in a dynamic perspective where the spatial distribution of renewable electricity is endogenous. Not only environmental non-governmental organizations (NGOs) argue against overinvestment into the transmission network, and that issues of sustainable generation should be prioritized vis-à-vis transmission issues[2]; this has also been shown, again,

[2]Naturschutzbund Deutschland e. V. (2019): "Stellungnahme zum NEP Strom 2030".

recently in techno-economic research on the German electricity grid (in the European context), such as Grimm et al. (2016a) and Grimm et al. (2016b).

In this chapter, we add a spatial component of distributed resources, and also integrate (spatially differentiable) storage capacities, to assess the relation between different transmission designs and the optimal allocation of generation and storage.

6.3 Model, Data, and Scenarios

6.3.1 Dispatch and Investment Model with Linearized Power Flow

The analysis is methodically based on an investment model minimizing the sum of the costs of installed infrastructure investments and operational power generation cost. The model is inspired by ELMOD (Egerer 2016), Joulia.jl (Weibezahn and Kendziorski 2019), dynELMOD (Gerbaulet and Lorenz 2017) and DIETER (Zerrahn and Schill 2015). Combining elements of the models mentioned before, the following equations account for investment and dispatch activities, while also considering the network topology. The model does not account for the current power plant fleet (greenfield model approach), as infrastructure has to be renewed until 2050 anyway.

The model sets are technologies $\mathcal{T}$ (with subsets for dispatchable units $\mathcal{T}_{\mathcal{D}}$, non-dispatchable units $\mathcal{T}_{\mathcal{N}}$, and storage technologies $\mathcal{T}_{\mathcal{S}}$), regional zones $\mathcal{Z}$ (as subsets of countries $\mathcal{C}$), alternating current (AC) transmission lines $\mathcal{L}$, hours $\mathcal{H}$, and seasons $\mathcal{W}$. Decision variables for the dispatch are power output by generation units G^{gen} (including storage discharge), storage charge G^{ch}, storage state of charge E^{soc}, transmitted power through power injection in one region F^{ni}, HVDC line usage F^{dc}, and lost load LL. Investment relevant variables are installed power output P^{inst}, installed charging power P^{ch}, and installed storage energy capacity E^{inst}. Model parameters are power demand p^{load}, the availability factor ζ additionally restricting power availability for non-dispatchable technologies, the autarky factor ϕ reducing international electricity exchange, and investment and generation cost factors c^p, c^{ch}, c^e and c^{mc}, as well as c^{ll} reducing unserved electricity demand. Further network parameters are power and energy restrictions on network elements, that is, generation (p^{max}), storage (e^{max}, η, ρ) and transmission ($ptdf$, f^{max}). The time scaling factor γ allows for cost comparisons on a yearly scale. See Appendix D.1 for the full nomenclature.

minimize

$$\gamma^{\text{year}} \left[\sum_{\substack{t\in\mathcal{T}\\z\in\mathcal{Z}\\h\in\mathcal{H}}} c_t^{mc} G_{t,z,h}^{gen} + c^{ll} \sum_{\substack{z\in\mathcal{Z}\\h\in\mathcal{H}}} LL_{z,h} \right] + \sum_{\substack{t\in\mathcal{T}\\z\in\mathcal{Z}}} c_t^{p} P_{t,z}^{inst} + \sum_{\substack{t\in\mathcal{T_S}\\z\in\mathcal{Z}}} c_t^{ch} P_{t,z}^{ch} + \sum_{\substack{t\in\mathcal{T_S}\\z\in\mathcal{Z}}} c_t^{e} E_{\text{t,z}}^{inst} \tag{6.1}$$

subject to

$$\sum_{t\in\mathcal{T}} G_{t,z,h}^{gen} - \sum_{t\in\mathcal{T_S}} G_{t,z,h}^{ch} - load_{z,h} + \sum_{zz\in\mathcal{Z}} F_{zz,z,h}^{dc} - \sum_{zz\in\mathcal{Z}} F_{z,zz,h}^{dc} + LL_{z,h} = F_{z,h}^{ni} \quad (\forall\, z \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.2}$$

$$G_{t,z,h}^{gen} \leq \zeta_{t,z,h} P_{t,z}^{inst} \quad (\forall\, t \in \mathcal{T_N}, z \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.3}$$

$$G_{t,z,h}^{gen} \leq P_{t,z}^{inst} \quad (\forall\, t \in \mathcal{T_D}, z \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.4}$$

$$G_{t,z,h}^{gen} \leq P_{t,z}^{inst} \quad (\forall\, t \in \mathcal{T_S}, z \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.5}$$

$$G_{t,z,h}^{ch} \leq P_{t,z}^{ch} \quad (\forall\, t = p2g, z \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.6}$$

$$E_{t,z,h}^{soc,h} + \gamma^{\text{season}} E_{t,z,w}^{soc,w} \leq E_{t,z}^{inst} \quad (\forall\, t \in \mathcal{T_S}, z \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.7}$$

$$\gamma^{\text{year}} \sum_{\substack{z\in\mathcal{Z}\subseteq\mathcal{C}\\h\in\mathcal{H}}} G_{t,z,h}^{gen} \leq p_{t,c}^{max,gen} \quad (\forall\, t\in\mathcal{T}, c \in \mathcal{C}) \tag{6.8}$$

$$P_{t,z}^{inst} \leq p_{t,z}^{max,inst} \quad (\forall\, t \in \mathcal{T}, z \in \mathcal{Z}) \tag{6.9}$$

$$E_{t,z}^{inst} \leq e_{t,z}^{max,inst} \quad (\forall\, t \in \mathcal{T_S}, z \in \mathcal{Z}) \tag{6.10}$$

$$\begin{aligned} E_{t,z,h}^{soc,h} &= \rho_{\text{t}} E_{t,z,h-1}^{soc,h} + \sqrt{\eta_t^{ch}} G_{t,z,h}^{ch,h} - \frac{1}{\sqrt{\eta_t^{dch}}} G_{t,z,h}^{gen} \\ &+ G_{t,z,h\,\text{if first h of}\,\mathcal{W}}^{ch,w} - G_{t,z,h\,\text{if last h of}\,\mathcal{W}}^{dch,w} \\ &\quad (\forall\, t \in \mathcal{T_S}, z \in \mathcal{Z}, h \in \mathcal{H}) \end{aligned} \tag{6.11}$$

$$E_{t,z,w}^{soc,w} = \rho_t^{\gamma^{\text{season}}} E_{t,z,w-1}^{soc,w} + G_{t,z,w}^{ch,w} - G_{t,z,w}^{dch,w} \quad (\forall\, t \in \mathcal{T_S}, z \in \mathcal{Z}, w \in \mathcal{W}) \tag{6.12}$$

$$-f_l^{max} \leq \sum_{z \in \mathcal{Z}} ptdf_{l,z} F_{z,h}^{ni} \leq f_l^{max} \qquad (\forall\, l \in \mathcal{L}, h \in \mathcal{H}) \tag{6.13}$$

$$F_{z,zz,h}^{dc} \leq f_{\text{z,zz}}^{max} \qquad (\forall\, z, zz \in \mathcal{Z}, h \in \mathcal{H}) \tag{6.14}$$

$$\sum_{z \in \mathcal{Z}} F_{z,h}^{ni} = 0 \qquad (\forall\, h \in \mathcal{H}) \tag{6.15}$$

$$\sum_{\substack{z \in \mathcal{Z} \subseteq \mathcal{C} \\ h \in \mathcal{H}}} \left(LL_{z,h} + \sum_{t \in \mathcal{T}} G_{t,z,h}^{gen} - \sum_{t \in \mathcal{T_S}} G_{t,z,h}^{ch} \right) \geq \phi \sum_{\substack{z \in \mathcal{Z} \subseteq \mathcal{C} \\ h \in \mathcal{H}}} load_{z,h} \qquad (\forall\, c \in \mathcal{C}) \tag{6.16}$$

The objective function minimizes the overall system costs that are represented by the sum of the power plant fleet investment cost, the storage investment cost, the power generation cost, and penalty costs for lost load (Equation (6.1)). Market clearing in each region implies that power generation, demand, storage power interaction, power exchange through HVDC lines, and lost load equal the net exchange over conventional transmission lines between regions (Equation (6.2)). Power output from dispatchable and non-dispatchable power plants has to be within the installed capacity, power output from fluctuating technologies might be lower due to lacking availability (Equations (6.3) and (6.4)). The power output from storage entities is limited by its installed power rating and—particularly for the power-to-gas technology—the power infeed rate can be set differently from its outflow rate (Equations (6.5) and (6.6)). The state of charge of the storage units including the seasonal storage energy flows needs to be within the installed storage capacity (Equation (6.7)). If technologies have a restriction on the energy that can be provided per year, it may not exceed that limit (Equation (6.8)). The amount of installed storage power and storage capacity cannot be increased above its exogenously given potentials (Equation (6.9) and (6.10)). Storage interaction exhibits losses when being charged, discharged, or when energy is kept within the storage device (self-discharge). If applicable, at the time slices defining a season start or ending, the energy injection or withdrawal, respectively, is possible (Equation (6.11)). For each season, seasonal storage balance is defined by last seasons storage state of charge, inter-seasonal losses, and the interaction with storage at the season's start and end (Equation (6.12)). The transmission line capacities are limited by their thermal limits (Equations (6.13) and (6.14)). The net power balance in all modeled regions has to be zero (Equation (6.15)). Each country's cross-border energy exchange is restricted to an autarky factor, such that a country's energy balance to the neighboring countries does not exceed an exogenously set percentage (Equation (6.16)).

The model is written in the programming language Julia v1.1 in combination with the modeling tool JuMP v0.19 and uses the solver Gurobi v8.1.

6.3.2 Data

A regional split-up is implemented based on the Nomenclature of Territorial Units for Statistics, Level 2 (NUTS2) information of the European Union. This framework divides Germany into 38 regions. Appendix D.2 gives an overview of all NUTS2 area codes in Germany used as nodes in the model. Each neighboring country is mapped as one model region, thus obtaining nine further network nodes (Netherlands, Belgium, France, Switzerland, Austria, Czech Republic, Poland, and Denmark). Figure 6.1 illustrates the geographical zone set-up for this analysis. The names of the regions are attached in Table D.2 in Appendix D.2. The model includes the transmission lines of 380 kV and 220 kV, whereas lower voltage levels are neglected. The set of transmission lines is reduced to "system-relevant" lines following the methodology of Weinhold and Mieth (2020) so that only those lines are considered, whose bounds directly constrain the DC Power Flow solution, as they reach their thermal limits first. For the scenarios with transmission network expansion, data from the network development plan (NDP) (50Hertz Transmission GmbH et al. 2019) is taken as reference. Based on this source, HVDC transmission lines are also modeled in the future scenarios as proposed by the NDP (see Figure 6.2).

The potentials for renewable energies are calculated based on an approach put forward by Nahmmacher, Schmidt, and Knopf (2014). Firstly, data on land area categorized into agriculture, forest, continuous urban fabric, and discontinuous urban fabric are taken from the European Environment Agency (2019). As the dataset is reported on a NUTS3 level, the values are then dis-aggregated to meet the defined NUTS2 zones. The land area that is available for wind turbines and PV panels is calculated according to factors in Table 6.1. This amount of land area is then multiplied with the energy density in order to obtain the potential generation capacity in MW. Wind offshore is assumed to have an installation limit of 75 GWh in Germany. Also no distinction is made in terms of investment costs or full load hours. However, in reality costs will increase the further away from the coast the offshore wind park is being built.

Electricity demand data for each NUTS2 region is taken from Kunz et al. (2017a) and Kunz et al. (2017b). Availability time series of renewable energy sources—wind and PV—is provided by Pfenninger and Staffell (2016). Offshore wind data is assigned to the three coastal regions Weser-Ems, Schleswig-Holstein and Mecklenburg-Vorpommern in Northern Ger-

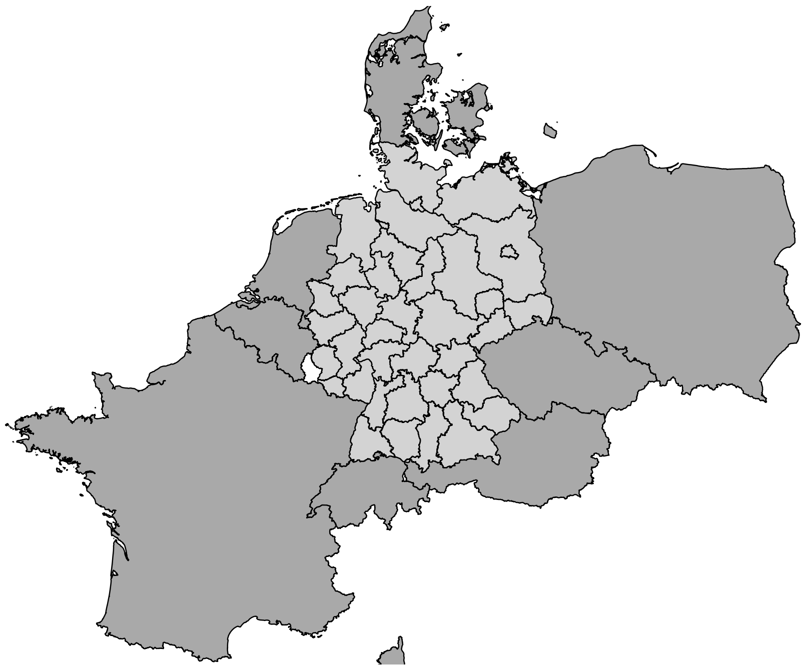

Figure 6.1: NUTS2 zones in Germany (light grey) and neighboring countries (dark grey).

Source: own depiction.

Table 6.1: Parameters used in the calculation of the renewable potentials.

	Wind onshore	**Open-space PV**	**Rooftop PV**	
			commercial	residential
Source	Nahmmacher, Schmidt, and Knopf (2014)	Nahmmacher, Schmidt, and Knopf (2014)	own assumptions	own assumptions
Agriculture	30 %	2 %	—	—
Forest	5 %	—	—	—
Continuous urban fabric	—	—	8 %	25 %
Discontinuous urban fabric	—	—	2 %	1 %
Energy density [MW/km^2]	4	30	0.16	0.16

Table 6.2: Technology data.

Technology	Fixed cost [€/MW]	Overnight cost [€/MW]	Overnight cost [€/MWh]	Marginal cost [€/MWh]	Lifetime [years]
pv-open	6.375	246.000	0	0	20
pv-roof	6.375	467.000	0	0	20
wind-on	21.500	900.000	0	0	20
wind-off	80.000	2.280.000	0	0	20
lib	1.960	75.000	164.000	1.3	12
rfb	2.000	550.000	122.000	1.3	20
PHES	10.000	3.000.000	10.000	0.5	60
PtG	20.000	2.287.000	300	8	10
RoR	30.000	3.000.000	0	0	50

many, depending on where the submarine cables are linked to the onshore transmission grid.

The model contains the following generation and storage technologies: open-space photovoltaics (pv-open), rooftop photovoltaics (pv-roof), onshore wind (wind-on), offshore wind (wind-off), lithium-ion batterys (libs), redox flow batterys (rfbs), PHESs, PtG, and run-of-river (RoR). Cost assumptions of each generation and storage technology are listed in Table 6.2.

Due to the computational complexity of the investment model, the time series method from Poncelet et al. (2017) is applied to obtain a time period of four weeks suitable for analysis.

6.3.3 Scenarios

The objective of this chapter is to relate distributed renewable generation portfolios to different scenarios of transmission topologies and congestion patterns. To that end, we define different representative scenarios, in order to assess different investment patterns resulting thereof. These (exogenously defined) transmission scenarios are the following:

(i) Copper Plate A corner solution is to allow an unrestricted flow of electricity within the transmission grid. Thus, the geographical location of generation would become irrelevant;

(ii) Grid 2022 is a scenario in which the existing transmission network in the year 2022 is taken as the basis for the analysis. In this setting, a little network congestion does occur since the optimal locations for renewable sources are not identical to load centers;

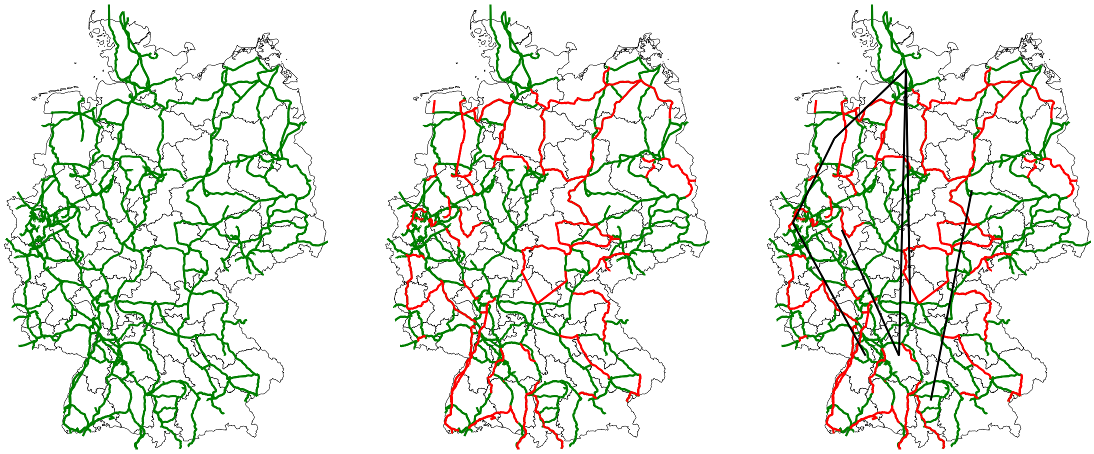

Figure 6.2: Grid 2022, Grid 2035 w/o HVDC, and Grid 2035 w/ HVDC. Existing AC lines in green, AC lines built or reinforced until 2035 in red, HVDC lines in black.

Source: own depiction.

(iii) Grid 2035 w/o HVDC describes a transmission expansion scenario that corresponds to the official network development plan by the TSOs, but without engaging into HVDC lines;

(iv) Grid 2035 w/ HVDC corresponds to the full-fledged version of the official network development plan until 2035, including the HVDC lines.

Assuming a copper plate system setup, geographical distances on a national basis are neglected. Power flow between different regional zones is unlimited. Another analysis is performed with the existing/planned transmission grid of 2022. In the real world, network congestion occurs as renewable energy sources were installed far from the demand centers. As a consequence the NDP quests for additional transmission capacity until 2035.[3] This enforced grid then also is going to contain direct current (DC) transmission links that allow for a more flexible energy dispatch, as transmitted power can be directly controlled. The analysis of these different scenarios allows to draw conclusions about what would be the cost minimal solution for designing an efficient energy system starting from scratch or starting from today's setup. Differences in the obtained results thus indicate long-term lock-in costs from today's network topology.

[3]In this analysis we refer to scenario B 2035 of the NDP.

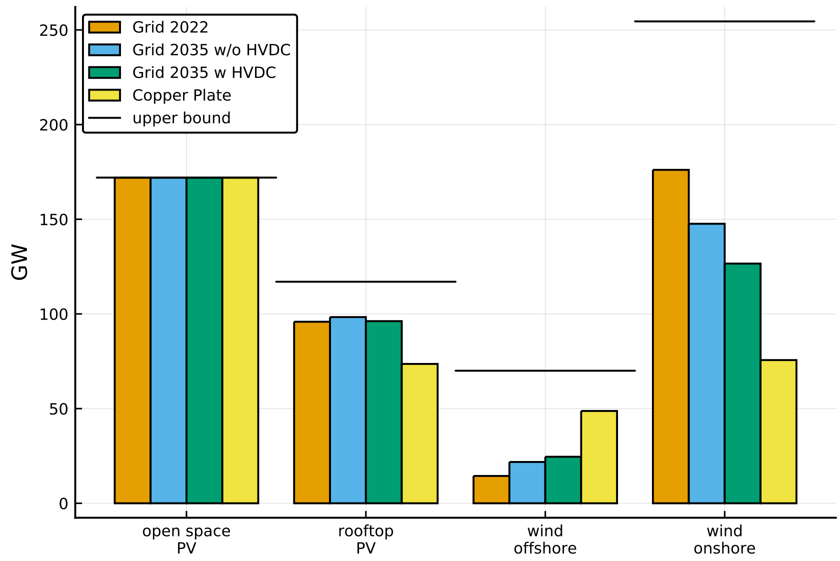

Figure 6.3: Installed power in GW in Germany.

Source: own depiction.

6.4 Results and Discussion

Since this chapter is primarily concerned with the link between transmission and distributed generation, we focus on the changes that different transmission designs, that is, the scenarios, have on generation, both in a static and a dynamic perspective. In particular, a 100 % renewable electricity mix requires a fine balance between flexibility options, amongst them transmission grids and storage.[4] The results and the discussion therefore focus on generation, storage, and transmission congestion, respectively.

6.4.1 Distributed Electricity Mix

Results show that the existing transmission grid has a huge impact on the optimal investment decisions. Figures 6.3 and 6.6 show the optimal investments into generation and storage power for the different scenarios. The solid black line in Figure 6.3 indicates the upper bound for the respective technology given its installation potentials.

While utilizing the maximum installable potential of open-space PV is worthwhile in every scenario, other decisions vary depending on the level of grid expansion. The largest trade-off exists between onshore wind and offshore wind. In the copper plate scenario only 76

[4]Demand-side management, another important flexibility option, is not covered in this chapter.

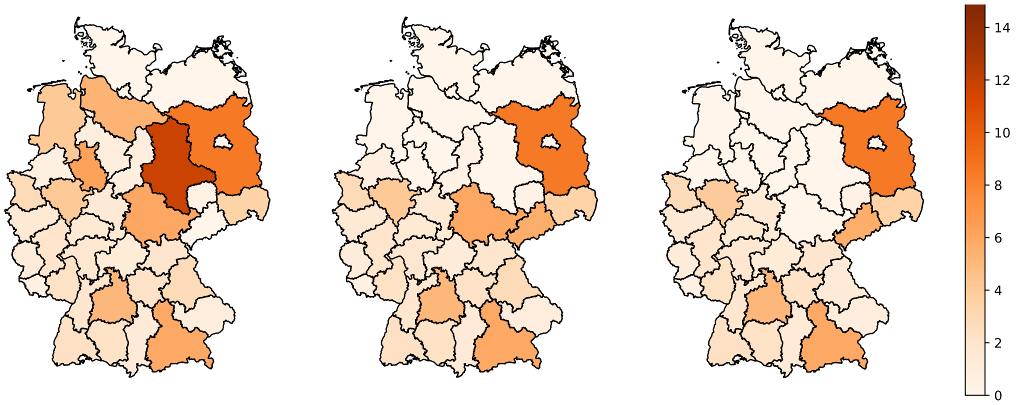

Figure 6.4: Installed generation power of rooftop PV in Grid 2022, Grid 2035 w/o HVDC, Grid 2035 w/ HVDC [GW].

Source: own depiction.

GWh of onshore wind is being built. In contrast, in the Grid 2022 scenario—having the lowest level of grid expansion—the investment into onshore wind increases to 176 GWh . On the other side, the installed power of offshore wind decreases from 49 GWh to 15 GWh . Due to Germany's geographical location, the offshore wind sites are positioned in the north only while a significant share of the electricity demand lies in the southern regions. As a result, high investments into offshore power are only feasible if enough transmission capacity is available. However, the lack of transmission capacity is offset by higher and more diversified investments into onshore wind and rooftop PV capacities. These two technologies are not bound to the coast and hence can be placed in a system-friendlier fashion.

Albeit the amount of installed power of rooftop PV does not differ between the scenarios that consider grid constraints, the spatial pattern changes (depicted in Figure 6.4). In the scenario Grid 2022 rooftop PV panels are relatively evenly distributed among the regions while in the other scenarios the investments are more concentrated in the southern regions where the full load hours are higher.

A similar pictures can be seen in Figure 6.5. The onshore wind turbines are also present in the south even though yields are lower. With an an increasing grid expansion the installed wind power diminishes almost completely in the very south.

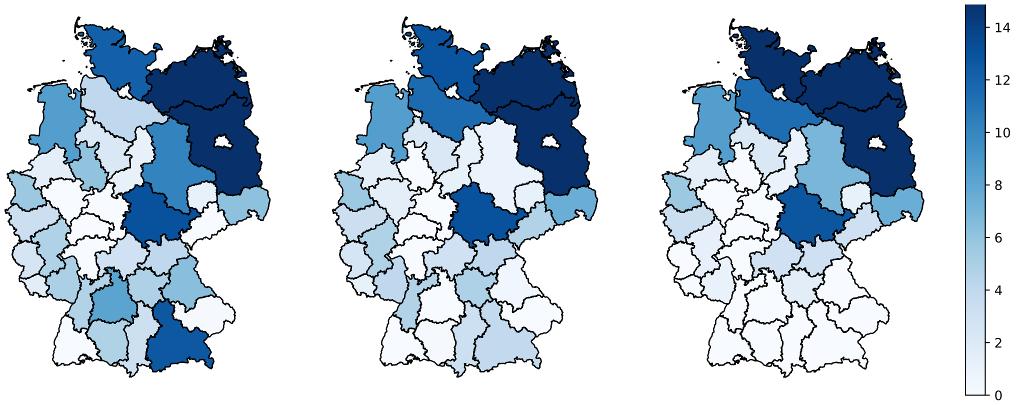

Figure 6.5: Installed generation power of onshore wind in Grid 2022, Grid 2035 w/o HVDC, Grid 2035 w/ HVDC [GW].

Source: own depiction

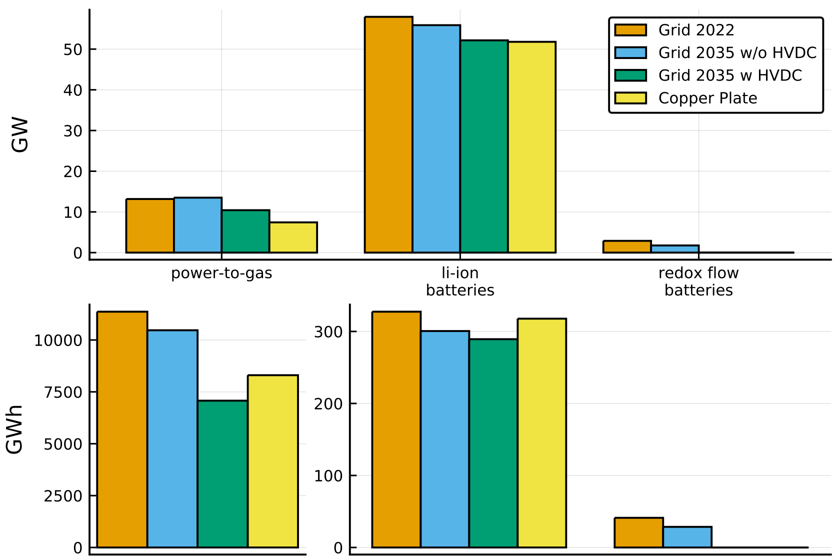

Figure 6.6: Installed storage power [GW] and capacity [GWh] in Germany.

Source: own depiction.

6.4.2 Storage Capacities

The flexibility option "storage" is particularly important in a system dominated by distributed generation. The storage capacity in GWh is depicted in Figure 6.6. The left part of the plot shows the investment into power-to-gas storage. This large-scale storage is used for seasonal storing due to its low investment costs in capacity (GWh) while the conversion from electricity to gas and the re-electrification is inefficient and associated with high investment costs into power (GW). On the right hand side, the installed storage capacity of the lithium-ion and the redox flow batteries are plotted (note that the scale of the y-axis is different). Lithium-ion batteries serve as a short-term storage that is frequently in use for shifting smaller amounts of energy due to low investments cost in storage power and a high efficiency. The redox flow batteries are less efficient and more expensive in storage power (GW) than lithium-ion batteries but in return cheaper in terms of storage capacity (GWh). Thus, redox flow batteries are best suited for mid-term flexibility.

Interestingly, redox flow batteries are not being built in the scenarios Copper Plate and Grid 2035 w/ HVDC while in the scenarios with higher grid constraints investments in redox flow storage capacity is advantageous. Contrarily, the seasonal storage capacity declines with a higher level of grid expansion which is not true for the copper plate scenario. The redox flow batteries in combination with the lithium-ion batteries are used to resolve grid congestion. Since grid bottlenecks can occur for more than a several hours (e.g. the wind is blowing strongly in the north for a couple of days and a longer period of cloudy days occurs in the south) a mid-term storage is sufficient. These bottlenecks do not exist in the copper plate scenario where the excessive energy is stored in a seasonal storage immediately. While the scenarios including the grid have an investment pattern that diversifies stronger into different technologies and locations, the copper plate scenario can harvest the best spots without considering any grid limitations. As discussed in the previous section, investments into onshore wind and rooftop PV are significantly higher in the scenario Grid 2035 w/ HVDC than in Copper Plate, resulting in a lower need for seasonal storage.

In Figure 6.7, the locations of the lithium-ion batteries also shift from a more distributed pattern to a slightly stronger concentrated pattern in the case of Grid 2035. The effect is more distinct for the locations of the power-to-gas storage capacity, which are mainly focused in the north-west.

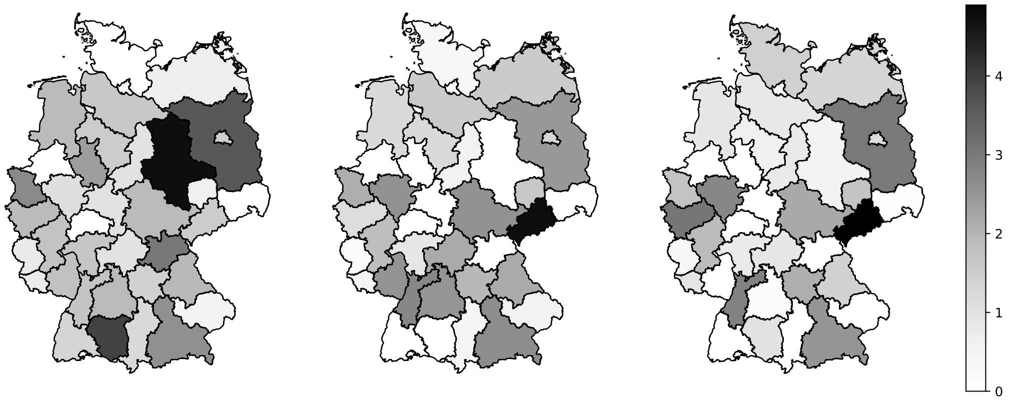

Figure 6.7: Installed storage power of lithium-ion batteries in Grid 2022, Grid 2035 w/o HVDC, Grid 2035 w/ HVDC [GW].

Source: own depiction.

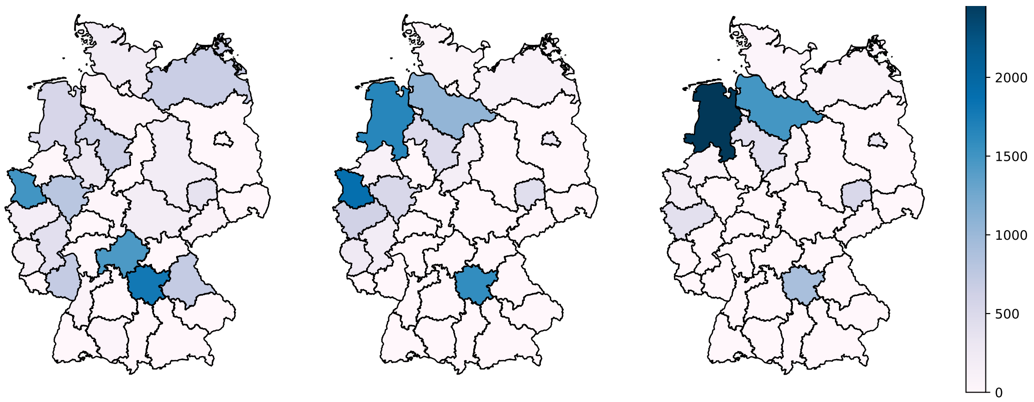

Figure 6.8: Installed storage capacity of power-to-gas in Grid 2022, Grid 2035 w/o HVDC, Grid 2035 w/ HVDC [GWh].

Source: own depiction.

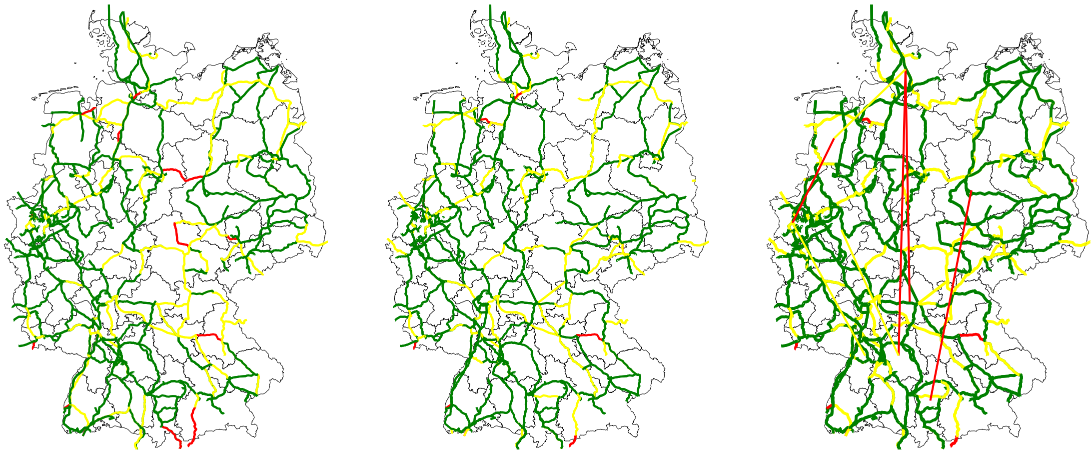

Figure 6.9: Average utilization of AC lines [% of thermal limit] in Grid 2022, Grid 2035 w/o HVDC, and Grid 2035 w/ HVDC. Categorized into high (>70 %, red), medium (>30 %, yellow), and low (<30 %, green).

Source: own depiction.

6.4.3 Transmission Congestion

The model also allows for an assessment of line utilization (whereas the transmission investment scenarios are exogenously defined). Figure 6.9 shows a very modest level of overload: In scenario Grid 2022, a few line connections are highly utilized. However, this potentially congested lines disappear for the most part in both the 2035 scenarios. Interestingly, even the 2035 grid without HVDC lines seems to be able to accommodate the distributed energy mix quite comfortably. Most of the regions with high generation and/or high load are well equipped and do not suffer congestion. When HVDC lines are added, they are highly utilized, though. However, the number of average line congestions per hour does not decrease in the Grid 2035 w/ HVDC scenario. This explains the higher investments in storage capacity of power-to-gas and redox flow batteries. The HVDC lines can transport the electricity right away while in the other scenarios the energy has to be stored until enough transmission capacity is available.

6.4.4 Cost Considerations

Last but not least, in Figure 6.10 we compare the costs of electricity generation and of storage in the different transmission scenarios relative to the costs in the copper plate scenario:

Table 6.3: Total system wide average line utilization.

Scenario	**AC lines** [%]	**DC lines** [%]	**Avg. Number of congestions per hour** (binding constraints)
Grid 2022	22.0	-	19.8
Grid 2035 w/o HVDC	21.2	-	16.2
Grid 2035 w/ HVDC	20.9	71.4	16.3

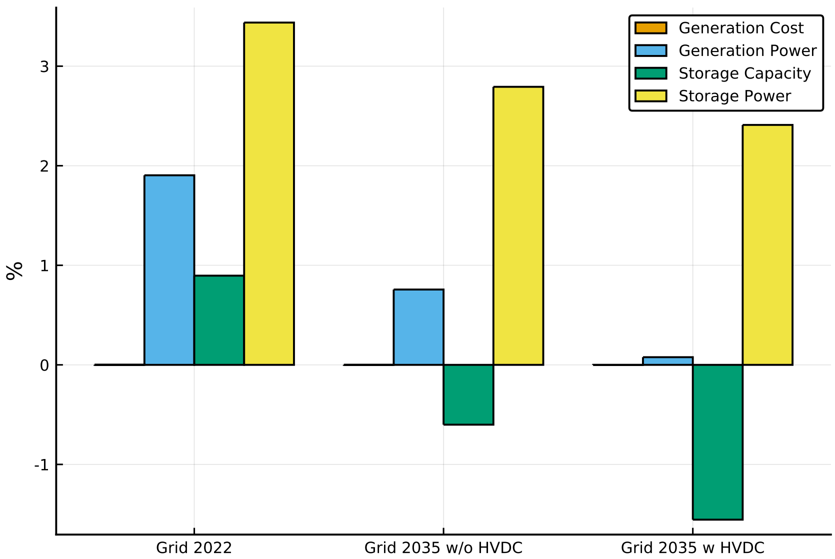

Figure 6.10: Relative costs to the copper plate scenario.

Source: own depiction.

Clearly, more transmission leads to less generation investment, resulting from less capacity installed, as shown above. The same results hold for storage power and storage capacity, which is inversely related to the level of grid development. The generation costs do not play a role since renewable energies are assumed to not have any variable costs.

Investment costs in generation power increase less than 2 % between the full grid of 2035 and the existing grid of 2022. The increase for investment costs in storage power amounts to about 1 %. A peculiar result emerges for storage capacity: costs compared to the copper plate scenario even decrease in the Grid 2035 w/ HVDC scenario. These changes in costs have to be counted against the changes in transmission investments.

6.5 Conclusions

Transmission investment is an important element of the low-carbon energy policy agenda that many industrialized countries have embraced over the last years, and that will shake the sector upside down with respect to the (almost entirely de-carbonized) generation mix and the interaction with storage and other flexibility options. In this chapter, we have chosen an extreme scenario, 100 % distributed renewable generation resources, to analyze the interdependence between transmission development and other elements of the electricity system. To this end, we have developed a stylized model in the spirit of previous electricity sector models in our research group, adding technical detail on generation and storage. The application to a 38 region-representation of the German electricity system allows for a spatially dis-aggregated analysis, yielding new insights into the interaction between the design of the transmission system, the generation mix, and storage infrastructure. In the model, transmission expansion is exogenous, whereas we differentiate into four possible designs, ranging from the status quo in 2022, an extended network in 2035 with and without HVDC lines, and a full-fledged copperplate without any congestion.

The model runs yield some expected results, but also offer some challenges. Amongst the expected results, a higher level of transmission expansion leads to lower requirements of distributed renewable capacities, mainly for rooftop solar and onshore wind. On the other hand, offshore wind benefits from more transmission capacities.

A similar, though less strong effect can be observed for long-term power-to-gas and short-term lithium-ion storage, which play an important role in the new, renewables-based energy system: storage capacity requirements tend to decrease with more transmission, though this relation is not quite robust with respect to the scenarios (particularly the copper plate scenario). Due to the assumption of high national autarky, that is the requirement that countries have to fulfil their own energy demand netted over the course of the year, long-term storage capacity (in GWh) turns out to be quite important, whereas short-term capacities are very small. The model allows a spatial representation of the installation, indicating a trend to less storage requirements in the North as transmission is expanded.

Simplified network analysis suggests that Germany would be well on its way moving to a 100 % distributed renewable generation portfolio: though some network congestion is observed in the 2022 and the 2035 w/o HVDC scenarios, those seem to be of minor importance, and represent only a marginal share of the electricity transported. Even in the 2035 w/o HVDC scenario, line overruns can hardly be identified, and if so these occur mainly at the margins of the network. We conclude that a 100 % distributed renewables world leads indeed to a major overhaul of the system, but—given the simplified, aggregated level of modeling deployed here—it seems that transmission grids are unlikely to be a critical factor of that pathway. Future research should extend the analysis to a fully European level, and consider stochasticity (mainly of distributed generation) and other flexibility options, mainly demand-side management.

Chapter 7

On Distributional Effects in Local Electricity Market Designs — Evidence from a German Case Study

"Distributed energy technologies and consumer empowerment have made community energy an effective and cost-efficient way to meet citizens' needs and expectations regarding energy sources, services and local participation. Community energy offers an inclusive option for all consumers to have a direct stake in producing, consuming or sharing energy."

(European Parliament and European Council (2019))

This chapter is the accepted version of Energies 13 (8), 1993 (Lüth, Weibezahn, and Zepter 2020). Appendix E contains the original appendix to this publication.

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7.1 Introduction

With the *Clean Energy for all Europeans* package released in 2016, the European Commission called for a stronger participation of residential electricity consumers—individually or through communities—and for a flexible and responsive demand side via dynamic pricing (European Commission and Directorate-General for Energy 2019; European Parliament and European Council 2019). Energy communities are legally seen as a new organizational form for active energy consumers to participate in the energy market (Caramizaru and Uihlein 2020). Based on different market concepts, pilot projects in many countries have shown the technical and economic feasibility of their energy communities in Europe and around the world in the early 2010s (Zhang et al. 2017). Kampman, Blommerde, and Afman (2016) estimate that 83 % of the European Union's households (approximately 187 million) could potentially contribute to production and storage of renewable energy as well as system flexibility as *energy citizens*. They estimate that about half of those households could generate electricity from renewable sources and even more would be able to provide system flexibility with either electrical or thermal storage devices, for instance electric vehicles, stationary home batteries or electric boilers.

Research has quickly picked up the concept of energy communities and investigated their economic potential, technical feasibility, and possible market designs. The leading concepts highlight the necessity of local energy markets with some form of peer-to-peer trading—that is, direct financial compensation for electricity use in exchange with a neighboring participant—and show the market design and characteristics needed for a successful implementation. However, the feasibility and practicability of these market designs with respect to the current regulatory framework is critical and far from clear, which is why recent studies see the need for changing the legal support to enhance the European Commission's call. The European legislation defines not more than a scope without a specific guideline to nationally put these communities into practice (European Parliament and European Council 2019) while the impact of a widespread implementation on existing markets also remains indistinct.

To complement the academic literature concerning the feasibility of market designs within the current regulatory framework, we specifically address the following questions in this chapter: What are the implications and effects of local electricity market designs for energy communities under Germany's current tariff mechanism? And, how can we adjust the existing concepts of local electricity markets in order to ensure a fair distribution of costs between all participants?

By answering these questions, we identify a threefold contribution of our work to the literature: (i) We develop and make openly accessible a simplistic policy analysis tool for (local) energy markets that can help policymakers to understand the impacts of changes in the current regulatory framework and their implications for the end-users. (ii) We analyses the outcome of existing market designs presented in recent literature under different regulatory contexts and address their drawbacks regarding distributional effects by presenting a new market design that is beneficial for all participants. (iii) We outline hurdles and barriers for market designs to be attractive for all market participants in the presence of the current regulatory framework.

To this end, we specifically focus the attention on a German case study, tailoring both data as well as tariffs and pricing rules to the German framework. The developed model is formulated as a mixed complementarity problem (MCP), simulating a community of heterogeneous market participants, that is, consumers, prosumers (defined as electricity producers who self-consume parts of their electricity (Šajn 2016); some literature has extended this term to *prosumagers*, referring to prosumers who also own and operate a storage device), energy suppliers, and network operators. These players are assigned their individual objective function and constraints based on their role in the market. The model is freely adaptable to other tariff structures, market designs, and data and could thus be applied to the frameworks of other countries, albeit similar to the German one (Mathiesen et al. 2017; Inderberg, Tews, and Turner 2018; Gfk Belgium Consortium 2017).

The outcome of the proposed market design numerically shows—in the given context—that there is a tendency of mitigating distributional effects and the avoidance of system service charges in the community, while leading at the same time to monetary savings for all market participants.

The remainder of the chapter is structured as follows: Section 7.2 presents recent literature on the development of local electricity markets and introduces the methodology of mixed complementarity problems. In Section 7.3, the MCP model is introduced. Section 7.4 presents the case study, its data as well as the results and Section 7.5 concludes on the performance and points towards further research possibilities.

7.2 Background and Literature

The ongoing discussion on the future role of end-users has two perspectives: a European one and a national one. In this study, we will apply German data which puts Germany in the focus of analysis. While the European Union is promoting the end-user of electricity (and therewith both the consumer and prosumer) as a key player in the future market design, national regulation is often not proceeding fast enough in this transition process. Within the European Union's winter package in 2016, the Commission calls for a change of national—and also European—markets towards a more decentralized design with the smallest-scale participant, the consumer, at its heart (European Comission 2016).

One emerging approach of integrating consumers to a larger extent into the energy market was taken up by single pilot projects—most famously the *LO3 Brooklyn Microgrid*. These pilot projects have started testing the possibilities of trade between neighboring households—peer-to-peer trading options—as a means of sharing distributed generation in a local community. Zhang et al. (2017) provide an overview of and reference to recent projects and characterize their targets and outcomes. Business models for local markets have been reviewed by Park and Yong (2017), and their economic performance has been assessed by Zhang et al. (2016) and Zhang et al. (2018).

In theory, these local electricity markets could depict the bridge between decentralized electricity production and wholesale electricity exchanges, and foster investments in distributed energy resources without governmental subsidies: Participants can sell excess production to other customers (or peers) in the market, while in turn these customers pay less for the electricity from the local than from the retail market, resulting in a seller-buyer win-win situation. The research on local market designs and associated features developed on top of these pilot projects is, however, still in an early stage, especially regarding their regulatory and economic frameworks.

Local electricity markets and peer-to-peer (P2P) trading have been analyses and addressed from various perspectives. There is a broad range of literature on different market design aspects for such markets, for which Khorasany, Mishra, and Ledwich (2018) present a comprehensive overview. Studies focusing on local markets are reviewed by Mengelkamp, Diesing, and Weinhardt (2019), entailing a discussion of concepts, methods, trading designs, and participants. Generally, P2P trading can be seen as a key component in a local market as it allows for direct trade between local entities (Park and Yong 2017). Including P2P trade in local markets, there are two main design choices (Parag and Sovacool 2016): full P2P markets and community-based P2P markets. While the former design appears in rather few studies (e.g. by Sorin, Bobo, and Pinson (2019) and Mengelkamp et al. (2018b)), the latter one has a wider appeal (see Sousa et al. (2019) for a review). Moret and Pinson (2019) show, for instance, that enabling local energy exchange in communities leads to revealed prosumer preferences while Hahnel et al. (2020) empirically analyses trading strategies of prosumers for local energy exchange. Morstyn et al. (2018) propose a combination of P2P trade and virtual power plants, in order to capture the advantages of both models in a *federated power plant*.

Local electricity market designs for P2P trading in connection to residential storage systems have been proposed by Lüth et al. (2018). The authors find that the combination of local trade and storage result in electricity bill reductions of 30 % for the end-users. Zepter et al. (2019) present the economic benefits of integrating local market operations into the existing wholesale market regime, investigating synergies of residential storage and P2P trading towards local demand side flexibility in an integrated market setting.

From a technical perspective, Long et al. (2017) show that local markets are a feasible system and the authors present a guideline for the construction of a distribution network incorporating local trade. Whether local markets provide a conducive service to the grid has not yet been evaluated. In the presence of local storage entities within a local market, there is a wide range of possibilities to serve the system, as for instance in the operating reserves energy market. Mengelkamp et al. (2018a) include residential demand response into their local energy market simulation, showing that local sufficiency can be increased while decreasing the residual peak demand of the community significantly.

Another approach to allow for more participation of end-users, mainly prosumers, is the introduction of aggregation concepts for players with small capacities (Ottesen, Tomasgard, and Fleten 2016). Correa-Florez, Michiorri, and Kariniotakis (2018) allow prosumers to participate in the day-ahead market through an aggregator, while Ottesen, Tomasgard, and Fleten (2018) investigate the participation in a flexibility market. In a recent study, Olivella-Rosell et al. (2020) present a scalable optimization framework for the aggregation and operation of flexibility from distributed storage units of prosumer households or energy communities. One example of such a flexibility platform is the project ENKO (see www.enko.energy), aiming at the reduction of curtailment (*Einspeisemanagement*). Ableitner et al. (2019) introduce a real-world local energy market in Switzerland including a proposition of a tariff design.

A different way towards local markets are locational marginal pricing (LMP) or zonal pricing in wholesale electricity markets where grid constraints and therefore possible congestions are already taken into account in the market outcome. If the transmission capacity between two points is insufficient, the market zones or nodes start to disintegrate, leading to diverging prices reflecting the scarcity of transmission capacity (Egerer, Weibezahn, and Hermann 2016). Morstyn et al. (2019) combine the two approaches.

However, there is a mismatch between the developed market designs and their feasibility in the current regulatory framework. The legal context of P2P electricity trading with a focus on European law has been reviewed by Soest (2019), while Eid et al. (2016) analyze the market integration potential of several European case studies. Following the streams and discussions in literature and media, the concept of local electricity markets is not easily integrated into the current national regulatory framework (Soest 2019; Scheller et al. 2018). While from the standpoint of European directives P2P trading would theoretically be realizable, the specific transcription into national laws and acts hinders the implementation of such decentralized trading systems.

When market designs for local electricity markets are investigated, they often fall short in analyzing the need for changes in current regulatory frameworks or the impact of the current regulation on the outcome of their design suggestion. Existing analysis tools are tailored to recently proposed market designs but not all rules and conditions of legislation can be easily evaluated in their set-ups. This is a result of—amongst other things—the specific examination of single features in local markets or different foci of the developed analysis tools. Therefore, we see a need for an analysis tool that is on the one hand rather simplistic but on the other allows for a comparative study of national policies with regard to a stronger involvement of the end-users. In addition, the illustration of different actors in an energy system is of high relevance: the supply chain of electricity comprises multiple entities with disparate objectives and even the demand side consists of a set of heterogeneous end-users. Thus, this chapter aims at extending the existing toolbox of policymakers for the analysis of energy markets incorporating distinctive actors and their associated objectives to assess the value of decentralized small-scale production. This chapter's model will contribute to the literature by providing a flexible, easily adjustable, and openly accessible tool to investigate market designs, policy changes and the feasibility of business models.

Market models are often used to analyze policies and their corresponding system implications (Grimm et al. 2017). If formulated as an optimization problem, these models do not allow for the market price to be an endogenous variable. The market prices may be obtained after the optimization is complete by the respective dual variable, but they cannot be used within the optimization. Mixed complementarity problems, on the other hand, are equilibrium models that combine both primal and dual variables in one framework and therewith depict a more general class of models. They transition from a mere optimization to the solution of a Nash equilibrium, that is, the market outcome from which none of the participants desires to deviate, as the optimal decisions of the others are already taken into account. A theoretical introduction to mixed complementarity modeling in energy markets is provided by Gabriel et al. (2013). MCPs have been applied to several energy market problems, for example by Schill and Kemfert (2011), Egging, Holz, and Gabriel (2010), and

Huppmann and Egging (2014). For a recent overview on advancements in complementarity modeling, see the introduction of Egging-Bratseth, Baltensperger, and Tomasgard (2020). In this chapter, we develop a MCP as a tool to assess impacts of policy changes in local electricity markets on costs, flows, prices, and interaction among the modeled players.

7.3 Methodology

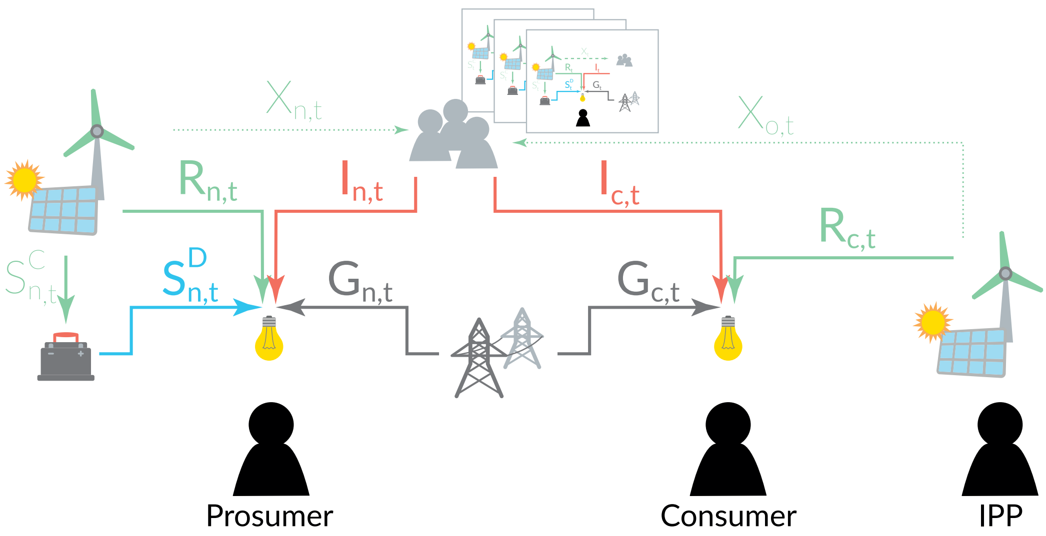

Figure 7.1: A stack of heterogeneous players.

Source: own depiction.

The purpose of this section is to present the general structure of the proposed policy analysis tool for energy communities. Although applied here to players in an electricity market setting, the tool can easily be adjusted to any other market setting for households with trading activities, different distributed energy resources, energy domains, storage, and cost schemes.

Following the taxonomy of Hall and Buckley (2016), the range of the model is spatially defined to a local energy community consisting of prosumers and consumers with heterogeneous production and consumption profiles as well as an independent power producer (IPP), all in an hourly temporal resolution. The model incorporates a set of (static) prices for both the electricity production and consumption of the players, namely the long-term marginal costs of production, as well as spot prices, network tariffs, taxes, levies, and other duties. A market operating player optimizes the local balancing mechanism and acts as price-setter. Figure 7.1 visualizes this set-up.

This set-up is structured as a quantitative and monetary disaggregated bottom-up model, and formulated as a mixed complementarity problem allowing for endogenous price determination in the local balancing mechanism. The following paragraphs describe the specific characteristics of the model for which Table 7.1 presents the used nomenclature. Note that variables are denoted in uppercase and parameters in lowercase letters.

Table 7.1: Designated sets, parameters and variables.

Sets	
$a \in \mathcal{A}$	player a in community $\mathcal{A}$
$n \in \mathcal{N} \subseteq \mathcal{A}$	prosumer n in community $\mathcal{A}$
$c \in \mathcal{C} \subseteq \mathcal{A}$	consumer c in community $\mathcal{A}$
$o \in \mathcal{O} \subseteq \mathcal{A}$	independent producer o in community $\mathcal{A}$
	$N \cap C, C \cap O, O \cap N = \emptyset$
$t \in \mathcal{T}$	hour t in time horizon $\mathcal{T}$
Scalars	
p^{dso}	distribution grid tariff per kWh
p^{tso}	transmission grid tariff per kWh
p^{eeg}	EEG reallocation charge per kWh
p^{G}	grid consumption tariff per kWh
p^{I}	LBM consumption tariff per kWh
$p^{t\&d}$	taxes and duties per kWh
p^{h}	handling fee per kWh
η	battery round trip efficiency

Parameters	
$dem_{a,t}$	demand of player a in time step t
$res_{a,t}$	renewable energy production of player a in time step t
p_t^{eex}	price of electricity from energy exchange in time step t
p_a^{fit}	feed-in tariff per kWh for player a
p_a^{mc}	marginal cost per kWh for player a
p_a^{sto}	marginal discharge costs per kWh for player a
p_a^D	discharge penalty per kWh for player a
p_a^O	price per kWh of electricity sold from player o to shareholder a
$\overline{s}_a$	upper bound of storage level in battery for player a
$\underline{s}_a$	lower bound of storage level in battery for player a
α_a/β_a	maximum charge/discharge rate of battery for player a
s_a^{init}	initial storage level in battery for player a
Primal Variables	
$R_{a,t} \in \mathbb{R}^+$	consumption of renewable energy for player a in time step t
$G_{a,t} \in \mathbb{R}^+$	consumption of energy from the grid for player a in time step t
$X_{a,t} \in \mathbb{R}^+$	sale of renewable energy to LBM for player a in time step t
$I_{a,t} \in \mathbb{R}^+$	consumption from LBM for player a in time step t
$F_{a,t} \in \mathbb{R}^+$	feed into the grid for player a in time step t
$S_{a,t}^C \in \mathbb{R}^+$	battery storage charging for player a in time step t
$S_{a,t}^D \in \mathbb{R}^+$	battery storage discharging for player a in time step t
$S_{a,t} \in \mathbb{R}^+$	battery storage level for player a in time step t
Dual Variables	
$P_t^{LBM} \in \mathbb{R}$	price of electricity in the LBM in time step t
$P_{a,t}^N \in \mathbb{R}$	price of electricity for player a in time step t
$P_{a,t}^S \in \mathbb{R}$	price of electricity in the storage for player a in time step t
$\lambda_{a,t}^{res} \in \mathbb{R}^+$	price of curtailment for each player a in time step t
$\lambda_{a,t}^{\underline{s}} \in \mathbb{R}^+$	price of storage lower bound for each player a in time step t
$\lambda_{a,t}^{\overline{s}} \in \mathbb{R}^+$	price of storage upper bound for each player a in time step t
$\lambda_{a,t}^{\alpha} \in \mathbb{R}^+$	price of storage charging for each player a in time step t
$\lambda_{a,t}^{\beta} \in \mathbb{R}^+$	price of storage discharging for each player a in time step t

7.3.1 The Prosumer's Problem

Prosumer households $n \in \mathcal{N}$ are equipped with divergent technology portfolios consisting of solar photovoltaic installations, wind turbines, and battery energy storage devices. Each of the prosumers aims at minimizing its objective function, Equation (7.1), by minimizing costs of electricity from different operational choices: Costs for renewable production going to self-consumption $R_{n,t}$, export into the local balancing mechanism $X_{n,t}$, feed into the grid $F_{n,t}$, or charging a battery $S^C_{n,t}$ are priced at a prosumer-specific marginal rate of production p^{mc}_n of this technology. For the consumption from the external grid $G_{n,t}$ the grid price p^G is paid. An endogenously determined price P^{LBM}_t as well as grid related costs p^I are paid for buying electricity $I_{n,t}$ from the local balancing mechanism. Prosumers selling quantity $X_{n,t}$ into the local balancing mechanism receive the price P^{LBM}_t, and for selling to the grid prosumers are remunerated at p^{fit}_n. In addition, some prosumers might own an energy storage. The discharge quantity $S^D_{n,t}$ will be charged at a marginal discharge cost p^D_n.

$$\begin{aligned}\min_{R_{n,t},G_{n,t},X_{n,t},I_{n,t},F_{n,t},S^C_{n,t},S^D_{n,t},S_{n,t}} \quad & \sum_t \Big[\big(R_{n,t} + X_{n,t} + F_{n,t} + S^C_{n,t}\big) \cdot p^{mc}_n + G_{n,t} \cdot p^G \\ & + I_{n,t} \cdot \big(P^{LBM}_t + p^I\big) + S^D_{n,t} \cdot p^D_n \\ & - X_{n,t} \cdot P^{LBM}_t - F_{n,t} \cdot p^{fit}_n \Big]\end{aligned} \tag{7.1}$$

The prosumers' objective is subject to a set of constraints. These comprise the supply-demand balance, production limits, and storage characteristics if applicable. The demand $dem_{n,t}$ for each prosumer $n \in \mathcal{N}$ must be covered by the sum of self-consumption $R_{n,t}$, grid consumption $G_{n,t}$, the purchases from the local balancing mechanism $I_{n,t}$, or a discharge $S^D_{n,t}$ from a storage as represented in Equation (7.2) with the dual variable $P^N_{n,t}$.

$$dem_{n,t} - R_{n,t} - G_{n,t} - I_{n,t} - S^D_{n,t} = 0 \qquad \forall\, t \qquad (P^N_{n,t}) \tag{7.2}$$

The available production $res_{n,t}$ originates from a data set and is inserted as a parameter into the model. Available production can be used for self-consumption $R_{n,t}$, local balancing sales $X_{n,t}$, grid feed-in $F_{n,t}$, or to charge a storage $S^C_{n,t}$, see Equation (7.3). The equation's dual variable $\lambda^{res}_{n,t}$ can be seen as the marginal value of curtailment.

$$R_{n,t} + X_{n,t} + F_{n,t} + S^C_{n,t} - res_{n,t} \leq 0 \qquad \forall\, t \qquad (\lambda^{res}_{n,t}) \tag{7.3}$$

If available in a prosumer household, we introduce a set of storage equations (Equations (7.4)-(7.7)) representing their physical characteristics. The storage level $S_{n,t}$ is determined by the level $S_{n,t-1}$ of the period before and the additionally charged ($S_{n,t}^C$) or discharged ($S_{n,t}^D$) quantity with a round trip efficiency of η (Equation (7.4)). For the first period an initial storage level $s_{n,0} = 0$ is assumed.

$$S_{n,t-1} - S_{n,t} + \eta \cdot S_{n,t}^C - S_{n,t}^D = 0 \qquad \forall t \qquad (P_{n,t}^S) \tag{7.4}$$

The storage level $S_{n,t}$ itself is bounded by a lower limit $\underline{s}_n$ and an upper limit $\overline{s}_n$ (Equation (7.5)).

$$\underline{s}_n \leq S_{n,t} \leq \overline{s}_n \qquad \forall t \qquad (\lambda_{n,t}^{\underline{s}}, \lambda_{n,t}^{\overline{s}}) \tag{7.5}$$

Storage charge $S_{n,t}^C$ and discharge $S_{n,t}^D$ are limited by a maximum charge and discharge rate α_n and β_n, respectively (Equations (7.6) and (7.7)).

$$S_{n,t}^C - \alpha_n \leq 0 \qquad \forall t \qquad (\lambda_{n,t}^{\alpha}) \tag{7.6}$$

$$S_{n,t}^D - \beta_n \leq 0 \qquad \forall t \qquad (\lambda_{n,t}^{\beta}) \tag{7.7}$$

We formulate the following Lagrangian function (Equation (7.8)) for the prosumer's problem.

$$\begin{aligned}
\mathcal{L} = \sum_t \Big[& \big(R_{n,t} + X_{n,t} + F_{n,t} + S_{n,t}^C\big) \cdot p_n^{mc} + G_{n,t} \cdot p^G \\
& + I_{n,t} \cdot \big(P_t^{LBM} + p^I\big) + S_{n,t}^D \cdot p_n^D - X_{n,t} \cdot P_t^{LBM} - F_{n,t} \cdot p_n^{fit} \Big] \\
& + P_{n,t}^N \cdot \big(dem_{n,t} - R_{n,t} - G_{n,t} - I_{n,t} - S_{n,t}^D\big) \\
& + \lambda_{n,t}^{res} \cdot \big(R_{n,t} + X_{n,t} + F_{n,t} + S_{n,t}^C - res_{n,t}\big) \\
& + P_{n,t}^S \cdot \big(S_{n,t-1} - S_{n,t} + \eta \cdot S_{n,t}^C - S_{n,t}^D\big) \\
& + \lambda_{n,t}^{\underline{s}} \cdot (\underline{s}_n - S_{n,t}) \\
& + \lambda_{n,t}^{\overline{s}} \cdot (S_{n,t} - \overline{s}_n) \\
& + \lambda_{n,t}^{\alpha} \cdot \big(S_{n,t}^C - \alpha_n\big) \\
& + \lambda_{n,t}^{\beta} \cdot \big(S_{n,t}^D - \beta_n\big)
\end{aligned} \tag{7.8}$$

7.3.2 The Consumer's Problem

In addition to prosumer households there are pure consumer households $c \in \mathcal{C}$, not directly owning any generation capacity or storage. They still aim at minimizing their electricity costs, Equation (7.9), yet only electricity procurement from the grid $G_{c,t}$ or from the local balancing mechanism $I_{c,t}$ are possible. Consumers might also have the option to acquire the right of use for a given share of an independent power producer's generation installation. In this case self-consumption $R_{c,t}$ from that share at a consumer specific self-consumption rate p_c^{mc} is possible.

$$\min_{R_{c,t},G_{c,t},I_{c,t}} \quad \sum_t \left[R_{c,t} \cdot p_c^{mc} + G_{c,t} \cdot p^G + I_{c,t} \cdot \left(P_t^{LBM} + p^I \right) \right] \tag{7.9}$$

The supply-demand balance (Equation (7.10)) and bounds on use of renewables (Equation (7.11)) are analogue to the prosumer's problem. The parameter $res_{c,t}$ is exogenously set according to the acquired share in the independent power producer's system.

$$dem_{c,t} - R_{c,t} - G_{c,t} - I_{c,t} = 0 \qquad \forall\, t \qquad (P_{c,t}^N) \tag{7.10}$$

$$R_{c,t} - res_{c,t} \leq 0 \qquad \forall\, t \qquad (\lambda_{c,t}^{res}) \tag{7.11}$$

Equation (7.12) shows the Lagrangian function for consumers.

$$\begin{aligned} \mathcal{L} = &\sum_t \left[R_{c,t} \cdot p_c^{mc} + G_{c,t} \cdot p^G + I_{c,t} \cdot \left(P_t^{LBM} + p^I \right) \right] \\ &+ P_{c,t}^N \cdot (dem_{c,t} - R_{c,t} - G_{c,t} - I_{c,t}) \\ &+ \lambda_{c,t}^{res} \cdot (R_{c,t} - res_{c,t}) \end{aligned} \tag{7.12}$$

7.3.3 The Independent Power Producer's Problem

An independent power producer (IPP) $o \in \mathcal{O}$ does not have any residential demand but owns and operates a large-scale rooftop PV system. Any consumer $c \in \mathcal{C}$ can acquire the right to consume generated electricity ($R_{c,t}$) from the IPP according to an agreed share. Excess electricity not used by these shareholders can be sold into the local balancing mechanism ($X_{o,t}$). Electricity for shareholders is produced at a marginal production cost p_o^{mc}, while electricity for the local balancing mechanism is charged at the electricity exchange rate p_t^{eex} in order to prevent the large IPP to always be the price-setter on the market due to the more favorable generation conditions. Exports are remunerated with the local balancing rate P_t^{LBM} and the supply of shareholders is compensated at a rate p_o^O. The overall objective in Equation (7.13) again is to minimize operating costs. Exports to the local balancing mechanism and deliveries to the shareholders are capped at the renewable generation $res_{o,t}$ (Equation (7.14)).

$$\min_{X_{o,t}} \quad \sum_t \left[X_{o,t} \cdot p_t^{eex} + \sum_c R_{c,t} \cdot p_o^{mc} - X_{o,t} \cdot P_t^{LBM} - \sum_c R_{c,t} \cdot p_o^O \right] \tag{7.13}$$

$$X_{o,t} + \sum_c R_{c,t} - res_{o,t} \leq 0 \qquad \forall t \qquad (\lambda^{res}_{o,t}) \tag{7.14}$$

The Lagrangian function of this player is displayed in Equation (7.15).

$$\begin{aligned}\mathcal{L} = &\sum_t \left[X_{o,t} \cdot p^{eex}_t + \sum_c R_{c,t} \cdot p^{mc}_o - X_{o,t} \cdot P^{LBM}_t - \sum_c R_{c,t} \cdot p^O_o \right] \\ &+ \lambda^{res}_{o,t} \cdot \left(X_{o,t} + \sum_c R_{c,t} - res_{o,t} \right)\end{aligned} \tag{7.15}$$

7.3.4 Local Balancing Mechanism

In the presence of a local balancing mechanism all players in the mechanism (prosumers, consumers, and the independent power producer) are linked via a market clearing condition (Equation (7.16)). It balances all sales ($X_{n,t}, X_{o,t}$) and purchases ($I_{n,t}, I_{c,t}$) within the local balancing mechanism in each time step $t \in \mathcal{T}$. Local trade within the distribution networks is afflicted with losses that are inherent to the distribution of electricity—e.g. due to dissipated energy by resistances in network equipment—and cannot be eliminated. It is assumed that all network losses are already financially compensated for by electricity acquisition of the network operators that are reflected in the charged grid tariffs. This player represents the market operator. Equation (7.16) is assigned P^{LBM}_t as its dual variable. As this condition connects all players in balancing the amounts traded and therefore clears the market, the dual variable can be seen as the local balancing price, endogenously determined within the problem. It is part of the objective functions of all players.

$$\sum_n I_{n,t} + \sum_c I_{c,t} - \sum_n X_{n,t} - \sum_o X_{o,t} = 0 \qquad \forall t \qquad (P^{LBM}_t) \tag{7.16}$$

In order to solve the Lagrangian functions, we derive the Karush-Kuhn-Tucker conditions (KKTs), as listed in Appendix E.1. The problem implementation was done using the programming language Julia and the PATH solver v5.0.02 (Dirkse and Ferris 1995; Ferris and Munson 2000) was used for the numerical solution. It solves the optimization problem for four representative weeks in about 90 seconds on an intel core i7-8565 with 1.8 GHz and 16 GB RAM depending on the used set-up. The model code and data will be freely available on GitHub.

The developed model can be applied to different environments of energy problems as well as modified towards a wider range of possible policy analyses. In the chosen setting of an electricity market, we showcase in the following an application of the full model and some modifications, presenting a case study on German data.

7.4 A Case Study in the German Regulatory Context

The presented model will be used to analyze the impact of different market designs on market participants, based on data from Germany. We split the case study in three parts and start with the application of local market designs proposed by Lüth et al. (2018) to a German town (Section 7.4.1). The second part elaborates and describes the impact of the current German regulatory framework on the outcome of these suggested market designs (Section 7.4.2). The third part proposes a novel market design based on the outcome of the first and second part as well as on recent discussions in research, society, and among policymakers about the future role and importance of small-scale prosumers in the energy system (Brown, Hall, and Davis 2019; Friends of the Earth Europe 2019; European Parliament and European Council 2019) (Section 7.4.3). A summary of the basic data used in all three of the following sections is given in the next paragraphs. Market design specific data will be introduced along with their descriptions. For all data, Appendix E.2 and Table E.1 provide more details on raw data processing, assumptions, and specific values.

The place of analysis is the town of *Grevesmühlen* in the Northern part of Germany. There is no specific reason for choosing *Grevesmühlen* as subject of analysis within this chapter, except for the fact that the town offers different distributed energy resources in immediate vicinity. The case study comprises a community of 14 households including both prosumers and pure consumers (Table E.1 in Appendix E.2), a market operator and an IPP. Specifically, one household is equipped with a small-scale wind turbine with an installed capacity of 2 kW, and 11 households have rooftop PV installations that vary in size between 1.20 kilowatt peak (kWp) and 4.08 kWp. The independent power producer operates a 100 kWp roof-top installation.

Hourly data sets for the production patterns of renewable energy sources (i.e. wind and solar) in *Grevesmühlen* were taken from the open-access data platform *renewables.ninja* for the year 2018. Demand data for the households originate from a database for real houses in London, UK. The demand data of these households match the German average electricity consumption in magnitude and pattern. Unfortunately, comprehensive databases for German households are difficult to find. To our knowledge, only the *Open Power System Data (OPSD)* platform provides real open-access German household consumption data in hourly resolution. However, the data seem inconsistent.

In *Grevesmühlen*, the basic provision with electricity is performed by the municipal utility *Stadtwerke Grevesmühlen*, serving as reference for this case study. We apply the prices listed in Table 7.2.

Table 7.2: Components of end-user electricity price.

	[ct/kWh]	[%]
electricity spot price (p_t^{eex})	6.44	22.4
distribution network charge (p^{dso})	3.48	12.1
transmission network charge (p^{tso})	3.44	12.0
EEG reallocation charge (p^{eeg})	6.52	22.7
other taxes & duties ($p^{t\&d}$)	8.85	30.8
total kilowatt-hour rate	28.73	100.0

Production from own technologies is subject to marginal costs. The long-term marginal production costs have been calculated for each technology owning player by using the levelized cost of energy (LCOE) approach (Brown, Poudineh, and Foley 2015; Tegen et al. 2012). Prosumers owning a fully written-off PV rooftop system are in this study assumed to be offering at marginal production costs of just the operation and maintenance costs.

The following three sections describe the different steps our our case study, their structure, specific data, as well as their results and reflections. The community is exposed to a total of six market designs. Table 7.3 presents an overview on these market designs and outlines the difference in prices each of the market designs implies.

7.4.1 The Benchmark of a Market Design

The first market design ① **BAU Feed-in** resembles ***self-consumption in combination with a fixed feed-in tariff***—business as usual as of today (Weniger, Tjaden, and Quaschning 2012): A household consumes its self-generated electricity at costs equal to its marginal operational costs p_n^{mc}. In case of underproduction, electricity is procured from the grid at a static rate of $p^G = p_t^{eex} + p^{dso} + p^{tso} + p^{eeg} + p^{t\&d}$, equaling the end-user price in Germany consisting of the wholesale price p_t^{eex}, distribution network tariffs p^{dso}, transmission network tariffs p^{tso}, a reallocation charge p^{eeg} and taxes and duties $p^{t\&d}$. For details on this reallocation charge please refer to the *Excursion Box* in Section 7.4.2. Excess production is fed into the grid and remunerated at the rate p_n^{fit} that is determined by the German regulatory authority (*German Federal Network Agency (BNetzA)*) based on size and date of installation and paid as a subsidy. These specific rates for the assessed households can be determined based on the data from the *Markstammdatenregister (MaStR)* and the open-access platform

Table 7.3: Overview of simulated set-ups.

Set-up	**Consumption from Grid** p^G	**Consumption from LBM** p^I	**Consumption from Storage** p^D	Feed-in into Grid	**Feed-in into LBM**
① BAU Feed-in	$p_t^{eex} + p^{dso} + p^{tso} + p^{eeg} + p^{t\&d}$	—	—	p_n^{fit}	—
② Local Sharing	id.	$p^{dso} + p^{t\&d}$	—	—	P^{LBM}
③ Home Storage	id.	—	p_n^{sto}	—	—
④ Home Storage & Local Sharing	id.	$p^{dso} + p^{t\&d}$	p_n^{sto}	—	P^{LBM}
⑤ Current Regulatory Framework for ④	id.	$p^{dso} + p^{t\&d} + p^{tso} + p^{eeg}$	p_n^{sto}	—	P^{LBM}
⑥ Tech4all	id.	$p^{dso} + p^{t\&d} + p^{tso} + 0.4 \cdot p^{eeg}$	$p_n^{sto} + 0.4 \cdot p^{eeg}$	—	P^{LBM}

Netztransparenz.de.

Following the work of Lüth et al. (2018), we apply their three additional market designs to the presented case study. These designs aim at investigating the post feed-in tariff era, and thus feed-in will not be considered in any of the following designs, that is, $F_{n,t}$ is fixed to zero. First, the possibility of *trading* is enabled, that is, supply and demand are balanced locally before the procurement from the grid. This is implemented by adding a further constraint on top of ① BAU Feed-in that links the players and represents a local market clearing. In the scenario ❷ **Local Sharing** with ***self-consumption and local sales*** a household can hence additionally procure electricity from the local production at rate $P^{LBM} + p^{I}$ where $p^{I} = p^{dso} + p^{t\&d}$. This local electricity stems from households' excess generation that is fed into the local grid and remunerated at the same local rate P^{LBM}. This local rate is determined within the optimization of the mixed complementarity model originating from the dual variable of Equation (7.16), as this equation clears the local trading balance. Second, residential energy storage facilitates a number of households to privately store their own generation: In the design ❸ **Home Storage** with ***self-consumption and own storage***, a household can consume electricity from the own battery at a discharge rate p_n^D equal to a levelized cost of storage p_n^{sto} (see also Crespo Del Granado, Wallace, and Pang (2014) for a similar approach) instead of trading within the community. Excess production can, thus, be stored in the home storage if available and used, for example, for load shifting purposes. In Germany, there exist some business models that specifically sell combined PV and battery storage installations with the most popular being the *sonnenCommunity*. The home storage systems assumed in this chapter have an installed capacity of 4 kWh or 6 kWh. For a specific description of their characteristics, please refer to Appendix E.2 and Table E.2 at the same place. The scenario ❹ **Home Storage & Local Sharing** with ***self-consumption, own storage, and community sharing*** combines ② with ③, allowing for local sharing *and* battery storage.

The application of these existing market designs to the German case study verify the tendency of outcomes presented in Lüth et al. (2018) and Zepter et al. (2019). We observe that

- the more features enabled within the community, the higher the monetary savings.
- prosumers profit most from owning both generation technologies and storage, and a pure consumer sees only a small decrease in costs.
- cheap rates in the local market can only be reached by avoiding grid fees, surcharges and/or levies, which is the main assumption for the local rate.
- the community's self-sufficiency rate increases (see Figure 7.2) while the peak load

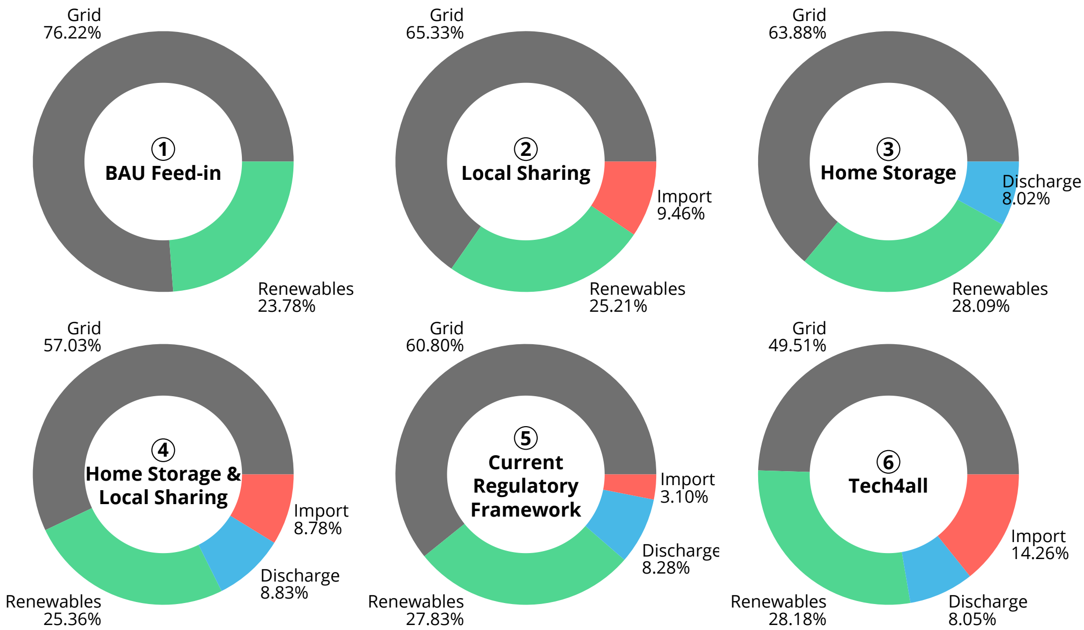

Figure 7.2: Overview of demand sources for the simulated market designs.

Source: own depiction.

remains rather constant.

As costs for the existing network infrastructure will remain part of the tariffs and they are not subject to change, the avoidance of grid tariffs and surcharges in a local trading mechanism will only give rise to the grid charges on the remaining quantity procured through the network. In short: less power in the grid at the existing costs for network infrastructure results in a higher grid fee. Figure 7.3 visualizes this implication. We plot the overall quantity in each of the market designs against the fees paid and see a decrease in network charges the more features we introduce. As pure electricity consumers remain the players with a rather stable grid consumption, they will be affected most by lower procurement from the grid while prosumers avoid these charges by self-consuming, trading, and storing local production. This is in line with the findings of Pollitt (2018).

We conclude that these market designs could lead to a redistribution of costs for the network, which will be at the expense of a pure consumer—most likely a household without own property or less affluent—who might not have the same evasion possibilities as prosumers (we entitle this the proverbial *dentist effect*). Figure 7.4 gives a summary of the costs. We benchmark the different market designs against ④ Home Storage & Local Sharing where all features are enabled, and cluster the households in groups of prosumagers (residential technology and storage), prosumers (residential technologies) and pure consumers. For some, ① BAU Feed-in is still the cheapest option because their feed-in tariffs on their large excess production result in high remuneration profits. However, for the majority of the community costs decrease along with the introduction of local trading and storage under the presented market designs.

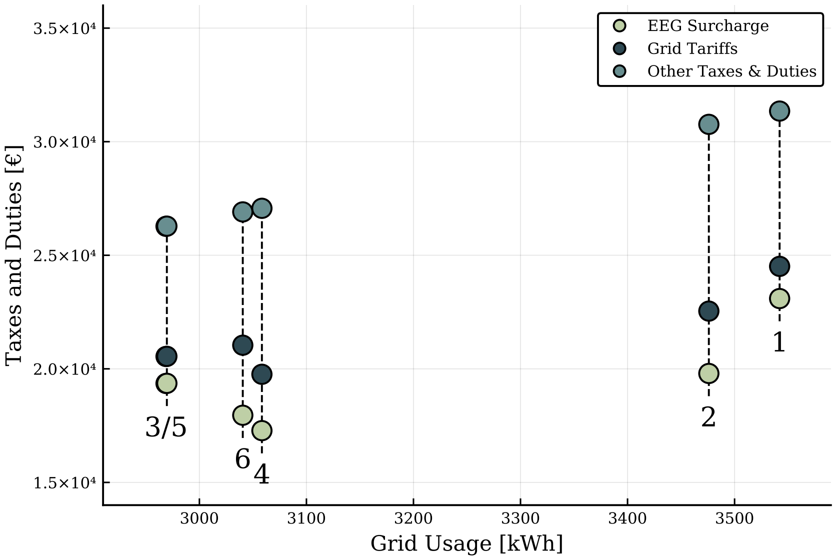

Figure 7.3: Comparison of taxes and duties for the simulated market designs.

Source: own depiction.

Yet, the proposed market designs do not take into account any current regulatory framework that mostly foresees obligatory grid tariffs on any quantity procured from the grid. In order to see how results change if we do not exclude the local trading activities from paying grid charges, we adjust the market design slightly, applying the German regulatory framework, and evaluate the influence of the current regulation on the suggested market design.

7.4.2 Integration Into the German Regulatory Framework

In this section, we test a further case ⑤ **Current Regulatory Framework** with ***self-consumption, own storage, community sharing, and current taxes and duties***, for which we introduce current German regulation to ④. Consumption from the local balancing mechanism is then charged at a varied $p^I = p^{dso} + p^{tso} + p^{eeg} + p^{t\&d}$ as the German regulatory framework does not make exemptions from paying grid fees and surcharges once the electricity is passing the public grid. See the *Excursion Box* for details on the German regulatory framework.

The results show that due to the higher costs, benefits of the local trade shrink significantly. In order to have any benefits for participating players in a ④ Home Storage & Local Sharing market, the taxes and duties structure would need to be adjusted as argued by Schäfer-Stradowsky and Bachmann (2016) and Scheller et al. (2018). In their report, Oppen, Streitmayer, and Huneke (2017) show that trading among neighbors or within a community is highly uneconomic as well as not manageable for small prosumers due to a compact regulatory framework that would lead to high costs as well as a major amount of administrative work. We summarize the obligations and implications for prosumers in a local trading scheme in the German regulatory framework in Appendix E.3.

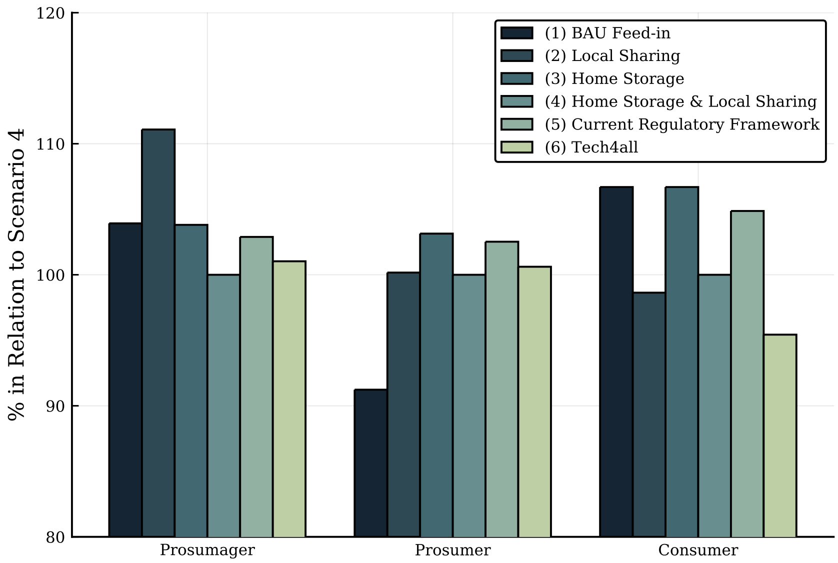

Figure 7.4: Comparison of costs for the simulated scenarios in % in relation to design ④.

Source: own depiction.

Figure 7.4 sketches the change of the cost-related results when we introduce the market design to the current regulatory framework. While costs increase, the overall quantity being traded when paying grid fees decreases as Figures 7.2 and 7.4 show. With ④ Home Storage & Local Sharing as the benchmark for the overall costs we observe that introducing the current framework will increase costs for all—mostly for pure consumers. The local trade is only profitable at a price lower than the grid price. In the presence of all surcharges, levies, and grid fees, this results in a local market rate being lower than the electricity spot price. As the local rate is determined by the marginal production costs of a prosumer, only prosumers with a fully written-off installation will be able to supply cheaper than the grid—the quantity traded therefore decreases. From this, we can draw the following conclusions on the impact of the current regulatory framework on the market designs:

- The regulatory framework makes it unattractive for prosumers to trade locally when their marginal costs are higher than the electricity spot price.
- Under the framework, local trade is only economically viable for prosumers with fully written-off installations.
- Once more installations are written-off this model can become competitive under the current regulation if we disregard the administrative burden.

In order to adjust for these market designs, the regulation would need to undergo major changes to make it as attractive as argued by for example Lüth et al. (2018) and Mengelkamp et al. (2017). Any redesign of legislation needs a careful consideration of these trade-offs, not only in the German context. To our understanding, however, the presented market designs enlarge distributional effects between households with the financial and organizational means to invest into generation and/or storage technology and those with no access to these technologies due to their budget or the ownership structure of their housing, and we consequently propose an additional market design.

7.4.3 New Market Design: Tech4all

We extend the ⑤ Current Regulatory Framework by introducing an IPP with a production capacity of 100 kWp. This player can sell capacity shares of its production to consumers that neither own capacity nor a roof to install technology. In this proposed market design ❻ **Tech4all** with ***self-consumption, own storage, community sharing, and an independent power producer***, pure consumers now have obtained a right for self-production, which they can consume at a price $p_c^{mc} = p_o^{mc} + 0.4 \cdot p^{eeg} + p^{dso} + p^{tso} + p^{t\&d} + p^h$, taking into account a markup p^h at 1 ct/kWh for the technology owner as well as fees for grid use and extended self-consumption from installations larger than 10 kWp. Additionally, we reduce the EEG surcharge on local trading to only 40 % of its full value and now increase the price of consumption from storage discharge to $p_n^D = p_n^{sto} + 0.4 \cdot p^{eeg}$. A fraction of 40 % of the EEG surcharge is currently charged for residential technology and self-consumption from an installation larger than 10 kWp. Although local trading that is not remunerated by a feed-in tariff reduces the quantity that needs to be financed by this surcharge, the lower grid consumption also implies less inflows on the other side. To keep this mechanisms rather stable, we assume that all players continue on paying a share of the surcharge whenever the grid is used. The IPP sells its production either to its shareholders at $p_o^O = p_o^{mc} + p^h$ or for the electricity exchange price p_t^{eex} to the local balancing mechanism.

Excursion: Regulatory Framework in Germany

With the first version of the German Renewable Energy Sources Act (EEG) in 2000, Germany started a series of laws on prioritizing green energy in the electricity mix. Together with the Energy Industry Act (Energiewirtschaftsgesetz (EnWG)), the basic legal framework for the German electricity market is formed. [a] While the EEG handles mostly rules on renewable energy sources and their integration into the system, the EnWG defines also the regulatory framework for the overall energy—including the electricity—sector.

From a legal perspective, the prosumer is end-user (§ 3 Nr. 33 EEG) and auto-producer (§ 3 Nr. 19 EEG). As of today, regulation allows prosumers with a capacity of up to 100 kWp to feed their electricity into the network but exempts them from regulatory duties and rewards them at a rate determined by the Federal Network Agency (*BNetzA*) based on the overall installed capacity. The rate is transferred into consumers' electricity bills by adding a reallocation charge (*EEG-Umlage*) on top of each kWh consumed. Thus, end-users pay a surcharge which in turn is paid to prosumers and operators of renewable energy installations for each kWh they feed in.

If prosumers intend to bypass the fixed feed-in tariff and instead trade with a chosen, presumably locally circumjacent partner instead, they will need to perform some or all retailing duties depending on the prosumer's intention. The EnWG declares in principle every participant feeding electricity into the grid as an energy utility. Thus, parties making use of the grid by sending electricity through the network have to pay a grid fee and perform a set of bureaucratic duties. These duties comprise accounting, billing, reporting and metering tasks (Oppen, Streitmayer, and Huneke 2017). While grid fees are usually passed on to the customers' bills, these duties stay on the producers' list of tasks, and generally exceed the average prosumer's personal capacity of work load as the processes are matched with energy utilities' businesses (Oppen, Streitmayer, and Huneke 2017).

Aside from the fixed feed-in tariff, other existing business models are difficult to implement for prosumers with small capacities. On the one hand, responsibilities increase to a large extent once electricity is directly sold to another customer. On the other hand, the economic potential is fairly unattractive (Scheller et al. 2018). Appendix E.3 elaborates on the details.

It is noteworthy at this point that fixed feed-in rates phase out 20 years after installation and will—as of today—not be given to new installations once an aggregated capacity of 52 GW of installed solar power is reached in Germany, despite recent political discussions.

[a] There are about 90 other acts, directives and regulations on European and national level that affect Germany's energy supply system (BMWi 2017).

The results of the case study introducing ⑥ Tech4all show that we can counteract the redistribution of costs. Looking at the overall costs depicted in Figure 7.4, there is a decrease in costs compared to ⑤. Prosumers and prosumagers, however, face a slight increase in their costs compared to the benchmark ④ (but a decrease compared to ① today), while consumers can now also profit from self-consumption. In terms of taxes and duties, ⑥ Tech4all reduces the electricity going through the network compared to a design with only additional storage or today's feed in, but Figure 7.3 visualizes that ⑥ has a higher share of grid tariffs paid on a lower quantity procured. In this asymmetrical set-up of 12 prosumers and only two consumers, the observed effect on the grid charges is certainly only a small effect. We can nevertheless conclude that the introduction of an IPP and a rather small modification of current tariffs flattens the effect on avoiding grid charges. In addition, an IPP enables the possibility to have self-consumption for electricity end-users without access to an own roof or the liquidity to invest in the technology, and a small surcharge on battery discharge mitigates the large arbitrage potential through private storage. We summarize our results in the following points:

- Consumers are allowed to participate in the energy transition.
- Most participants can lower their costs compared to today's framework.
- The quantity financed by the EEG surcharge is lowered due to a separate rate for local trading.
- Players always pay full grid charges when the grid is used.

We see major advantages in sharing a large installation in a close spatial vicinity among community members instead of privately owning small installations as main economic concepts apply in this context. Economies of scale give more benefits to larger installations. A smaller number of players can reduce information asymmetry but also economics of coordination within the energy system. But not only economic concepts play a role here. From a societal perspective, public acceptance can rise in the presence of participation and private ownership (Tobiasson and Jamasb 2016) which could lead the IPP to being a form of *Bürgerenergiegenossenschaft* (citizen energy cooperative), a local legal entity representing regional interests and keeping the economic benefits close. Regulation would need to judiciously define the *close spacial vicinity* distinctly, for example as being grid connected in the same distribution grid/voltage level.

7.5 Conclusions

Recently proposed local electricity market designs allowing for battery storage and peer-to-peer trade are found to be profitable for energy communities under specific assumptions. The given regulatory framework in, for example, Germany diminishes, however, their profitability significantly. There are two pathways forward to realize the proposed market designs: either there has to be a major change in regulation to allow for the specific assumptions of the proposed designs to be implemented, or the market design needs to be adjusted to fit into the legal framework. For a German case study, we specifically show that under current regulation there is large arbitrage potential for prosumers with a storage entity but no incentive to locally trade electricity as marginal costs exceed wholesale prices while taxes and duties stay constant. A change in the regulatory framework bears the risk of distributional effects at the expense of pure electricity consumers due to very high self-consumption rates by prosumers (with storage) that avoid using the network. Thus, the overall fixed network costs need to be distributed among a lower grid consumption, mainly affecting pure consumers.

In order to counteract the elaborated trade-off, we suggest a new market design—*Tech4all*—that allows each market participant to benefit from the concept of energy communities. This is done through an IPP selling shares of a large local production facility, for example, a roof of a supermarket to end-users who do not have the financial or ownership means for installing distributed generation technologies. The quantity procured by the consumers is supplied through the distribution grid and purchased at a rate including all taxes and duties as well as marginal costs of production. In this market design, grid charges are proportional to today's share of fees paid and the system is profitable for new installations. The characteristics of the presented MCP model facilitate the modification of existing market design proposals towards heterogeneous categories of players with own objectives and constraints.

For a market implementation of this design in Germany, regulation needs to allow for self-consumption in a larger spatial context as well as define rules on the purchase of shares of a larger installation, ownership rights, the taxes and duties paid on this electricity and the rights of the IPP. We outline that concepts of economics favor a more centralized solution. Our numerical results based on the German tariff structure support a centralized approach as in particular battery storage devices lead to a redistribution of social costs. Mathiesen et al. (2017) find a similar result in a study on the solar potential in the Danish context.

In further studies, the proposed market design needs to be tested with a larger and more representative data set as well as a greater variety of market participants. It needs to be embedded in the larger power system in order to capture changes in tax and duty revenues for the whole system or sensitivities thereof. The effect of our assumption that excess production is curtailed instead of made available to the system needs to be critically assessed and the market design should be adjusted such that those quantities support the system in a profitable way for all participants. The MCP allows for the introduction of additional players that could represent a business provider for a local sharing mechanism in order to fully analyze the impact of all associated features.

Part IV

Appendix

Appendix A

Appendix to Chapter 3

A.1 Chapter 3: Description of Used Symbols

A.1.1 Sets

Table A.1: Model sets.

Set	Description
l	transmission network lines
n/nn	transmission network nodes
p	power plant blocks
$phes$	pumped hydroelectric storages
s	renewable generation technologies
t	time steps

A.1.2 Parameters

Table A.2: Model parameters.

Parameter	Description
$\overline{gsto}_{phes}$	maximum generation/pumping capacity of PHES
$\overline{g}_p$	installed conventional capacity
$\overline{lsto}_{phes}$	maximum PHES energy content
$\overline{pf}_l$	power flow limit
$\overline{r}_{n,s}$	installed renewable capacity
$\theta_{n,t}$	voltage angle
$avag_{p,t}$	availability of conventional capacity
$avar_{n,s,t}$	availability of renewable capacity
$b_{n,nn}$	network susceptance matrix
$d_{n,t}$	electricity demand
eff_{phes}	efficiency of a PHES
$ex_{n,t}$	exchange with electrical neighbors
$h_{l,n}$	flow sensitivity matrix
$vc_{p,t}$	variable generation cost

A.1.3 Variables

Table A.3: Model variables.

Variable	Description
$G_{p,t}$	generation from conventional power plant block
$PF_{l,t}$	power flow on a transmission line
$phesD_{phes,t}$	demand from a PHES
$phesG_{phes,t}$	generation from a PHES
$phesLevel_{phes,t}$	storage filling level of a PHES
$R_{n,s,t}$	generation from renewable energy source
$\theta_{n,t}$	voltage angle

A.2 Chapter 3: Input Data

A.2.1 Generation

Table A.4: Installed conventional and renewable generation capacity by fuel/technology.

Fuel	Installed capacity [MW_{el}]	Renewable technology	Installed capacity [MW_{el}]
Nuclear	12,075	Run-of-river hydro	3,700
Lignite	20,901	Wind onshore	41,242
Hard coal	28,571	Wind offshore	3,263
Natural gas	23,625	Solar PV	39,332
Oil	3,675	Biomass	6,900
Waste	1,631	Geothermal	33
Other fuels	2,466		
Pumped storage	8,789		
Total	101,732	Total	94,312

Source: Kunz et al. (2017a).

Table A.5: Annual fuel cost data for 2015 and carbon intensity.

	Fuel costs		**Carbon factor**	
	[€/t SKE]	[€/MWh_{th}]	[t CO_2/MWh_{th}]	[€/MWh_{th}]
Uranium	-	3.00	-	
Lignite	-	3.10	0.399	3.03
Hard coal	68.00	8.35	0.337	2.56
Natural gas	185.00	22.73	0.201	1.53
Fuel oil (light)	373.00	45.82	0.266	2.02
Fuel oil (heavy)	180.00	22.11	0.293	2.22
Emission allowances	€ 7.59 per t CO_2			

Source: Kunz et al. (2017a).

A.2.2 Transmission Network

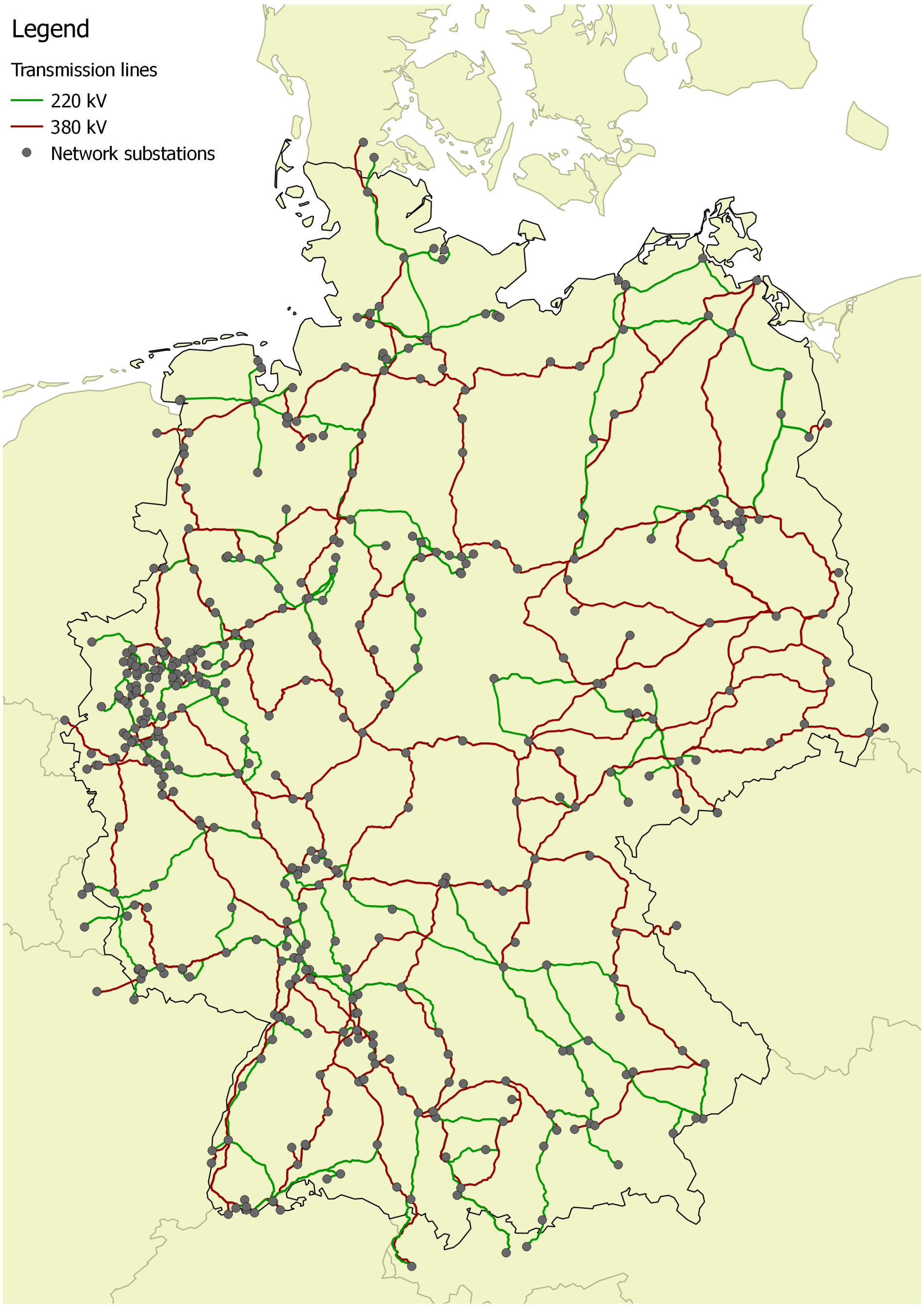

Figure A.1: The German high voltage transmission network (nodes & lines).

Source: Kunz et al. 2017a

Appendix B

Appendix to Chapter 4

B.1 Chapter 4: Nomenclature

Table B.1: Nomenclature.

Indices and Sets		
$e \in E$		pumped-storage hydroelectric plants
$l \in L$		transmission lines in the network
$n, k \in N$		nodes in the network
$p \in P$		power plant blocks
$s \in S$		renewable technologies
$t \in T$		Hours
$z, y \in Z$		price zones
Parameters		
$AVG_{p,t}$		hourly availability of conventional units
$AVR_{n,s,t}$		hourly availability of renewable generation
$B_{n,k}$	1/Ω	network susceptance matrix
C_p	€/MWh	variable generation costs
$EX_{n,t}$	MW	cross-border export flow
$\overline{G}_{p,t}$	MW	maximum conventional generation capacity
$g^0_{p,t}$	MW	result for conventional generation in spot market model
$H_{l,n}$	1/Ω	Network transfer matrix
$IM_{n,t}$	MW	cross-border import flow
$\overline{LS}_e$	MWh	maximum energy storage of pumped-storage plant
$\overline{NTC}_{z,y}$	MW	maximum net transfer capacity (NTC)
$\overline{P}_l$	MW	maximum power flow on transmission line
$\overline{PS}_e$	MW	maximum turbine capacity of pumped-storage plant
$ps^0_{e,t}$	MW	result for pumped-storage operation in spot market model
$Q_{n,t}$	MW	electricity load
$\overline{R}_{n,s}$	MW	maximum renewable generation capacity
$r^0_{n,s,t}$	MW	result for renewable generation in spot market model

Nomenclature (continued).

Variables		
$costs^{rd}$	€	re-dispatch costs of the re-dispatch model
$costs^{sp}$	€	dispatch costs of the spot market model
$\theta_{n,t}$		phase angle difference in respect to slack bus
$ni_{n,t}$	MW	net grid input
$pf_{l,t}$	MW	power flow
$pz_{z,y,t}$	MW	cross-zonal trade flows in spot market model
Positive Variables		
$g_{p,t}$	MW	conventional generation in spot market model
$g^{+}_{p,t}$	MW	ramped up conventional generation in re-dispatch model
$g^{-}_{p,t}$	MW	ramped down conventional generation in re-dispatch model
$\overrightarrow{ps}_{e,t}$	MW	pumped-storage generation in spot market model
$\overleftarrow{ps}_{e,t}$	MW	pumped-storage pumping in spot market model
$pslevel_{e,t}$	MWh	pumped-storage energy content in spot market model
$r_{n,s,t}$	MW	renewable generation in spot market model
$r^{-}_{n,s,t}$	MW	ramped down renewable generation in re-dispatch model

B.2 Chapter 4: Additional Figures on Results

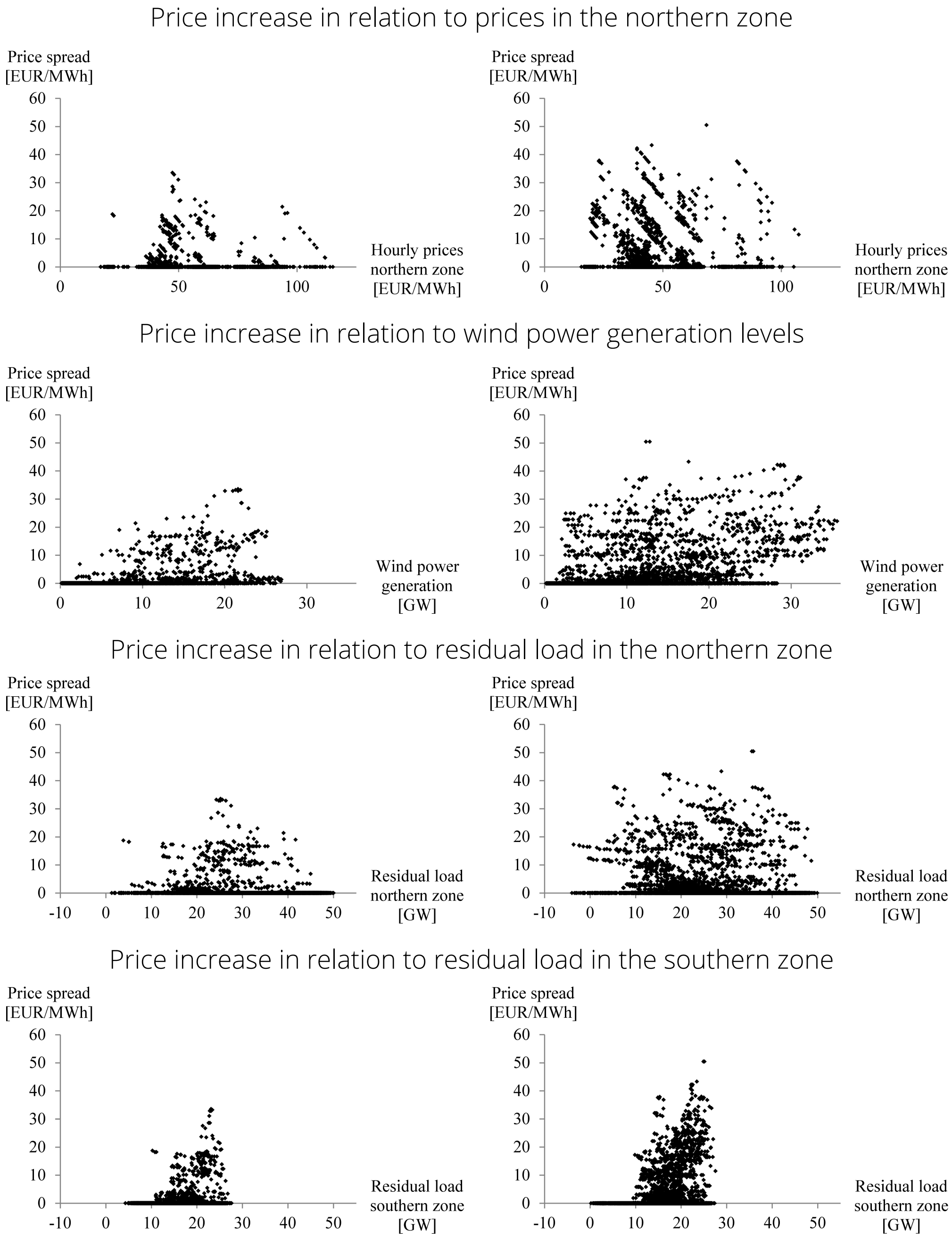

Figure B.1: Panel with hourly data on the increase of zonal spot prices in the southern zone compared to the northern zone for different indicators in 2012 (left) and 2015 (right)

Appendix C

Appendix to Chapter 5

C.1 Chapter 5: Data

The calculations of stELMOD are based on a data set that comprises information for the year 2012. This data set approximates the actual electricity system in Germany, relying on the open-source data set described in Egerer (2016) and Kunz et al. (2017a), solely using publicly accessible data sources.[1] It comprises the topology and technical characteristics of the German AC transmission network, connecting a detailed representation of 594 thermal generation plant blocks distributed over 438 network nodes. Each node in the data set has specified shares of demand and installed renewable energy capacities. Furthermore, the data set lists data on fuel and carbon prices, net exports to neighboring countries at a nodal level, characteristics and availability of included generation technologies, and an hourly load profile that is scaled to meet annual statistics. Cost data for fuel costs, carbon costs, and start-up costs was derived from those literature values based on the carbon content of the used fuel, the efficiency of the used technology, and the age of the generation unit. In order to account for alterations, especially with respect to the increasing employment of RES, the relevant parts of the data base were updated to the year 2016. These adjustments comprise the time horizon, installed capacities, as well as time series of RES infeed, and are described in the following sections.

C.1.1 Time Horizon and Demand Structure

For a comprehensive evaluation of the effects of seasonality, the original time horizon of one week was extended in this paper to four non-consecutive weeks. Due to inherent seasonal differences of the power output of PV (see Section 1.3.3), the selected weeks are the first week of a quarter, respectively. Due to an initialization process of the model and possible contortions at the end of calculation, for each week nine days are computed of which the first and the last day are not evaluated. Accordingly, the time frame effectively covers the 2^{nd} to 8^{th} days of the months of January, April, July, and October. Thereby, different amounts of PV generation as well as diverse error structures are incorporated into the examination. Moreover, the huge computational runtime of the model limits the analysis to sole weeks in this paper's framework. Each week is solved separately. In the future, novel linearization methods of the unit commitment model formulations as, for example, proposed by Han et al. (2019) could be of use.

[1] Data sources include ENTSO-E, the four German Transmission System Operators, and the German federal regulatory agency BNetzA. A detailed description of the used data sets can be found in Schröder et al. (2013), Egerer et al. (2014), and Kunz et al. (2017a).

The demand structure is considered to be inelastic, assuming no strong variation over the last years. Thus, the demand profile remains the same as in the original data base. However, it was adjusted to the weeks for the examination in order to fit the seasonal patterns. Uncertainty of electrical load is explicitly not taken into account in this work to solely assess the impact of uncertain PV generation. Further research should include stochasticity of load patterns to more comprehensively evaluate the impact of uncertainties on system operations.

C.1.2 Installed Capacities of Renewable Energy Plants

Due to an extensive growth of RES over the last year (UBA 2018), the installed capacities were adjusted to the levels of 2016. The growth of RES is depicted in Table C.1 and compared to the values assumed in the original data setting.

Table C.1: Comparison of installed capacities of RES in original and updated data base of stELMOD.

RES	**original data base** [GW]	**updated data base** [GW]
Wind onshore	30.406	45.510
Wind offshore	0.388	4.130
Solar PV	28.843	40.850
Biomass	6.377	7.060
Hydro	3.350	5.590
Geothermal	0.019	0.041

Source: based on Abrell and Kunz (2015) and data from AGEE, BMWi, and Bundesnetzagentur

The growth rate of the installed capacities of wind onshore, wind offshore and solar PV were particularly high over the last years, leading to more uncertainty in the system and hence to higher absolute error terms.

The installed capacities of conventional power plants are assumed to remain unchanged to the original setting based on Egerer (2016) and incorporates conventional power plants on a nodal level. Nine types of thermal power plants that vary in generation technology and used fuel type, namely nuclear, lignite, hard coal, OCGT, OCOT, CCGT, combined cycle oil turbines (CCOT), as well as gas and oil steam turbines, are incorporated. Moreover, three hydro based technologies are included in the model for either generation or storage: RoR, hydro reservoirs and PSP. Refer to Abrell and Kunz (2015) for a more detailed documentation on the data of conventional plants.

C.1.3 Time Series for Wind and Photovoltaic Generation

The time series of wind and PV generation were updated to 2016 values. These comprise the hourly forecasts and actual realizations. The profile of these time series is based on values derived from the German TSOs for their respective control area. The data set used for the year 2016 was derived from 50Hertz, Kennzahlen (online)[2]; TransnetBW, Marktdaten und Kennzahlen (online)[3]; Amprion, Grid-Data (online)[4]; TenneT, Network Figures (online)[5]. Accordingly, the data is aggregated to country level and arithmetically averaged to hourly data as some time series profiles were provided in a resolution of 15 minutes. The time series for the actual and day-ahead forecasted wind and photovoltaic infeed are subsequently processed to relative values by dividing each element by the respective installed capacity.

[2] www.50hertz.com/de/Kennzahlen
[3] www.transnetbw.de/de/transparenz/marktdaten/kennzahlen
[4] www.amprion.net/Grid-Data
[5] www.tennettso.de/site/en/Transparency/publications/network-figures/overview

Appendix D

Appendix to Chapter 6

D.1 Chapter 6: Nomenclature

Table D.1: Nomenclature.

Indices and Sets		
$c \in \mathcal{C}$		Set of countries
$z \in \mathcal{Z}$		Set of zones/regions
$h \in \mathcal{H}$		Set of hours
$w \in \mathcal{W}$		Set of seasons
$t \in \mathcal{T}$		Set of technologies
$t \in \mathcal{T}_{\mathcal{D}} \subseteq \mathcal{T}$		Subset of dispatchable technologies
$t \in \mathcal{T}_{\mathcal{N}} \subseteq \mathcal{T}$		Subset of non-dispatchable technologies
$t \in \mathcal{T}_{\mathcal{S}} \subseteq \mathcal{T}$		Subset of storage technologies
$l \in \mathcal{L}$		Set of transmission lines
Parameters		
c_t^p	€/MWh	Investment cost for generation technologies
c_t^{ch}	€/MWh	Investment cost for charging technologies
c_t^e	€/MWh	Investment cost for storage technologies
c_t^{mc}	€/MWh	Marginal generation cost for generation technologies
c^{ll}	€/MWh	Penalty cost for lost load
$load_{z,h}$	MW	Load in MW
$p_{t,z}^{max,inst}$	MW	Maximum installed generation power
$p_{t,c}^{max,gen}$	MWh	Maximum provided energy per year
$e_{t,z}^{max,inst}$	MWh	Maximum installed storage capacity
$\zeta_{t,z,h}$		Availability factor for non-dispatchable technologies
ρ_t		Self-discharge rate of storage
η_t^{ch}		Storage charge efficiency
η_t^{dch}		Storage discharge efficiency
f_l^{max}	MW	Thermal limit of AC line
$f_{z,zz}^{max}$	MW	Thermal limit of DC line
$ptdf_{l,z}$		Power transfer distribution factor matrix
γ		Scaling factors for reduced time horizon in one year
ϕ		Autarky factor

Nomenclature (continued).

Variables		
$P_{t,z}^{inst}$	MW	Installed generation power
$P_{t,z,h}^{ch}$	MW	Storage charge power
$E_{t,z}^{inst}$	MWh	Installed storage capacity
$G_{t,z,h}^{gen}$	MW	Generation power
$LL_{z,h}$	MW	Lost load
$G_{t,z}^{ch,w}$	MW	Storage charge for first hour of a season
$G_{t,z}^{dch,w}$	MW	Storage discharge for first hour of a season
$E_{t,z,h}^{soc,h}$	MWh	Storage hourly state of charge
$E_{t,z,w}^{soc,w}$	MWh	Storage seasonal state of charge
$F_{z,zz}^{dc}$	MW	Flow on DC lines from zone z
$F_{zz,z}^{dc}$	MW	Flow on DC lines to zone z
$F_{z,h}^{ni}$	MW	Net input

D.2 Chapter 6: Model Nodes

Table D.2: List of NUTS2 area codes for Germany.

Code	Region	Code	Region
DE11	Stuttgart	DE91	Braunschweig
DE12	Karlsruhe	DE92	Hannover
DE13	Freiburg	DE93	Lüneburg
DE14	Tübingen	DE94	Weser-Ems
DE21	Oberbayern	DEA1	Düsseldorf
DE22	Niederbayern	DEA2	Köln
DE23	Oberpfalz	DEA3	Münster
DE24	Oberfranken	DEA4	Detmold
DE25	Mittelfranken	DEA5	Arnsberg
DE25	Unterfranken	DEB1	Koblenz
DE27	Schwaben	DEB2	Trier
DE30	Berlin	DEB3	Rheinhessen-Pfalz
DE40	Brandenburg	DEC0	Saarland
DE50	Bremen	DED2	Dresden
DE60	Hamburg	DED4	Chemnitz
DE71	Darmstadt	DED5	Leipzig
DE72	Gießen	DEE0	Sachsen-Anhalt
DE73	Kassel	DEF0	Schleswig-Holstein
DE80	Mecklenburg-Vorpommern	DEG0	Thüringen

Appendix E

Appendix to Chapter 7

E.1 Chapter 7: Karush-Kuhn-Tucker Conditions

The following equations describe the Karush-Kuhn-Tucker conditions (KKTs) for the presented problem. The following three sections show the implemented KKTs for the prosumers, consumers, and independent power producer. For the sake of completeness, we add a fourth section recalling the local balancing mechanism.

E.1.1 The Prosumer's Problem

$$0 \leq p_n^{mc} - P_{n,t}^N + \lambda_{n,t}^{res} \qquad \perp R_{n,t} \geq 0, \qquad \forall n,t \tag{E.1}$$
$$0 \leq p^G - P_{n,t}^N \qquad \perp G_{n,t} \geq 0, \qquad \forall n,t \tag{E.2}$$
$$0 \leq P_t^{LBM} + p^I - P_{n,t}^N \qquad \perp I_{n,t} \geq 0, \qquad \forall n,t \tag{E.3}$$
$$0 \leq p_n^{mc} - P_t^{LBM} + \lambda_{n,t}^{res} \qquad \perp X_{n,t} \geq 0, \qquad \forall n,t \tag{E.4}$$
$$0 \leq p_n^{mc} - p_n^{fit} + \lambda_{n,t}^{res} \qquad \perp F_{n,t} \geq 0, \qquad \forall n,t \tag{E.5}$$
$$0 \leq p_n^{mc} + \lambda_{n,t}^{res} + \eta \cdot P_{n,t}^S + \lambda_{n,t}^{\alpha} \qquad \perp S_{n,t}^C \geq 0, \qquad \forall n,t \tag{E.6}$$
$$0 \leq p_n^D - P_{n,t}^N - P_{n,t}^S + \lambda_{n,t}^{\beta} \qquad \perp S_{n,t}^D \geq 0, \qquad \forall n,t \tag{E.7}$$
$$0 \leq -P_{n,t}^S + P_{n,t+1}^S - \lambda_{n,t}^{\underline{s}} + \lambda_{n,t}^{\overline{s}} \qquad \perp S_{n,t} \geq 0, \qquad \forall n,t \tag{E.8}$$
$$0 = dem_{n,t} - R_{n,t} - G_{n,t} - I_{n,t} - S_{n,t}^D \qquad ,P_{n,t}^N \in \mathbb{R} \qquad \forall n,t \tag{E.9}$$
$$0 \leq res_{n,p} - R_{n,t} - X_{n,t} - F_{n,t} - S_{n,t}^C \qquad \perp \lambda_{n,t}^{res} \geq 0 \qquad \forall n,t \tag{E.10}$$
$$0 = S_{n,t-1} - S_{n,t} + \eta \cdot S_{n,t}^C - S_{n,t}^D \qquad ,P_{n,t}^S \in \mathbb{R} \qquad \forall n,t \tag{E.11}$$
$$0 \leq S_{n,t} - \underline{s}_n \qquad \perp \lambda_{n,t}^{\underline{s}} \geq 0 \qquad \forall n,t \tag{E.12}$$
$$0 \leq \overline{s}_n - S_{n,t} \qquad \perp \lambda_{n,t}^{\overline{s}} \geq 0 \qquad \forall n,t \tag{E.13}$$
$$0 \leq \alpha_n - S_{n,t}^C \qquad \perp \lambda_{n,t}^{\alpha} \geq 0 \qquad \forall n,t \tag{E.14}$$
$$0 \leq \beta_n - S_{n,t}^D \qquad \perp \lambda_{n,t}^{\beta} \geq 0 \qquad \forall n,t \tag{E.15}$$

E.1.2 The Consumer's Problem

$$0 \leq p_c^{mc} - P_{c,t}^N + \lambda_{c,t}^{res} \qquad \perp R_{c,t} \geq 0, \qquad \forall c,t \tag{E.16}$$
$$0 \leq p^G - P_{c,t}^N \qquad \perp G_{c,t} \geq 0, \qquad \forall c,t \tag{E.17}$$
$$0 \leq P_t^{LBM} + p^I - P_{c,t}^N \qquad \perp I_{c,t} \geq 0, \qquad \forall c,t \tag{E.18}$$
$$0 = dem_{c,t} - R_{c,t} - G_{c,t} - I_{c,t} \qquad ,P_{c,t}^N \in \mathbb{R} \qquad \forall c,t \tag{E.19}$$
$$0 \leq res_{c,t} - R_{c,t} \qquad \perp \lambda_{c,t}^{res} \geq 0 \qquad \forall c,t \tag{E.20}$$

E.1.3 The Independent Power Producer's Problem

$$0 \leq p_o^{mc} - P_t^{LBM} + \lambda_{o,t}^{res} \qquad \perp X_{o,t} \geq 0, \qquad \forall\, o,t \qquad \text{(E.21)}$$

$$0 \leq res_{o,t} - X_{o,t} - \sum_c R_{c,t} \qquad \perp \lambda_{o,t}^{res} \geq 0 \qquad \forall\, o,t \qquad \text{(E.22)}$$

E.1.4 Local Balancing Mechanism

$$0 = \sum_n X_{n,t} + \sum_c X_{o,t} - \sum_n I_{n,t} - \sum_o I_{c,t} \qquad ,P_t^{LBM} \in \mathbb{R} \qquad \forall\, t \qquad \text{(E.23)}$$

E.2 Chapter 7: Data

This section describes more details on the data for the case study of a German prosumer community. Table E.1 provides an overview of all players' data, comprising demand, production, specifications of the installed technologies and cost characteristics. Figure E.1 visualizes the magnitude of each players' characteristics in relation to others within the community.

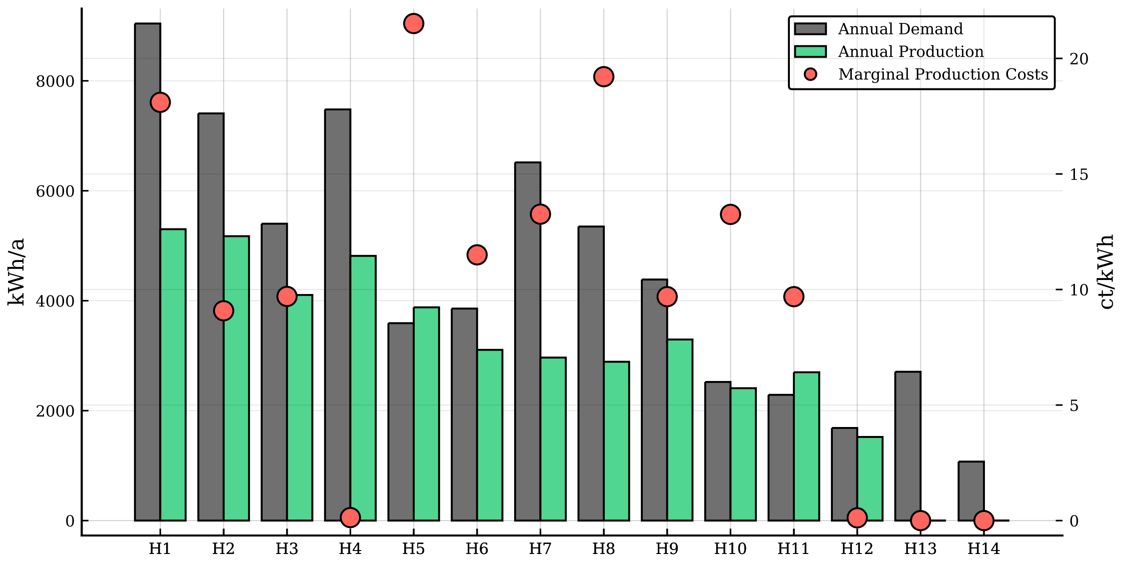

Figure E.1: Overview of model community.

Source: own depiction.

Hourly data sets for the production patterns of renewable energy sources (i.e. wind and solar) were retrieved from *renewables.ninja*[1] for the year 2018. This platform provides the converted power output of decentralized energy resources based on wind speed and solar irradiation data from the MERRA-2 database. The power output of the small-scale wind turbine has been calculated for a hub height of 15 meters; the solar panels of the 12 rooftop installations are assumed to be facing southward at an ideal 35 degree tilt.

The demand data originates from the *London Low Carbon* project[2] that digitally monitored 6,600 households and gathered residential consumption data subject to different tariff structures over the years 2011 – 2014 in a resolution of 30 minutes. The demand time series of the 14 different households considered in this study were retrieved from that database for the year 2012 and subsequently processed to hourly values.

Existing distributed generation portfolios of the households were downloaded from the *MaStR* provided by the Federal Network Agency. From this register, both the installed capacity and the year of installation of the distributed energy resources were retrieved in order to compute the specific marginal costs of production of each household. For the calculation of these marginal costs of production, we use the concept of the LCOE (Brown, Poudineh, and Foley 2015; Tegen et al. 2012) as shown in Equation (E.24):

$$LCOE_h = \frac{I_0 \cdot ANF + OM}{M} \tag{E.24}$$

where ANF is the annuity factor

$$ANF = \frac{i \cdot (1+i)^T}{(1+i)^T - 1}. \tag{E.25}$$

Investment costs I_0 are discounted by the annuity factor ANF and added to yearly operations and maintenance costs OM which are estimated to be approximately 2.5 % of I_0 (Fraunhofer ISE 2018). This sum is divided by annual production M of the system. The annuity factor ANF is calculated by the interest rate i over a system's lifetime T.

Data on investment costs have been obtained from *BSW Solar*[3]. Each installation in the MaStR that is located in *Grevesmühlen* is assigned its marginal production cost and fixed feed-in tariff based on the date of installation that is recorded in the register. Interest rate is assumed to be 5 % and lifetime is assumed to be 25 years. The same calculation of levelized costs of storage (LCOS) is used to determine the discharge price p_n^D for the two

[1] see www.renewables.ninja or (Staffell and Pfenninger 2016; Pfenninger and Staffell 2016)

[2] for further information, see data.london.gov.uk/dataset/smartmeter-energy-use-data-in-london-households

[3] see www.solarwirtschaft.de

types of batteries with investment costs of € 400 per kWh (Cole and Frazier 2019), a lifetime of 20 years, and 3,300 and 4,400 operating hours per year, respectively.

For the independent power producer, the marginal costs of production are taken from a report by Fraunhofer ISE (2018) at a value of $p_o^{mc} = 5.4$ ct/kWh. The introduced markup for the operator is estimated from the difference between the marginal production costs and the current feed-in premium resulting in $p^h = 1$ ct/kWh. The two consumers buy access to a proportion of 2 kWp (2 %) and 1 kWp (1 %) of the installation. The marginal production costs for these houses add up to 24.77 ct/kWh.

Table E.1: Data for each household in the model community.

player	annual demand [kWh]	annual production [kWh]	type	installed capacity [kWp]	year of installation	feed-in tariff [ct/kWh]	marginal prod. cost [ct/kWh]	storage capacity [kWh]
H1	9043	5301	Wind	2.00	2011	8.97	18.10	6
H2	7408	5174	PV	4.08	2019	11.11	9.08	4
H3	5401	4104	PV	3.24	2017	12.20	9.70	4
H4	7480	4816	PV	3.80	2006	—	0.13	4
H5	3592	3880	PV	3.06	2010	33.03	21.51	4
H6	3857	3106	PV	2.45	2015	12.47	11.50	—
H7	6516	2966	PV	2.34	2012	24.43	13.26	—
H8	5350	2890	PV	2.28	2011	28.74	19.21	—
H9	4386	3294	PV	2.60	2017	12.30	9.69	—
H10	2522	2409	PV	1.90	2012	24.43	13.25	—
H11	2288	2698	PV	2.13	2017	12.20	9.69	—
H12	1685	1521	PV	1.20	2004	—	0.12	—
H13	2708	0/ 208	—	–/ 2.00	—	—	–/25.77	—
H14	1073	0/ 104	—	–/ 1.10	—	—	–/25.77	—
IPP	0	0/10,419	PV	–/100.00	—	—	–/ 5.40	—
Sum	63,308	40,288/50,707	—	31.08/131.08	—	—	—	22

The price end-users pay as customers of the *Stadtwerke Grevesmühlen* amounts to a yearly base fee of € 114.24 plus a kilowatt-hour rate of 28.73 ct/kWh in the basic tariff.[4] The working price includes the spot price of electricity, the network tariffs, the EEG reallocation charge as well as other taxes and duties such as electricity and value added taxes. Unfortunately, the exact splitting of the working price in *Grevesmühlen* into its components is not made publicly available, which is why averages for German households need to be considered. Specifically, the average prices and shares for German households from data

[4]Please refer to www.stadtwerke-gvm.de/de/produkte-leistungen/strom.html for more information.

processing of the *BMWi* were taken into account within this case study[5].

The network tariff amounts in the region of *Grevesmühlen* in 2018 to net 7.51 ct/kWh, of which 3.73 ct/kWh is due to the distribution network and 3.78 ct/kWh to higher voltage levels.[6] These dues are higher than the German average as the electricity network in the eastern part of Germany is relatively new compared to other parts. However, in consistence to the above shares of average household customers in Germany, the network tariffs are scaled according to the data of the BMWi. For this paper, the distribution and transmission network charges amount to 3.48 ct/kWh and 3.44 ct/kWh, respectively. The EEG reallocation charge is 6.52 ct/kWh, the spot price of electricity 6.44 ct/kWh, and all other taxes and duties amount to 8.85 ct/kWh. See Table 7.2 for an overview.

The battery sizes in common applications vary quite significantly. While small-scale batteries at residential level often do not exceed a 10 kWh installed capacity, the sizes of batteries at farms or companies often outreach hundreds of kWh. For the purpose at hand, the battery systems have an installed capacity of 4 kWh and 6 kWh with a charge and discharge power of 2.5 kW and 3.0 kW, respectively. The round-trip efficiency of the batteries is 94.08 %, including losses both for the conversion and storing processes. For the purpose of this case study we assume the households to own battery storage devices of the type sonnenBatterie eco 8.0.[7]

E.3 Chapter 7: Business Cases for Consumers and Prosumers

As of today's regulation, a prosumer can follow different paths to sell/use self-produced electricity, but not all of them are equally economically and temporally viable. Generally, regulation foresees a single way for prosumers and consumers to purchase electricity from a public grid while there are different options for prosumers to sell their electricity. Scheller et al. (2018) give an overview of the models. Table E.3 summarizes the regulations affecting each model.

[5] see www.bmwi.de/Redaktion/DE/Infografiken/Energie/strompreise.html

[6] Details on the network tariffs for the year 2018 in the region of *Grevesmühlen* can be found at www.e-dis-netz.de/content/dam/revu-global/e-dis-netz/dokumente/Preisblaetter_Netzentgelte_Strom_20180101.pdf.

[7] See sonnenbatterie.de/sites/default/files/datenblatt_sonnenbatterie_eco_8.0_dach_1.pdf for details on the technical specifications, which are summarized in Table E.2.

Table E.2: Technical characteristics of battery storage devices.

	sonnenBatterie	
	eco 8.0/4	eco 8.0/6
usable battery capacity [kWh]	4	6
max. efficiency battery	98 %	
max. efficiency inverter	96 %	
max. charge rate α [kW]	2.5	3.0
max. discharge rate β [kW]	2.5	3.0
investment costs I_0 [EUR/kWh]	400	
lifetime [years]	20	
operating hours per year	3,300	4,400
discharge price [ct/kWh]	1.21	1.36

Source: sonnen GmbH and own estimations.

E.3.1 Electricity consumption

For a pure consumer, electricity can only be procured from an **electricity supplier**. The costs of electricity offered by an electricity supplier consist of several cost components which add up to about 30 ct/kWh. Production, marketing and sales make up about 30 % of the overall costs. All other costs arise when a kWh of electricity is fed into the grid, but they are directly transferred to the consumer. Prosumers will generally have a contract with an electricity supplier, but they will also make use of the model of **self-consumption (Eigenversorgung)**. In general, it describes the self-consumption of self-produced electricity from the owned technology. It is defined in EEG § 3 Nr. 19.

A prosumer will, thus, be confronted with costs amounting to his levelized cost of electricity plus EEG surcharge and value added tax. As there is no use of a public grid, grid related fees and surcharges are not applicable. Certain legal definitions can also lead to lower (40 %) or no EEG charge in the case of installations smaller than 10 kWp with a production of less than 10,000 kWh per year (de minimis rule), see § 61 EEG 2017. Furthermore, self-consumption is exempted from electricity tax (§ 9 StromStG) and in some cases also from the value added tax (§ 19 UStG or non-entrepreneurial activity).

E.3.2 Electricity production

Prosumers often face periods of excess generation and could potentially sell this quantity to others. Although there are different business models that allow prosumers to sell their electricity, practice has shown that mainly one model is economically viable for small-scale household prosumers: **Feed-in remuneration (Einspeisevergütung)** according to § 21 EEG is today's most common way for a prosumer to receive compensation for delivered quantity. Excess generation is fed into the grid and rewarded at a fixed rate which is determined by the BNetzA and paid by the distribution grid operator. This fixed rate is split from the EEG surcharge that consumers pay with each kWh purchased from the grid. The level of feed-in tariffs is based on the year of the technology's installation, decreasing over time as the number of renewable installations grows. The remuneration is guaranteed for the year of installation and the following 20 years (§ 25 EEG).

Larger prosumers with more than 100 kWp installed capacity are obliged to take part in the model of **direct marketing (Direktvermarktung)** (§ 21 EEG). The owner of the distributed resource passes the right to sell his production on the electricity exchange to an aggregator. The quantity sold at the exchange is rewarded with the exchange market price plus a market premium from the EEG surcharge for all electricity that has been sold (§ 20 (1) No. 1). Legal definition of direct marketing is given in § 3 No. 16 and describes sales to a third party using the grid.

Another option to sell electricity follows the model of **direct supply (Direktlieferung)** (§ 3 No. 16 and § 21b (4) EEG 2017). This model differs from direct marketing as the main grid cannot be used and spatial context has to be given. This spatial context is legally defined as a 4.5 km radius around the place of generation. The rate at which electricity is sold depends on the bid and is no longer supported by the market premium. In addition to the bid, the EEG surcharge and value added tax (19 %) have to be added to the consumption price. In a context of a community with a public grid, this model is not feasible in the current regulatory framework.

Another model, which is linked to selling electricity in a spatial context, is called **direct consumption (Mieterstrom)**. This model assumes that self-consumption involves not only the installation's owner but also tenants within a residential building with, for example, rooftop PV. The owner is then allowed to sell the generated electricity within the building. The Mieterstromgesetz came into force to define all legal characteristics.

Table E.3: Overview on the German regulatory framework for prosumers.

	Self-Consumption	Direct Supply	Direct Marketing
Tax/Levy	§ 5 (1) StromStG: tax payment for electricity from the public grid § 9 (1) StromStG: exemption for installations <2 MW used for self-consumption § 61 (1) EEG: payment of EEG levy § 61 a, b EEG: exemption or reduction to 40 % of EEG levy possible	§ 2 (3) StromStG: obligation to disclose as *small utility* § 4 StromStG: request at the main Customs Office § 5 StromStG: supplier is subject to taxation § 60 EEG: full payment of EEG levy No exemption from fiscal coverage/supply obligations	Prosumer becomes energy utility – obligations are similar to direct supply Direct marketing can only be realized with the help of a service provider: Taxes, levy, reporting and notification duties as well as responsibilities are similar to self-supply, i.e. registration obligations to network operators and authorities, maintenance and repair work/costs Additional contractual obligations between the prosumer and the service provider who assumes the responsibilities of the energy supplier (GTC and contractual services)
Reporting andnotification duties	§ 6 EEG: registration of installation § 62b EEG: definition of production quantities § 71 EEG: reporting obligations to DSO: billing and tax exemption § 74a EEG: reporting obligations lapse from § 74a (1) S.3 for PV up to 7 kW and other installations to 1 kW § 76 EEG: reporting to BNetzA might be necessary	§ 5 EnWG: Notification requirements towards BNetzA § 6 EEG: registration of installation § 74 EEG: reporting obligations to from § 61i, and annual statements § 75 EEG: Auditing § 76 EEG: Information to be provided to the Federal Network Agency § 4 (6) StromStG: reporting of tax exemptions to main customs office	
Responsibilities	*Energiesammelgesetz*: formal requirements of DSOs for reporting are to be respected Prosumer has obligation to stay informed	Obligation for utilities to report quantities to main customs office; applies for self-consumed and direct supply § 4 StromNZV: designation of balancing group pursuant	
Payment entitlements	§ 19 EEG: entitled to claim 1. feed-in tariff/market premium from § 21 (1) and (2) EEG 2. surcharge from tenant electricity law § 21 (3) EEG	§ 41 EnWG: Utilities need to conclude contracts for retail sale with customers (in conjunction with § 40, 42 EnWG)	Payment entitlements and obligations to service providers in accordance with contractual agreements

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Modeling an Integrated Energy Transformation of the Electricity Sector

This thesis addresses research questions and implications in the context of the German and European energy transformation and is comprised of three parts:
Part I starts with a chapter providing an introduction to the topic. Chapter 2 then focuses on the topic of „sector coupling“ and the technical and economic challenges of coupling electricity, heat, and transportation, in order to further transform towards a system relying on renewables instead of fossil and fissil fuels as a primary source of energy.
Part II deals with economic dispatch modeling. In Chapter 3, a five-fold approach to open science is introduced and the advantages of open energy models are being discussed. A fully open-source bottom-up electricity sector model with high spatial resolution using the Julia programming environment is then developed describing source code and a data set for Germany. Chapter 4 examines the ongoing discussion about potential effects of introducing bidding zones in Germany. An electricity sector model with network representation is applied to analyze the system implications and the distributional effects of two bidding zones in the German electricity system. Chapter 5 investigates the impact of uncertain photovoltaic generation on unit commitment decisions. This is done for a market following the rolling planning procedure employing a large-scale stochastic electricity market model. A novel approach to simulate a time-adaptive intra-day photovoltaic forecast, solely based on an exponential smoothing of deviations between realized and forecast values, is presented.
Part III shifts the focus to issues of the decentral energy transformation. In Chapter 6, the interdependencies between transmission line infrastructure and the electricity mix are being assessed. Chapter 7 deals with local electricity markets. Implications of recently proposed market designs under the current rules in the German market are tested using a simplistic equilibrium model representing heterogeneous market participants in an energy community with their respective objectives.
The dissertation shows approaches and methodologies to overcome techno-economic challenges of the transformation towards renewable energy opening up even further research possibilities.

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