

Transmission Grid Operation and Congestion Management in Future Renewable-Dominated Power Systems

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Abstract

The ongoing transformation of the European energy system, driven by ambitious decarbonization targets and the rapid expansion of renewable energy sources (RES), places increasing operational and structural stress on electrical transmission grids. Fluctuating generation patterns, declining dispatchable conventional capacity, and rising electricity demand exacerbate congestion, challenge security of supply, and increase reliance on costly redispatch measures. To address these issues, this thesis develops a comprehensive and highly customizable alternating current optimal power flow (AC-OPF) framework designed for large-scale, real-world power system simulations with a particular focus on congestion management. The model incorporates detailed representations of conventional grid components as well as flexible network elements such as Flexible AC Transmission Systems (FACTS), and supports both optimal dispatch and optimal redispatch calculations. Modules for simplified market simulation and expansion planning, time coupling dynamics for storage systems, detailed cost formulations, and interfaces to external models further extend the applicability of the framework.

The model is evaluated on standard test systems and subsequently applied in two major case studies involving the German and European transmission networks for the period 2025–2050. The analyses are based on, and further develop, a comprehensive and high resolution data set of the European transmission system, ensuring a detailed and consistent representation of network topology and generation capacities. The results highlight substantial challenges for future system operation. In scenarios with high RES penetration, security of supply risks may arise during extended periods of low wind and solar availability, emphasizing the continued need for firm capacity and demand flexibility. Grid congestion in Germany is expected to intensify, particularly due to concentrated wind generation along the North and Baltic Sea coasts and limited north–south transfer capability. The analyses further show that high-voltage direct current corridors and cross border exchange are crucial for ensuring resource adequacy and reducing system costs. In addition, the deployment of FACTS devices appears to offer considerable potential to reduce redispatch volumes, associated costs, and occurrences of forced load shedding. For Germany, the simulations suggest that redispatch costs could be reduced by up to 30 % by installing 40 FACTS devices. A comparison of market simulation outcomes with grid constrained optimal dispatch underscores that integrating network constraints earlier in the decision chain yields significant cost reductions, chiefly by improving the allocation of RES curtailment. Market-based instruments such as bidding

zone splits and dynamic, temporally and spatially differentiated grid fees further demonstrate the potential to reduce redispatch requirements, although they may introduce side effects such as influencing wholesale prices or creating distributional effects for plant operators.

Overall, this thesis demonstrates that a combination of targeted grid reinforcement, flexible network elements, and market designs that internalize network constraints offers a credible pathway to reduce redispatch needs and system costs while maintaining security of supply in a European power system with a high share of renewable energy sources.

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Abbreviations and symbols

Abbreviations

AC	Alternating Current
ADMM	Alternating Direction Method of Multipliers
ALADIN	Augmented Lagrangian Based Alternating Direct Inexact Newton
aFRR	automatic Frequency Restoration Reserve
BESS	Battery Energy Storage Systems
CHP	Combined Heat and Power
CWE	Central Western Europe
DC	Direct Current
DSM	Demand Side Management
DSO	Distribution System Operator
EEX	European Energy Exchange
EU	European Union
EUPHEMIA	Pan European Hybrid Electricity Market Integration Algorithm
EV	Electric Vehicle
FACTS	Flexible AC Transmission Systems
FBMC	Flow Based Market Coupling
FCP	Frequency Containment Process
FCR	Frequency Contrainment Reserve

FRP	Frequency Restoration Phase
GA	Genetic Algorithm
HVDC	High-Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IEM	Internal Energy Market
KKT	Karush-Kuhn-Tucker
LCOE	Levelized Cost of Electricity
LM	Lagrange Multiplier
LMP	Locational Marginal Price
LP	Linear Programming
M	Million
MC	Market Coupling
MILP	Mixed Integer Linear Programming
MINLP	Mixed Integer Nonlinear Programming
MRC	Multi-Regional Coupling
mFRR	manual Frequency Restoration Reserve
NLP	Nonlinear Programming
NTC	Net Transfer Capacity
NUTS	Nomenclature of Territorial Units for Statistics
OPF	Optimal Power Flow
OR	Operations Research
OTC	Over-the-Counter
PCR	Price Coupling of Regions
PtG	Power to Gas
PTDF	Power Transfer Distribution Factor

PV	Photovoltaic
PST	Phase Shifting Transformer
RRP	Reserve Replacement Process
RR	Replacement Reserve
RES	Renewable Energy Sources
SCOPF	Security-Constrained Optimal power flow
SDAC	Single Day-Ahead Coupling
SEM	Single Electricity Market
SOC	State of Charge
SSSC	Static Synchronous Series Compensator
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
TCSC	Thyristor Controlled Series Compensator
TS	Transmission Switching
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UK	United Kingdom
UPFC	Universal Power Flow Controller

Latin symbols and variables

B	Nodal susceptance matrix
C	Costs
E	Energy
F	Energy flow
G	Nodal conductance matrix

I	Current
P	Real power
Q	Reactive power
R	Ohmic resistance
S	Apparent power
V	Voltage magnitude
X	Reactance
Y	Nodal admittance matrix
Z	Impedance
c	Costs parameter
j	Imaginary unit
l	Lower bound
n	Quantity
r	Ohmic resistance in p.u.
u	Upper bound
x	Reactance in p.u.
z	Impedance in p.u.

Greek symbols and variables

δ	Phase angle difference
η	Efficiency
μ	Barrier parameter
$\underline{\psi}$	Complex tap ratio
τ	Tap ratio magnitude
θ	Phase angle

ϑ Tap ratio phase angle

Operators and mathematical symbols

$\bar{a}$ Upper limit

$\underline{a}$ Complex number or lower limit

a^* Complex conjugate

$|a|$ Absolute value

Indices

c Countries

i Buses or entities in general

k Buses

l Lines

t Time steps

Sets

$\mathcal{C}$ Set of countries

$\mathcal{G}$ Set of generators

$\mathcal{I}$ Set of network nodes

$\mathcal{L}$ Set of transmission lines

$\mathcal{M}$ Set of devices

$\mathcal{S}^{\text{bat}}$ Set of battery storages

$\mathcal{S}^{\text{ps}}$ Set of pumped-storages

$\mathcal{T}$ Set of time steps

1 Introduction

1.1 Motivation

The modern energy landscape is undergoing significant transformations, driven by a shift towards renewable energy sources (RES) and an increasing demand for electricity due to decarbonization targets across all sectors. The EU Climate Law [1] sets a binding target for the European Union to achieve greenhouse gas neutrality by 2050. With the European Green Deal [2], the EU climate target for 2030 was increased to at least 55 % reduction in greenhouse gas emissions compared to 1990 levels.

However, these changes present substantial challenges for the transmission grid. The fluctuating generation from renewables, coupled with the declining availability of easily controllable generation from conventional power plants, creates a complex scenario for grid management. Maintaining a balance between generation and demand is crucial at all times to ensure grid stability. This balance must be achieved without violating voltage, frequency, or transmission line flow restrictions, which are essential for the reliable operation of the power system.

One of the primary solutions to address these challenges is grid expansion. Building new transmission lines is necessary to meet the growing demand and integrate renewable energy sources effectively. However, the process of grid expansion is not only expensive but also time-consuming. It involves numerous regulatory hurdles, environmental assessments, and community consultations, which can delay the implementation of new infrastructure projects.

In addition to grid expansion, grid reinforcement is another critical measure. Grid reinforcement focuses on utilizing the existing transmission lines to their full potential. This approach involves upgrading and optimizing the current infrastructure to enhance its capacity and efficiency. By doing so, it is possible to alleviate some of the pressure on the grid without the need for extensive new construction. One way to enhance the grid is to use flexible network elements, which can play a pivotal role in future grid management. Technologies such as Flexible AC Transmission Systems (FACTS), Phase Shift Transformers (PST) and Battery Energy Storage Systems (BESS) offer significant advantages. FACTS devices can provide real and reactive power, thereby securing voltage stability and helping to control power flows. This capability is essential for maintaining

grid stability, especially in scenarios with high penetration of renewable energy sources. Similarly, PST can help in controlling active power flows, while BESS can store excess energy generated during periods of low demand and release it during peak demand times, thus balancing supply and demand more effectively.

One of the key benefits of flexible network elements is their ability to prevent and resolve congestions in the transmission grid. Congestions occur when the demand for electricity exceeds the capacity of the transmission lines, leading to potential grid instability. The traditional way to resolve congestions is to use redispatch measures, which involve adjusting generation by power plants and RES and reallocating power generation, a process that can be costly and inefficient. By managing power flows and providing additional support, FACTS, PST, and BESS can reduce the need for redispatch volumes and costs. Additionally, these technologies can minimize RES curtailment, where excess renewable energy generation is wasted due to grid constraints, and load shedding, where electricity supply is intentionally reduced to prevent grid overload.

Another approach to addressing challenges in the transmission grid is to explicitly account for grid conditions and potential bottlenecks already within the electricity market. Corresponding approaches have been discussed more intensively recently, such as dividing large market areas into several smaller zones [3] or introducing dynamic network charges that explicitly take into account the forecast situation in the network [4]. The most extreme variant of these approaches would be nodal pricing, where each network node is assigned an individual electricity price that takes into account generation and demand at the node as well as transmission restrictions. Such concepts are currently being applied in some regions of the USA, for example.

In conclusion, the challenges posed by increasing electricity demand and fluctuating generation from RES require a multifaceted approach. Grid expansion and reinforcement, along with the deployment of flexible network elements, are essential strategies for maintaining grid stability and ensuring a reliable electricity supply. Additionally, market-oriented approaches could be used to further decrease the need for costly redispatch measures and possibly even grid expansion. This work contributes to this field of research by proposing a modeling framework for the simulation of present and future power systems with a focus on the electrical transmission grids and several case studies to provide a techno-economic evaluation of flexible network elements and market-driven solutions in the context of grid operation and congestion management.

1.2 Research goals and structure of the study

The overarching research goal of this work is to study the techno-economic impacts of flexible network elements and market-based solutions on the operation of electrical transmission grids with

a special focus on congestion management. For this purpose, an optimization model framework for the operation of power transmission systems shall be developed. This model, which is a so-called Optimal Power Flow (OPF) model, should inherit the following specifications:

- An alternating current (AC) formulation to properly represent complex voltages, currents, and power flows
- Models of flexible network elements like FACTS with a high level of technical detail
- Consideration of time-coupling dynamics, especially for storage systems
- Cost models for system operation and redispatch measures
- The ability and scalability to be applied to large-scale real-world systems, like the German or European transmission network
- The ability to be either used for determining optimal system operation or for calculating optimal congestion management measures based on a previous market or system simulation
- Interfaces for the data exchange with other models, e.g., market simulation models or models for the calculation of RES and demand profiles

The model shall then be applied to the German and the European power system, analyzing different scenarios from the year 2025 up to 2050. The analysis shall help to answer the following research questions:

1. How is transmission grid operation evolving in the upcoming years and what costs or technical problems are expected to emerge?
2. What are the technical and economic benefits of the use of flexible network elements in grid operation and congestion management?
3. How can market-based solutions be employed and to what extent can they reduce redispatch and total system costs?

After a literature review on recent developments in the field of OPF modeling in Section 1.3, the remainder of the study is structured as follows: The relevant and necessary theoretical fundamentals are described in Chapter 2, including background information on the energy-economic principles underlying the European electricity system, electrical engineering fundamentals on electrical energy systems, and fundamentals on operations research (OR).

In Chapter 3, the modeling approach, the formulation of the OPF model, and several additional component models are described in detail. Chapter 4 provides a description of the input data and

the scenarios used, followed by Chapter 5, which presents the results of validation exercises and two case studies. The study concludes with a summary and discussion in Chapter 6.

1.3 Literature review

OPF models have existed for a considerable period of time and can be applied to a wide range of research questions. Consequently, the body of related research is extensive. While some studies focus on the development of novel solution methods, others investigate the integration of additional system components. Moreover, OPF models are applied in a wide range of contexts, from the analysis of transient phenomena under fault conditions to system-level assessments spanning several years or even decades. The following section gives an overview of recent developments in the field of OPF research, structured by the topic of the main contributions or main focus of the selected studies.

Reviews

A number of review papers provide valuable insights into the evolution and current state of optimization methods for power system operation, particularly in solving OPF and related problems. Risi et al. categorize modern OPF solution techniques based on their inspiration: human-inspired (e.g., harmony search, tabu search), evolutionary (e.g., genetic algorithms), and physics-based (e.g., particle swarm, firefly, ant colony) [5]. They also introduce a successive mixed-integer linear programming approach for reactive power flow, demonstrating reliable performance compared to metaheuristic methods [5]. Saddique et al. survey meta-heuristic techniques for the optimal reactive power dispatch problem, a complex and nonlinear task essential for secure and efficient grid operation [6]. Their review includes a new Sine-Cosine algorithm and comparative performance analysis, offering a comprehensive reference for researchers exploring heuristic optimization in power systems [6]. Capitanescu provides a critical review of OPF research developments since 2010, focusing on deterministic, risk-based, and uncertainty-aware OPF in the context of smart grids [7]. The paper emphasizes the role of core optimization algorithms in solving master-slave nonlinear programming problems and outlines future challenges such as scalability and integration of uncertainty [7]. In an earlier work, Capitanescu et al. also review the state-of-the-art in Security-Constrained OPF (SCOPF), discussing key challenges including limited corrective actions, voltage and transient stability modeling, and discrete variable handling [8]. The paper highlights the need for improved contingency filtering and modeling approaches to advance SCOPF methodologies [8]. Molzahn et al. survey distributed algorithms for power system optimization and control, emphasizing their growing relevance due to the rise of distributed energy resources [9]. The review covers both offline and real-time applications, including OPF, frequency control,

voltage control, and wide-area control, providing a broad overview of distributed optimization strategies in modern power systems [9].

Solving and decomposition techniques

Distributed approaches to solving the OPF problem have gained significant attention due to the increasing complexity and decentralization of modern power systems. One of the early contributions in this area introduces a distributed scheme suitable for large, interconnected power systems, utilizing three coordination methods, the Auxiliary Problem Principle, the Predictor-Corrector Proximal Multiplier Method, and the Alternating Direction Method. This approach enables collaboration among heterogeneous utilities and has been validated on IEEE Test Systems and parts of the ERCOT grid [10]. Building on the need for decentralization, Erseghe proposes a fully distributed algorithm for non-convex OPF that eliminates the need for central coordination [11]. The method is based on a customized version of the Alternating Direction Method of Multipliers (ADMM), structured as a region-based optimization procedure and tested in realistic scenarios [11]. In a related work, the same author presents an augmented Lagrangian method with increasing penalty parameters, offering convergence under mild assumptions and maintaining fidelity to the original non-convex problem. This approach is efficient for moderately sized networks and broadly applicable to distributed optimization tasks [12].

Houska et al. contribute a parallelizable distributed optimization algorithm for problems with separable objectives and coupled affine constraints. Their method combines sequential quadratic programming and augmented Lagrangian techniques, achieving superlinear or quadratic convergence rates under suitable conditions, significantly outperforming traditional methods like ADMM. The algorithm also incorporates globalization techniques to ensure convergence from any starting point [13]. The Augmented Lagrangian Based Alternating Direction Inexact Newton (ALADIN) method has emerged as a powerful tool for distributed non-convex AC-OPF problems. Engelmann et al. demonstrate its applicability to electrical grids of generic topology and show that it outperforms ADMM in a case study using the IEEE 5-bus system [14]. In a subsequent study, the same authors extend ALADIN to larger test cases (5-300 buses), showing that it achieves locally quadratic convergence and reduces the number of iterations by an order of magnitude compared to ADMM [15]. They also propose a variant using inexact Hessians to reduce communication overhead, while maintaining strong convergence guarantees even with suboptimally solved local problems [15].

Recent work has expanded the scope of distributed OPF to hierarchical and hybrid grid structures. Wang et al. propose a nested decomposition method for solving AC-OPF in hierarchical grids, enabling efficient coordination across grid levels while preserving computational tractability and solution accuracy [16]. Lin et al. introduce a non-iterative, decoupled framework for robust OPF in interconnected transmission and distribution networks, explicitly accounting for uncertainty from

variable generation sources [17]. In another contribution, Lin et al. present a decentralized method for solving AC-OPF in integrated transmission-distribution grids, emphasizing data privacy for distribution networks [18]. Dai et al. advance the ALADIN framework by incorporating second-order correction and convexification strategies, improving trajectory tracking and simplifying subproblem decoupling in integrated transmission-distribution systems [19]. In the context of hybrid AC/DC grids, Huebner et al. apply ADMM to distributed AC-DC OPF in the European transmission grid [20], while Meyer-Huebner et al. reformulate the AC-DC OPF problem using both ADMM and ALADIN, achieving high accuracy and faster convergence [21]. Scalability and performance in distributed simulations are also addressed by Kyesswa et al., who evaluate graph-based partitioning algorithms such as KaFFPa, spectral clustering, and METIS [22]. Their results show that KaFFPa significantly improves computational speed and efficiency for both AC-OPF and dynamic simulations [22]. Meyer-Huebner et al. further contribute a distributed computing approach using Smart Grid Communication Middleware to solve large-scale dynamic OPF problems with energy storage, demonstrating substantial reductions in computation time on the German transmission grid [23]. Alvarez-Bustos et al. propose a universal OPF model for hybrid AC/DC grids, enabling simultaneous optimization across the entire network [24]. Their approach incorporates control variables for AC/DC interface devices and demonstrates scalability and accuracy on various test systems, including a modified PEGASE grid [24]. In radial distribution systems, Christakou et al. present a novel algorithm for solving the non-convex AC-OPF problem without relying on branch-flow convexification or ADMM [25, 26]. Their method, based on the method of multipliers and primal decomposition, is shown to converge reliably in both centralized and distributed asynchronous forms [25, 26].

Finally, heuristic methods have also been explored for OPF. Pardalos et al. compare nonlinear optimization tools with genetic algorithms (GAs) for optimal location and sizing of distributed generation in distribution networks [27]. Bakirtzis et al. propose an enhanced genetic algorithm that incorporates operational constraints as penalties and introduces advanced operators to improve efficiency and accuracy, validated on benchmark test systems [28]. A deep learning model that integrates neural networks with Lagrangian duality to efficiently approximate AC-OPF solutions is presented in Chatzos et al. [29]. It was tested on large-scale French transmission systems and achieved near-optimal results within milliseconds, accurately capturing physical and operational constraints despite the complexity and non-convexity of AC-OPF. Li et al. introduce a physics-informed machine learning framework for solving the OPF problem, leveraging imitation learning and historical European weather data to enable real-time, non-iterative power dispatch decisions [30]. The proposed method outperforms traditional and data-driven OPF solvers in speed and robustness [30].

FACTS and other flexible network elements

FACTS and other advanced grid technologies have become central to modern congestion management and OPF strategies. Siddiqui et al. investigate the impact of FACTS devices (SVC, TCSC, and UPFC) on power flows and bus voltages under high loading conditions, demonstrating their effectiveness in mitigating congestion and enhancing stability in IEEE-14 and WSCC 9-bus systems [31]. Jiang et al. present a method for integrating phase shifters into interior point OPF algorithms using a novel injection model that preserves admittance matrix symmetry [32]. Mithulanathan et al. propose a framework to quantify the monetary benefits of FACTS devices in deregulated markets, showing how OPF-based pricing schemes can support investment recovery and increase market surplus without distorting incentives [33]. Nemat-Talebi et al. develop a sequential Newton-Raphson algorithm tailored for systems with embedded FACTS devices and high-voltage direct current (HVDC) lines, validated on multiple networks including the Ward-Hale system [34]. Singh et al. introduce an approach to congestion management based on AC power flow using UPFCs, demonstrating reduced rescheduling and improved generator bidding strategies in large test systems [35].

Heuristic optimization also plays a role in FACTS deployment. Balamurugan et al. propose a differential evolution algorithm for optimal FACTS placement, outperforming evolutionary programming in minimizing cost, overload severity, and losses [36]. Berizzi et al. integrate FACTS into a compact SCOPF formulation, enabling global solutions and reducing market disruptions caused by grid bottlenecks [37]. Leibfried et al. show that a minimal number of strategically placed flow control buses can achieve near-optimal power flows, enhancing controllability and reducing costs under increased load conditions [38]. Singh et al. also propose a two-step model for congestion management using FACTS, involving optimal location selection followed by control parameter optimization, validated on a 5-bus system [39]. Kamel et al. present an implicit modeling approach for integrating SSSCs into Newton-Raphson load flow algorithms, simplifying implementation and effectively controlling power flows across various test systems [40]. Momoh et al. develop a rule-based OPF approach incorporating phase shifters, combining continuous and discrete adjustments to enhance system security and manage overloads [41].

Beyond FACTS, recent studies have addressed broader OPF challenges. Karagiannopoulos et al. introduce a centralized OPF framework for active distribution network operation, delivering voltage support to transmission networks under Swiss regulatory constraints [42]. Knittel et al. propose a two-stage reactive power scheduling method using STATCOMs, combining linear programming and genetic algorithms to minimize switching actions and losses [43]. Majumdar et al. develop a successive MILP method for reactive power flow, efficiently incorporating discrete transformer tap settings [44]. Ergun et al. present an OPF model for hybrid AC/DC grids, integrating various converter technologies and enabling scalable analysis of large systems through nonlinear

and linearized formulations [45]. Wienholt et al. investigate future storage needs in the German grid under increasing renewable integration, showing that higher renewable shares require significantly more storage capacity even without grid expansion [46]. Blunck et al. model congestion management using market-based and grid-related measures, incorporating hydro storage, phase-shifting transformers, and HVDC links in an AC power flow framework [47]. Finally, Altun et al. introduce a topology-aware OPF framework for multi terminal DC grids, using mixed-integer second-order cone programming to optimize switching decisions and prevent voltage violations, validated on modified IEEE test systems [48].

Security constrained OPF

SCOPF has become a critical area of research to ensure grid reliability under contingencies. Hu et al. develop a post-contingency control strategy for AC/DC hybrid grids that incorporates dynamic electrothermal effects of transmission lines, enhancing operational stability [49]. Kollenda et al. propose a method to include thermal reserves of overhead lines in congestion management, ensuring N-1 security through both preventive and curative actions [50]. Huang et al. present a robust optimization model for wind-integrated hybrid grids, combining HVDC control and transmission switching to manage uncertainty and improve flexibility [51]. Li et al. introduce an integrated restoration strategy combining reinforcement learning for repair sequencing with linear optimization for dispatch, effectively coordinating resources after extreme events [52]. Huebner et al. propose a security constrained, distributed OPF model using ADMM, which accounts for N-1 security and time-dependent constraints like ramping and storage, achieving near-centralized performance while preserving privacy [53]. Isuru et al. develop a two-stage robust optimization model for day-ahead scheduling in hybrid grids, using second-order cone relaxation to improve scalability and voltage security under renewable uncertainty [54]. Zuo et al. present an OPF-driven under-frequency load shedding scheme for low-inertia grids with large-scale battery storage, outperforming standard strategies in maintaining system limits during contingencies [55]. Wang et al. propose an OPF model that incorporates transient thermal behavior of overhead lines, improving electrothermal coordination through dynamic optimization [56]. Kolster et al. develop a fast and robust method for curative operation across transmission-distribution boundaries, aggregating flexibility from thousands of assets to support scalable transmission operations [57]. Aghahassani et al. introduce a transient-stability constrained OPF algorithm that compares grid-forming and grid-following controls in renewable-rich systems, drawing insights from real-world events in the Iberian Peninsula [58]. Arredondo et al. extend this work by integrating synthetic inertia into SCOPF formulations, demonstrating improved stability and reduced costs in the North-West Spanish grid [59]. Tosatto et al. explore HVDC interconnectors for exchanging primary frequency reserves between asynchronous AC areas, showing cost reductions and enhanced N-1 security [60]. Platbrood et al. present a scalable iterative algorithm for solving large-scale SCOPF problems,

combining contingency filtering and network compression to handle nonlinear AC models with thousands of buses [61].

Uncertainty-aware and risk-based OPF

Recent research has focused on incorporating uncertainty into OPF formulations to improve reliability and operational efficiency. Bauer et al. propose a compact dynamic stochastic chance-constrained DC OPF model that minimizes generation costs while accounting for distributed energy storage systems [62]. Assuming Gaussian uncertainty, the model uses affine policies to reformulate the problem as a tractable second-order cone program [62]. Mühlpfordt et al. extend chance-constrained OPF to nonlinear AC power flow equations using polynomial chaos expansion, enabling accurate modeling of arbitrary uncertainties with finite variance [63]. Fang et al. introduce a probabilistic OPF model using affine arithmetic to address wind and load uncertainties in dynamic thermal rating analysis, improving planning and operational decisions [64]. Knittel et al. present a probabilistic reactive power flow model that integrates uncertainty in renewable generation into voltage control, using Monte Carlo simulations and soft constraints to balance stability and cost [65].

Data privacy

As data privacy becomes increasingly important, Dindar et al. propose a machine learning-based method for integrating distributed generators into AC OPF while preserving privacy, validated on the Baden-Württemberg transmission grid [66]. Strunz et al. develop a distributed AC-DC OPF framework using a modified fully parallel ADMM, where consensus constraints rely only on local neighbor exchanges [67]. The model also considers social acceptance in grid expansion planning.

Flexibility from distribution to transmission grids

Nozal et al. evaluate the maximum aggregated inertial capability of active distribution networks and propose a dispatch strategy for distributed renewable energy sources to provide inertial response defined by the transmission grid operator (TSO) at minimal cost [68]. Mayorga Gonzalez et al. present a framework to quantify flexibility of active distribution networks for ancillary services across voltage levels, offering both deterministic and probabilistic methodologies to assess future flexibility under uncertainty [69].

Transmission switching

Transmission switching (TS) has emerged as a key tool for enhancing grid flexibility. Crozier et al. develop a heuristic for optimal TS based on DC OPF [70]. Huang et al. integrate TS with HVDC control in a robust optimization model for wind-integrated hybrid grids, showing that TS complements HVDC in reducing operational risks [51]. Little et al. explore TS as a cost-saving strategy in renewable-rich grids, demonstrating its growing value with increased variability [71].

Khanabadi et al. formulate TS as a mixed-integer nonlinear programming problem embedded in AC OPF, proposing a Benders decomposition-based method to maintain voltage security and guide switching sequences [72].

Three-phase OPF

Three-phase OPF models are essential for accurate distribution network analysis. Baran et al. present a model minimizing electrical losses while accounting for mutual cable impedances and voltage regulator taps, solved using a primal-dual interior point method [73]. Zhao et al. develop a three-phase OPF model with discretely adjustable devices and a quadratic on-load tap changer model, ensuring a constant Hessian matrix and integrated voltage regulation [74]. Meng et al. propose a three-phase unbalanced OPF algorithm for high-DG distribution networks, validated on IEEE feeders and suitable for smart grid applications [75].

Real-time optimization

Real-time OPF strategies are increasingly vital for dynamic grid operations. Wang et al. propose a progressive period OPF framework that extends interval OPF by coordinating day-ahead scheduling with real-time dispatch using median and endpoint values [76]. Klein-Helmkamp et al. present a real-time coordination method using Online Feedback Optimization to dispatch DERs for curative transmission support, validated in a low-voltage grid experiment [77]. Dai et al. introduce a real-time distributed operational framework for integrated transmission-distribution systems, using power-energy envelopes and distributed nonlinear model predictive control to enable efficient multi-TSO dispatch while preserving privacy [78].

Sector coupling and integrated energy systems

Sector coupling has emerged as a promising strategy to enhance grid flexibility and efficiency by linking electricity with other energy domains such as gas and heat. Mazza et al. explore the use of Power-to-Gas (PtG) technology to convert surplus renewable electricity into synthetic natural gas, using a DC OPF-based framework to simulate day-ahead and intra-day markets on a simplified European grid [79]. Lohr et al. present a successive linear programming approach for solving large-scale, multi-period Optimal Power and Gas Flow (OPGF) problems [80]. Applied to the German power and gas transmission grid, the method effectively addresses gas system nonlinearities and demonstrates high computational efficiency for system-wide sector coupling analysis [80]. Rubio et al. introduce an energy system dispatch optimization model that incorporates sector coupling impacts from heat pumps and electric vehicles [81]. By iteratively generating grid constraints decoupled from unit commitment, the model reduces curtailment by up to 45% and eliminates grid violations in a typical German neighborhood scenario [81].

Grid planning, investment strategies, and flexibility integration

Modern grid planning increasingly incorporates flexibility resources, sector coupling, and advanced optimization techniques to address evolving energy system challenges. Müller et al. present eGo, an open-source tool for optimizing grid and storage expansion across all voltage levels using a top-down approach [82]. By integrating transmission and distribution planning with multi-period linear and nonlinear power flow models, the tool identifies cost-efficient strategies for Germany, showing that spatially detailed time series outperform storage-based grid relief alone [82]. Minetti et al. propose a technical-economic methodology for allocating additional inertia in transmission networks to maintain sustainable Rate of Change of Frequency levels [83]. Tested on the Italian grid, the method combines contributions from RES, BESS, and synchronous compensators, enabling full-year statistical analysis for 2030 with low computational cost [83]. Karmakar et al. introduce a bi-level optimization strategy for reactive power planning, identifying weak nodes for var support and using meta-heuristics to optimize sizing and control settings [84]. The method incorporates reactive power cost coefficients and line charging elements, validated on multiple IEEE test systems [84]. Misić et al. present a mixed-integer linear programming approach to optimize the placement, type, and size of energy storage systems in transmission grids with renewable and non-renewable sources [85]. A time-decomposition strategy and heuristic constraints enable tractable solutions for large-scale instances, demonstrated on a Sardinian grid model [85]. Migliavacca et al. introduce a comprehensive grid-planning methodology developed in the FlexPlan Horizon2020 project, integrating storage and flexibility as alternatives to traditional expansion [86]. The tool includes multi-year assessments, cost-benefit analysis, environmental impacts, probabilistic contingencies, and Monte Carlo simulations, offering regulatory guidance through six regional case studies [86]. Luburic et al. and Franken et al. contribute investment planning models for transmission-level non-generation flexibility assets. Luburic et al. use a linearized AC OPF and Benders' decomposition to optimize deployment of BESS, TCSC, and transmission lines, demonstrating adaptability to varying BESS costs and strategies [87]. Franken et al. formulate a mixed-integer linear program to jointly optimize AC systems and power flow control technologies such as HVDC, PSTs, and TCSCs, showing that integrated planning can reduce expansion costs by up to 32.4% [88].

Congestion management strategies

Congestion management remains a central challenge in power system operation, especially with increasing renewable integration and decentralized generation. Kumar et al. propose a methodology for congestion management in pool electricity markets that incorporates voltage stability as a loadability limit [89]. Their approach optimizes generator rescheduling using a three-block bid structure and evaluates the impact of third-generation FACTS devices, demonstrating effective

integration of economic dispatch and market bidding strategies on IEEE 24-bus and 57-bus systems. Bouhouras et al. introduce a three-stage coordination method for managing congestion in day-ahead planning across transmission and distribution systems [90]. By sequentially applying OPF analyses and a relaxation scheme, the method enables coordinated redispatch and quantifies flexibility between TSOs and DSOs, validated on the Greek power system [90]. Mueller et al. explore the use of PtG technology as a flexible alternative to grid expansion, showing how PtG placement and sizing within a transmission grid can support congestion relief and sector coupling in Germany [91]. Contreras et al. present a distributed bottom-up method for aggregating flexibility from distributed energy resources to support high-voltage congestion management [92]. Using linear optimization, the method reduces computation time and demonstrates practical applicability on a real distribution grid model [92]. Gutermuth et al. assess the economic viability of network operator-owned energy storage for congestion mitigation, showing that such storage is only cost-effective when combined with additional applications, emphasizing the importance of value-stacking strategies [93]. Lindner et al. investigate the use of distributed grid-scale battery energy storage systems for both preventive and curative congestion management [94]. Their case study on the German grid shows that storage enhances curative measures and reduces overall congestion costs, particularly under operational uncertainties [94]. Blunck et al. model a comprehensive optimization framework for congestion management using both market-based and grid-related measures [47]. Their approach incorporates pumped hydro storage, phase-shifting transformers, and HVDC links within an AC power flow formulation, demonstrating how redispatch flexibility can minimize future congestion and operational costs in the German transmission system [47].

Real-world modeling and system-level applications

Recent studies have emphasized the importance of applying OPF and energy system optimization techniques to realistic grid models and operational scenarios. Bauer et al. present a second-order cone formulation of OPF applied to a detailed model of the Turkish transmission grid, enabling more realistic testing of advanced optimization methods [95]. Reveron Baecker et al. propose a co-optimization framework that integrates transmission and distribution system constraints, facilitating efficient bidirectional energy flows and bottom-up modeling of energy demands and technologies [96]. Meyer-Hübner et al. introduce a time-constrained OPF methodology applied to the German transmission grid, incorporating full AC power flow and inter-temporal constraints such as storage operation and generator ramping [97]. Their 24-hour optimization using synthetic load and renewable profiles validates the model's operational realism [97]. Huebner et al. apply distributed AC-DC OPF using ADMM to the European transmission grid, demonstrating feasibility for single-timestep optimization [20]. Syranidou et al. develop a high-resolution pan-European DC-OPF model to address integration challenges of variable renewable energy sources [98]. Their analysis reveals that congestion, especially between northern and central Europe, is a major driver

of curtailments, and identifies optimal converter locations for solar and wind integration [98]. Gutermuth et al. and Lindner et al. explore the role of energy storage in congestion management within the German grid. Gutermuth et al. show that network operator-owned storage is only economically viable when combined with multi-use strategies [93], while Lindner et al. demonstrate that distributed grid-scale batteries enhance curative congestion management and reduce costs under uncertainty [94]. Minetti et al. present a methodology for optimal inertia allocation in the Italian grid, combining contributions from RES, BESS, and synchronous compensators to maintain sustainable Rate of Change of Frequency levels with low computational cost [83]. Lohr et al. solve large-scale multi-period Optimal Power and Gas Flow problems using successive linear programming, applied to the German power and gas transmission grid [80]. Their method effectively handles gas system nonlinearities and supports sector coupling analysis [80]. Blunck et al. model congestion management using market-based and grid-related measures in the German transmission system, incorporating pumped hydro plants, PSTs, and HVDC links to minimize operational costs [47]. Ruppert et al. examine the impact of distributed flexibilities, such as heat pumps, EVs, BESSs, and flexible RESs, on transmission grid operation [99]. Using a two-stage optimization approach based on the Ten-Year Network Development Plan (TYNDP) 2030 scenario, they show that integrating these flexibilities enhances supply security with minimal generation adjustments [99].

To support these modeling efforts, PyPSA has emerged as a key open-source toolbox for simulating and optimizing modern power systems. Brown et al. describe PyPSA's capabilities, including models for conventional and renewable generation, storage, sector coupling, and mixed AC/DC networks [100]. Its extensibility and scalability make it suitable for large networks and long time series, bridging traditional power flow tools with comprehensive energy system models [100]. Horsch et al. introduce PyPSA-Eur, the first open dataset of the European transmission-level power system covering the full ENTSO-E area [101]. It supports both operational and expansion planning studies and includes a fully automated modeling pipeline [101]. Brown et al. further extend this work with PyPSA-Eur-Sec-30, a spatially and temporally resolved model for Europe that investigates two competing strategies for integrating high shares of renewables: cross-sector coupling and continent-wide transmission reinforcement [102]. Their results show that flexibility from battery electric vehicles, power-to-gas units, and long-term thermal storage effectively smooths renewable variability and reduces system costs, while transmission expansion offers diminishing returns as sector coupling tightens [102]. Neumann et al. use PyPSA-Eur to compare approximations of nonlinear power flow and transmission losses in linear capacity expansion models, providing guidance on model selection for co-optimizing generation, storage, and transmission infrastructure [103].

Differentiation of the proposed model from the literature

Against this background, the present work differentiates itself from existing approaches by employing a technically detailed AC-OPF formulation that explicitly incorporates advanced models of flexible network elements, including various types of FACTS devices and phase-shifting transformers. In contrast to purely methodological or conceptual studies, the model is applied to real-world systems like Germany and Central Europe, thereby ensuring practical relevance. Furthermore, congestions are addressed through a redispatch formulation that is consistent with the current German regulatory framework, allowing for a realistic representation of operational measures. Finally, the modeling framework features clearly defined interfaces to market simulation models, enabling consistent analyses across the market-network boundary and facilitating integrated system studies.

2 Theoretical background

2.1 The European electricity system

This section describes the basics about European electricity markets and system operation regulations that are relevant for the remainder of this study.

2.1.1 European electricity markets

Electricity derivatives emerged in Europe following the liberalization of energy markets in the 1990s. The EU's Internal Energy Market (IEM) initiative aimed to dismantle monopolistic structures and foster competition [104, 105]. This led to the creation of organized exchanges and the development of financial instruments to hedge against price volatility. The first electricity exchange in Europe was Nord Pool, established in 1993 in Scandinavia, where hydroelectricity's storability made derivatives trading more feasible [105]. Other countries followed, with Germany, the UK, and the Netherlands becoming key players. Later, the European Energy Exchange (EEX), founded in Leipzig, and its subsidiary EPEX Spot became the leading venues for power derivatives and spot market trading in Europe [105].

Electricity markets can be divided into two categories: derivative markets and spot markets. In derivative markets, contracts whose value is derived from an underlying asset (such as commodities or electrical energy) are traded. The settlement of these contracts happens at a future date, so they allow one to bet on price movements or to hedge risks. On spot markets, the asset (e.g., electrical energy) is bought or sold immediately at the current market price. The transaction settles "on the spot," usually within two business days. Before the liberalization of electricity markets, the trading on spot markets usually took place one day before delivery. Therefore, the term spot market is often used as a synonym for the day-ahead market. However, additional spot markets have emerged in energy economics, such as the intraday market and the markets for ancillary services, including primary reserve. The different types of markets are described in more detail in the following sections.

2.1.1.1 Derivative market

Medium- and long-term electricity markets enable participants to manage price risks and to secure planning certainty. Generators typically use these markets to lock in revenues for future production, while consumers and retailers seek to stabilize procurement costs. At the same time, financial actors may take speculative positions due to the inherent volatility of electricity prices. The principal instruments serving these purposes are futures and forwards. Futures are standardized contracts traded on organized exchanges for delivery periods ranging from days to several years. Unless they are offset before the delivery period, they are usually financially settled against the spot market's day-ahead price. Because the exchange assumes counterparty risk, participants must maintain margin accounts with the clearing house, post initial margins and meet daily variation margins as the futures price diverges from the spot price. These daily mark-to-market adjustments can significantly affect liquidity, particularly for generators hedging short positions, who may be required to supply additional collateral when spot prices rise. [106]

Alongside exchange trading, a substantial share of electricity is traded bilaterally in the over-the-counter (OTC) market. Here, forwards¹ allow for flexible, non-standardized terms regarding delivery dates and product characteristics. Unlike futures, forwards expose market participants directly to counterparty risk, making creditworthiness and bilateral collateral arrangements central to contract design. Because forwards are not settled daily, they accumulate positive or negative replacement values over time, appearing as financial assets or liabilities on balance sheets at the reporting date. OTC markets often exhibit higher traded volumes than exchanges, although liquidity is fragmented between heterogeneous products. [106]

2.1.1.2 Day-ahead market

The day-ahead market is an auction-based market in which participants on the supply and demand sides submit their offers in so-called bids. Each bid consists of two properties: The amount of electricity to be sold/bought and the corresponding price. By sorting the bids after volume and price, supply and demand curves can be obtained. The supply curve is also called the "merit order" [107]. The market result and the corresponding market clearing price are obtained by calculating the equilibrium of the supply and demand curve. The most expensive accepted supply bid determines the market price. In Europe, market clearing is usually done on an hourly or quarter-hourly basis for the 24 hours of the following day, resulting in hourly electricity prices for the next 24 hours.

¹ Contracts with a linear payoff similar to futures.

Electricity demand is generally characterized by low price elasticity, whereas the merit order curve exhibits significant price sensitivity. The shape of the merit order curve is determined by the composition and availability of power plants and other generation units within the market. Historically, the merit order was typically composed of three parts: Renewables and base load power plants (typically nuclear and lignite) that bid with rather low (or even zero) prices, mid-merit load power plants (typically coal and gas) that bid with medium-high prices, and peak load power plants (typically gas and oil) that bid with high prices. With the expansion of renewable energies, rising prices for CO₂ certificates and changing regulatory conditions like the nuclear and coal phase-out in Germany, the structure of the merit order has changed in recent years and the former classification no longer holds for all markets and countries. An example of a merit order curve, demand curve, and the resulting market clearing price for two different times of a day for Germany is shown in Fig. 2.1 [108].

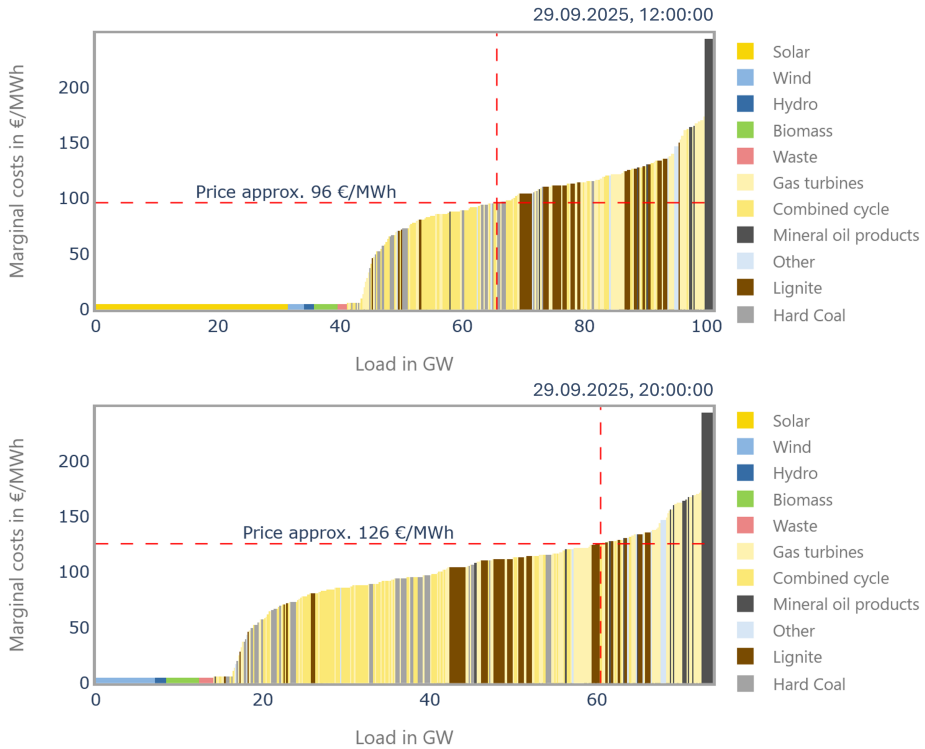


Figure 2.1: Merit order for thermal power plants and renewable energies in Germany on 29.09.2025 at 12:00 p.m. (top) and 08:00 p.m. (bottom) [108].

Day-ahead market trading is structured around a fixed gate closure time, such as 12:00 on the EPEX SPOT exchange. At this time, all submitted bids are centrally matched, resulting in the determination of uniform market-clearing prices for each hour of the subsequent day, with physical delivery occurring at a specified location. This framework enables market participants to trade not only individual hours but also to submit classic or complex block bids. Block bids follow a "fill-or-kill" principle, meaning they must be either fully accepted or not accepted at all. This bidding format is particularly relevant for less flexible technologies and smaller portfolios, where operators, e.g., need to commit to running a plant for several consecutive hours to meet minimum operating requirements. Notably, even if the market price in a single hour falls below the bid price, that hour can still be accepted as part of a block bid if the entire block meets the criteria [109]. The following block bids are currently available on the EPEX SPOT day-ahead market [110]:

- **Classic block** orders span multiple hours at a fixed price and feature flexible volume profiles. These blocks are executed at the same ratio across all included hours.
- **Big blocks** are larger than classic blocks, with a maximum size of up to 1500 MW. They are designed to accommodate large production capacities.
- **Loop blocks** consist of two interdependent blocks that are either both executed or both rejected. This structure allows market participants to bundle buy and sell orders, effectively representing storage activities.
- **Curtailed blocks** are a set of orders that can be either fully accepted or rejected (following an All-or-None principle), or partially accepted above a minimum threshold defined by the trader.
- **Linked blocks** are structured with execution dependencies, where the acceptance of one block is contingent on the execution of its parent block. This setup enables modeling of generation variations in response to market prices.
- **Exclusive blocks** are grouped in such a way that only one block within the group can be executed. This ensures that electricity is traded at the most profitable moment.

The introduction of block bids is an advantage for the market participants, as it allows them for more flexible and individual bidding strategies. On the other hand, it makes market clearing much more complex, as handling such bids requires binary variables, which transforms the market clearing problem to a mixed-integer optimization model [109].

Over the past two decades, electricity markets have experienced substantial structural and regulatory transformations. These include shifts in the generation mix, most notably the expansion of renewable energy and the phase-out of nuclear power in countries such as Germany, as well as

significant reforms in market design and regulation. The introduction of the European Emissions Trading System in 2005 has further increased interdependencies and influenced price formation. Additional regulatory changes, such as the allowance of negative prices and competitive procurement procedures for reserves, have also shaped market outcomes. To address rare instances of extreme price volatility in day-ahead auctions, a secondary auction mechanism enables participants to adjust bids and support market clearing. Among the most impactful developments, however, are the establishment of intraday markets and the progressive integration of international market coupling [109].

2.1.1.3 Intraday market

The day-ahead market is the most important market in most electricity systems and can be regarded as the reference market. Although it is already a relatively short-term market, new and potentially relevant information may emerge between the time of trading and the time of settlement on the following day. This applies in particular to forecasts for weather-dependent generation from renewable energies such as wind power or PV, but also to forecasts for demand or short-term unavailability of power plants. This can result in significant deviations between the amount of energy traded by a market participant and the amount actually available or demanded, which must be balanced. For this purpose, the intraday market was introduced.

Market participants can trade either continuously on the intraday continuous market or via intraday auctions. On the intraday continuous market, participants trade 24 hours a day, with delivery taking place on the same day. As soon as a buy and sell order match, the trade is executed. Electricity can be traded up to 0 minutes before delivery and via hourly, half-hourly, or quarter-hourly contracts. This allows market participants to make adjustments and align their positions right up to the last minute. Intraday auctions are also available on the intraday market. They allow liquidity to be pooled at a specific point in time and provide a reference price for electricity delivery on the same or following day, depending on the time of the auction [111].

2.1.1.4 Markets for ancillary services

Ancillary services are essential for maintaining the stability, reliability, and efficiency of the European electricity grid. As the energy system transitions from large generators in conventional power plants with controllable power output toward higher shares of weather dependent renewable energy, the role of ancillary services becomes increasingly critical. These services support grid operations by balancing supply and demand, by managing frequency and voltage levels, and by ensuring system recovery after disturbances. Among these, reserves intended for frequency

control are increasingly being procured through market-based mechanisms. Over recent years, European regulations have established standardized definitions for various types of reserve power. Additionally, the European Network Codes have aligned operational procedures to facilitate cross-border competitive procurement [112, 113]. These codes outline three key processes, each associated with a specific reserve category [109]:

- **Frequency Containment Process (FCP):** As its designation implies, the FCP is designed to maintain the system frequency within a permissible band around the nominal setpoint of 50 Hz. This objective is achieved through the automatic activation of Frequency Containment Reserves (FCR).
- **Frequency Restoration Process (FRP):** In contrast to the FCP, which primarily mitigates frequency deviations, the FRP aims to restore the system frequency to its nominal value of 50 Hz while simultaneously rebalancing inter-area power exchanges to their scheduled setpoints. This process relies on the deployment of two distinct categories of reserves: Frequency Restoration Reserves with automatic activation (aFRR) and Frequency Restoration Reserves with manual activation (mFRR).
- **Reserve Replacement Process (RRP):** The RRP can be used to reinstate reserves that got activated previously by using Replacement Reserves (RR). However, the RRP is not mandatory across the EU.

In these markets, three overarching challenges emerge. First, there is the requirement for close coordination between short-term grid operation (done by the TSO) and the deployment of flexibility resources, including generation assets (done by the asset operator). Second, technical constraints associated with the provision of reserves and energy delivery, particularly in conventional and other power plants, must be addressed. Third, it is essential to prevent excessive market entry barriers, which carry the risk of facilitating market power abuse [109].

2.1.2 European market coupling

Market coupling (MC) represents a mechanism for integrating multiple regional electricity markets into a unified framework. Within a coupled market, demand and supply bids are no longer restricted to their respective local jurisdictions. Instead, the MC approach enables cross-border energy transactions between participants from different regions, subject only to the physical constraints of the transmission network. The primary advantage of MC lies in enhancing market liquidity, which is often accompanied by the secondary effect of reducing price volatility. Furthermore, MC offers significant benefits to market participants by eliminating the need to acquire explicit transmission capacity rights for cross-border exchanges. These transactions are implicitly facilitated through

the MC mechanism. Participants submit a single order to their local power exchange, which is then matched against competitive bids from both domestic and foreign markets, provided that network constraints are respected [114].

Initial efforts for the coupling of electricity markets in Europe began with the Tri-Lateral Market Coupling between France, Belgium, and the Netherlands in 2006, followed by the launch of Central Western Europe (CWE) coupling in 2010. A major step occurred in 2014 with the implementation of Price Coupling of Regions (PCR) in north-western Europe for simultaneous price and flow calculation across interconnectors. This integration initially covered CWE, Great Britain, the Nordics, and the Baltics. Subsequent expansions included Spain and Portugal (2014) and Italy with France, Austria, and Slovenia (2015), forming the Multi-Regional Coupling (MRC), which now accounts for approximately 85 % of European electricity consumption [115]. The European Commission's Target Model for Single Day-Ahead Coupling (SDAC), formalized in the CACM Regulation from 2015 [116], provided the regulatory framework for these developments. Further milestones include the adoption of flow-based capacity calculation in CWE (2015), the integration of Central and Eastern European markets into MRC (2021), and the implementation of flow-based implicit allocation in the Core region (2022). In 2024, flow-based methodology was successfully extended to the Nordic region, marking near-complete alignment with the SDAC framework [115]. In 2024, a total of 27 countries participated in the SDAC, as it is also depicted in Fig. 2.2 [117].

The availability of reliable information on cross-border capacities is crucial for the successful implementation and operation of European market coupling. One way to map cross-border flow capacities is via the so called NTC approach. In this way, TSOs calculate net transfer capacities (NTCs), which represent fixed, bilateral maximum capacities for cross-border exchanges between two bidding zones. The NTC values are used by the market clearing algorithm as upper bounds for cross-border flows. The main advantage of this approach is the simplicity, as it does not cause any additional complexity in the market clearing algorithm. On the other hand, the NTC approach does not fully capture current network situations and thus network constraints or loop flows. As a result, conservative estimates often lead to underutilization of the grid and thus welfare losses. That is why in recent years the Flow Based Market Coupling (FBMC) approach was introduced. With FBMC, the physical reality of the interconnected grid is approximated by using Power Transfer Distribution Factors (PTDFs, see Section 2.2.3.6). Instead of fixed bilateral capacities, FBMC calculates available capacity based on the entire network's constraints and by modeling how each transaction affects flows across all critical network elements. As a main advantage, this allows a more efficient use of transmission capacities and thus welfare gains through better price convergence and reduced congestion costs. The disadvantage is a much higher computational complexity and the requirement of detailed grid data.

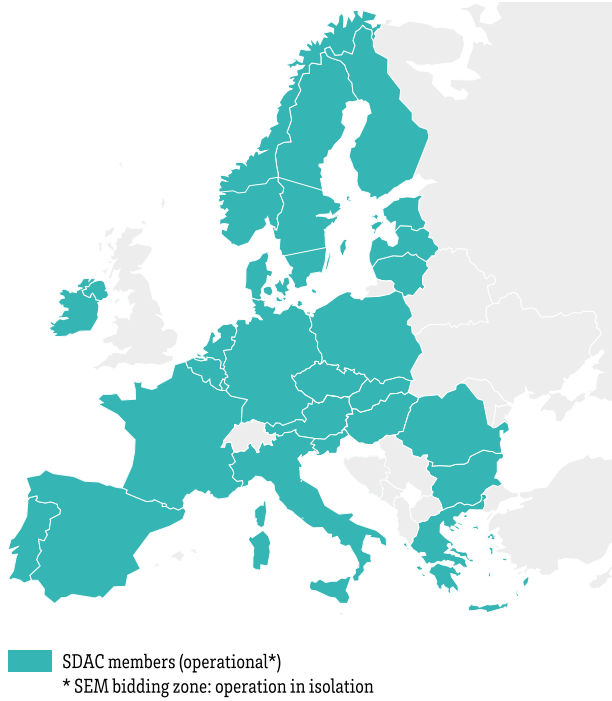


Figure 2.2: Countries participating in SDAC in 2024 [117]. The SEM (Single Electricity Market) bidding zone includes Ireland and Northern Ireland.

The coupling of different markets results in one large-scale market clearing optimization problem, mainly containing different kinds of bids as well as network constraints. Since 2014, this market clearing problem is solved using EUPHEMIA [114]. Initially, market participants submit their bids to their respective power exchanges. These bids are aggregated and processed by EUPHEMIA, which determines the set of orders to be executed and the corresponding market prices. The algorithm operates under two primary objectives [114]:

- Maximize overall economic welfare, defined as the sum of consumer surplus, producer surplus, and congestion rents across all coupled regions.
- Ensure compliance with network constraints, meaning that the power flows resulting from the accepted orders and corresponding net positions do not exceed the available transmission capacity of relevant network elements.

EUPHEMIA is designed to handle both standard and complex order types, respecting all associated requirements. Its optimization process begins by identifying a feasible initial solution and iteratively improving it to increase the total economic surplus. The algorithm is generic and

scalable: it imposes no strict limitations on the number of markets, orders, or network constraints, and treats all orders of the same type submitted by participants uniformly [114].

2.1.3 Electricity network levels

In Germany and most other European countries, the electricity system is structured into four hierarchical voltage levels: extra-high voltage, high voltage, medium voltage, and low voltage. Each level fulfills distinct technical and operational functions within the integrated transmission and distribution landscape [118]:

The extra-high voltage grid, operated at 220 kV to 380 kV, whereby higher voltages are possible, especially in HVDC connections, forms the backbone of the European electricity system. It enables the long-distance transmission of large power volumes from generation to load centers and cross-border power exchange, which is why it is also called the transmission grid. The extra-high voltage grid is the focus of this study.

The high-voltage network, typically operated at 110 kV, serves as an intermediate layer between electricity transmission and distribution. It transports electricity from medium-sized generators to lower-voltage distribution networks and supplies major industrial consumers.

The German electricity grid

Network levels and electricity flow

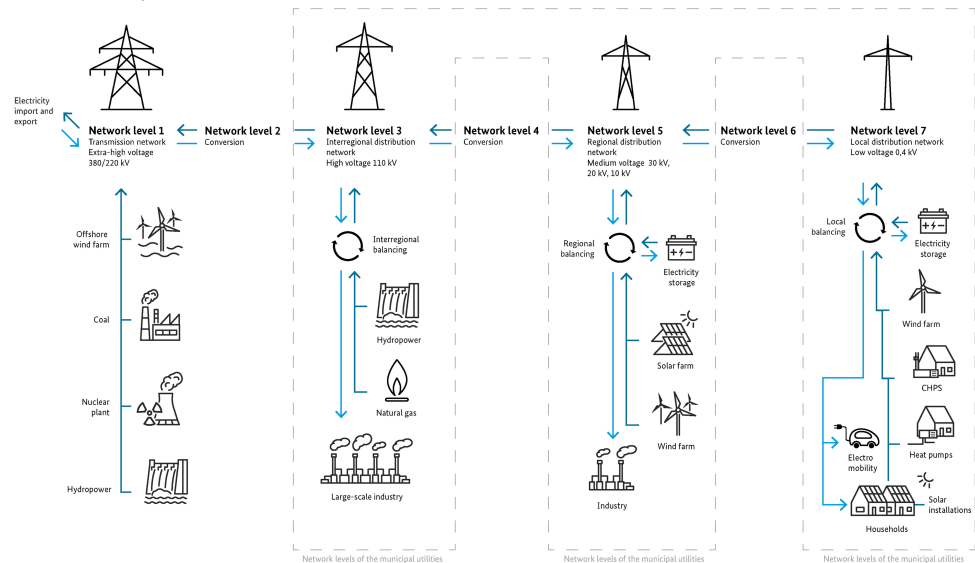


Figure 2.3: Overview of the four network levels in the German electricity system [118].

Below this, the medium-voltage network operates in the 10 kV to 30 kV range. It distributes electricity from smaller generators, such as local renewable energy plants, to medium-sized towns, commercial areas, and medium-scale industrial consumers. As decentralized generation has expanded in recent years, the medium-voltage level has gained increased relevance for system integration of distributed energy resources.

The low-voltage network, operating at 400 V, is the final delivery stage in the electricity system. It supplies households, commercial facilities, and small industrial consumers, and represents the interface between the power system and end-users.

An overview of the different network levels on the example of Germany is given in Fig. 2.3.

2.1.4 Congestion management

In European electricity markets, the determination of market outcomes does not consider the detailed underlying grid infrastructure beyond cross-border transmission limits. As a result, the market outcome is not necessarily feasible with respect to the physical network, meaning that implementing the market-based power flows may overload individual transmission lines or transformers. If the market result cannot be realized due to N-1 grid constraints, this is called a congestion [109]. N-1 security refers to the requirement that the power system must be able to withstand the failure of any single system component, such as a transmission line or transformer, without violating operational limits or interrupting supply [109]. To ensure a stable and secure grid operation, these congestions have to be alleviated via so-called congestion management. Managing these congestion issues is the task of the relevant system operator. Overloads in the transmission grid are addressed by the transmission system operator (TSO), while congestion in the distribution grid is handled by the corresponding distribution system operator (DSO). Talking about congestion management, we can differentiate two types: ex-ante and ex-post congestion management.

In ex-ante congestion management the aim is to anticipate future congestions on the long-term perspective and prepare the system in the best possible way, e.g., by calculating and allocating cross-border transmission capacities, investing into new grid infrastructure or developing new market designs. Ex-post congestion management happens on a shorter time frame, most of the time after the day-ahead market clearing is done, and thus the market result for the next day is obtained. The TSO (or DSO) determines the anticipated power flows resulting from the market result using a load flow calculation (see Section 2.2.3.2) and then takes actions to manage expected congestion.

2.1.4.1 Technical measures

Technical measures in ex-ante congestion management primarily comprise investments in grid infrastructure aimed at preventing congestion before it occurs. These measures include the construction of new transmission lines, the reinforcement of existing lines, the installation of additional transformers, and the deployment of power-flow-controlling devices such as Flexible AC Transmission Systems (FACTS). At the low-voltage and medium-voltage levels, ex-ante measures mainly involve the expansion of local distribution substations and the reinforcement of distribution lines, particularly in regions with high penetration of renewable energy sources. At the high-voltage and extra-high-voltage levels, the construction of new transmission corridors and the upgrading of existing lines constitute the most important instruments to address the increasing stress on the transmission network resulting from the expansion of renewable energy sources. A prominent example is the ongoing deployment of high-voltage direct current (HVDC) transmission lines transporting electricity from northern to southern Germany, designed to mitigate congestion caused by high wind generation in the north and high demand in the south. Beyond pure grid expansion, enhancing the controllability of power flows to increase the utilization of existing infrastructure is becoming increasingly important in systems with a growing share of variable renewable generation. Accordingly, investments in controllable transmission assets such as FACTS devices or phase-shifting transformers (PSTs) are an integral component of ex-ante congestion management strategies. Another relevant technical measure is the application of dynamic line rating (DLR). Since the transmission capacity of overhead power lines is primarily constrained by thermal limits, the maximum admissible power flow depends strongly on prevailing environmental conditions. DLR is a real-time approach that determines the current-carrying capacity of a transmission line based on actual weather conditions, such as ambient temperature, wind speed, and solar radiation. To enable this functionality, appropriate meteorological sensors must be installed along the transmission line to continuously monitor the relevant parameters. By continuously updating the line rating in real time, DLR enables higher utilization of transmission capacity under favorable cooling conditions, with potential increases of up to 30 % [119].

For ex-post congestion management, system operators, especially TSOs, have several technical possibilities to manage power flows and thus try to resolve anticipated congestion. One category of such measures is the operational use of power-flow-controlling devices, including FACTS technologies such as Static Synchronous Series Compensators (SSSC), Thyristor-Controlled Series Compensators (TCSC), Unified Power Flow Controllers (UPFC), as well as PSTs. By adjusting the setpoints of these devices, system operators can influence power flows and redirect them away from overloaded network elements, thereby enhancing the utilization of existing transmission capacity. A further ex-post measure is transmission switching, which comprises switching operations at transmission substations (e.g., opening or closing a switch that connects two busbars at

a substation which again connect different transmission lines). These actions alter the network topology and, consequently, the resulting power flow pattern, with the objective of alleviating congestion and improving overall system efficiency. Since these operational measures involve no direct costs beyond the operating expenses of the installed equipment, they are typically employed as first-line actions before resorting to more costly market-based or redispatch interventions.

2.1.4.2 Redispatch

If technical ex-post measures are not sufficient to resolve congestion, market intervention is necessary. This is done by countertrading or redispatch measures. With countertrading, the system operator makes trades against the direction of the congested flow (e.g., between two bidding zones) to reduce the flow over the line [109]. In the case of redispatch, the TSO gives instructions to the operators of power plants (conventional or RES) or storage systems to adjust the planned operation schedule of one or more of their plants, meaning they have to increase or decrease the plant's power production (or demand in case of storages) by a given value for a given time period. For example, a congestion on a transmission line can be resolved by power plants located upstream of the congestion reducing their production, and power plants located downstream of the congestion increasing their production. Plant operators affected by redispatch measures must be compensated accordingly. Hereby, the principle applies that the plant operator should be neither worse off nor better off financially as a result of the redispatch measure than they would have been without the measure. In Germany, the currently active Redispatch 2.0 regulation determines that the grid operator is responsible for compensating for redispatch measures in the balance group to maintain the balance of supply and demand [120]. Therefore, redispatch measures do not affect the market position of the plant operator. Generally, this implies that for positive redispatch measures (increase in real power generation), the grid operator must pay compensation to the plant operator, since the plant operator has to pay for additional operational expenses like fuel and CO₂ certificates without being able to sell the additional produced energy on the market. For negative redispatch measures (decrease in real power generation), the plant operator has to pay compensation to the grid operator, since the production costs decrease while the sold energy on the market remains the same. A more detailed description of the compensation calculation and its implementation in an energy system model can be found in Section 3.2.2.

If the available free generation capacity is not sufficient to provide the required amount of positive redispatch, units of the grid reserve must be activated. These are conventional power plants that no longer participate in the market but are kept in reserve for such contingencies. In addition to their typically relatively high operating costs, they receive remuneration for maintaining readiness.

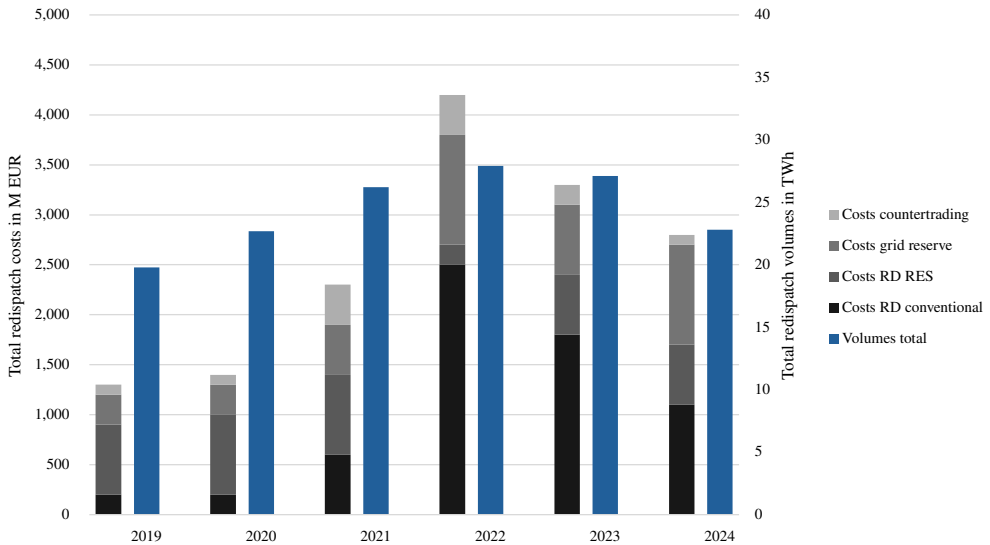


Figure 2.4: Annual volumes and costs related to congestion management measures in Germany for the years 2019 to 2024. The volumes are the sum of positive and negative redispatch measures. Own illustration based on data from SMARD [121].

The recent development of annual redispatch volumes and related costs in Germany is depicted in Fig. 2.4. There is a noticeable increase in both volumes and costs, with costs peaking in 2022 due to high fuel prices, especially gas, caused by the beginning of the Russia-Ukraine war. The increase in redispatch volumes is mainly driven by the increasing share of wind and PV, as the energy production of these technologies is often geographically concentrated and weather-dependent, which amplifies regional imbalances and congestion in the transmission as well as distribution grid. Costs related to redispatch with RES arise primarily for plants under fixed feed-in tariffs. Because these generators are remunerated for the energy physically injected into the grid, any redispatch-induced reduction in feed-in directly lowers their revenue. Accordingly, they receive compensation for the curtailed output.

2.1.4.3 Regulatory approaches

In addition to technical measures, regulatory instruments and economic incentives can effectively be used in congestion management to reduce necessary redispatch costs. In general, these measures aim to regulate the market or incentivize market participants such that the market outcome is more compatible with the transmission grid infrastructure. Therefore, these measures belong to ex-ante congestion management. In recent years, mainly three approaches have been in discussion and

are partially in operation in different parts of the world: Market zone splits, nodal pricing, and dynamic grid fees.

Market zone splitting

Market (or bidding zone) splitting describes the geographical breakdown of a market area into several smaller market areas. Although at the moment most European countries have a single market zone for the whole country, there are some exceptions. E.g., Denmark is divided into two distinct market zones, Sweden into four, Norway into five, and Italy even into seven. For each of the market areas, generation and demand must be in balance, with exchange flow capacities between market areas being restricted by physical capacity limits. In this way, large geographical imbalances of generation and demand can be prevented, which leads to less congestion and the associated redispatch costs [122]. On the downside, market zone splitting leads to different wholesale price levels across the affected areas, and the transition process involves substantial administrative effort and associated costs [123].

In Germany, the introduction of a market zone split has been the subject of increasing discussion in recent years, both in politics and in academia. According to the Bidding Zone Review for Europe and the target year 2025 of ENTSO-E [3], splitting the Germany-Luxembourg market zone could yield economic benefits of roughly 300 M EUR in the target year 2025, with no notable differences between configurations of two, three, or four market zones. Other studies suggest that the potential annual cost benefits are less than 1 % [124] or that splitting the German market area into three zones could even lead to a cost increase of up to 300 M EUR, which is roughly 1 % of total system costs [125].

A major challenge in implementing market zone splitting lies in defining a geographically stable zone layout that remains robust over time [126]. Since the expansion of renewable energy sources leads to changes in geographical feed-in patterns, an optimal zone configuration for 2025 may look quite different from that for 2035. Given the regulatory and organizational burden of introducing such a market regime, a frequent reconfiguration of the zones is not manageable. A second obstacle is political resistance from high-demand regions with relatively low renewable generation, as a market zone split would likely raise electricity prices in these regions [122]. In Germany, this would especially affect the industrially powerful southern part of the country, including the states of Baden-Württemberg and Bavaria.

Nodal pricing

In nodal pricing regimes (also called locational marginal pricing, LMP), the market clearing algorithm computes one price per network node and time period, rather than a single uniform price for the whole market [123, 127]. Every network node can be considered as a single market area where supply and demand must be balanced. The market is cleared using an OPF algorithm

that incorporates physical transmission constraints between network nodes. This way, feasibility of the market result with the underlying grid infrastructure is guaranteed. The resulting nodal price equals the short-run marginal cost to meet the demand at that node, considering all network constraints [127]. Nodes located in areas with structural generation deficits tend to exhibit higher prices than nodes in surplus regions. In a network without any congestion, the prices for all nodes in the system would be the same [123].

The resulting locational price differentials create incentives for market participants to schedule generation and sales at expected high-price nodes in order to maximize revenues, thereby promoting a spatially more efficient and grid-compatible dispatch of generation. Moreover, nodal pricing provides long-term investment signals by making it more attractive to site new generation and storage assets in deficit regions, which can contribute to the mitigation of structural network bottlenecks. Nodal pricing has already been implemented in several electricity markets worldwide, including Argentina, Chile, Mexico, and multiple regions in the United States [127]. For the European context, recent studies indicate that the introduction of nodal pricing could yield significant efficiency gains. For the Germany-Luxembourg bidding zone, potential cost savings of approximately 5 % to 8 % are estimated for the year 2025 [124]. Moreover, total cost savings of around 1000 MEUR, corresponding to roughly 2 % of overall system costs, have been estimated for Germany for the year 2023 under a nodal pricing regime [125]. The drawbacks of nodal pricing regimes are high operational and regulatory complexity, distributional and political issues and concerns, challenges for liquidity and hedging markets, and high implementation costs [123].

Dynamic grid fees

Another approach to incorporating network constraints into electricity market design is the introduction of temporally and spatially differentiated network charges, often referred to as dynamic grid fees. In contrast to a nodal pricing regime, wholesale electricity prices remain uniform across the entire market area, while only the network charges are dynamically adjusted in response to the current or anticipated state of the grid [4]. Practical examples of related tariff structures can already be found in the Norwegian and Swedish transmission systems, where the marginal costs of transmission losses is reflected in the grid tariff on a node-by-node basis. In both countries, transmission grid tariffs are levied on both withdrawals from and injections into the grid, thus providing location-specific incentives for all grid users. However, transmission constraints or bottlenecks and the related costs are not reflected in the tariffs.

In Germany, by contrast, only electricity consumers currently pay grid fees, while producers do not contribute to the financing of the electricity grid. The Federal Network Agency has recently proposed extending grid cost recovery to producers and, in this context, conceptually differentiates between a financing function and an incentive function of grid charges [128]. The financing function is intended to ensure an appropriate contribution to grid expansion and reinforcement

costs, for example through capacity-based charges for producers that are linked to their contracted grid connection capacity. Complementing this, the incentive function aims to promote grid-friendly behavior by both producers and consumers. Corresponding tariff components would be volume-based and temporally as well as spatially differentiated, with a sign-consistent design to ensure that price signals are aligned with system needs (e.g. higher charges in situations of network stress and lower, potentially even negative, charges in system-relieving situations).

Despite these conceptual advances and a growing interest in academic and regulatory literature [4, 123, 128–130], several design questions remain open. In particular, it is necessary to clarify on which network levels dynamic grid fees should be applied, which categories of grid users (e.g., household consumers, industrial customers, power plant operators, distributed generators, storage operators) should face which components of the tariff, and how exactly the temporal and spatial differentiation of the charges ought to be specified and operationalized in practice.

2.2 Electrical energy systems

This section provides an overview of the fundamental electrical engineering principles of power systems that are relevant to the present study. Core topics include steady-state power system representation, power flow theory, and the electrical characteristics of network components such as transmission lines, transformers, and flexible network elements. Furthermore, principles of applied power flow calculation methods are introduced.

2.2.1 Electrical energy transmission

This section introduces the basic principles of electric power transmission over high-voltage lines. Key physical and technical aspects that govern power flows and transmission limits are briefly outlined to provide the foundation for the subsequent chapters.

2.2.1.1 Simplified energy transmission on electricity lines

Energy transmission through electricity is typically achieved using three-phase alternating current (AC). This system employs three conductors, along with a neutral conductor, each carrying an AC voltage of identical frequency but phase-shifted by 120 degrees. Such an arrangement enables highly efficient power transmission and is widely utilized in high-energy applications, such as transmission systems, due to its capability to deliver consistent power and handle substantial loads. When the three conductors of the transmission line and the loads across the three phases

are symmetrical, and the line is electrically short relative to the wavelength of the electromagnetic oscillation, the transmission line can be effectively represented using a simplified single-phase equivalent circuit diagram, as depicted in Fig. 2.5 [131].

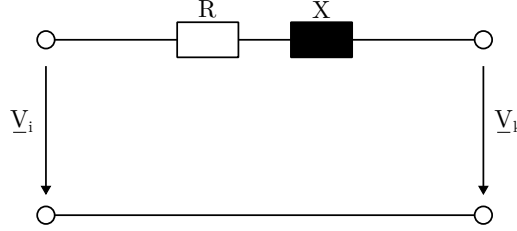


Figure 2.5: Depiction of the 1-phase equivalent circuit diagram for electrically short AC transmission lines.

The nominal frequency in Europe's transmission grid is 50 Hz, which leads to the following wave length for the electromagnetic oscillation:

$$\lambda = \frac{v}{f} = \frac{c}{50 \text{ Hz}} = 6000 \text{ km} \quad (2.1)$$

Since transmission lines in Europe have a length of at maximum a few hundred kilometers, the assumption of electrically short lines is valid.

The 1-phase equivalent circuit diagram consists of the complex input and output voltages $\underline{V}_i$ and $\underline{V}_k$ and the complex line impedance $\underline{Z} = R + jX$. Since typically the resistance R is much smaller than the reactance X , at this point the resistance is neglected and the impedance is equal to the reactance jX . In order to calculate the power transferred from input node i to output node k , the second of Kirchhoff's laws is used, which states that the sum of all partial voltages in a mesh must be zero. With the complex voltages $\underline{V}_i = V_i e^{j\theta_i}$ and $\underline{V}_k = V_k e^{j\theta_k}$ and the complex mesh current $\underline{I}$ this leads to [132]:

$$\underline{V}_i - \underline{V}_k - jX\underline{I} = 0 \quad (2.2)$$

$$\underline{I} = \frac{\underline{V}_i - \underline{V}_k}{jX} \quad (2.3)$$

The apparent power $\underline{S}_i$ injected in node i can be calculated as follows:

$$\underline{S}_i = P + jQ = \underline{V}_i \cdot \underline{I}^* = \frac{\underline{V}_i(\underline{V}_i^* - \underline{V}_k^*)}{-jX} \quad (2.4)$$

With $\underline{V}_i = V_i e^{j\theta_i}$, $\underline{V}_k = V_k e^{j\theta_k}$, $\delta = \theta_i - \theta_k$ and the Euler equation $e^{j\delta} = \cos \delta + j \sin \delta$ the equation for the calculation of the injected apparent, real and reactive power can be reformulated:

$$\underline{S}_i = \frac{V_i^2 - V_i V_k e^{j\delta}}{-jX} = \frac{V_i V_k \sin \delta}{X} + j \frac{V_i^2 - V_i V_k \cos \delta}{X} \quad (2.5)$$

$$P_i = \frac{V_i V_k \sin \delta}{X} \quad (2.6)$$

$$Q_i = \frac{V_i^2}{X} - \frac{V_i V_k \cos \delta}{X} \quad (2.7)$$

With the same procedure and $\sin(-\delta) = -\sin(\delta)$, $\cos(-\delta) = \cos(\delta)$ also the injected power at node k at the end of the transmission line can be calculated:

$$P_k = -\frac{V_i V_k \sin \delta}{X} \quad (2.8)$$

$$Q_k = \frac{V_k^2}{X} - \frac{V_i V_k \cos \delta}{X} \quad (2.9)$$

It is easy to see that the active power entering and leaving the line is identical, which is due to the neglect of the line resistance and thus the assumption of a lossless line. The amount of transmitted active power depends on the product of voltage magnitudes, reactance and phase angle difference $\delta = \theta_i - \theta_k$. Maximum active power transfer is achieved with a phase angle difference of $\delta = 90^\circ$ and results in $P = \frac{V_i V_k}{X}$. The amount of transmitted reactive power, on the other hand, is directly dependent on the difference between the voltage amplitudes at the start and end nodes and is always transferred from the larger to the smaller voltage magnitude.

Since up to now a lossless transmission was assumed, in the following an assessment for the transmission losses shall be made. For a transmission line with resistance R the losses transfer to:

$$P^l = I \cdot I^* \cdot R \quad (2.10)$$

With Eq. (2.4) and the average voltage on the line $\underline{V}$, we get the current I :

$$\underline{I} = \frac{P - jQ}{\underline{V}} \quad (2.11)$$

Inserting the two equations into each other yields an approximation for the transmission losses:

$$P^l = \frac{(P^2 + Q^2)R}{V^2} \quad (2.12)$$

The amount of line losses therefore depends not only on the transmitted active power but also on the transmitted reactive power. In addition, they decrease with the square of the transmission voltage, which is the main reason for using very high voltages in transmission grids.

2.2.1.2 Complete complex power flow equations

In the previous section, the assumption of a negligibly small line resistance R was made to simplify the calculations. This section assumes a complex line impedance $\underline{Z} = R + jX$. The formula for the calculation of the injected power is then as follows, also using the admittance $\underline{Y} = G + jB$ as the reciprocal of the impedance $\underline{Z}$:

$$\underline{S}_i = P + jQ = \underline{V}_i \cdot \underline{I}^* = \frac{\underline{V}_i(\underline{V}_i^* - \underline{V}_k^*)}{\underline{Z}^*} = \underline{V}_i(\underline{V}_i^* - \underline{V}_k^*)\underline{Y}^* \quad (2.13)$$

With $\underline{V}_i = V_i e^{j\theta_i}$, $\underline{V}_k = V_k e^{j\theta_k}$, $\delta = \theta_i - \theta_k$ and the Euler equation $e^{j\delta} = \cos \delta + j \sin \delta$ we can again reformulate the equation and calculate the injected active and reactive power at start node i :

$$\begin{aligned} \underline{S}_i &= (V_i^2 - V_i V_k e^{j\delta})(G - jB) = (V_i^2 - V_i V_k \cos \delta - jV_i V_k \sin \delta)(G - jB) \\ &= V_i^2 G - V_i V_k G \cos \delta - V_i V_k B \sin \delta + j(-V_i^2 B - V_i V_k G \sin \delta + V_i V_k B \cos \delta) \end{aligned} \quad (2.14)$$

$$P_i = V_i^2 G - V_i V_k G \cos \delta - V_i V_k B \sin \delta \quad (2.15)$$

$$Q_i = -V_i^2 B - V_i V_k G \sin \delta + V_i V_k B \cos \delta \quad (2.16)$$

For end node k and with $\sin(-\delta) = -\sin(\delta)$, $\cos(-\delta) = \cos(\delta)$ we get:

$$P_k = V_k^2 G - V_i V_k G \cos \delta + V_i V_k B \sin \delta \quad (2.17)$$

$$Q_k = -V_k^2 B + V_i V_k G \sin \delta + V_i V_k B \cos \delta \quad (2.18)$$

Since either P_i or P_k is always positive while the other is negative, and the magnitude of the positive value (representing power injected into the line) consistently exceeds that of the negative value (representing power drawn from the line), the losses can be directly calculated as the sum of the injected power P_i at the start node i and P_k at the end node k .

$$\begin{aligned}
P_{ik}^l &= P_i + P_k \\
&= V_i^2 G - V_i V_k G \cos \delta - V_i V_k B \sin \delta + V_k^2 G - V_i V_k G \cos \delta + V_i V_k B \sin \delta \\
&= V_i^2 G + V_k^2 G - 2V_i V_k G \cos \delta
\end{aligned} \tag{2.19}$$

Obviously, the relations between transmitted power and bus voltages are more complex than in the simplified case in Section 2.2.1.1. However, the basic statements still apply: while the magnitude and direction of the transmitted real power depends mainly on the difference in the voltage angles $\delta = \theta_i - \theta_k$, the magnitude and direction of the transmitted reactive power depends mainly on the difference in the voltage magnitudes $V_i - V_k$.

2.2.2 Flexible network elements

As described in the preceding sections, voltages, currents, and power flows in transmission grids are governed by the physical laws of alternating current systems. Consequently, active and reactive power flows are largely determined by the fixed network topology as well as the spatial and temporal distribution of generation and demand. *Flexible network elements* are transmission system assets that provide transmission system operators with additional controllable degrees of freedom beyond passive network operation. By allowing the targeted modification of electrical parameters such as impedance, voltage magnitude, phase angle, or active power injection and withdrawal, these elements enable operators to directly influence power flow patterns in order to prevent or alleviate congestion, improve voltage control, and enhance overall system security.

Typical flexible network elements include power-electronic devices such as Flexible AC Transmission Systems (FACTS), phase-shifting transformers (PSTs), and high-voltage direct current (HVDC) converters, as well as energy storage systems when deployed for grid-supportive operation. FACTS devices and PSTs primarily act on the impedance or phase angle of AC network elements, thereby redistributing flows within meshed transmission grids. HVDC systems provide fully controllable active and reactive power exchange between network nodes or control areas and allow partial decoupling from AC network constraints. Energy storage systems, including battery storage, can likewise function as flexible network elements when their operation is driven by system-level requirements rather than market-based objectives.

In the following, the technical fundamentals and operating principles of the main classes of flexible network elements considered in this thesis are described.

2.2.2.1 Shunt connected FACTS

In this section, the functionality of the Static Var Compensator (SVC) and Static Synchronous Compensator (STATCOM) are explained. Both devices are shunt connected FACTS, which means that they are connected to a busbar in parallel to transmission lines. Shunt-connected FACTS controllers provide inductive or capacitive reactive power compensation depending on their configuration, or they inject self-generated inductive or capacitive reactive power into network nodes. Under normal operating conditions, they therefore contribute to voltage regulation at the respective node. During transient disturbances, additionally, active power can be provided to enhance system stability. The current flowing through shunt FACTS controllers is phase-shifted by 90° relative to the network voltage, which means that there is no exchange of active power. Inductive reactive power injected into a node supports the node voltage and, from the network's perspective, behaves like a shunt connected capacitor. Conversely, capacitive reactive power injection lowers the node voltage and appears to the network as a shunt connected inductor. Shunt-connected FACTS controllers are coupled to the network via transformers to avoid designing the converter valves for the full system voltage [131, 133].

SVC

The SVC consists of an inductor, a capacitor and controlling elements like thyristors, which can adjust the effective impedance of the device. An exemplary configuration of an SVC is shown in Fig. 2.6.

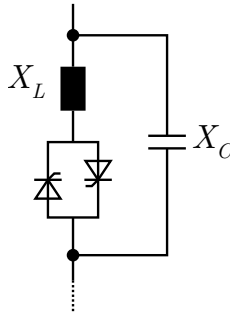


Figure 2.6: Exemplary configuration of an SVC. Own illustration based on [131].

It consists of a capacitance, an inductance, and a set of thyristors which can switch the inductance on and off in a high frequency and thus control the effective inductance. Therefore, the overall impedance can also be controlled, which can be calculated as

$$X^{\text{SVC}} = \frac{X_L(\alpha) \cdot X_C}{X_L(\alpha) + X_C} \quad (2.20)$$

with the thyristor firing angle α . The effective impedance, in turn, acts as a source of positive or negative reactive power on the system and can thus regulate the voltage.

STATCOM

Unlike SVC systems, which achieve compensation by switching reactive components in and out of the network (thus only providing reactive power compensation), a STATCOM behaves like an additional synchronous generator connected to the grid, capable of producing and supplying inductive or capacitive reactive power (however, without generating active power and without any rotating masses) [131]. A STATCOM consists of a voltage source converter (VSC), a capacitive energy storage element C_s and a three-phase coupling transformer with short-circuit reactance X_k (see Fig. 2.7 left).

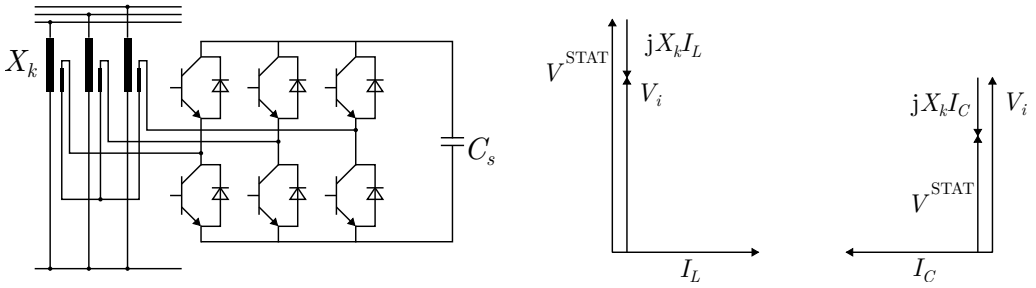


Figure 2.7: Circuit diagram (left) and phasor diagram (right) of the STATCOM. Own illustration based on [131].

Using the charged capacitive energy storage, the VSC synthesizes three controllable, approximately sinusoidal AC voltages $\underline{V}^{\text{STAT}}$, shifted by 120° from each other, through pulse-width modulation. This three-phase voltage system is connected in parallel to the grid voltage system $\underline{V}_i$ via the short-circuit reactance X_k of the coupling transformer. When $|\underline{V}^{\text{STAT}}| > |\underline{V}_i|$, the current phasors $\underline{I}_L$ lag behind the voltage phasors $\underline{V}^{\text{STAT}}$ and $\underline{V}_i$ by 90° , resulting in the generation of inductive reactive power. Conversely, when $|\underline{V}^{\text{STAT}}| < |\underline{V}_i|$, the current phasors $\underline{I}_B$ lead the voltage phasors by 90° , producing capacitive reactive power. In both cases, the voltages of the STATCOM and the grid node share the same phase angle [131]. The corresponding phasor diagram is shown in the right side of Fig. 2.7. From the grid's perspective, the STATCOM behaves like a shunt capacitor in the first case, providing capacitive reactive power, and like a shunt reactor in the second case, supplying inductive reactive power.

2.2.2.2 Series connected FACTS

Series connected FACTS are used in steady-state operation mainly to control the power flows in a transmission network. They are installed in series with the phases of a transmission line and

operate at high-voltage potential. These devices can manipulate the effective line impedance and in this way they can control the current and power flow on the line. Although they can only directly control the flow on the line at which they are installed, indirectly they also impact the flows on other lines or even the whole system. For example, they can be used to achieve an even distribution of power flows across two parallel paths or prevent and resolve congestions. In addition, they can affect not only real but also reactive power flows and thus have an influence on voltage magnitudes as well [131, 133, 134].

In the following, the Thyristor Controlled Series Compensator (TCSC), the Static Synchronous Series Compensator (SSSC) and the Unified Power Flow Controller (UPFC) are described in more detail.

TCSC

Similarly to the SVC, the TCSC consists of the parallel circuit of a static capacity and an inductance which is controlled by a set of thyristors. The effective inductance, and thus the effective impedance of the whole device, is controlled by the firing angle α of the thyristors [131, 134]. An exemplary configuration of an SVC is shown in Fig. 2.6. The impedance of the TCSC acts as a series impedance to the line's impedance. This means that the effective line impedance is either decreased or increased, depending on whether the impedance of the TCSC is negative (it acts as a capacitance) or positive (it acts as an inductance). According to Eq. (2.7), a decrease in the line impedance leads to an increase in the transmitted real power while an increase in the line impedance leads to a decrease in the transmitted power.

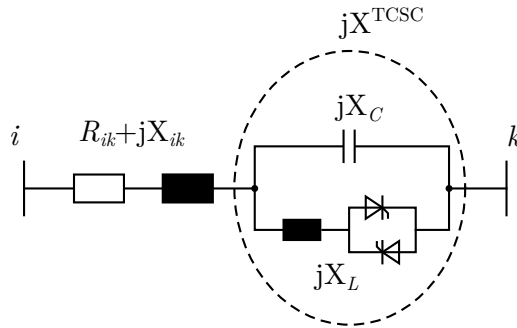


Figure 2.8: Equivalent circuit diagram of an exemplary TCSC configuration installed on a transmission line. Own illustration based on [131].

The effective impedance of the TCSC is calculated as follows [131]:

$$X^{\text{TCSC}} = \frac{X_L(\alpha) \cdot X_C}{X_L(\alpha) + X_C} \quad (2.21)$$

SSSC

The Static Synchronous Series Compensator (SSSC) fulfills a similar purpose as the TCSC in controlling real and reactive power flows. Instead of an adjustable series capacitor, the SSSC consists of an adjustable voltage source that is connected in series to the transmission line whose height corresponds exactly to the voltage drop of an equivalent series capacitance or inductance. Similarly to the STATCOM the 3-phase voltage source is realized with power electronics, a voltage source converter combined with a capacitor connected to the line with the help of a transformer. The SSSC induces an additional series voltage on the line. Depending on the phase angle of the induced voltage, the effective voltage V_L over the line gets either increased or decreased, which then leads to an increased or decreased line current and thus power flow [131, 134]. This means that the transferred active and reactive power can be controlled (in limits) by adjusting the voltage magnitude and phase angle of the SSSC. The equivalent circuit diagram as well as the phasor diagram for the SSSC are shown in Fig. 2.9.

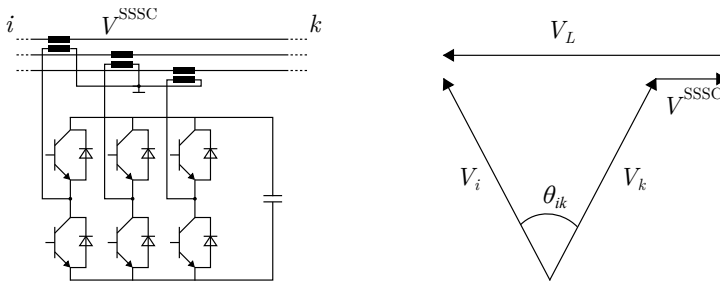


Figure 2.9: Circuit diagram (left) and phasor diagram (right) of the SSSC. Own illustration based on [131].

In normal steady-state operation, the SSSC can generate only reactive power and no real power. However, for short time periods, e.g., in the case of a failure in the network, active power flow exchange can also take place, until the capacitor is either empty or fully charged. By installing an additional storage system, the capability for real power exchange could be enhanced.

UPFC

The UPFC is an advanced FACTS device that integrates the functionalities of a SSSC and a STATCOM. It employs two voltage source converters: one connected in shunt (parallel) and the other in series with the transmission line. By combining the capabilities of both devices, the UPFC provides comprehensive control over power flow and system voltage. Specifically, it enables precise regulation of active power through series compensation and maintains voltage stability by injecting or absorbing reactive power via the shunt converter [131, 134]. The schematic equivalent circuit diagram is shown in Fig. 2.10.

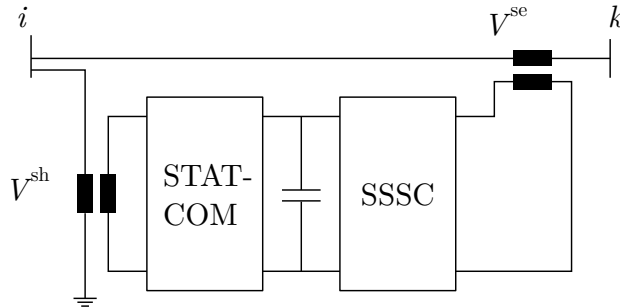


Figure 2.10: Simplified circuit diagram of the UPFC. Own illustration based on [131].

2.2.2.3 Phase shift transformer

PSTs are electromechanical devices designed to control active power flow in high-voltage transmission networks by introducing a controlled phase angle shift between sending and receiving end voltages. They are composed of two main components: a series transformer, which injects a voltage in series with the transmission line, and a shunt transformer, which supplies this injected voltage. The shunt transformer is equipped with a tap changer that allows discrete adjustments of its tap position. Each tap setting modifies the magnitude and polarity of the injected voltage, thereby altering the phase angle of the line voltage [131]. The general circuit diagram of a PST and an exemplary phasor diagram to illustrate its functionality are shown in Fig. 2.11.

2.2.2.4 HVDC converters

HVDC converters connect a high-voltage DC transmission system, most commonly consisting of a single point-to-point line or cable, with a high-voltage AC transmission grid. HVDC transmission lines are increasingly being deployed as an alternative to conventional AC lines for long-distance

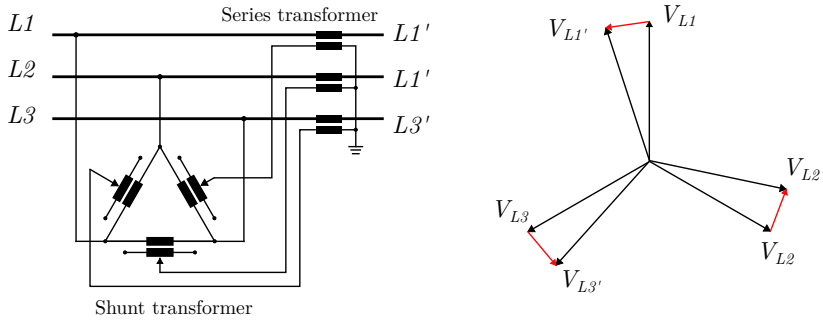


Figure 2.11: Circuit diagram and exemplary phasor diagram of the PST. Own illustration based on [131].

bulk power transport, as DC transmission is associated with lower electrical losses and avoids issues related to reactive power flows and stability constraints. In Germany alone, four major HVDC corridor projects are currently under construction or in advanced planning stages, reflecting their central role in the transport of renewable electricity from generation-rich regions in the north to major load centers in the south [135]. Beyond onshore bulk transmission, HVDC systems are widely used for the connection of offshore wind farms and for linking asynchronous or weakly coupled AC grid areas.

The HVDC converter itself is a power-electronic device that enables bidirectional conversion between DC and AC power. Several converter technologies exist, of which VSC-based systems have gained particular importance in recent projects. Within this category, the Modular Multi-Level Converter (MMC) has emerged as the most promising and widely adopted topology due to its scalability, high efficiency, and favorable harmonic performance. A key characteristic of VSC-based HVDC converters is their ability to independently control the magnitude and phase angle of the AC voltage at the converter terminals, largely decoupling their operation from the connected AC grid. As a result, VSC-HVDC converters can actively control both active and reactive power exchange with the AC system. By adjusting their output voltage, they are capable of regulating power flows, providing voltage support, and contributing to system stability even under weak grid conditions.

2.2.2.5 Energy storage systems

When employed for grid-supportive purposes, energy storage systems constitute a distinct class of flexible network elements. In this role, storage units are dispatched by the system operator to absorb or inject active power at specific grid locations, thereby relieving transmission congestions, supporting voltage levels, and enhancing operational reserves [94]. Unlike market-oriented storage operation, where charging and discharging decisions are driven by price signals, grid-oriented

storage operation follows system-level objectives such as secure operation, congestion mitigation, and reliability enhancement.

The contribution of storage systems to network flexibility primarily stems from their ability to temporally decouple generation and consumption. By shifting electrical energy in time, storage can reduce peak power flows on stressed network elements and compensate for short-term mismatches between supply and demand [136]. In contrast to transmission-oriented power-electronic devices, such as FACTS, PSTs, or HVDC converters, which mainly provide spatial controllability of power flows, storage systems add a temporal dimension to grid operation. This temporal flexibility complements spatial flow control and broadens the range of feasible operational interventions available to transmission system operators [137]. From a system operation perspective, storage systems can be used both preventively and curatively. Preventive operation includes charging or discharging actions scheduled in anticipation of expected network constraints, for instance, during periods of high renewable generation or forecasted peak demand. Curative operation, by contrast, refers to short-term activation of storage in response to unforeseen contingencies or rapidly evolving congestion situations. In both cases, storage provides fast and localized control capabilities, enabling targeted interventions without requiring immediate changes to generation dispatch or network topology [94].

2.2.2.6 Other flexible network elements

In addition to power-electronic devices and network-oriented energy storage systems, several further measures can be classified as flexible network elements, as they provide transmission system operators with additional operational degrees of freedom. These include transmission switching, dynamic line rating, and network-driven load flexibility. While these elements differ from conventional grid assets in that they often require limited or no new physical infrastructure, they nonetheless contribute significantly to the operational flexibility of transmission systems through targeted adjustments in network operation.

Transmission switching refers to deliberate switching actions within the transmission network, such as the opening or closing of lines, bus couplers, or tie switches, with the objective of temporarily altering the network topology [51, 70–72]. By modifying the topological configuration of the grid, power flows can be redistributed, overloaded network elements relieved, and the utilization of existing infrastructure improved. Transmission switching does not change the physical characteristics of individual grid components. Instead, it expands the feasible operating space by introducing additional topological degrees of freedom.

Dynamic line rating (DLR) increases the operational flexibility of overhead transmission lines by replacing static, conservative thermal limits with ratings that adapt to real-time environmental

conditions. Since the current-carrying capacity of transmission lines primarily depends on ambient temperature, wind speed, and solar radiation, higher power transfers can be safely achieved under favorable weather conditions. DLR thus allows a temporary increase in usable transmission capacity without altering the physical design of the lines. Although dynamic line rating does not actively control power flow patterns, it enlarges the operational margin available to system operators [119, 138, 139].

Load flexibility can also be regarded as a flexible network element when it is activated for system-operation purposes rather than market participation. In this context, large controllable consumers, such as industrial loads, electrolyzers, or other flexible demand units, adjust their electricity consumption upon request by the system operator to support secure grid operation. By temporarily reducing or shifting demand at specific locations, load flexibility can alleviate local congestions or stabilize critical operating conditions [140].

2.2.3 Applied power flow calculation

In this section, the most common methods to perform different kinds of power flow analysis in electricity networks are introduced as well as some definitions that are key to understanding the following chapters.

2.2.3.1 Nodal admittance matrix

Since electrical energy systems consist of more than two nodes and one transmission line connecting them, but rather of meshed networks with up to several thousands of nodes and lines, we need efficient methods to calculate voltages, currents and power flows in these networks. The basic for most of the calculation methods is the nodal admittance matrix $\underline{Y}$. It includes all transfer admittances between the nodes of a network. To establish this matrix, the admittances of all electrical components in the single-phase system must first be determined. Once this is done, all n nodes of the network are numbered from 1 to n , with the neutral conductor assigned the index 0. Each node i has a node voltage $\underline{V}_i$ relative to an arbitrary reference node, typically the ground. The current $\underline{I}_{ik}$ flowing from node i to node k can be calculated from the respective node voltages and the admittance $\underline{Y}_{ik}$ between the two nodes. Outgoing currents are indicated by a positive sign, while incoming currents are indicated by a negative sign. Currents injected into node i from external sources, such as from a generator or a load, are represented by $\underline{I}_{ii}$.

$$\underline{I}_{ik} = \underline{Y}_{ik}(\underline{V}_i - \underline{V}_k) \quad (2.22)$$

According to Kirchhoff's first law, the sum of all incoming and outgoing currents in a node must be zero. This yields the following for each node i in the network:

$$\sum_{k=0}^n \underline{I}_{ik} = 0 \quad \forall i \in \mathcal{N} \quad (2.23)$$

Using Eq. (2.22) for the currents and simple transformation gives the following:

$$\underline{Y}_{i0}(\underline{V}_i - \underline{V}_0) + \underline{Y}_{i1}(\underline{V}_i - \underline{V}_1) + \dots + \underline{I}_{ii} + \dots + \underline{Y}_{in}(\underline{V}_i - \underline{V}_n) = 0 \quad (2.24)$$

$$\underline{V}_i(\underline{Y}_{i0} + \underline{Y}_{i1} + \dots + \underline{Y}_{in}) - \underline{Y}_{i0}\underline{V}_0 - \underline{Y}_{i1}\underline{V}_1 - \dots - \underline{Y}_{in}\underline{V}_n = -\underline{I}_{ii} \quad (2.25)$$

Since a node has no branch admittance to itself, the entries $\underline{Y}_{ii}$ are currently all 0. These empty entries can be used to store the so called loop admittance of node i which represents the negative sum of all adjacent branch admittances.

$$\underline{Y}_{ii} = - \sum_{k=0, k \neq i}^n \underline{Y}_{ik} \quad (2.26)$$

Using Eq. (2.25) and Eq. (2.26) yields the following equation:

$$\underline{Y}_{i0}\underline{V}_0 + \underline{Y}_{i1}\underline{V}_1 + \dots + \underline{Y}_{ii}\underline{V}_i + \dots + \underline{Y}_{in}\underline{V}_n = \sum_{j=1}^n \underline{Y}_{ij}\underline{V}_j = \underline{I}_{ii} \quad (2.27)$$

Setting up this equation for all $n + 1$ nodes in the system (including the reference node $i = 0$), a linear equation system is established which can be described with the admittance matrix $\underline{Y}$, the vector of complex node voltages $\underline{V}$ and the vector of external currents injected into the nodes $\underline{I}$.

$$\begin{pmatrix} \underline{Y}_{00} & \underline{Y}_{01} & \dots & \underline{Y}_{0n} \\ \underline{Y}_{10} & \underline{Y}_{11} & \dots & \underline{Y}_{1n} \\ \vdots & \vdots & \ddots & \vdots \\ \underline{Y}_{n0} & \underline{Y}_{n1} & \dots & \underline{Y}_{nn} \end{pmatrix} \begin{pmatrix} \underline{V}_0 \\ \underline{V}_1 \\ \vdots \\ \underline{V}_n \end{pmatrix} = \begin{pmatrix} \underline{I}_{00} \\ \underline{I}_{11} \\ \vdots \\ \underline{I}_{nn} \end{pmatrix} \quad (2.28)$$

This linear equation system can further be simplified by choosing the ground as reference node. The potential of the reference node is then equal to the potential of the neutral conductor leading to $\underline{V}_0 = 0$ which enables us to eliminate the first row and column of the equation system.

$$\begin{pmatrix} \underline{Y}_{11} & \underline{Y}_{12} & \dots & \underline{Y}_{1n} \\ \underline{Y}_{21} & \underline{Y}_{22} & \dots & \underline{Y}_{2n} \\ \vdots & \vdots & \ddots & \vdots \\ \underline{Y}_{n1} & \underline{Y}_{n2} & \dots & \underline{Y}_{nn} \end{pmatrix} \begin{pmatrix} \underline{V}_1 \\ \underline{V}_2 \\ \vdots \\ \underline{V}_n \end{pmatrix} = \begin{pmatrix} \underline{I}_{11} \\ \underline{I}_{22} \\ \vdots \\ \underline{I}_{nn} \end{pmatrix} \quad (2.29)$$

In a simplified way, this equation system is often written as:

$$\underline{Y} \cdot \underline{V} = \underline{I} \quad (2.30)$$

2.2.3.2 Load flow calculation

Load flow calculation can be classified in two different categories: Either the branch currents are known and the resulting voltages and branch power flows shall be calculated or the power injected into the network nodes is given and the branch currents and nodal voltages shall be determined. Both have in common that the steady-state operation of the network and thus all parameters like voltages and currents is already predetermined by the inputs and only the unknown values have to be calculated. The first case is quite trivial, as the vector of complex voltages is the only unknown in the equation system, the voltages can be obtained by rearranging the equation, calculating the reverse of the admittance matrix and solving the resulting linear equation system:

$$\underline{V} = \underline{Y}^{-1} \cdot \underline{I} \quad (2.31)$$

Once the nodal voltages are determined, the branch power flows can be calculated using Eq. (2.22):

$$\underline{S}_{ik} = \underline{V}_i \cdot \underline{I}_{ik}^* = \underline{V}_i (\underline{V}_i - \underline{V}_k)^* \cdot \underline{Y}_{ik}^* \quad (2.32)$$

In practice, most of the time not the branch currents but the injected nodal powers, e.g., from generators or loads, are known, and the resulting voltages and branch power flows shall be calculated. In order to obtain the branch currents, we need an approximation for the nodal voltages. This values can, for example, come from a previous load flow calculation or the nominal

voltages can be used. With the injected power and the approximated voltage we can calculate the nodal current:

$$\underline{I}_{ii} = \frac{\underline{S}_i^*}{\underline{V}_i^*} = \frac{P_i - jQ_i}{\underline{V}_i^*} \quad (2.33)$$

And by inserting this into Eq. (2.25) we get the so called power flow equations:

$$\underline{S}_i^* = P_i - jQ_i = \underline{V}_i^* \sum_{k=1}^n \underline{Y}_{ik} \underline{V}_k \quad (2.34)$$

These equations are non-linear and can only be solved using an iterative approach or numerical methods.

For the iterative approach, first of all a start vector for the nodal voltages has to be determined. Afterwards, the nodal currents can be calculated using Eq. (2.33) and the known nodal power injections. Then, with the calculated nodal currents and Eq. (2.31), a new value for the nodal voltages can be obtained. This approach is repeated until a predefined termination criterion is fulfilled.

2.2.3.3 Optimal power flow

Optimal Power Flow (OPF) is an extension of the traditional power flow analysis, which not only calculates the steady-state operation of a power system but also optimizes an objective function subject to various constraints. The objective function typically represents the total system operation costs, while the constraints include physical laws and operational limits of the power system components.

In order to formulate the optimization problem, a cost function must first be established, which acts as the objective function f , depends on the vector of variables x and gets minimized. In traditional OPF, the cost function consists of costs associated to the power generation of conventional power plants.

In addition to the objective function that needs to be minimized, there are numerous constraints that the optimal solution must satisfy. These constraints can be categorized into a set of equality constraints g and inequality constraints h . While the equality constraints typically have to be transformed in a way that on the right hand side of the equation there is only a zero remaining, inequality constraints are typically defined by constant lower and upper bounds l and u . This leads to the following basic formulation of the OPF problem:

$$\min f(x) \quad (2.35)$$

s.t.

$$g(x) = 0 \quad (2.36)$$

$$l \leq h(x) \leq u \quad (2.37)$$

Classic constraints in optimal power flow calculations include satisfying the power flow equations and adhering to limits on nodal voltages and line currents. The control variables for the optimization are the active and reactive power injections from the generators. The state variables, in the simplest case, are merely the magnitudes and phases of the nodal voltages, which are necessary for calculating the power flows. The optimal power flow calculation can be extended with additional constraints, control variables, and state variables, thereby tailoring it to the specific problem at hand. Depending on the modeling choices, the resulting optimization problems in the context of optimal power flow are linear problems, mixed-integer linear problems, and nonlinear problems. The following section provides an overview of solving techniques for the beforementioned problem types.

2.2.3.4 The per-unit system

The per-unit (p.u.) system is a normalized representation widely used in power system analysis to simplify calculations and improve clarity when dealing with electrical quantities across components of different ratings. In this system, all electrical quantities such as voltage, current, impedance, and power are expressed as fractions of selected base values rather than in absolute units. This normalization eliminates the complexity arising from varying voltage levels and equipment ratings in large interconnected networks [131, 141].

The p.u. value of any quantity is defined as:

$$\text{Per-unit value} = \frac{\text{Actual value}}{\text{Base value}} \quad (2.38)$$

According to convention, absolute values are written in capital letters, p.u. values in small letters. Typically, four base quantities are chosen: apparent power S_{base} , voltage magnitude V_{base} , current I_{base} , and impedance Z_{base} . These are interrelated by:

$$I_{\text{base}} = \frac{S_{\text{base}}}{\sqrt{3}V_{\text{base}}}, \quad Z_{\text{base}} = \frac{V_{\text{base}}^2}{S_{\text{base}}} \quad (2.39)$$

for three phase power systems. For complete standardization, it is sufficient to select two reference values: the base apparent power S_{base} and the base voltage V_{base} . The base apparent power can be chosen arbitrarily, a typical value for power system analysis on a transmission network level would be 100 MVA. For each subsystem (e.g., buses and lines with different voltage levels) of the overall system the subsystem's voltage level is chosen as base voltage. In this way, all the voltages in the system have a value around 1.0, which makes it easier to analyze the voltages across the system.

After determining the values for S_{base} and V_{base} , the p.u. values for the impedances of all grid elements can be calculated [131]:

$$\underline{z} = \underline{Z}_1 \frac{S_{\text{base}}}{U_1^2} \quad (2.40)$$

$\underline{Z}_1$ is the absolute impedance of the element, referring to the voltage level U_1 the element is located in.

2.2.3.5 Lagrange multipliers and locational marginal prices

Lagrange multipliers (LM) are a secondary result of solving the Lagrangian function of the OPF problem (see Section 2.3.2.2 for more details). They can be obtained for every constraint of the optimization problem and indicate how the value of the objective function would change with a marginal relaxation of the constraint [142]. This allows for economic interpretation: The LMs for the thermal branch flow limit constraints give an indication if a line is congested (in this case, relaxing the constraint would be economically beneficial, and thus the LM is greater than zero) or not (in this case, relaxing the constraint has no impact on the objective function, and the LM would be zero).

The LMs for the nodal power balance constraints can be economically interpreted as the marginal cost of energy at that specific network node. Therefore, they are also called locational marginal prices (LMP) or nodal prices [142]. They inherit generation costs as well as costs related to congestion and transmission losses. In a system without congestion or transmission constraints, the LMPs would be nearly the same value for all nodes of the network, since energy could be transported to all nodes, regardless of where it is generated. Small differences can be caused by transmission losses. If, on the other hand, there are greater differences in LMPs, this indicates

congestion in the grid. In this case, energy cannot be transported without restrictions and therefore different generators must be used to supply different nodes, which leads to different nodal prices due to different operating costs.

2.2.3.6 Power transfer distribution factors

Power Transfer Distribution Factors (PTDFs) quantify the percentage change in power flow across a specific transmission branch ($i - j$) resulting from a new power transaction between two buses ($x \rightarrow Y$) within the network [142]. Mathematically, PTDF is expressed as:

$$\text{PTDF} = \frac{\text{Change in power flow through branch } (i - j)}{\text{Power transaction between buses } (X - Y)} \quad (2.41)$$

PTDFs provide a linear approximation of the nonlinear AC power flow equations, enabling the estimation of active power flows in response to market transactions. This linearization makes PTDFs particularly useful in optimization frameworks such as linear programming, where they facilitate the determination of cost-effective dispatch solutions [142]. However, PTDF values are not constant, they vary with changes in network topology and operating conditions because they depend nonlinearly on transmission line parameters, particularly impedance and reactance. Consequently, any modification in line capacity or grid configuration requires recalculation of the PTDFs to ensure an accurate representation of the resulting system state. Network contingencies, even a single fault, can significantly alter power flows, potentially leading to line overloads and cascading failures. To mitigate such risks, accurate estimation of PTDFs is essential, as they provide a computationally efficient means to approximate the impact of changes in power injections on branch flows. By analyzing PTDFs, the influence of altered paths on the transmission network can be assessed effectively [142]. The calculation of PTDFs typically involves:

- Formulation of the network susceptance matrix
- Computation of distribution factors

In larger systems, the number of possible bus pair combinations ($X \rightarrow Y$) can become extremely large and difficult to manage. To simplify this, a slack is typically designated. The slack serves as a reference point: when power is injected at bus X , the corresponding withdrawal is assumed to occur at the slack rather than being distributed across all possible buses. The slack can be either a single slack bus or a vector of weights specifying the proportion of the slack taken up at each bus. With this slack, the PTDF matrix can be calculated. The matrix dimension is $n_{br} \times n_b$, where n_{br} is the number of branches and n_b the number of buses in the system. The entry $PTDF[i_{br}, i_b]$

describes the percentage change in power flow across branch i_{br} if a defined additional amount of power is injected at bus i_b and withdrawn at the slack.

2.3 Introduction to Operations Research

Operations Research (OR) refers to a branch of knowledge that deals with the analysis of practical, complex problems within the framework of a planning process for the purpose of preparing the best possible decisions through the application of mathematical methods. The main tasks in OR consist of mapping a real decision problem using an optimization or simulation model and the application or development of an algorithm to solve the problem [143]. In the narrower sense, in the literature, OR is primarily limited to the mathematical modeling of optimal decision problems and the development of algorithms for the solution of these models [143, 144]. The following sections present the most common problem categories in energy system analysis and their respective solution methods.

2.3.1 Linear programming

Linear programming (LP) describes the goal to minimize or maximize a linear cost function under the consideration of linear constraints and, in most cases, non-negativity conditions for variables. In addition to linearity, determinism and divisibility (meaning that all variables must be continuous and not discrete) are prerequisites for LP [144].

2.3.1.1 Problem structure

The LP problem has the following general structure:

$$\max \sum_{i=1}^{n_x} c_i x_i \quad (2.42)$$

s.t.

$$Ax \leq b \quad (2.43)$$

$$x \geq 0 \quad (2.44)$$

$$x \in \mathbb{R}^{n_x}, c \in \mathbb{R}^{n_x}, A \in \mathbb{R}^{n_g \times n_x}, b \in \mathbb{R}^{n_g}$$

Here, x is the vector of variables, c the vector with costs associated to x , A is a matrix of constant coefficients and called A-matrix, constraint matrix or coefficient matrix, b is a vector of constant parameters called b-vector, right-hand-side vector or constraint vector, n the number of variables and g the number of constraints. Equality constraints can be written as a set of two corresponding inequality constraints. Variables that are not constrained by non-negativity can be substituted by the difference of two variables that are only allowed to be greater than zero. A point or vector x is called a feasible solution if it satisfies all the constraints of the problem. It is called an optimal solution x^* if there exists no other feasible solution x with a lower objective function value [143].

By introducing the slack variables to the problem formulation, we can transform all the inequality constraints g , defined in Eq. (2.49), to equality constraints. In the objective function, the slack variables are valued with zero.

$$f(x) = \sum_{i=1}^{n_x} c_i^T x_i + \sum_{i=n_x+1}^{n_x+n_g} 0 \cdot x_i \quad (2.45)$$

$$\sum_{i=1}^{n_x} a_{gi} x_i + x_{n_x+g} = b_g \quad \text{for } g = 1 \dots n_g \quad (2.46)$$

This way we can obtain the so called nominal form of the LP [143].

$$\min \sum_{i=1}^n c_i^T x_i \quad (2.47)$$

s.t.

$$Ax = b \quad (2.48)$$

$$x \geq 0 \quad (2.49)$$

$$x \in \mathbb{R}^{n_x+n_g}, c \in \mathbb{R}^{n_x}, A \in \mathbb{R}^{n_g \times n_x}, b \in \mathbb{R}^{n_g}$$

The solution space of an exemplary LP with two variables and three constraints is shown in 2.12. The set of feasible solutions is limited by the constraints, which act as hyperplanes, as well as the $x \geq 0$ condition. Geometrically, the solution space can be interpreted as a polyhedron. All points $x \in X$ are feasible solutions to the problem, but not all of them are optimal solutions. Three cases can be differentiated:

- The problem is ill-defined, which means that at least two constraints contradict each other and there exists no feasible solution.

- The problem is unrestricted, meaning that there is an infinite number of feasible solutions with arbitrary low objective function values (when the objective function is to be minimized).
- The problem has at least one optimal solution. This is the case when the solution space and its corresponding polyhedron are not empty and restricted.

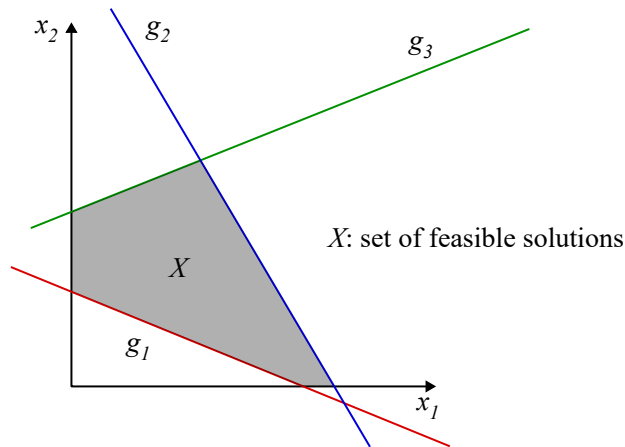


Figure 2.12: Graphical depiction of the solution space of a LP with two variables x_1 , x_2 and three constraints g_1 , g_2 , g_3 .

It can be shown that, if there is at least one optimal solution of the LP, the optimal solution will occur at least at one vertex (corner point) of the polyhedron X . Therefore, when solving LPs, it suffices to consider only the vertices of the feasible region [143, 144].

2.3.1.2 Duality

Duality is a fundamental concept in linear programming that connects two related optimization problems: the original (primal) problem and the dual problem, while the dual problem of the dual problem is again the primal one. A feasible solution of the dual problem gives a bound on the optimal objective function value of the primal problem, and vice versa [145]. Given a LP in standard form, as described in Eqs. (2.43), (2.49) and (2.50), the associated dual problem is given by:

$$\min \sum_{j=1}^{n_g} b_j y_j \quad (2.50)$$

s.t.

$$Ay \geq c \quad (2.51)$$

$$y \geq 0 \quad (2.52)$$

$$y \in \mathbb{R}^{n_g}, b \in \mathbb{R}^{n_g}, c \in \mathbb{R}^{n_x}, A \in \mathbb{R}^{n_x \times n_g}$$

Feasible solutions of the dual problem can generally provide upper bounds for the primal problem. This is referred to as weak duality [145].

$$\sum_{i=1}^{n_x} c_i x_i \leq \sum_{j=1}^{n_g} b_j y_j \quad (2.53)$$

For LPs it can be shown that the gap between the optimal solution of the primal problem and the optimal solution of the dual problem is zero. This is called strong duality and is an important tool to verify optimality, since finding feasible solutions to the primal and dual problem with similar objective function values is sufficient to prove that both the primal and the dual solution are optimal [145].

$$\sum_{i=1}^{n_x} c_i x_i \leq \sum_{j=1}^{n_g} b_j y_j^* = \sum_{i=1}^{n_x} c_i x_i^* \quad (2.54)$$

2.3.1.3 Solution methods

While small LP problems can sometimes be solved manually, real-world applications often involve hundreds, thousands or even millions of variables and constraints. To solve these problems in a reasonable amount of time, efficient computational methods are required. In the following the two most important methods, the simplex algorithm and the interior-point method are briefly explained. More detailed explanations can be found e.g., in [143, 144, 146].

Simplex algorithm

The simplex algorithm is perhaps the most common method used to solve LPs in real world application. The algorithm is based directly on the insight that optimal solutions are located on

the vertices of the solution space polyhedron. Additionally, if a vertex does not represent the maximum (or minimum) of the objective function, then there exists at least one edge connected to that vertex along which the value of the objective function strictly increases (or decreases) as one moves away from it. This leads to the implication that if no adjacent vertex or point along any connecting edge yields a better objective value than the current one, then the current vertex must be optimal [146].

Starting from an initial feasible vertex of the solution polyhedron, the algorithm progresses along its edges, moving from one vertex to another. This iteration continues until it reaches a vertex where no neighboring solutions offer a better value for the objective function, indicating that the optimal solution has been found. The iteration can be divided into the following steps [146]:

1. Considering the edges adjacent to the current solution, choose to move along the edge which improves the objective function the fastest.
2. Stop at the first new constraint boundary.
3. Obtain a new vertex solution by solving the problem for the intersection of the new set of constraint boundaries.

Depending on the problem, getting an initial feasible solution can be trivial, e.g., by choosing the origin, which means all decision variables are equal to zero. If there is no trivial feasible solution to be found, computational procedures must be applied to solve for an initial solution, e.g., by applying the simplex algorithm to a modified version of the original program.

Despite its conceptual simplicity, the simplex algorithm has proven to be remarkably effective, even for large-scale linear programming problems. Although its worst-case runtime is exponential, in practice it often performs much better, with average-case complexity typically observed to be polynomial [147].

Interior-point algorithm

The first interior-point algorithm, also called barrier algorithm, was introduced by Narendra Karmarkar in 1984 and was the first algorithm that was proved to solve LPs in polynomial time [148, 149]. The method begins by identifying an initial feasible trial solution. With each iteration, the algorithm moves from the current solution to a better one within the feasible region, continuing this progression until it arrives at a solution that is essentially optimal. In contrast to the simplex algorithm, the interior-point method generates trial solutions that are interior points, located within the boundaries of the feasible region rather than on its edges.

A key theoretical distinction between interior-point algorithms and the simplex method lies in their computational complexity. Karmarkar's interior-point algorithm is proven to run in polynomial time, while the simplex method has exponential worst-case complexity. However, this worst-case comparison does not reflect typical performance on real-world problems. In practice, performance depends on the number of iterations and the time per iteration. The simplex method is computationally simpler per iteration and often faster for small to medium-sized problems. In contrast, interior-point methods require more computation per iteration, but scale better with problem size. For very large problems, they often outperform the simplex method because they follow a more direct path through the interior of the feasible region, avoiding the potentially long and circuitous edge-following path of the simplex method [146].

2.3.2 Nonlinear programming

Nonlinear programming (NLP) is a more generalized form of LP. While determinism and divisibility still hold as prerequisites, the cost function and constraints are not necessarily linear, but can have any form, provided they are at least once differentiable.

2.3.2.1 Problem structure

The general structure of the problem, with constraints divided into equality constraints $g_i(x)$ and inequality constraints $h_j(x)$ and the cost function $f(x)$, is as follows:

$$\min f(x) \tag{2.55a}$$

s.t.

$$g_i(x) = 0 \tag{2.55b}$$

$$h_j(x) \leq 0 \tag{2.55c}$$

$$x \in \mathbb{R}^{n_x}, \forall i \in \mathcal{N}^{\text{eq}}, \forall j \in \mathcal{N}^{\text{ineq}}$$

NLP is a broad field with many different problem types. Unlike linear programming, where e.g., the simplex method offers a universal solution, no single algorithm works for all nonlinear

problems. As a result, specialized algorithms tailored to specific classes of NLP problems have been developed. The main types of NLP problems are the following [146]:

- **Unconstrained optimization:** The optimization problem has no constraints at all.
- **Linearly constrained optimization:** The constraints are completely linear, the objective function is not.
- **Quadratic programming:** The constraints are again linear, but the objective function must be quadratic.
- **Convex programming:** The objective function $f(x)$ must be a convex function (concave if the objective is to maximize $f(x)$ instead of minimize) and all constraints $g_i(x)$ and $h_j(x)$ must be convex functions.
- **Nonconvex programming:** All NLP problems that do not satisfy the conditions of convex programming.

Since nonconvex programming is the most general form of NLP and the optimization problems formulated later in this thesis correspond to this type, the focus in the following will be on nonconvex programming.

2.3.2.2 Lagrangian function and optimality conditions

Before defining optimality conditions for nonconvex NLP, the Lagrangian function is introduced. Here, the basic idea is to transform a problem with constraints into a form that allows the gradient test of a problem without constraints to be applied. The relationship between the gradient of the function and the gradients of the constraints leads to a reformulation of the original problem, known as the Lagrange function $\mathcal{L} : \mathbb{R}^{N_x} \times \mathbb{R} \times \mathbb{R}^{N_z} \times \mathbb{R}^{N_h} \rightarrow \mathbb{R}$. The Lagrangian function of the optimization problem described in Eq. (2.55c) is defined as follows [150, 151]:

$$\mathcal{L}(x, l_0, \lambda, \nu) := l_0 f(x) + \sum_{i=1}^{N_g} \lambda_i g_i(x) + \sum_{j=1}^{N_h} \nu_j h_j(x) \quad (2.56)$$

l_0 , λ_i and ν_j are called Lagrange multipliers.

Based on the Lagrangian function, many necessary conditions for optimality with different assumptions can be found in literature. The most common ones are the so called Karush-Kuhn-Tucker

(KKT) conditions [152, 153]. Assuming that the functions $f(x)$, $g_i(x)$ and $h_j(x)$ are continuously differentiable with respect to x , a local minimum (x^*, λ, ν) must satisfy the following KKT conditions [150]:

$$\nabla_x \mathcal{L}(x^*, 1, \lambda, \nu) = \nabla f(x^*) + \sum_{i=1}^{N_g} \lambda_i \nabla g_i(x^*) + \sum_{j=1}^{N_h} \nu_j \nabla h_j(x^*) = 0 \quad (2.57a)$$

$$\nabla_\lambda \mathcal{L}(x^*, 1, \lambda, \nu) = g_i(x^*) = 0 \quad (2.57b)$$

$$\nabla_\nu \mathcal{L}(x^*, 1, \lambda, \nu) = h_j(x^*) \leq 0 \quad (2.57c)$$

$$\nu_j h_j(x^*) = 0 \quad (2.57d)$$

$$\nu_j \geq 0 \quad (2.57e)$$

$$x \in \mathbb{R}^{n_x}, \forall i \in \mathcal{N}^{\text{eq}}, \forall j \in \mathcal{N}^{\text{ineq}}$$

The KKT conditions allow for the identification of local optima. In the case of convex NLP, a local optimum is also the global optimum, which means the KKT conditions are necessary and sufficient conditions for a global optimum. For nonconvex NLP, the problem can have multiple local optima, so there is no guarantee that the local optimum found is also global. To find the global optimum, one would have to determine all local optima and compare the corresponding objective function values [143, 146].

The computed Lagrange multipliers λ and ν associated with the optimal solution admit further interpretation. For each constraint, these multipliers indicate the rate at which the objective function value would change if the constraint were relaxed, which is also known as the shadow price. A high Lagrange multiplier signifies that the constraint is strongly binding, implying that relaxing this constraint would lead to a substantial improvement in the objective function value (e.g., a significant cost reduction). Conversely, a low or zero multiplier indicates that the constraint has little or no influence on the optimization outcome, and relaxing it would not yield a meaningful change.

2.3.2.3 Newton's method

Newton's method is used to iteratively solve the nonlinear system of equations formed by the KKT conditions. The idea is to linearize the system around the current iterate and solve the resulting linear system for the next iterate [146].

For simplicity, we write the KKT-conditions from Eq. (2.57e) as:

$$F(z) = 0, \quad \text{where } z = (x, \lambda, \nu) \quad (2.58)$$

Here F is the vector of all KKT conditions.

At each iteration, $F(z)$ is linearized around the current point z_k :

$$F(z_k + \Delta z) \approx F(z_k) + J(z_k)\Delta z \quad (2.59)$$

$J(z_k)$ is the Jacobian (matrix of all first partial derivatives) of F at z_k . It has the following structure:

$$J(z_k) = \begin{bmatrix} \nabla_{xx}^2 \mathcal{L} & \nabla g(x)^T & \nabla h(x)^T \\ -\text{diag}(\lambda) \nabla g(x) & \text{diag}(g(x)) & 0 \\ \nabla h(x) & 0 & 0 \end{bmatrix} \quad (2.60)$$

In the top left there is the Hessian (matrix of all second partial derivatives) of the Lagrangian function (Eq. (2.56)) and the other blocks come from constraints and complementary slackness.

To get the values (direction) of the Newton step Δz , the following linear system has to be solved:

$$J(z_k)\Delta z = -F(z_k) \quad (2.61)$$

Afterwards, the next iterate can be determined with the calculated step direction Δz and the step length α_k , which can be chosen, for example, by a line search algorithm [154]:

$$z_{k+1} = z_k + \alpha_k \Delta z \quad (2.62)$$

The algorithm continues to generate new trial solutions through successive iterations until these solutions have effectively converged. Convergence can be determined by several criteria [154]:

- The KKT-conditions are satisfied within a sufficiently small tolerance ϵ
- The calculated Newton step is very small, indicating that the solution is not changing significantly: $\|\Delta z\| \leq \epsilon_{\text{step}}$
- The change in the objective function value is sufficiently small: $|f(x_{k+1}) - f(x_k)| \leq \epsilon_{\text{obj}}$

- The number of iteration exceed a predefined maximum: $k \geq k_{\max}$

There exists a variety of modifications and improvements on Newton's method for different applications. Since the underlying principle in all cases goes back to the basic principle of Newton's method described above, these methods are called Newton type methods.

2.3.2.4 Interior point methods for NLP

As already mentioned before, there exist many different types of NLP problems and for each one of them a different solution algorithm is the most suited one. Energy and especially electricity systems often yield large scale, nonconvex NLP problems. The most common solution strategies for these kind of problems are interior point or barrier algorithms, which are explained in more detail in the following.

Barrier method

The core idea of interior point methods is to replace inequality constraints with a barrier term that penalizes proximity to the constraint boundary, resulting in a problem that is much easier to solve than the original one. For a problem with inequality constraints $h_j(x) \leq 0$, the barrier problem corresponding to the original problem Eq. (2.55c) can be formulated as [155]:

$$\min_{x \in \mathbb{R}^n} \phi_\mu(x) = f(x) - \mu \sum_{j=1}^m \ln(-h_j(x)) \quad (2.63a)$$

s.t.

$$g_i(x) = 0 \quad (2.63b)$$

$$x \in \mathbb{R}^{n_x}, \forall i \in \mathcal{N}^{\text{eq}}, \forall j \in \mathcal{N}^{\text{ineq}}$$

Where $\mu > 0$ is the barrier parameter. The logarithmic term ensures that the solution remains strictly within the feasible region. As $\mu \rightarrow 0$, the solution of the barrier problem converges to a local optimum of the original constrained problem. This process is known as path-following. For large values of μ , the exact solution is not of interest, so it is sufficient to solve the barrier problem with a relaxed accuracy. The approximate solution is then used as a starting point for the next iteration of the barrier problem [156].

Primal-dual interior point methods

To solve the barrier problem, the KKT-conditions can be used. Applied on Eq. (2.63b), the KKT-conditions can be formulated as:

$$\nabla f(x) - \mu \sum_{j=1}^m \left(\frac{1}{h_j(x)} \nabla h_j(x) \right) + \sum_{i=1}^n \nabla g_i(x) \lambda_i = 0 \quad (2.64a)$$

$$\begin{aligned} g_i(x) &= 0 \\ x &\in \mathbb{R}^{n_x}, \forall i \in \mathcal{N}^{\text{eq}}, \forall j \in \mathcal{N}^{\text{ineq}} \end{aligned} \quad (2.64b)$$

Solving this system, e.g., with the Newton method, is a so-called primal interior point method. However, as μ gets closer to zero, the algorithm can face numerical difficulties [156, 157].

In order to avoid this problem, most of the times the so-called primal-dual interior point method is used. Here a slack variable s_j is introduced for each inequality constraint $h_j(x)$, so that:

$$h_j(x) + s_j = 0, \quad s_j \geq 0, \quad \forall j \in \mathcal{N}^{\text{ineq}} \quad (2.65)$$

The introduction of the slack variable leads to the following reformulated barrier problem:

$$\min_{x \in \mathbb{R}^n} \phi_\mu(x) = f(x) - \mu \sum_{j=1}^m \ln(s_j) \quad (2.66a)$$

s.t.

$$h_j(x) + s_j = 0 \quad (2.66b)$$

$$g_i(x) = 0 \quad (2.66c)$$

$$x \in \mathbb{R}^{n_x}, \forall i \in \mathcal{N}^{\text{eq}}, \forall j \in \mathcal{N}^{\text{ineq}}$$

With the introduction of another variable τ defined as $\tau_j := -\frac{\mu}{s_j}$, again the KKT-conditions, also called primal-dual equations, can be derived for the modified problem:

$$\nabla f(x) + \sum_{i=1}^n \nabla g_i(x) \lambda + \sum_{j=1}^m \tau = 0 \quad (2.67a)$$

$$g_i(x) = 0 \quad (2.67b)$$

$$h_j(x) + s_j = 0 \quad (2.67c)$$

$$\tau_j s_j = \mu \quad (2.67d)$$

$$s_j > 0 \quad (2.67e)$$

$$\tau_j > 0 \quad (2.67f)$$

$$x \in \mathbb{R}^{n_x}, \forall i \in \mathcal{N}^{\text{eq}}, \forall j \in \mathcal{N}^{\text{ineq}}$$

The introduction of s and τ allows us to formulate $\tau s = \mu$ instead of $\tau = -\frac{\mu}{h(x)}$ which each have the same solution, but the linearization of the reformulated version yields better search directions and is thus favorable in terms of convergence [157].

The equation system in Eq. (2.67f) can be solved using a Newton-type method. After finding a sufficiently optimal solution of the current barrier problem, the barrier parameter μ is reduced and a new barrier problem with the corresponding primal-dual equations is formulated and solved. This procedure is repeated until μ converges against zero.

2.3.3 Mixed integer programming

While divisibility was a main prerequisite in linear and nonlinear programming, in mixed integer programming (MIP) discrete variables (and therefore also binaries) are allowed. Especially binary variables are an important addition to many problems related to energy system analysis, e.g., for investment decisions of new power plants or transmission lines. They are also necessary for the so called unit commitment problem, where the operating state of plants is modeled with a binary variable (running or at standstill) which allows for example to include start up costs into the model. Depending on the nature of the objective function and constraints of the problem, in energy system analysis, commonly mixed integer linear programming (MILP) or mixed integer nonlinear programming (MINLP) is applied. Both of these are much more difficult to solve than their strictly continuous counterparts, and solving a MINLP is much harder than solving a MILP. That is why in practice, large-scale problems including discrete variables are most of the time linearized to get a MILP problem instead of a MINLP.

To solve MIP problems, the use of branch and bound methods has become established. Hereby, first of all, the LP relaxation of the problem (ignoring the integer constraints) is solved. If the solution violates integer constraints, a search tree is constructed by recursively dividing the original problem into subproblems such that their combined solution sets cover all solutions of the original problem, while overlaps between individual subproblem solutions are minimized

(branching). Bounding helps to restrict the branching process so that unnecessary computational effort can be avoided. Lower and upper bounds on objective function values are computed to determine whether subproblems require further branching. Assuming that we are dealing with a minimization problem, a global upper bound for the objective value of an optimal solution to the original problem can always be specified by the currently best known feasible solution. Additionally, for each subproblem, a local lower bound for the objective value of its optimal solution can be determined by solving the LP relaxation of the subproblem [143].

A subproblem is called fathomed or pruned (it does not need to be considered further, i.e., it does not need to be branched further) if one of the three mutually exclusive cases applies [143]:

- (i) The objective function value of the solution of the relaxed subproblem is higher (which means worse) than the current upper bound.
- (ii) The objective function value of the solution of the relaxed subproblem is lower (which means better) than the current upper bound and the solution is feasible for the not-relaxed subproblem and therefore also for the original problem. In this case, a new best and feasible solution was found and the upper bound gets set to the objective function value of this solution.
- (iii) The relaxed subproblem has no feasible solution, therefore also the original subproblem and all subproblems that would be retrieved by further branching do not have a feasible solution.

If all nodes of the search tree are either solved or pruned, the algorithm terminates and the best feasible integer solution found is the optimal solution.

The optimality of the currently best integer solution can also be measured using the so called optimality gap. It determines how close the current solution is to the theoretical optimum.

$$\text{Optimality Gap} = \frac{|\text{Best Integer Solution} - \text{Best Bound}|}{|\text{Best Integer Solution}|} \times 100\% \quad (2.68)$$

The best bound equals the lower bound for minimization problems, as described earlier. If the optimality gap equals 0 %, the current solution is proven to be optimal. Since solving large-scale MIPs to optimality can be very time-consuming even using branch and bound methods, often times finding a near-optimal solution is sufficient. In this case, the optimality gap can serve as a termination criterion. The algorithm stops as soon as the optimality gap is smaller than a predefined value and the currently best integer solution is returned as the near-optimal solution. There exist numerous branch and bound methods with different kinds of enhancements, e.g., the combination with cutting planes (branch and cut), presolving techniques or other heuristics.

3 Methodology

3.1 Optimal power flow model formulation

In this section, the formulation of the main model of this work, the AC-OPF model, is described in detail. Since the model contains a large number of variables and equations, a comprehensive presentation of the formulation is not provided. Instead, the individual components of the model and their formulations are presented separately in the sections of this chapter.

3.1.1 Basic form of the OPF

The model is a typical OPF model as described in Section 2.2.3.3. In its basic form, the model aims to minimize operational costs of conventional power plants (Eq. (3.1)) while ensuring nodal active and reactive power balance (Eqs. (3.2) and (3.3)), operational limits of power plants (Eqs. (3.4) and (3.5)), voltage limits (Eq. (3.6)) and thermal limits of transmission lines (Eq. (3.7)). The model is treated as quasi-stationary, i.e., all transient effects are assumed to have fully decayed, and only steady-state behavior is considered.

$$\min \sum_{g \in G} \sum_{t \in T} c_{g,t} P_{g,t} \quad (3.1)$$

s.t.

$$\sum_{g \in G_i} P_{g,t} - P_{i,t}^{\text{load}} - \sum_{k \in I} P_{ik,t} = 0 \quad \forall i \in \mathcal{I}^{\text{bus}}, \forall t \in \mathcal{T} \quad (3.2)$$

$$\sum_{g \in G_i} Q_{g,t} - Q_{i,t}^{\text{load}} - \sum_{k \in I} Q_{ik,t} = 0 \quad \forall i \in \mathcal{I}^{\text{bus}}, \forall t \in \mathcal{T} \quad (3.3)$$

$$\underline{P}_g \leq P_{g,t} \leq \overline{P}_g \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (3.4)$$

$$\underline{Q}_g \leq Q_{g,t} \leq \overline{Q}_g \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (3.5)$$

$$\underline{V}_i \leq V_{i,t} \leq \overline{V}_i \quad \forall i \in \mathcal{I}^{\text{bus}}, \forall t \in \mathcal{T} \quad (3.6)$$

$$F_{l,t} \leq \overline{F}_l \quad \forall l \in \mathcal{L} \quad (3.7)$$

Here, $\mathcal{I}^{\text{bus}}$ is the set of nodes in the network, G_i is the set of generators located at bus i , $\mathcal{L}$ is the set of the network's transmission lines, and $P_{i,t}^{\text{load}} + jQ_{i,t}^{\text{load}}$ is the sum of static loads and static generation (negative sign) from, e.g., renewables at bus i and time step t . Further details on the modeling of components and extensions of the model, e.g., storage systems, are described in the following sections.

Due to the nonlinear AC power flow equations used to model nodal active and reactive power balances as well as transmission line flows (see Sections 3.1.2 and 3.1.3.2), the resulting OPF formulation is a nonlinear and non-convex optimization problem. At the same time, the model is purely continuous and does not incorporate integer decision variables, distinguishing it from mixed-integer OPF formulations.

3.1.2 Nodal power balance

Kirchhoff's first law states that at a node the sum of incoming currents equals the sum of outgoing currents, and the same principle applies to active and reactive power flows. Therefore, the core constraints of the OPF model ensure that for each busbar the sum of power inflows equals the sum of power outflows for all time steps. This includes power injections in the node through generation (positive injection) or load (negative injection), as well as power flows from one node to another via transmission lines or transformers. Reformulating this constraint so that all inflows and outflows are on the left-hand side of the equation leads to the following constraints:

$$P_{i,t}^{\text{in}} - P_{i,t}^{\text{out}} - V_{i,t} \sum_{k \in \mathcal{I}, k \neq i} V_{k,t} (G_{ik} \cos(\theta_{i,t} - \theta_{k,t}) + B_{ik} \sin(\theta_{i,t} - \theta_{k,t})) - V_{i,t}^2 G_{ii} = 0, \\ \forall i \in \mathcal{I}^{\text{bus}}, \forall t \in \mathcal{T} \quad (3.8)$$

$$Q_{i,t}^{\text{in}} - Q_{i,t}^{\text{out}} - V_{i,t} \sum_{k \in \mathcal{I}, k \neq i} V_{k,t} (G_{ik} \sin(\theta_{i,t} - \theta_{k,t}) - B_{ik} \cos(\theta_{i,t} - \theta_{k,t})) + V_{i,t}^2 B_{ii} = 0, \\ \forall i \in \mathcal{I}^{\text{bus}}, \forall t \in \mathcal{T} \quad (3.9)$$

with $P_{i,t}^{\text{in}}$ describing the sum of all types of real power injection (e.g., generation from conventional power plants, renewables, storages) at node i and time step t , and $P_{i,t}^{\text{load}}$ describing the sum of all types of real power withdrawal (e.g., demand, charging of storages) at node i and time step t . The

power flows to the neighboring nodes $k \in I$ through AC transmission lines or transformers are formulated using the AC power flow equations (see Section 2.2.1.2), which means that they depend on complex voltages $V_{i,t}e^{j\theta_{i,t}}$ and $V_{k,t}e^{j\theta_{k,t}}$ as well as the nodal admittance matrix $\underline{Y} = G + jB$. In- and outgoing power flows through DC lines are modeled as (positive or negative) power injections at the AC node i and thus are part of $P_{i,t}^{\text{in}}$ and $P_{i,t}^{\text{out}}$. The details on the modeling of DC lines are described in Section 3.1.4. The same relations also hold true for the reactive power balance at each node, see Eq. (3.9).

3.1.3 Transmission lines and transformers

This section describes the modeling of AC transmission lines and transformers, regarding the basic equivalent circuit model, the formulation of branch flow constraints, the modeling of transmission losses, and how the model deals with parallel transmission lines.

3.1.3.1 The π equivalent circuit model

Three-phase transmission lines and transformers are modeled using the single-phase π equivalent circuit model depicted in Fig. 3.1. The prerequisites for this modeling approach are symmetrical operation and an electrically short or medium-length line [132, 141]. As already described in Section 2.2.1.1, AC transmission lines in Germany and Europe can be considered as electrically short and therefore described in good approximation by the equivalent circuit model. The model consists of the series reactance X_s , the series resistance R_s , the susceptance B_c and an ideal transformer with the complex tap ratio $\underline{\psi} = \tau e^{j\vartheta_T}$ where τ describes the transformation in voltage magnitude and ϑ_T the phase shift. For a standard transmission line, $\underline{\psi}$ has the value $1e^{j0}$ and therefore has no influence on the calculation of the transmitted power. The active conductance is negligible for a typical transmission line and was therefore not taken into account in the modeling.

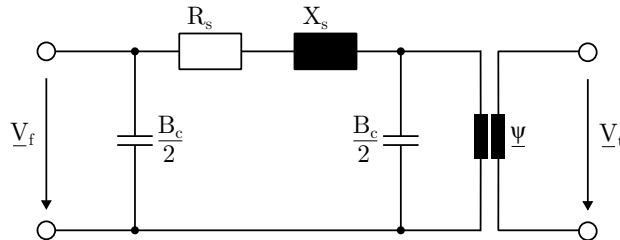


Figure 3.1: Depiction of the π equivalent circuit diagram for AC transmission lines.

The complex input and output currents $\underline{I}_f$ and $\underline{I}_t$ can be calculated using the 2x2 branch admittance matrix $\underline{Y}_{br}$ and the complex input and output voltages $\underline{V}_f$ and $\underline{V}_t$:

$$\begin{pmatrix} \underline{I}_f \\ \underline{I}_t \end{pmatrix} = \underline{Y}_{br} \begin{pmatrix} \underline{V}_f \\ \underline{V}_t \end{pmatrix} \quad (3.10)$$

The branch admittance matrix can be calculated using the elements of the π equivalent circuit diagram as follows [132, 141]:

$$\underline{Y}_{br} = \begin{bmatrix} -(\underline{Y}_s + j\frac{B_c}{2})\frac{1}{\tau^2} & \frac{\underline{Y}_s}{\underline{\psi}^*} \\ \frac{\underline{Y}_s}{\underline{\psi}} & -(\underline{Y}_s + j\frac{B_c}{2}) \end{bmatrix} \quad (3.11)$$

with

$$\underline{Y}_s = \frac{1}{\underline{Z}_s} = \frac{1}{R_s + jX_s} = \frac{R_s}{R_s^2 + X_s^2} - j\frac{X_s}{R_s^2 + X_s^2} \quad (3.12)$$

The branch admittance matrices of the single transmission lines and transformers are then used to obtain the nodal admittance matrix $\underline{Y} = G + jB$ of the entire AC system (see Section 2.2.3.1).

3.1.3.2 Line flow restrictions

For each line l the real and reactive power injected at the start bus i and the end busbar k of the line is calculated. The injected power depends on the complex voltages $V_{i,t}e^{j\theta_{i,t}}$ at the start and $V_{k,t}e^{j\theta_{k,t}}$ at the end bus as well as the line parameters, which are represented by the complex nodal admittance matrix $Y = G + jB$.

$$\begin{aligned} P_{l,t}^{\text{from}} = & V_{i,t} \cos(\theta_{i,t}) (G_{ik} (V_{i,t} \cos(\theta_{i,t}) - (V_{k,t} \cos(\theta_{k,t}))) \\ & + V_{i,t} \sin(\theta_{i,t}) (G_{ik} (V_{i,t} \sin(\theta_{i,t}) - (V_{k,t} \sin(\theta_{k,t}))) \\ & - V_{i,t} \cos(\theta_{i,t}) (B_{ik} (-V_{i,t} \sin(\theta_{i,t}) + (V_{k,t} \sin(\theta_{k,t}))) \\ & + V_{i,t} \sin(\theta_{i,t}) (B_{ik} (-V_{i,t} \cos(\theta_{i,t}) + (V_{k,t} \cos(\theta_{k,t}))) \end{aligned} \quad (3.13a)$$

$$\begin{aligned}
P_{l,t}^{\text{to}} = & V_{k,t} \cos(\theta_{k,t}) (G_{ik} (-V_{i,t} \cos(\theta_{i,t}) + (V_{k,t} \cos(\theta_{k,t}))) \\
& + V_{k,t} \sin(\theta_{k,t}) (G_{ik} (-V_{i,t} \sin(\theta_{i,t}) + (V_{k,t} \sin(\theta_{k,t}))) \\
& - V_{k,t} \cos(\theta_{k,t}) (B_{ik} (V_{i,t} \sin(\theta_{i,t}) - (V_{k,t} \sin(\theta_{k,t}))) \\
& + V_{k,t} \sin(\theta_{k,t}) (B_{ik} (V_{i,t} \cos(\theta_{i,t}) - (V_{k,t} \cos(\theta_{k,t}))) \quad (3.13b)
\end{aligned}$$

$$\begin{aligned}
Q_{l,t}^{\text{from}} = & V_{i,t} \sin(\theta_{i,t}) (G_{ik} (V_{i,t} \cos(\theta_{i,t}) - (V_{k,t} \cos(\theta_{k,t}))) \\
& - V_{i,t} \cos(\theta_{i,t}) (G_{ik} (V_{i,t} \sin(\theta_{i,t}) - (V_{k,t} \sin(\theta_{k,t}))) \\
& - V_{i,t} \sin(\theta_{i,t}) (B_{ik} (-V_{i,t} \sin(\theta_{i,t}) + (V_{k,t} \sin(\theta_{k,t}))) \\
& - V_{i,t} \cos(\theta_{i,t}) (B_{ik} (-V_{i,t} \cos(\theta_{i,t}) + (V_{k,t} \cos(\theta_{k,t}))) \quad (3.13c)
\end{aligned}$$

$$\begin{aligned}
Q_{l,t}^{\text{to}} = & V_{k,t} \sin(\theta_{k,t}) (G_{ik} (-V_{i,t} \cos(\theta_{i,t}) + (V_{k,t} \cos(\theta_{k,t}))) \\
& - V_{k,t} \cos(\theta_{k,t}) (G_{ik} (-V_{i,t} \sin(\theta_{i,t}) + (V_{k,t} \sin(\theta_{k,t}))) \\
& - V_{k,t} \sin(\theta_{k,t}) (B_{ik} (V_{i,t} \sin(\theta_{i,t}) - (V_{k,t} \sin(\theta_{k,t}))) \\
& - V_{k,t} \cos(\theta_{k,t}) (B_{ik} (V_{i,t} \cos(\theta_{i,t}) - (V_{k,t} \cos(\theta_{k,t}))) \quad (3.13d)
\end{aligned}$$

Crucial for maintaining thermal limits is the apparent current over the transmission line. Since the OPF formulation relies on power flows instead of currents, the apparent power is used for the formulation of the transmission constraints and set a limit $\overline{S}_l$, which can be calculated from the maximum apparent current allowed and the nominal voltage of the line.

$$\overline{S}_l = \sqrt{3} \cdot V_l^N \cdot I_l^{\text{s,max}} \quad (3.14)$$

Due to transmission losses, the injected powers at the start and end nodes of the lines do not necessarily have the same magnitude. That is why constraints must be formulated for the injected power at the start as well as at the end of the line.

$$P_{l,t}^{\text{from}^2} + Q_{l,t}^{\text{from}^2} \leq (\gamma \cdot \overline{S}_l)^2 \quad \forall l \in \mathcal{L}, \forall t \in \mathcal{T} \quad (3.15a)$$

$$P_{l,t}^{\text{to}} + Q_{l,t}^{\text{to}} \leq (\gamma \cdot \overline{S}_l)^2 \quad \forall l \in \mathcal{L}, \forall t \in \mathcal{T} \quad (3.15b)$$

The thermal power limit $\overline{S}_l$ of the respective transmission line is reduced by an adjustable safety margin factor γ . This approach is chosen to represent N-1 security constraints in a simplified manner [158, 159]. The default value for the security margin is $\gamma = 0.7$. N-1 security is not explicitly integrated in the model due to complexity and calculation time issues.

3.1.3.3 Losses on transmission lines and transformers

One of the benefits of AC OPF compared to DC OPF calculation is the representation of transmission losses in the model. For transmission lines, the calculation and consideration of the losses is done implicitly. Since all transmission lines have non-negative values for the resistance R , with Eqs. (3.10) to (3.12), we can conclude that the currents and thus also the power injections at start and end busbars differ. The losses are therefore represented in the model and can be calculated as the absolute value of the sum of power injections at the start and end busbars (since one of them is always positive and one is always negative, depending on the flow direction).

$$P_{\text{line}}^{\text{loss}} = \left| P_{\text{line}}^{\text{from}} + P_{\text{line}}^{\text{to}} \right| \quad (3.16)$$

For transformers, losses are not only based on ohmic resistance but also consist of eddy currents and hysteresis losses. Since these losses are hard to calculate, they are approximated by a fixed value, which is given in the input data and scales with the nominal power of the transformer. The losses are modeled as an additional power demand in one of the busbars to which the transformer is connected.

3.1.3.4 Parallel transmission lines

The subsequent model setup heavily relies on the nodal admittance matrix. This matrix only provides for one entry for a connection between two nodes. This means that parallel lines (lines with the same start and end nodes) must be dealt with in a way that only one connection between two nodes remains without altering the electrical properties of the original connections. To achieve this, two different approaches are used.

If the parallel lines have the same technical characteristics (resistance, impedance, susceptance and thermal current limit) and there are no flow controlling devices (FACTS or PST) connected to either one of them, the resulting power flow over these lines will always be exactly the same

for each of them. This allows us to combine the relevant parallel lines into one replacement line. The technical parameters of the replacement line are calculated as:

$$r_{rl} = \frac{r_l}{n_{pl}} \quad (3.17a)$$

$$x_{rl} = \frac{x_l}{n_{pl}} \quad (3.17b)$$

$$b_{rl} = b_l \cdot n_{pl} \quad (3.17c)$$

$$F_{rl}^{\max} = F_l^{\max} \cdot n_{pl} \quad (3.17d)$$

with n^{pl} being the number of parallel lines that are combined, r_l , x_l , b_l and $F_l^{\max}$ the resistance, impedance, susceptance and thermal flow limit of the original individual lines.

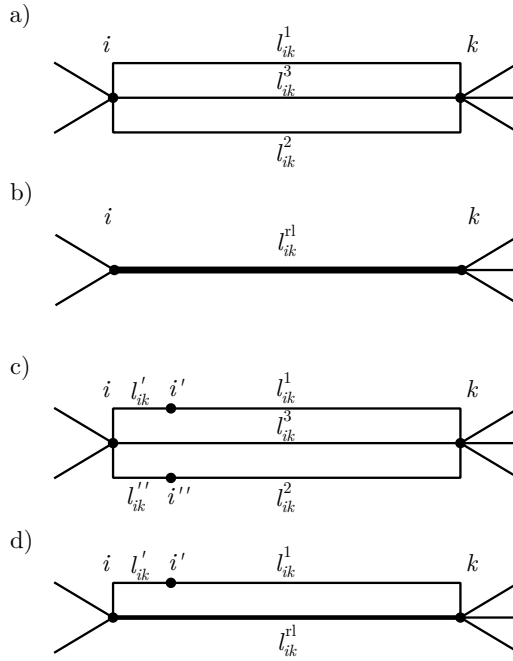


Figure 3.2: Depiction of the different modeling approaches for parallel lines. a): Original setup with parallel lines. b): Approach one, combining parallel lines to a replacement line. c): Approach two, introduction of auxiliary nodes and lines. d): Hybrid of approaches one and two.

In case the parallel lines have unequal technical parameters or in case they are equipped with power flow controlling devices, the resulting power flows over the lines will not be equal. By combining

them to one replacement line, the compliance with thermal flow restrictions for the individual lines could no longer be guaranteed. Still, some modifications have to be made since the nodal admittance matrix can only store one entry for each connection between two nodes. That's why additional auxiliary nodes and lines are introduced. For n parallel lines l_{ik}^n connecting nodes i and k that cannot be combined, $n - 1$ auxiliary nodes i' and auxiliary lines l' are created. The auxiliary line l'_{ik} connects starting node i and auxiliary node i' . The auxiliary node is then connected to the end node k via the original line l_{ik}^1 . The auxiliary line has a resistance and susceptance of zero and a very low impedance (zero is not possible here due to numerical reasons). This means that the power flow over the auxiliary line is basically unlimited (without inducing losses) even for very small voltage differences between node i and auxiliary node i' , which means $V_i \approx V_{i'}$ and this again ensures that the power flow on the original line is not influenced by the introduction of the auxiliary node and line.

A hybrid approach is also feasible, where certain lines are merged and additional auxiliary lines and nodes are added for the rest. A graphical representation of the different approaches is depicted in Fig. 3.2.

3.1.4 HVDC networks

With the proposed framework, HVDC point to point connections as well as HVDC networks can be modeled. The AC/DC converter is modeled as two generators, one connected to the corresponding AC busbar and one to the DC busbar [97]. On the AC side, the generator can inject negative and positive real and reactive power, and on the DC side it can only inject real power. Since the converter is only converting and not generating or consuming (except for losses) power, the injected real power on the AC side and on the DC side must be equal in magnitude and opposite in sign. That is why we can use one variable P_t^{VSC} to describe both the real power injection in the AC busbar as well as in the DC busbar. When considering losses, they must be added to the injected power in one of the two busbars. The loss component is assigned to the DC busbar, so the injected power in the AC busbar is equal to P_t^{VSC} and in the DC busbar it is equal to $-(P_t^{\text{VSC}} + P_t^{\text{VSC,loss}})$.

The DC connections are modeled as lines with a resistance r and an admittance g . For the current through the line connecting the DC busbars i and k we therefore get:

$$I_{ik,t}^{\text{DC}} = \frac{V_{i,t}^{\text{DC}} - V_{k,t}^{\text{DC}}}{r_{ik}^{\text{DC}}} = (V_{i,t}^{\text{DC}} - V_{k,t}^{\text{DC}})g_{ik}^{\text{DC}} \quad (3.18)$$

And for the power injected in the line at busbar i :

$$P_{ik,t}^{\text{DC}} = V_{i,t}^{\text{DC}} I_{ik,t}^{\text{DC}} = V_{i,t}^{\text{DC}} (V_{i,t}^{\text{DC}} - V_{k,t}^{\text{DC}}) g_{ik}^{\text{DC}} \quad (3.19)$$

The balance of incoming and outgoing power flows is then given as follows for each busbar i in the DC network:

$$-(P_{i,t}^{\text{VSC}} + P_{i,t}^{\text{VSC,loss}}) - V_{i,t}^{\text{DC}} \sum_{k \in I} (V_{i,t}^{\text{DC}} - V_{k,t}^{\text{DC}}) g_{ik}^{\text{DC}} = 0, \quad \forall i \in \mathcal{I}^{\text{DC}} \quad (3.20)$$

For the losses caused by the voltage source converter we assume one constant part a^{VSC} that is proportional to the power rating of the converter and one part b^{VSC} that is proportional to the actual operating point of the converter.

$$P_{i,t}^{\text{VSC,loss}} = \left(a_i^{\text{VSC}} + b_i^{\text{VSC}} \frac{P_{i,t}^{\text{VSC}^2} + Q_{i,t}^{\text{VSC}^2}}{\bar{S}_i^{\text{VSC}^2}} \right) \cdot \bar{S}_i^{\text{VSC}^2} \quad (3.21)$$

Additionally, the limits for currents over DC transmission lines, for voltage limits at DC nodes and the operating point of voltage source converters must be complied with:

$$(V_{i,t}^{\text{DC}} - V_{k,t}^{\text{DC}}) g_{ik}^{\text{DC}} \leq \bar{I}_{ik} \quad \forall (ik) \in \mathcal{L}^{\text{DC}} \quad (3.22)$$

$$\underline{V}_i^{\text{DC}} \leq V_{i,t}^{\text{DC}} \leq \bar{V}_i^{\text{DC}} \quad \forall i \in \mathcal{I}^{\text{DC}} \quad (3.23)$$

$$\underline{P}_i^{\text{VSC}} \leq P_{i,t}^{\text{VSC}} \leq \bar{P}_i^{\text{VSC}} \quad \forall i \in \mathcal{I}^{\text{VSC}} \quad (3.24)$$

$$\underline{Q}_i^{\text{VSC}} \leq Q_{i,t}^{\text{VSC}} \leq \bar{Q}_i^{\text{VSC}} \quad \forall i \in \mathcal{I}^{\text{VSC}} \quad (3.25)$$

$$P_{i,t}^{\text{VSC}^2} + Q_{i,t}^{\text{VSC}^2} \leq \bar{S}_i^{\text{VSC}^2} \quad \forall i \in \mathcal{I}^{\text{VSC}} \quad (3.26)$$

3.1.5 Flexible AC Transmission Systems (FACTS)

In the following, the modeling approach for different FACTS devices is explained. The approach is generally based on power injection models [31, 33–35, 39, 40, 89, 160], which allow the integration of FACTS devices into the OPF model with minimal changes to the core formulation of the OPF.

3.1.5.1 Static Var Compensator (SVC)

The SVC is used to control voltages by injecting positive or negative reactive power in the network node it is connected to. The SVC consists of an adjustable capacitor, inductance, or both. By adjusting the effective impedance of the device, the injected reactive power can be controlled. With losses neglected, the SVC is seen by the network as a variable node susceptance B^{SVC} and thus a reactive load. The injected reactive power varies quadratically with the electrical mains voltage magnitude and linearly with the effective susceptance of the SVC. The reactive power injected at corresponding busbar i is therefore:

$$Q_{i,t}^{\text{SVC}} = -V_{i,t}^2 B_{i,t}^{\text{SVC}} \quad \forall i \in \mathcal{I}^{\text{SVC}}, \forall t \in \mathcal{T} \quad (3.27)$$

The effective susceptance B can be adjusted between time steps, but must always remain within the technical limits of the SVC:

$$\underline{B}_i^{\text{SVC}} \leq B_{i,t}^{\text{SVC}} \leq \overline{B}_i^{\text{SVC}} \quad \forall i \in \mathcal{M}^{\text{SVC}}, \forall t \in \mathcal{T} \quad (3.28)$$

The equivalent circuit diagram of the modeling approach is shown in Fig. 3.3.

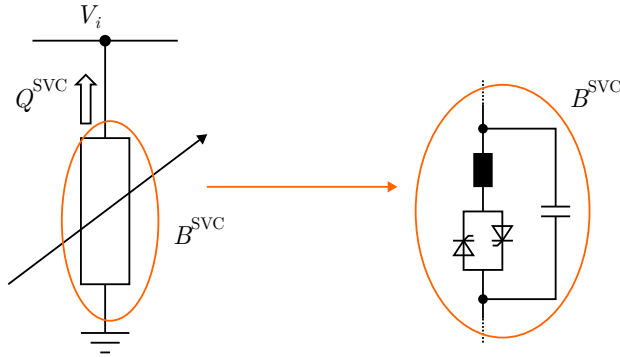


Figure 3.3: Illustration of the power injection model for the SVC.

3.1.5.2 Static Synchronous Compensator (STATCOM)

As for the SVC, the STATCOM belongs to the group of parallel FACTS, which means it is connected in parallel to the transmission grid. It generates a three-phase voltage system with variable voltage amplitude, shifted by 90° relative to the corresponding line currents. This means only reactive power is exchanged. The voltage system is generated by a voltage source converter

combined with a capacitor, which are connected to the network busbar via a coupling transformer with the short circuit impedance X_k . The injected reactive power Q_i^{STAT} at busbar i can be controlled by the amplitude and phase angle of the generated voltage $V^{\text{STAT}} e^{j\theta^{\text{STAT}}}$:

$$Q_{i,t}^{\text{STAT}} = V_{i,t}^2 B_{sh}^{\text{STAT}} + V_{i,t} V_t^{\text{STAT}} [G_{sh}^{\text{STAT}} \cos(\theta_{i,t} - \theta_t^{\text{STAT}}) - B_{sh}^{\text{STAT}} \sin(\theta_{i,t} - \theta_t^{\text{STAT}})] \quad (3.29)$$

$$\forall t \in \mathcal{T}, \forall i \in \mathcal{I}^{\text{STAT}}$$

With a phase shift different from 90° , also the exchange of real power can be achieved, which can be useful, e.g., in case of network outages. Since the model is assuming steady-state and there is no other storage system connected to the STATCOM besides the relatively small capacitor C_s , the real power exchange P_i^{STAT} must be equal to zero for all time steps. Theoretically, it is possible to couple the STATCOM with storage systems like a battery, then this constraint can be relaxed. The equivalent circuit diagram of the model is shown in Fig. 3.4.

$$P_{i,t}^{\text{STAT}} = 0 = -V_{i,t}^2 G_{sh} + V_{i,t} V_t^{\text{STAT}} [G_{sh}^{\text{STAT}} \sin(\theta_{i,t} - \theta_t^{\text{STAT}}) + B_{sh}^{\text{STAT}} \cos(\theta_{i,t} - \theta_t^{\text{STAT}})] \quad (3.30)$$

$$\forall t \in \mathcal{T}, \forall i \in \mathcal{M}^{\text{STAT}}$$

Furthermore, the rated power of the STATCOM must not be exceeded.

$$S_{i,t}^{\text{STAT}} \leq \overline{S}_i^{\text{STAT}} \quad \forall t \in \mathcal{T}, \forall i \in \mathcal{M}^{\text{STAT}} \quad (3.31)$$

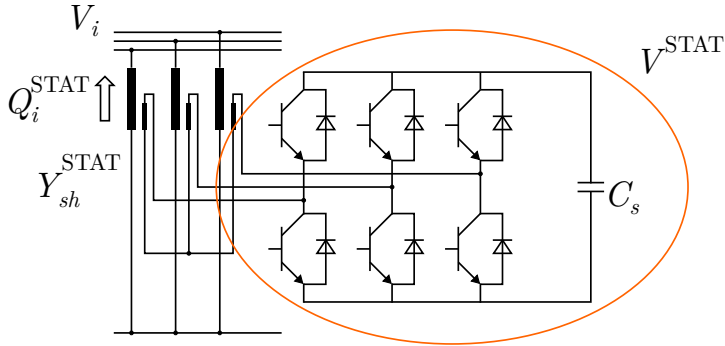


Figure 3.4: Illustration of the power injection model for the STATCOM.

3.1.5.3 Thyristor Controlled Series Compensator (TCSC)

The TCSC is a series FACTS device installed in series with a transmission line, enabling control of real and reactive power flows. In essence, it functions as an adjustable series impedance. By modifying this impedance, the effective line reactance changes, which in turn alters the amount of power transmitted.

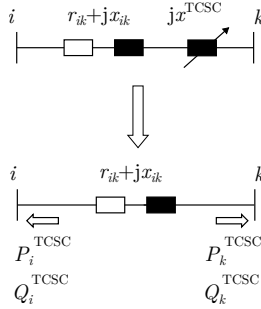


Figure 3.5: Illustration of the power injection model for the TCSC.

To model this change in transmitted power we use a power injection model, as it is shown in Fig. 3.5. Therefore, we describe the delta in the transmitted power as an additional power injection in the start and end busbars of the transmission line. In this way, we do not have to modify the power flow equation of the line and can simply add the power injections to the power equilibrium equations of the respective nodes. The injected powers at the two busbars have (nearly) the same value and opposite signs. The difference in value depicts the increased or decreased transmission losses induced by the change in power transmission and thus line current. We model the TCSC as an adjustable impedance x^{TCSC} , then the injected real and reactive power at start busbar i and end busbar k can then be calculated as follows:

$$P_{i,t}^{\text{TCSC}} = V_{i,t}^2 \Delta G_{ik,t} + V_{i,t} V_{k,t} (\Delta G_{ik,t} \cos \theta_{ik,t} + \Delta B_{ik,t} \sin \theta_{ik,t}) \quad (3.32a)$$

$$Q_{i,t}^{\text{TCSC}} = -V_{i,t}^2 \Delta B_{ik,t} + V_{i,t} V_{k,t} (\Delta G_{ik,t} \sin \theta_{ik,t} - \Delta B_{ik,t} \cos \theta_{ik,t}) \quad (3.32b)$$

$$P_{k,t}^{\text{TCSC}} = V_{k,t}^2 \Delta G_{ik,t} + V_{i,t} V_{k,t} (\Delta G_{ik,t} \cos \theta_{ik,t} - \Delta B_{ik,t} \sin \theta_{ik,t}) \quad (3.32c)$$

$$Q_{k,t}^{\text{TCSC}} = -V_{k,t}^2 \Delta B_{ik,t} + V_{i,t} V_{k,t} (-\Delta G_{ik,t} \sin \theta_{ik,t} - \Delta B_{ik,t} \cos \theta_{ik,t}) \quad (3.32d)$$

$$\forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{TCSC}}$$

with

$$\Delta G_{ik,t} = \frac{x_{i,t}^{\text{TCSC}} r_{ik} (x_{i,t}^{\text{TCSC}} + 2x_{ik})}{(r_{ik}^2 + x_{ik}^2)(r_{ik}^2 + (x_{ik} + x_{i,t}^{\text{TCSC}})^2)} \quad (3.33)$$

$$\Delta B_{ik,t} = \frac{x_{i,t}^{\text{TCSC}} (r_{ik}^2 - x_{ik}^2 - x_{i,t}^{\text{TCSC}} x_{ik})}{(r_{ik}^2 + x_{ik}^2)(r_{ik}^2 + (x_{ik} + x_{i,t}^{\text{TCSC}})^2)} \quad (3.34)$$

$$\underline{x}_i^{\text{TCSC}} \leq x_{i,t}^{\text{TCSC}} \leq \bar{x}_i^{\text{TCSC}} \quad \forall t \in \mathcal{T}, \forall i \in \mathcal{M}^{\text{TCSC}} \quad (3.35)$$

3.1.5.4 Static Synchronous Series Compensator (SSSC)

The SSSC is a series connected FACTS device designed to regulate real and reactive power flow in transmission lines. Unlike the TCSC, the SSSC employs a controllable voltage source implemented via a VSC and a DC energy storage element, connected to the line through a transformer. By injecting a variable series voltage with adjustable magnitude and phase angle, the SSSC modifies the effective line impedance and voltage, enabling dynamic control of line current and power transfer within defined limits.

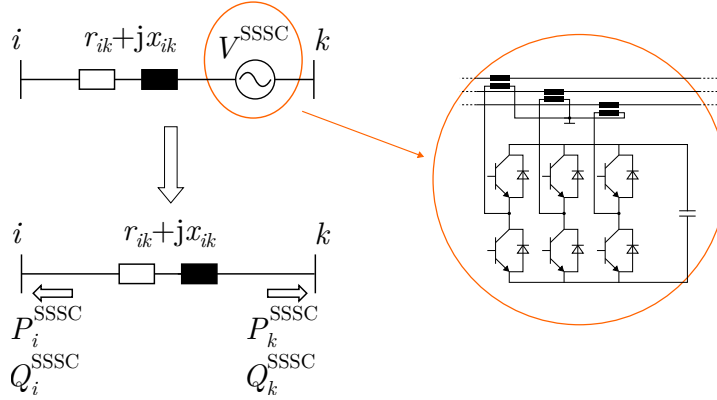


Figure 3.6: Illustration of the power injection model for the SSSC.

Similarly to the TCSC, we use the power injection model to describe the influence of the SSSC on the power flow over the respective line. The modeling approach is shown in Fig. 3.6. The real and reactive power injections P_i^{SSSC} and Q_i^{SSSC} induced by an SSSC with voltage magnitude V^{SSSC} and voltage phase angle θ^{SSSC} in node i and node k amount to:

$$P_{i,t}^{\text{SSSC}} = V_{i,t} V_{ik,t}^{\text{SSSC}} [G_{ik} \cos(\theta_{i,t} - \theta_{ik,t}^{\text{SSSC}}) + B_{ik} \sin(\theta_{ik,t} - \theta_{i,t}^{\text{SSSC}})] \quad (3.36a)$$

$$Q_{i,t}^{\text{SSSC}} = V_{i,t} V_{ik,t}^{\text{SSSC}} [G_{ik} \sin(\theta_{i,t} - \theta_{ik,t}^{\text{SSSC}}) - B_{ik} \cos(\theta_{i,t} - \theta_{ik,t}^{\text{SSSC}})] \quad (3.36b)$$

$$P_{k,t}^{\text{SSSC}} = -V_{k,t} V_{ik,t}^{\text{SSSC}} [G_{ik} \cos(\theta_{k,t} - \theta_{ik,t}^{\text{SSSC}}) + B_{ik} \sin(\theta_{k,t} - \theta_{ik,t}^{\text{SSSC}})] \quad (3.36c)$$

$$Q_{k,t}^{\text{SSSC}} = -V_{k,t} V_{ik,t}^{\text{SSSC}} [G_{ik} \sin(\theta_{k,t} - \theta_{ik,t}^{\text{SSSC}}) - B_{ik} \cos(\theta_{k,t} - \theta_{ik,t}^{\text{SSSC}})] \quad (3.36d)$$

$$\forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{SSSC}}$$

Similar to the STATCOM, in a steady state the sum of the injected real powers at busbar i and busbar k must be equal to zero, since we assume there is no energy storage connected to the SSSC:

$$P_{i,t}^{\text{SSSC}} + P_{k,t}^{\text{SSSC}} = 0 \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{SSSC}} \quad (3.37)$$

Furthermore, the nominal power of the SSSC must not be exceeded, which can be assured by limiting the voltage magnitude.

$$0 \leq V_{ik,t}^{\text{SSSC}} \leq \bar{V}_{ik}^{\text{SSSC}} \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{SSSC}} \quad (3.38)$$

3.1.5.5 Universal Power Flow Controller (UPFC)

The Universal Power Flow Controller (UPFC) is a combination of a SSSC and a STATCOM and thus consists of two voltage source converters, one connected in parallel and one in series to the transmission line. It unites the benefits of both the devices: active power flow control and voltage regulation via reactive power injection.

The modeling of the UPFC is the same as for the SSSC and the STATCOM. For the serial voltage source converter we use the power injection model to calculate the flows caused by the voltage injection $V^{\text{sc}} e^{j\theta^{\text{sc}}}$. The injected power by the parallel voltage source converter is dependent on the short circuit reactance of the transformer with the admittance $G^{\text{sh}} + jB^{\text{sh}}$ and the voltage $V^{\text{sh}} e^{j\theta^{\text{sh}}}$ of the voltage source converter.

$$P_{i,t}^{\text{UPFC}} = V_{i,t}^2 G_i^{\text{sh}} + V_{i,t} V_{ik,t}^{\text{se}} [G_{ik} \cos(\theta_{i,t} - \theta_{ik,t}^{\text{se}}) + B_{ik} \sin(\theta_{i,t} - \theta_{ik,t}^{\text{se}})] \\ + V_{i,t} V_{i,t}^{\text{sh}} [G_i^{\text{sh}} \cos(\theta_{i,t} - \theta_{i,t}^{\text{sh}}) + B_i^{\text{sh}} \sin(\theta_{i,t} - \theta_{i,t}^{\text{sh}})] \quad (3.39a)$$

$$Q_{i,t}^{\text{UPFC}} = -V_{i,t}^2 B_i^{\text{sh}} + V_{i,t} V_{ik,t}^{\text{se}} [G_{ik} \sin(\theta_{i,t} - \theta_{ik,t}^{\text{se}}) - B_{ik} \cos(\theta_{i,t} - \theta_{ik,t}^{\text{se}})] \\ + V_{i,t} V_{i,t}^{\text{sh}} [G_i^{\text{sh}} \sin(\theta_{i,t} - \theta_{i,t}^{\text{sh}}) - B_i^{\text{sh}} \cos(\theta_{i,t} - \theta_{i,t}^{\text{sh}})] \quad (3.39b)$$

$$P_{k,t}^{\text{UPFC}} = -V_{k,t} V_{ik,t}^{\text{se}} [G_{ik} \cos(\theta_{k,t} - \theta_{ik,t}^{\text{se}}) + B_{ik} \sin(\theta_{k,t} - \theta_{ik,t}^{\text{se}})] \quad (3.39c)$$

$$Q_{k,t}^{\text{UPFC}} = -V_{k,t} V_{ik,t}^{\text{se}} [G_{ik} \sin(\theta_{k,t} - \theta_{ik,t}^{\text{se}}) - B_{ik} \cos(\theta_{k,t} - \theta_{ik,t}^{\text{se}})] \quad (3.39d)$$

$$\forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{UPFC}}$$

Again, with the assumption of a steady state and no connected energy storage the sum of the injected real powers at busbar i and busbar k must be equal to zero:

$$P_{i,t}^{\text{UPFC}} + P_{k,t}^{\text{UPFC}} = 0 \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{UPFC}} \quad (3.40)$$

Furthermore, the nominal power of the parallel and serial voltage source converters must not be exceeded, which can be assured by limiting the voltage magnitude.

$$0 \leq V_{ik,t}^{\text{sh}} \leq \bar{V}_{ik}^{\text{sh}} \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{UPFC}} \quad (3.41)$$

$$0 \leq V_{ik,t}^{\text{se}} \leq \bar{V}_{ik}^{\text{se}} \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{UPFC}} \quad (3.42)$$

3.1.6 Phase shift transformers

Phase shift transformers are composed of both a series transformer and a shunt transformer. The tap position ϑ^{PST} of the shunt transformer can be adjusted, which leads to a change in the voltage phase angle. By modifying the tap position, power flow can be effectively controlled. In practice, the tap position can only be adjusted in discrete steps. To avoid dealing with discrete variables, a relaxation is applied, treating the tap position as a continuous variable.

The influence of the PST on the active and reactive power flow over the line connecting two nodes i and k is modeled by modifying the admittance Y_{ik} of this line. The resulting modified admittance is calculated as follows:

$$Y_{ik,t}^{\text{PST}} = \frac{Y_{ik}}{e^{-j\vartheta_{ik,t}^{\text{PST}}}} \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{PST}} \quad (3.43)$$

$$Y_{ki,t}^{\text{PST}} = \frac{Y_{ki}}{e^{-j\vartheta_{ik,t}^{\text{PST}}}} \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{PST}} \quad (3.44)$$

The admittance can be again split up in the real part G_{ik}^{PST} and imaginary part B_{ik}^{PST} :

$$G_{ik,t}^{\text{PST}} = G_{ik} \cos(\vartheta_{ik,t}^{\text{PST}}) - B_{ik} \sin(\vartheta_{ik,t}^{\text{PST}}) \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{PST}} \quad (3.45)$$

$$B_{ik,t}^{\text{PST}} = G_{ik} \sin(\vartheta_{ik,t}^{\text{PST}}) + B_{ik} \cos(\vartheta_{ik,t}^{\text{PST}}) \quad \forall t \in \mathcal{T}, \forall ik \in \mathcal{L}^{\text{PST}} \quad (3.46)$$

To account for the changed admittance caused by the PST, the power flow equations for all the busbars that are connected to a line with an installed PST must be modified:

$$\begin{aligned} & \sum_{g \in \mathcal{G}_i} P_{g,i,t}^G - P_{i,t}^d - V_{i,t} \sum_{k \in I^{\text{PST}}} V_{k,t} \left((G_{ik} \cos(\vartheta_{ik,t}^{\text{PST}}) - B_{ik} \sin(\vartheta_{ik,t}^{\text{PST}})) \cos(\theta_{i,t} - \theta_{k,t}) \right. \\ & \left. + (G_{ik} \sin(\vartheta_{ik,t}^{\text{PST}}) + B_{ik} \cos(\vartheta_{ik,t}^{\text{PST}})) \sin(\theta_{i,t} - \theta_{k,t}) \right) - V_{i,t}^2 G_{ii} = 0 \quad \forall t \in \mathcal{T}, \forall i \in \mathcal{M}^{\text{PST}} \end{aligned} \quad (3.47)$$

$$\begin{aligned} & \sum_{g \in \mathcal{G}_i} Q_{g,i,t}^G - Q_{i,t}^d - V_{i,t} \sum_{k \in I^{\text{PST}}} V_{k,t} \left(G_{ik} \cos(\vartheta_{ik,t}^{\text{PST}}) - B_{ik} \sin(\vartheta_{ik,t}^{\text{PST}}) \sin(\theta_{i,t} - \theta_{k,t}) \right. \\ & \left. - G_{ik} \sin(\vartheta_{ik,t}^{\text{PST}}) + B_{ik} \cos(\vartheta_{ik,t}^{\text{PST}}) \cos(\theta_{i,t} - \theta_{k,t}) \right) + V_{i,t}^2 B_{ii} = 0 \quad \forall t \in \mathcal{T}, \forall i \in \mathcal{M}^{\text{PST}} \end{aligned} \quad (3.48)$$

The adjustable tap ratio of the PST is limited by technical constraints:

$$\underline{\vartheta}_i^{\text{PST}} \leq \vartheta_{i,t}^{\text{PST}} \leq \overline{\vartheta}_i^{\text{PST}} \quad \forall t \in \mathcal{T}, \forall i \in \mathcal{M}^{\text{PST}} \quad (3.49)$$

3.1.7 Energy storage systems

Energy storage systems are modeled as fully controllable devices that either feed in or feed out real power at the network node i to which they are connected, depending on their operating state. Energy storage systems are divided into two sub-categories in the model, distinguishing between battery storage systems and pumped-storage plants. The modeling approach for both of them is described in more detail in the following.

3.1.7.1 Batteries

A battery system s connected to node i can either feed in the power $P_{s,t}^{\text{bat,d}}$ in the system, meaning the battery is discharging, or feed out the power $P_{s,t}^{\text{bat,c}}$, meaning the battery is charging. The state of charge (SOC) of the battery at time step t depends on the SOC at time step $t - 1$, the charging and discharging power at time step t and the charging and discharging efficiencies $\eta_s^{\text{bat,c}}$ and $\eta_s^{\text{bat,d}}$:

$$E_{s,t}^{\text{bat,SOC}} = E_{s,t-1}^{\text{bat,SOC}} + P_{s,t}^{\text{bat,c}} \eta_s^{\text{bat,c}} \Delta t - P_{s,t}^{\text{bat,d}} \frac{1}{\eta_s^{\text{bat,d}}} \Delta t \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{bat}} \quad (3.50)$$

Charging and discharging power as well as the SOC are constrained by the battery's technical limits:

$$0 \leq P_{s,t}^{\text{bat,c}} \leq \overline{P}_s^{\text{bat,c}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{bat}} \quad (3.51)$$

$$0 \leq P_{s,t}^{\text{bat,d}} \leq \overline{P}_s^{\text{bat,d}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{bat}} \quad (3.52)$$

$$0 \leq E_{s,t}^{\text{bat,SOC}} \leq \overline{E}_s^{\text{bat,SOC}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{bat}} \quad (3.53)$$

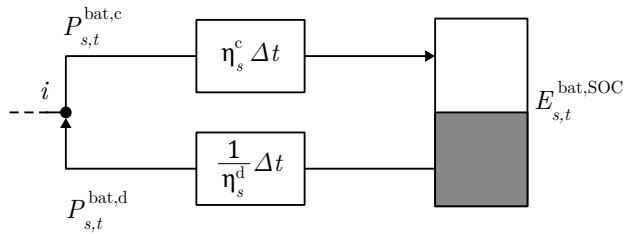


Figure 3.7: Sketch of the model used for battery energy storage systems.

Additionally, the SOC must be fixed for the beginning of the first time step and the end of the last time step of the simulation:

$$E_{s,t_0}^{bat,SOC} = SOC_s^{bat,start} \quad \forall s \in \mathcal{S}^{bat} \quad (3.54)$$

$$E_{s,t_{end}}^{bat,SOC} = SOC_s^{bat,end} \quad \forall s \in \mathcal{S}^{bat} \quad (3.55)$$

The used battery storage system model is also depicted in Fig. 3.7.

3.1.7.2 Pumped-storage

Pumped-storage plants include closed loop, open loop, pondage and reservoir plants. Depending on the type of storage plant, the parameters like pumping power, reservoir volumes, or inflows have to be adjusted.

The general pumped-storage model is shown in Fig. 3.8.

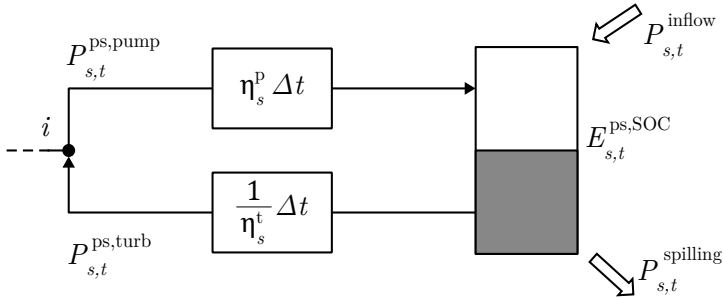


Figure 3.8: Sketch of the model used for pumped-storage power plants.

The model is the same as for the battery storage systems, with an additional inflow parameter $P_{s,t}^{inflow}$, which is exogenous time-series data, and spilling variable $P_{s,t}^{spilling}$. The spilling variable is introduced to prevent the storage from overflowing from high inflows by getting rid of water not only by turbining it, but also by draining water from the storage outside of the turbining system. With turbining power $P_{s,t}^{ps,turb}$ (which refers to the power feed-in at the node the pumpstorage plant is connected to), turbining efficiency $\eta_s^{ps,turb}$, pumping power $P_{s,t}^{ps,pump}$ (power feed-out at the connected node) and pumping efficiency $\eta_s^{ps,pump}$ we get the following time-coupling equation regarding the pumped-storage SOC:

$$E_{s,t}^{\text{ps,SOC}} = E_{s,t-1}^{\text{ps,SOC}} + P_{s,t}^{\text{ps,pump}} \eta_s^{\text{ps,pump}} \Delta t - P_{s,t}^{\text{ps,turb}} \frac{1}{\eta_s^{\text{ps,turb}}} \Delta t + P_{s,t}^{\text{inflow}} - P_{s,t}^{\text{spilling}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{ps}} \quad (3.56)$$

Similarly to batteries, pumping and turbinning power, as well as SOC are constrained by technical limits of the respective plant and the SOC at the beginning and end of the simulation period has to be fixed. The spilling variable is upper bounded by the plant's natural inflows.

$$0 \leq P_{s,t}^{\text{ps,pump}} \leq \bar{P}_s^{\text{ps,pump}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{ps}} \quad (3.57)$$

$$0 \leq P_{s,t}^{\text{ps,turb}} \leq \bar{P}_s^{\text{ps,turb}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{ps}} \quad (3.58)$$

$$0 \leq E_{s,t}^{\text{ps,SOC}} \leq \bar{E}_s^{\text{ps,SOC}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{ps}} \quad (3.59)$$

$$E_{s,t_0}^{\text{ps,SOC}} = \text{SOC}_s^{\text{ps,start}} \quad \forall s \in \mathcal{S}^{\text{ps}} \quad (3.60)$$

$$E_{s,t_{\text{end}}}^{\text{ps,SOC}} = \text{SOC}_s^{\text{ps,end}} \quad \forall s \in \mathcal{S}^{\text{ps}} \quad (3.61)$$

$$0 \leq P_{s,t}^{\text{spilling}} \leq P_{s,t}^{\text{inflow}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S}^{\text{ps}} \quad (3.62)$$

3.1.8 Exchange flows

Exchange flows between countries and market areas play a pivotal role in the European electricity system. Hence, they need to be properly modeled in the OPF. In order to do so, first two sets are defined: The set of active countries $\mathcal{C}^{\text{active}}$, which contains all countries that are modeled in detail with their electricity grid, and the set of neighbors $\mathcal{C}^{\text{neighbor}}$, which contains all countries that are electrical neighbors (at least one cross-border transmission line) to at least one of the active countries. The neighbor countries can either be modeled as a single-node representation of the respective energy system, including aggregated demand, RES generation and unit-wise modeling of power plants and storage systems but neglecting any intra-country transmission limits (see Section 3.4 for details), or as infinite sources/sinks for import/export flows. As a simplification, only countries and not market areas are considered in the modeling of exchange flows, which means that the market areas of countries with multiple market areas are aggregated at country level. In the following, the modeling approach for exchange flows and the associated constraints and impacts on the objective function are explained.

3.1.8.1 Modeling approach and physical and market-based constraints

We distinguish between three different cases: exchange flows between two active countries, exchange flows between two neighboring countries, and exchange flows between one active country and one neighboring country.

Exchange flows between active countries

The set of active countries is considered to be one coherent region. Hence, for exchange flows between two active countries, no further constraints are introduced. The maximum flow in each direction is restricted by the thermal limits of the transmission lines that connect two countries.

Exchange flows between neighboring countries

If neighboring countries are modeled as one node power systems, exchange flows between neighboring countries are possible. They are constrained by NTC values. Otherwise, exchange flows between two countries in the set of neighboring countries are not considered in the model.

Exchange flows between active and neighboring countries

Exports and imports between an active country and one of its neighbors are constrained by two restrictions: The physical limits of transmission lines connecting the two countries and a market-oriented upper limit of available exchange flow capacity. To be able to ensure the first, cross-border lines, connecting active with neighbor countries, together with their start and end busbars are included into the model. This means that also some busbars in neighboring countries are part of the model. Import flows (from the active country's point of view) are modeled as generation at the neighboring country nodes and export flows as demand, transported to the active country via the cross-border transmission lines. We therefore introduce a new variable P_i^{exchange} which denotes the power generation or demand at node i in a neighboring country induced by an exchange flow to an active country. The distribution of generation or demand on the nodes of the neighboring country is determined by the optimization model. To implement also a market oriented cap, an additional NTC approach is chosen. The sum of all export/import flows over the transmission lines from an active country to one of its neighboring countries is limited by the NTC value for the two countries. The NTC values are taken from external sources, e.g., TYNDP 2022 [161] or TYNDP 2024 [162]. A visual representation of the modeling approach is shown in Fig. 3.9.

This leads to the following constraints for the optimization model, first regarding the single AC and/or DC cross-border lines (for details on the calculation of the real power P and reactive power Q injections at the line's start and end nodes, see Section 3.1.3.2):

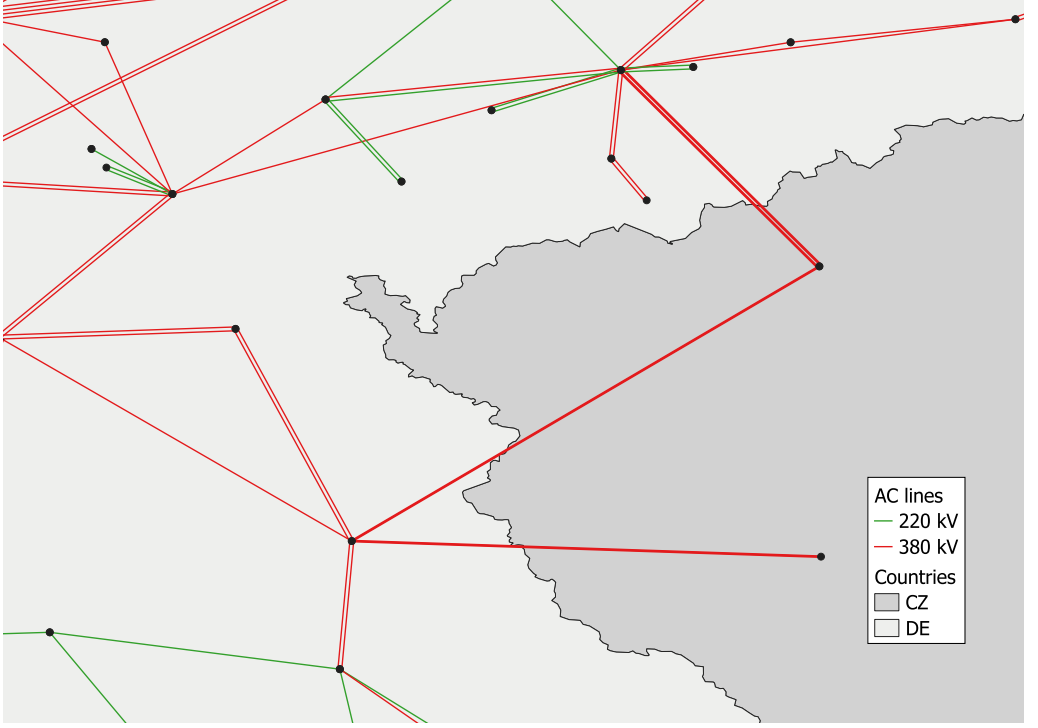


Figure 3.9: Snapshot of the German transmission grid around the German-Czechian border in 2025. Cross-border lines are highlighted bold. The exchange flows between Germany and Czechia are limited by the thermal capacities of the cross-border lines and NTC values.

$$P_{l,t}^{\text{from}^2} + Q_{l,t}^{\text{to}^2} \leq \overline{S}_l^2 \quad \forall l \in \mathcal{L}_{c_a-c_n}^{\text{cross-border,AC}}, \forall c_a \in \mathcal{C}^{\text{active}}, \forall c_n \in \mathcal{C}^{\text{neighbor}} \quad (3.63a)$$

$$P_{l,t}^{\text{to}^2} + Q_{l,t}^{\text{from}^2} \leq \overline{S}_l^2 \quad \forall l \in \mathcal{L}_{c_a-c_n}^{\text{cross-border,AC}}, \forall c_a \in \mathcal{C}^{\text{active}}, \forall c_n \in \mathcal{C}^{\text{neighbor}} \quad (3.63b)$$

$$P_l^{\text{DC}} \leq \overline{P}_l^{\text{DC}} \quad \forall l \in \mathcal{L}_{c_a-c_n}^{\text{cross-border,DC}}, \forall c_a \in \mathcal{C}^{\text{active}}, \forall c_n \in \mathcal{C}^{\text{neighbor}} \quad (3.63c)$$

And second for the total flows between active and neighboring countries:

$$-NTC_{c_a-c_n} \leq \sum_{l^{\text{AC}} \in \mathcal{L}_{c_a-c_n}^{\text{cross-border,AC}}} P_{l^{\text{AC}}} + \sum_{l^{\text{DC}} \in \mathcal{L}_{c_a-c_n}^{\text{cross-border,DC}}} P_{l^{\text{DC}}} \leq NTC_{c_n-c_a} \quad \forall c_a \in \mathcal{C}^{\text{active}}, \forall c_n \in \mathcal{C}^{\text{neighbor}} \quad (3.64)$$

Here, positive values for P_{lAC} and P_{lDC} indicate a power flow from the neighboring country c_n to the active country c_a and negative values indicate a power flow the other way round. This formulation also makes it possible to respect different NTC values for different directions between two countries.

With the newly introduced variable P_i^{exchange} , Eq. (3.64) can be simplified:

$$-NTC_{c_a-c_n} \leq \sum_{i \in \mathcal{I}_{c_n}} P_i^{\text{exchange}} \leq NTC_{c_n-c_a} \quad \forall c_a \in \mathcal{C}^{\text{active}}, \forall c_n \in \mathcal{C}^{\text{neighbor}} \quad (3.65)$$

Positive values of P_i^{exchange} indicate power generation in the corresponding busbar in the neighboring country, which translates to an import flow from the active country's point of view. Negative values represent power demand, which results in an export flow from the active country to the neighboring country.

3.1.8.2 Modeling of neighboring countries and costs/revenues

The neighboring countries are modeled in two different ways: Either as an infinite source for power generation or sink for power demand, or as a one node model of the corresponding power system.

For the first case, the exchanged energy is billed at a fixed price or price time series. By exporting energy to neighboring countries, the optimized system can gain money and thus reduce overall system costs, by importing energy from neighboring countries, the overall system costs increase. The amount of power exchanged is limited only by the transmission constraints formulated in Eq. (3.63c) and Eq. (3.65). The integration of the exchanged power in the model is done via variables P_i^{exchange} .

$$C_t^{\text{exchange}} = \sum_{c_n \in \mathcal{C}^{\text{neighbor}}} \sum_{i \in \mathcal{I}_{c_n}} c_{c_a,t}^{\text{exchange}} P_{i,t}^{\text{exchange}} \quad (3.66)$$

In the second case, each neighboring country is modeled as a one node system. Here, all power plants and storages are modeled unit-wise, demand is aggregated, and all intra-country transmission restrictions are neglected. The balance of power generation and demand for the country must always be fulfilled. A detailed description of the model formulation is provided in Section 3.4. The models of neighboring countries are integrated into the overall system optimization model. The coupling between the one node models and the detailed model of the active countries is again done with variables P_i^{exchange} . The integration into the overall model implies that here the power

systems of neighboring countries are also optimized and that their respective operating costs are part of the overall objective function. Therefore, the resulting exchange flows are optimized based on the system status of the corresponding active and neighboring countries, and they are not only constrained by transmission limits, but also by available energy. Obviously, this modeling approach is more sophisticated and closer to reality, but it also entails increased model complexity.

3.2 Redispatch formulation

In this section the modeling approach for the calculation of optimal congestion management measures is presented. For the congestion management calculation, a previous market simulation is mandatory. The most important results of the market simulation that are used as inputs for the congestion management calculation is the dispatch of conventional power plants, the operation of pumpstorages and batteries, the amount of market-driven renewables curtailment and exchange flows between market areas. The model outputs comprise modified schedules for power plant and storage operation, renewables curtailment, load shedding and the related costs.

The measures that can be used for the congestion management are the following:

- Redispatch, including RES curtailment
- Flexible network elements like FACTS
- Load shedding

While the operation of flexible network elements like FACTS or PSTs is considered cost neutral, for redispatch measures and load shedding the corresponding costs have to be considered. The technical implementation of the operation of flexible network elements and load shedding is no different from the basic OPF model. Therefore, in the following sections, only the additional variables, constraints, and costs with regard to the redispatch measures are presented.

3.2.1 Variables and constraints

In this section, the variables and constraints of the redispatch model are introduced and explained in detail.

3.2.1.1 Thermal power plants

Thermal power plants can be affected by redispatch measures in two ways: They can either increase (positive redispatch) or decrease (negative redispatch) their power output. Since remuneration mechanisms differ for positive and negative redispatch, we have to introduce one variable each for each power plant and time step. The resulting power output of the power plant g is the sum of the initial dispatch from the market simulation $P_{g,t}^{\text{market}}$, the requested positive redispatch $P_{g,t}^{\text{rd,pos}}$ and the requested negative redispatch $P_{g,t}^{\text{rd,neg}}$.

$$P_{g,t} = P_{g,t}^{\text{market}} + P_{g,t}^{\text{rd,pos}} - P_{g,t}^{\text{rd,neg}} \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (3.67)$$

The values for positive and negative redispatch are constrained by the technical limits and must-run requirements of the power plant, which may not be violated by the resulting generation $P_{g,t}$.

$$0 \leq P_{g,t}^{\text{rd,pos}} \leq \bar{P}_g - P_{g,t}^{\text{market}} \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (3.68)$$

$$0 \leq P_{g,t}^{\text{rd,neg}} \leq P_{g,t}^{\text{market}} - \underline{P}_g \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (3.69)$$

3.2.1.2 Pumped-storage plants

Pumped-storage plants can generally be operated in turbinning and in pumping mode. Redispatch measures can affect both operating modes in two different ways: increase turbinning power, decrease turbinning power, decrease pumping power or increase the pumping power. Again due to the remuneration mechanism scheme for pumped-storage plants, we need to introduce one variable each: $P^{\text{ps,rd,turb,pos}}$ for the increase in turbinning power, $P^{\text{ps,rd,turb,neg}}$ for the decrease in turbinning power, $P^{\text{ps,rd,pump,pos}}$ for the decrease in pumping power and $P^{\text{ps,rd,pump,neg}}$ for the increase in pumping power. The resulting turbinning and pumping powers $P_{s,t}^{\text{ps,turb}}$ and $P_{s,t}^{\text{ps,pump}}$ are calculated as the sum of the power output from the market results $P_{s,t}^{\text{ps,turb,market}}$ and $P_{s,t}^{\text{ps,pump,market}}$ and the positive and negative redispatch variables.

$$P_{s,t}^{\text{ps,turb}} = P_{s,t}^{\text{ps,turb,market}} + P_{s,t}^{\text{ps,rd,turb,pos}} - P_{s,t}^{\text{ps,rd,turb,neg}} \quad \forall s \in \mathcal{S}^{\text{ps}}, \forall t \in \mathcal{T} \quad (3.70)$$

$$P_{s,t}^{\text{ps,pump}} = P_{s,t}^{\text{ps,pump,market}} - P_{s,t}^{\text{ps,rd,pump,pos}} + P_{s,t}^{\text{ps,rd,pump,neg}} \quad \forall s \in \mathcal{S}^{\text{ps}}, \forall t \in \mathcal{T} \quad (3.71)$$

Again, the resulting power feed-in or feed-out must comply with the technical limits for the turbinning and pumping power of the respective plant.

$$0 \leq P_{s,t}^{\text{ps,rd,turb,pos}} \leq \bar{P}_s^{\text{ps,turb}} - P_{s,t}^{\text{ps,turb,market}} \quad \forall s \in \mathcal{S}^{\text{ps}}, \forall t \in \mathcal{T} \quad (3.72)$$

$$0 \leq P_{s,t}^{\text{ps,rd,turb,neg}} \leq P_{s,t}^{\text{ps,turb,market}} \quad \forall s \in \mathcal{S}^{\text{ps}}, \forall t \in \mathcal{T} \quad (3.73)$$

$$0 \leq P_{s,t}^{\text{ps,rd,pump,pos}} \leq P_{s,t}^{\text{ps,pump,market}} \quad \forall s \in \mathcal{S}^{\text{ps}}, \forall t \in \mathcal{T} \quad (3.74)$$

$$0 \leq P_{s,t}^{\text{ps,rd,pump,neg}} \leq \bar{P}_s^{\text{ps,pump}} - P_{s,t}^{\text{ps,pump,market}} \quad \forall s \in \mathcal{S}^{\text{ps}}, \forall t \in \mathcal{T} \quad (3.75)$$

3.2.1.3 Batteries

The redispatch for batteries is modeled similarly to the pumped-storage plants. This means there are again four variables introduced: $P^{\text{bat,rd,d,pos}}$ for the increase in discharging power, $P^{\text{bat,rd,d,neg}}$ for the decrease in discharging power, $P^{\text{bat,rd,c,pos}}$ for the decrease in charging power and $P^{\text{bat,rd,c,neg}}$ for the increase in charging power. Similar to the pumped-storage plants, the following constraints can be formulated which calculate the resulting discharging and charging power as well as the limits for the available redispatch power.

$$P_{s,t}^{\text{bat,d}} = P_{s,t}^{\text{bat,d,market}} + P_{s,t}^{\text{bat,rd,d,pos}} - P_{s,t}^{\text{bat,rd,d,neg}} \quad \forall s \in \mathcal{S}^{\text{bat}}, \forall t \in \mathcal{T} \quad (3.76)$$

$$P_{s,t}^{\text{bat,c}} = P_{s,t}^{\text{bat,c,market}} - P_{s,t}^{\text{bat,rd,c,pos}} + P_{s,t}^{\text{bat,rd,c,neg}} \quad \forall s \in \mathcal{S}^{\text{bat}}, \forall t \in \mathcal{T} \quad (3.77)$$

$$0 \leq P_{s,t}^{\text{bat,rd,d,pos}} \leq \bar{P}_s^{\text{bat,d}} - P_{s,t}^{\text{bat,d,market}} \quad \forall s \in \mathcal{S}^{\text{bat}}, \forall t \in \mathcal{T} \quad (3.78)$$

$$0 \leq P_{s,t}^{\text{bat,rd,d,neg}} \leq P_{s,t}^{\text{bat,d,market}} \quad \forall s \in \mathcal{S}^{\text{bat}}, \forall t \in \mathcal{T} \quad (3.79)$$

$$0 \leq P_{s,t}^{\text{bat,rd,c,pos}} \leq P_{s,t}^{\text{bat,c,market}} \quad \forall s \in \mathcal{S}^{\text{bat}}, \forall t \in \mathcal{T} \quad (3.80)$$

$$0 \leq P_{s,t}^{\text{bat,rd,c,neg}} \leq \bar{P}_s^{\text{bat,c}} - P_{s,t}^{\text{bat,c,market}} \quad \forall s \in \mathcal{S}^{\text{bat}}, \forall t \in \mathcal{T} \quad (3.81)$$

3.2.1.4 Curtailment and load shedding

For curtailment and load shedding, the same formulation is used as in the optimal dispatch case. Market-driven curtailment and load shedding are already included in the results of the market simulation and thus in the input data for the redispatch model, which means all of the additional necessary curtailment or load shedding determined by the model is purely related to grid restrictions.

In most cases of electricity market or system modeling, it is not possible to allocate market-driven curtailment to specific network nodes or even technologies, since RES generation costs are often assumed to be zero across all technologies and locations, and for the market model it is arbitrary where the curtailment happens. Therefore, the default procedure is to deduct the market curtailment proportionately from all RES producers. The same applies to market-driven load shedding.

3.2.2 Cost model

The implemented cost model for redispatch measures follows the current German Redispatch 2.0 regulation which was issued in 2024 by the Bundesnetzagentur [120, 163]. The core idea of the regulation is that a redispatch measure should have no financial consequences for the plant operator. This means, depending on the type of measure, that either the grid operator has to pay a compensation to the plant operator or the plant operator has to pay a compensation to the grid operator. For thermal power plants for example, the request for positive redispatch normally implies higher production costs for the plant operator, which have to be compensated by the grid operator, whereas negative redispatch leads to reduced production costs, which have to be paid back by the plant operator to the grid operator. In the regulation, there are six different financial positions that have to be compensated between the grid and plant operator [163]:

1. Production costs
2. Proportionate consumption of assets
3. Lost revenue opportunities (opportunity costs)
4. Necessary expenses for restoring operational readiness or postponing a planned revision
5. In the event of a reduction in active power generation from renewable energies or combined heat and power (CHP) plants, the lost revenue plus the additional expenses
6. The plant operator must reimburse the grid operator for any expenses saved

An overview of the application of the financial positions depending on the plant technology is given in Table 3.1 for the case of positive redispatch requests and in Table 3.2 for negative redispatch.

Since the classification as nonbiogenic and biogenic for waste power plants and the classification as priority and nonpriority CHP plants is not possible most of the time with the data basis used for the model, all waste plants are classified as nonbiogenic and all CHP plants are classified as nonpriority. This means that these power plants are handled in the same way as conventional

Table 3.1: Cost items to be applied in the event of positive redispatch [163].

Cost item	Conv. plants	Storages	Waste	Waste (bio)	CHP	CHP (prio)	Biogas	RES
No. 1	x	x	x	x	x	x	x	x
No. 2	x	x	x	x	x	x	x	x
No. 3	x	x	x	x	x	x	x	x
No. 4	x	x	x	x	x	x	x	x
No. 5	-	-	-	-	-	-	-	-
No. 6	x	x	x	x	x	x	x	x

Table 3.2: Cost items to be applied in the event of negative redispatch [163].

	Conv. plants	Storages	Waste	Waste (bio)	CHP	CHP (prio)	Biogas	RES
No. 1	x	x	x	-	x	-	-	-
No. 2	x	x	x	-	x	-	-	-
No. 3	x	x	x	-	x	-	-	-
No. 4	x	x	x	-	x	-	-	-
No. 5	-	-	-	x	-	x	x	x
No. 6	x	x	x	x	x	x	x	x

power plants with regard to the redispatch cost calculation. As can be seen in Table 3.1 and Table 3.2, the same cost calculation rules apply to biogas plants as to renewable energy plants. For this reason, in the following there will be no further differentiation between them and biogas plants will be considered as part of the RES.

Cost item no. 5, the expenses for restoring operational readiness or postponing a planned revision, is very difficult to model. That is why it is assumed that these costs are covered by the variable operating costs of a plant, which are part of cost item no. 1, the production costs.

The costs assigned to redispatch measures can be split in four parts: costs for redispatch measures regarding thermal power plants, measures regarding pumped-storage plants, curtailment and load shedding. The objective is to minimize the sum of these costs over all time steps in the optimization period. The implemented redispatch cost model follows the current German regulatory framework for the so-called Redispatch 2.0 [120, 163, 164].

$$C^{\text{rd}} = \sum_{t \in \mathcal{T}} \left(\sum_{g \in \mathcal{G}} C_{g,t}^{\text{ppl,rd}} + \sum_{s \in \mathcal{S}^{\text{ps}}} C_{s,t}^{\text{ps,rd}} + \sum_{r \in \mathcal{R}} C_{r,t}^{\text{curtailment}} + \sum_{l \in \mathcal{L}} C_{l,t}^{\text{ls}} \right) \quad (3.82)$$

The distinctive parts of the cost function are further explained in the following.

3.2.2.1 Redispatch expenses for thermal power plants

The costs for thermal power plants consist of the generation expenses and the higher value of opportunity costs and depreciation costs linked to the requested change in power plant operation.

$$C_{g,t}^{\text{ppl,rd}} = C_{g,t}^{\text{ppl,rd,gen}} + \max(C_{g,t}^{\text{ppl,rd,opp}}, C_{g,t}^{\text{ppl,rd,depr}}) \quad (3.83)$$

Generation expenses include fuel, emissions, start up and variable costs:

$$C_{g,t}^{\text{ppl,rd,gen}} = (c_{g,t}^{\text{fuel}} + c_{g,t}^{\text{co2}} + c_{g,t}^{\text{var}} + c_{g,t}^{\text{startup}}) P_{g,t}^{\text{rd,pos}} - (c_{g,t}^{\text{fuel}} + c_{g,t}^{\text{co2}} + c_{g,t}^{\text{var}} + c_{g,t}^{\text{startup}}) P_{g,t}^{\text{rd,neg}} \quad (3.84)$$

Where $c_{g,t}^{\text{fuel}} = c_{f,t}^{\text{fuel}} \frac{1}{\eta_g}$ describes the power plant specific fuel costs and $c_{g,t}^{\text{co2}} = c_t^{\text{co2}} \frac{1}{\eta_g} e f_f$ the power plant specific costs for CO₂ certificates with $e f_f$ being the fuel-type dependent CO₂ emissions factor.

For the start up costs an approximation is used by multiplying a power plant-dependent constant parameter by the positive redispatch variable, which is normalized to the nominal power.

$$c_g^{\text{startup}} = \begin{cases} \text{StartUp}_g * \frac{1}{P_g^N}, & \text{if } P_{g,t}^{\text{market}} = 0 \\ 0, & \text{else} \end{cases} \quad (3.85)$$

To obtain the opportunity costs, first of all the call and put option for each power plant and each time step are calculated using electricity market prices from the market simulation. Depending on whether the power plant is out or in the money, the value of the call or put option is offset against the requested redispatch power.

$$C_{(X,\mu,\sigma),g,t}^{\text{call}} = \sigma(d\Phi(d) + \phi(d)) \quad (3.86a)$$

$$C_{(X,\mu,\sigma),g,t}^{\text{put}} = \sigma(d\phi(d) - \Phi(-d)) \quad (3.86b)$$

$$C_{g,t}^{\text{ppl,rd,opp}} = \begin{cases} C_{(X,\mu,\sigma),g,t}^{\text{call}} * P_{g,t}^{\text{ppl,rd,pos}} + C_{(X,\mu,\sigma),g,t}^{\text{call}} * P_{g,t}^{\text{ppl,rd,neg}} & \text{if } X > \mu \\ C_{(X,\mu,\sigma),g,t}^{\text{put}} * P_{g,t}^{\text{ppl,rd,pos}} + C_{(X,\mu,\sigma),g,t}^{\text{put}} * P_{g,t}^{\text{ppl,rd,eg}} & \text{if } X < \mu \end{cases} \quad (3.86c)$$

$$\text{with } d = \frac{\mu - X}{\sigma} \quad (3.86d)$$

Hereby $c_{(X,\mu,\sigma)}^{\text{call}}$ stands for the value of the call option, $c_{(X,\mu,\sigma)}^{\text{put}}$ for the value of the put option, μ for the expected spot price, X the strike price of the power plant (approximated by the generation expenses), σ for the standard deviation of intraday prices, Φ for the cumulative probability function of the normal distribution and ϕ for the probability density function of the normal distribution.

The depreciation costs are highly specific to the power plant. Since it is not possible to obtain this data for each power plant, an approximation is used which calculates the depreciation costs based on a constant parameter which depends on the power plant's fuel type. Depreciation costs are only applied for positive redispatch measures.

$$C_{g,t}^{\text{ppl,rd,depr}} = c_f^{\text{depr}} P_{g,t}^{\text{rd,pos}} \quad (3.87)$$

3.2.2.2 Redispatch expenses for pumped-storage plants

The calculation of redispatch expenses regarding pumped-storage plants follows the guidelines for the current German redispatch regulatory framework [120, 163–165]. As for thermal power plants, the costs are based on generation expenses as well as opportunity and depreciation costs. However, since the value or cost of operating a pumped-storage plant is dependent on price spreads, it is much more difficult to determine a marginal price (also called shadow price) for the turbinng or pumping operation of a pumped-storage plant compared to a thermal power plant. The current regulation differentiates between daily and seasonal storages, depending on their ratio between volume and turbinng power. In this work, the proposed methodology for daily storages is applied to all storages.

The dispatch of daily storage systems is based on price expectations, primarily from short-term electricity markets. Due to the short planning horizon and the significant impact of balancing power activations, along with resulting reservoir level changes, variable dispatch prices emerge. However, for operational efficiency, least daily constant work prices for redispatch measures are preferred. The following approach therefore calculates dispatch prices and the resulting redispatch costs, neglecting balancing power provision and only partially accounting for reservoir constraints.

Unlike conventional power plants, where redispatch measures are limited to either increasing or decreasing power generation, for storages there are four possibilities, depending on the current operation:

1. Increase in turbinng power
2. Decrease in turbinng power

3. Decrease in pumping power
4. Increase in pumping power

Redispatch measures affecting storage systems not only disrupt the intended operation at the time of intervention but also impact future operational schedules, as they alter the available storage volume and thus constrain subsequent dispatch decisions. For the four possible redispatch measures, this impact can occur in two variants a) and b) each:

1. Increase in turbinning power leads to future
 - a) increase in pumping
 - b) decrease in turbinning
2. Decrease in turbinning power leads to
 - a) decrease in pumping
 - b) increase in turbinning
3. Decrease in pumping power leads to
 - a) decrease in turbinning
 - b) increase in pumping
4. Increase in pumping power leads to
 - a) increase in turbinning
 - b) decrease in pumping

Since it is not known which variant a) or b) will occur in the future, the costs for both variants must be determined, and the higher of the two values is chosen as compensation.

To calculate the costs for the four redispatch cases and the two variants each, the marginal prices for the operation of turbinning $g_{s,d}^T$ and pumping $g_{s,d}^P$ for each storage s and day d must first be derived. For this purpose, an iterative approach is used by calculating economically efficient round trip cycles. First, the hourly day-ahead prices (result of the previous market simulation, in the regulation the quarter-hourly intraday prices are intended instead) for day d are sorted from highest to lowest. Then, round trip cycles are calculated step by step in compliance with the conditions of energy conversion and economic efficiency.

The condition of energy conversion is given by:

$$H_{s,d}^T P_s^T = \eta_s^{\text{RT}} H_{s,d}^P P_s^P \quad (3.88)$$

Here, η_s^{RT} is the round trip efficiency of storage s , $H_{s,d}^T$ denotes the hours in which the storage is in turbining operation and $H_{s,d}^P$ are the pumping hours, assuming that the storage operation in one hour is either turbining or pumping and it is always operating with maximum power for the whole hour.

Together with the trivial condition that the sum of turbining and pumping hours may not exceed 24 h per day, we can derive the maximum number of round trip cycles for each storage:

$$H_{s,d}^T P_s^T + H_{s,d}^P \leq 24 \text{ h} \quad (3.89)$$

$$n_s^{\text{RTC,max}} = \left\lfloor 24 \cdot \frac{1}{1 + \frac{P_s^T}{\eta_s^{\text{RT}} P_s^P}} \right\rfloor \quad (3.90)$$

The round trip cycle is economically efficient, if the following condition holds:

$$g_{s,d}^T \eta_s^{\text{RT}} > g_{s,d}^P + c^{\text{NNE}}, \quad (3.91)$$

where c^{NNE} describes the grid usage fees incurred during pump operation. In the first iteration, the combination of the most expensive and the cheapest hour of the day are chosen to evaluate the condition of economic efficiency. The high price is assigned to $g_{s,d}^T$ and the low price to $g_{s,d}^P$. If the condition holds, the next iteration is performed by moving to the second-highest price and the second-lowest price hour of the day. This is carried out until either the maximum number of round trips is reached or economic efficiency no longer holds. The last feasible iteration determines the values for $g_{s,d}^T$ and $g_{s,d}^P$. The procedure is also illustrated in Fig. 3.10.

It may happen that the price curve for a day is so flat that no economically efficient round cycle is possible. For this case, the marginal prices are retrieved by adding or subtracting half of the economic round trip cycle losses to the average of the hourly prices.

$$g_{s,d}^T = p_d^{\text{avg}} + \frac{p_d^{\text{avg}}(1 - \eta_s^{\text{RT}}) + c^{\text{NNE}}}{1 + \eta_s^{\text{RT}}} \quad (3.92a)$$

$$g_{s,d}^P = p_d^{\text{avg}} - \frac{p_d^{\text{avg}}(1 - \eta_s^{\text{RT}}) + c^{\text{NNE}}}{1 + \eta_s^{\text{RT}}} \quad (3.92b)$$

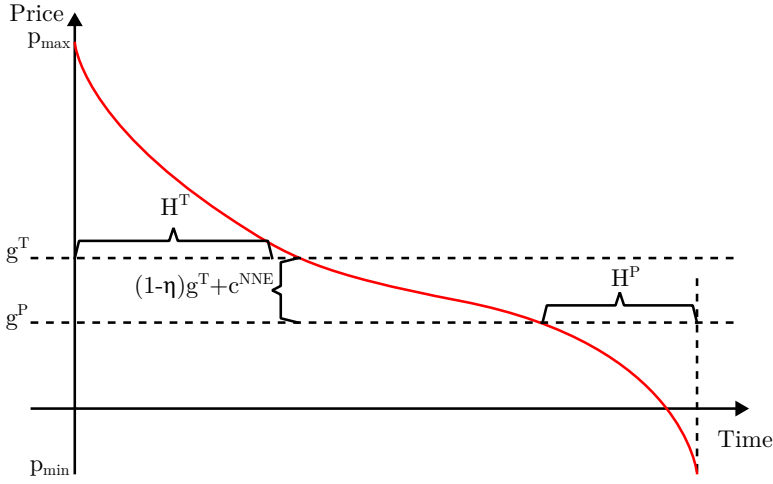


Figure 3.10: Schematic illustration of the determination of marginal prices for pump and turbine operation based on the price duration curve. Own illustration after [164].

With the marginal costs $g_{s,d}^T$ and $g_{s,d}^P$ obtained, it can now be differentiated between three different cases for which we can approximate prices related to the redispatch measures:

- The hours $H_{s,d}^T$, where the storage is in turbinning operation. In these hours, the price lies between the marginal costs for turbinning $g_{s,d}^T$ and the maximum price of the day $p_d^{\max}$. The prices for these hours are approximated by their average $\frac{\sum_{p_{d,h} \geq g_{s,d}^T} p_{d,h}}{n_d^T}$ with $p_{d,h}$ representing the price in day d and hour h and n_d^T representing the number of hours with $p_{d,h} \geq g_{s,d}^T$.
- The hours, where the storage is neither in turbinning nor in pumping operation, because prices do not allow for economically efficient cycles. The prices for these hours are approximated by the average of the marginal costs for turbinning and pumping $\frac{g_{s,d}^T + g_{s,d}^P}{2}$.
- The hours $H_{s,d}^P$, where the storage is in pumping operation. In these hours, the price lies between the minimum price of the day $p_d^{\min}$ and the marginal costs for pumping $g_{s,d}^P$. The prices for these hours are approximated by their average $\frac{\sum_{p_{d,h} \leq g_{s,d}^P} p_{d,h}}{n_d^P}$ with p_h representing the price in day d and hour h and n_d^P representing the number of hours with $p_{d,h} \leq g_{s,d}^P$.

Using these approximate values, the eight redispatch variants described earlier can be evaluated using the following compensation formulas:

$$p_{s,d}^{1a} = \left(\frac{g_{s,d}^T + g_{s,d}^P}{2} + c^{\text{NNE}} \right) / \eta_s^{\text{RT}} \quad (3.93a)$$

$$p_{s,d}^{1b} = \frac{\sum_{p_{d,h} > g_{s,d}^T} p_{d,h}}{n_d^T} \quad (3.93b)$$

$$p_{s,d}^{2a} = \left(\frac{\sum_{p_{d,h} < g_{s,d}^P} p_{d,h}}{n_d^P} + c^{\text{NNE}} \right) / \eta_s^{\text{RT}} \quad (3.93c)$$

$$p_{s,d}^{2b} = \frac{g_{s,d}^T + g_{s,d}^P}{2} \quad (3.93d)$$

$$p_{s,d}^{3a} = \frac{\sum_{p_{d,h} > g_{s,d}^T} p_{d,h}}{n_d^T} \eta_s^{\text{RT}} - c^{\text{NNE}} \quad (3.93e)$$

$$p_{s,d}^{3b} = \frac{g_{s,d}^T + g_{s,d}^P}{2} \quad (3.93f)$$

$$p_{s,d}^{4a} = \frac{g_{s,d}^T + g_{s,d}^P}{2} \eta_s^{\text{RT}} - c^{\text{NNE}} \quad (3.93g)$$

$$p_{s,d}^{4b} = \frac{\sum_{p_{d,h} < g_{s,d}^P} p_{d,h}}{n_d^P} \quad (3.93h)$$

As already mentioned before, it is uncertain whether variant (a) or (b) will occur in the future. Therefore, in the interest of the plant operator, the compensation for the plant operator is calculated based on the higher of the two values, whereas for repayments to the grid operator, the lower value is applied. The costs for the four different redispatch measures can thus be calculated ex ante for every time step t :

$$c_{s,t}^{\text{ps,rd,turb,pos}} = \max(p_{s,d}^{1a}, p_{s,d}^{1b}) \quad (3.94a)$$

$$c_{s,t}^{\text{ps,rd,turb,neg}} = \min(p_{s,d}^{2a}, p_{s,d}^{2b}) \quad (3.94b)$$

$$c_{s,t}^{\text{ps,rd,pump,pos}} = \max(p_{s,d}^{3a}, p_{s,d}^{3b}) \quad (3.94c)$$

$$c_{s,t}^{\text{ps,rd,pump,neg}} = \min(p_{s,d}^{4a}, p_{s,d}^{4b}) \quad (3.94d)$$

with $d = \lceil \frac{t}{24} \rceil$.

Multiplying the costs with the variable for the redispatch request leads to the cost function for generation expenses for storage s and time step t :

$$\begin{aligned}
C_{s,t}^{\text{ps,rd,gen}} = & P_{s,t}^{\text{ps,rd,turb,pos}} c_{s,d}^{\text{ps,rd,turb,pos}} - P_{s,t}^{\text{ps,rd,turb,neg}} c_{s,d}^{\text{ps,rd,turb,neg}} \\
& + P_{s,t}^{\text{ps,rd,pump,pos}} c_{s,d}^{\text{ps,rd,pump,pos}} - P_{s,t}^{\text{ps,rd,pump,neg}} c_{s,d}^{\text{ps,rd,pump,neg}}
\end{aligned} \quad (3.95)$$

Opportunity costs and depreciation costs are determined in the same way as for thermal power plants. For the depreciation costs, only the two variants *increase in turbinning power* and *increase in pumping power* are considered, since these result in higher strain on the pumped-storage plant.

$$C_{(X,\mu,\sigma),g,t}^{\text{call}} = \sigma(d\Phi(d) + \phi(d)) \quad (3.96a)$$

$$C_{(X,\mu,\sigma),g,t}^{\text{put}} = \sigma(d\phi(d) - \Phi(-d)) \quad (3.96b)$$

$$C_{g,t}^{\text{ppl,rd,opp}} = \begin{cases} C_{(X,\mu,\sigma),g,t}^{\text{call}} * P_{g,t}^{\text{ps,rd}} & \text{if } X > \mu \\ C_{(X,\mu,\sigma),g,t}^{\text{put}} * P_{g,t}^{\text{ps,rd}} & \text{if } X < \mu \end{cases} \quad (3.96c)$$

$$\text{with } d = \frac{\mu - X}{\sigma}, \quad (3.96d)$$

$$P_{g,t}^{\text{ps,rd}} = P_{g,t}^{\text{ps,rd,turb,pos}} + P_{g,t}^{\text{ps,rd,turb,neg}} + P_{g,t}^{\text{ps,rd,pump,pos}} + P_{g,t}^{\text{ps,rd,pump,neg}} \quad (3.96e)$$

$$C_{g,t}^{\text{ppl,rd,depr}} = c_f^{\text{depr}} (P_{g,t}^{\text{ps,rd,turb,pos}} + P_{g,t}^{\text{ps,rd,pump,neg}}) \quad (3.97)$$

The total costs associated with redispatch measures for pumped-storage plants are calculated as the sum of the cost components determined in this section:

$$C_{s,t}^{\text{ps,rd}} = C_{s,t}^{\text{ps,rd,gen}} + \max(C_{s,t}^{\text{ps,rd,opp}}, C_{s,t}^{\text{ps,rd,depr}}) \quad (3.98)$$

3.2.2.3 Redispatch expenses for battery storage systems

The methodology used to compute redispatch expenses for pumped-storage plants applies equally to batteries and other energy storage systems. Replacing turbinning with discharging and pumping with charging yields an equivalent formulation. Since this results in the same mathematical structure as in the pumped-storage case, the corresponding equations are not restated here in order to avoid redundancy.

3.2.2.4 Renewable energy sources

The German Redispatch 2.0 regulation [163] determines that plant operators affected by a redispatch measure must be financially compensated for any lost revenue or costs incurred as a result of the measure. Since electricity generation with renewable energy plants does not incur operating costs such as fuel costs, and lost revenues due to opportunities do not play a significant role according to [120], only potentially lost revenues associated with reduced generation (curtailment) due to redispatch must be compensated. According to the current German Energy Industry Act (EnWG) [166], remuneration for RES feed-in is done either by a fixed feed-in tariff (only for small plants) or by market-based mechanisms like a direct marketing scheme or a market premium scheme.

Regarding redispatch compensation, a distinction must be made between two cases here: Plants that are subject to fixed feed-in tariffs must be compensated, as they are remunerated for the energy physically fed into the grid and a reduction in the feed-in quantity due to the redispatch measure would therefore represent a financial disadvantage. Operators of RES plants that are in market-based schemes have already sold their potential generation on the market. Accordingly, they do not suffer any financial disadvantage from a reduction in physical feed-in, especially since the deviation in the balancing group must be compensated for by the grid operator who ordered the redispatch measure. Therefore, these operators do not have to be compensated. According to the EnWG, the fixed feed-in mechanism shall be replaced completely by market-based schemes in the coming years. Because of that, and since it is almost impossible to determine the share of RES generation accounted for by plants receiving fixed feed-in tariffs in current and future generation data, all RES generation is assumed to be part of market-based remuneration schemes and therefore no compensation measures apply for redispatch or curtailment actions. From a modeling perspective, this implies that RES curtailment is not associated with any costs and does not have a direct influence on the objective function.

3.3 Time coupling methodology

Time-coupled constraints pose a major challenge for solving optimization models, especially when dealing with large-scale models in terms of both spatial and temporal coverage. To tackle this problem, different methods to deal with time-coupled constraints are proposed and implemented in the model. An overview of these methods is shown in Fig. 3.11. Which method is most appropriate depends on the specific scenario, particularly the spatial scope, and on the overall objectives of the simulation. In the following, all four methods and their respective advantages and disadvantages are introduced.

Uncoupled optimization

In the uncoupled approach, each time step is treated independently, with no interaction or dependency between them. This means that separate models are created and solved for each individual time step, allowing for very low computational effort. Since there is no coupling between the separate models, the models can be solved in parallel, further speeding up the overall calculation time. However, this method does not capture any temporal dynamics or dependencies, which is a huge limitation in the case of energy systems. The only way to properly consider storage systems in this method is to include fixed external values for charging and discharging for each storage system and time step.

In the uncoupled optimization approach, each time step is treated as an entirely independent optimization problem, without any interaction or dependency between adjacent time steps. Consequently, the optimization model is instantiated and solved separately for every individual time

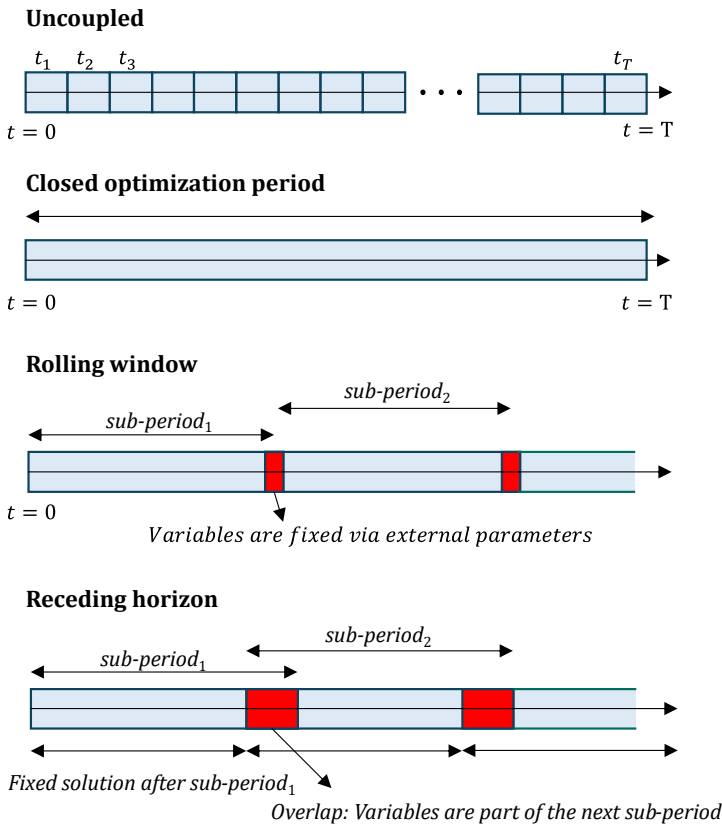


Figure 3.11: Overview of the four different time coupling methodologies implemented in the model.

step. This leads to very low computational complexity per model instance and enables extensive parallelization, making the approach particularly attractive for large-scale studies with high temporal resolution. However, the absence of temporal coupling implies that no intertemporal dynamics can be captured. In particular, operational constraints that link decisions over time, such as state of charge dynamics of storage systems, cannot be represented endogenously. As a result, the uncoupled approach is unsuitable for realistic modeling of energy storage and other assets with inherent temporal behavior. Storage systems can only be considered by prescribing exogenous charging and discharging schedules for each time step, which significantly reduces modeling flexibility and may lead to suboptimal or inconsistent system behavior. Overall, the uncoupled optimization approach is mainly useful for baseline analyses, sensitivity studies, or cases where temporal dependencies are either negligible or intentionally excluded.

Closed optimization period

The closed optimization period represents the most comprehensive approach to handling time-coupled constraints. In this method, a single optimization problem is formulated over the entire simulation horizon, and all time steps are optimized simultaneously. As a result, all temporal interdependencies are captured endogenously within the model, yielding globally optimal solutions with respect to the full time horizon. This approach allows for a consistent and accurate representation of storage systems, ramping constraints, and other intertemporal dynamics. In particular, the state of charge evolution of storage systems is explicitly modeled across all time steps, including cyclic boundary conditions to ensure consistency between the beginning and the end of the optimization horizon:

$$E_{s,t}^{\text{SOC}} = E_{s,t-1}^{\text{SOC}} + P_{s,t}^c \eta_s^c \Delta t - P_{s,t}^d \frac{1}{\eta_s^d} \Delta t + P_{s,t}^{\text{inflow}} - P_{s,t}^{\text{spilling}} \quad \forall t \in \mathcal{T}, \forall s \in \mathcal{S} \quad (3.99)$$

$$E_{s,t_0}^{\text{SOC}} = E_{s,t_{\max}}^{\text{SOC}} \quad \forall s \in \mathcal{S} \quad (3.100)$$

With $P_{s,t}^c$ as the charging power in time step t , $P_{s,t}^d$ the discharging power, $E_{s,t}^{\text{SOC}}$ the state of charge after t and E_{s,t_0}^{SOC} the initial state of charge. While this formulation yields the highest solution quality, it also results in very large-scale optimization problems for long time horizons or large networks. The resulting computational burden, both in terms of memory requirements and solution time, often renders this approach impractical for realistic, high-resolution energy system studies. Consequently, closed optimization periods are typically limited to short horizons or small systems and are mainly used as benchmarks or for methodological comparisons.

Rolling window approach

The rolling window approach seeks to balance computational tractability and temporal accuracy by dividing the overall simulation horizon into smaller, consecutive sub-periods $\mathcal{T}^{\text{sub}}$. Within each sub-period, all time steps are coupled, allowing short- to medium-term dynamics, such as storage operation, to be modeled endogenously. Between sub-periods, temporal consistency is maintained through external parameters, which act as boundary conditions. Each sub-period is optimized independently, and the coupling between adjacent sub-periods is enforced by externally specified state of charge values at the beginning and end of each window. This structure enables parallel execution of sub-period optimizations and significantly reduces overall computation time compared to a fully closed optimization period. At the same time, it provides a substantially more realistic representation of temporal dynamics than the uncoupled approach. The time coupling constraints for storage systems in the rolling window approach are given by:

$$E_{s,t}^{\text{SOC}} = E_{s,t-1}^{\text{SOC}} + P_{s,t}^c \eta_s^c \Delta t - P_{s,t}^d \frac{1}{\eta_s^d} \Delta t + P_{s,t}^{\text{inflow}} - P_{s,t}^{\text{spilling}} \quad \forall t \in \mathcal{T}^{\text{sub}}, \forall s \in \mathcal{S} \quad (3.101)$$

$$E_{s,t_0^{\text{sub}}}^{\text{SOC}} = E_{s,t_0^{\text{sub}}}^{\text{SOC,extern}} \quad \forall s \in \mathcal{S} \quad (3.102)$$

$$E_{s,t_{\text{max}}^{\text{sub}}}^{\text{SOC}} = E_{s,t_{\text{max}}^{\text{sub}}}^{\text{SOC,extern}} \quad \forall s \in \mathcal{S} \quad (3.103)$$

By choosing appropriate sub-period lengths and boundary values, the rolling window approach achieves a practical compromise between accuracy and computational efficiency and therefore represents the default methodology used in most applications of the model.

Receding horizon approach

The receding horizon approach, also referred to as model predictive control (MPC), extends the rolling window methodology by introducing overlapping sub-periods and sequential optimization [167, 168]. At each optimization sequence, a sub-period of fixed length is optimized, but only a subset of the resulting decisions, typically the first time step or a small number of initial steps, is implemented. The optimization window is then shifted forward in time, and the process is repeated. The key difference to the rolling window approach lies in the treatment of boundary conditions. Instead of relying on exogenous boundary values, the receding horizon approach uses the optimal state variables obtained from the previous optimization run as initial conditions for the next window. In particular, the state of charge of storage systems at the beginning of a sub-period is directly inherited from the solution of the previous sub-period:

$$E_{s,t}^{\text{SOC}} = E_{s,t-1}^{\text{SOC}} + P_{s,t}^c \eta_s^c \Delta t - P_{s,t}^d \frac{1}{\eta_s^d} \Delta t + P_{s,t}^{\text{inflow}} - P_{s,t}^{\text{spilling}} \quad \forall t \in \mathcal{T}^{\text{sub}}, \forall s \in \mathcal{S} \quad (3.104)$$

$$E_{s,t_0^{\text{sub}}}^{\text{SOC}} = E_{s,t_0^{\text{sub}}}^{\text{SOC,prev}} \quad \forall s \in \mathcal{S} \quad (3.105)$$

Here, $E_{s,t_0^{\text{sub}}}^{\text{SOC,prev}}$ denotes the state of charge resulting from the previous optimization run for the first time step of the current optimization period. No terminal condition is enforced at the end of the sub-period, which introduces a certain degree of myopia but allows for adaptive and flexible operation as new information becomes available. While the receding horizon approach offers improved continuity and realism compared to the rolling window method, it requires the sub-periods to be solved sequentially, eliminating the possibility of parallelization. This leads to significantly higher computational effort. Consequently, this approach is particularly well suited for real-time applications or operational studies where frequent data updates and adaptive decision-making are essential as well as studies incorporating uncertainties, e.g., in RES generation.

Coupling constraints across sub-periods

As already mentioned before, for the rolling window as well as the receding horizon method additional external parameters are needed, which link time-dependent variables across sub-periods. In the case of energy system models, this applies to batteries and pumped-storage plants. For these storage systems external values are needed that provide constraints for the SOC for the start and end (in case of rolling window) or only the end (in case of receding horizon) for each sub-period. If the model run is based on a previous market simulation, the results of this simulation with regard to the SOC of storage systems at the respective time steps can be used for this purpose. If the model is used to calculate the optimal system operation without building on the results of a previous market simulation, these values must be derived in a different way. For this purpose, storage systems are divided into two categories: short-term and seasonal storages. Short-term storages include all batteries and pumped-storage plants with a relatively small storage volume. Seasonal storages include pumped-storage plants with larger storage volumes. The classification is defined by the relation between the storage volume and the available turbinning power: If $\frac{E_s^{\text{ps,SOC}}}{P_s^{\text{ps,turb}}} > 8$ days, the storage is classified as seasonal storage, otherwise as short-term storage.

For short-term storages the SOC at the start and end of the sub-period is fixed at 50% of the respective maximum storage volume. For seasonal storages, this approach is not adequate, since, as the name already suggests, these storages are used to account for seasonal fluctuations in electricity generation and demand, leading to substantially varying storage filling levels throughout the year. To estimate these values, a normalized representative time series is calculated using historical storage level data from the ENTSOE Transparency Platform (include reference here). The resulting

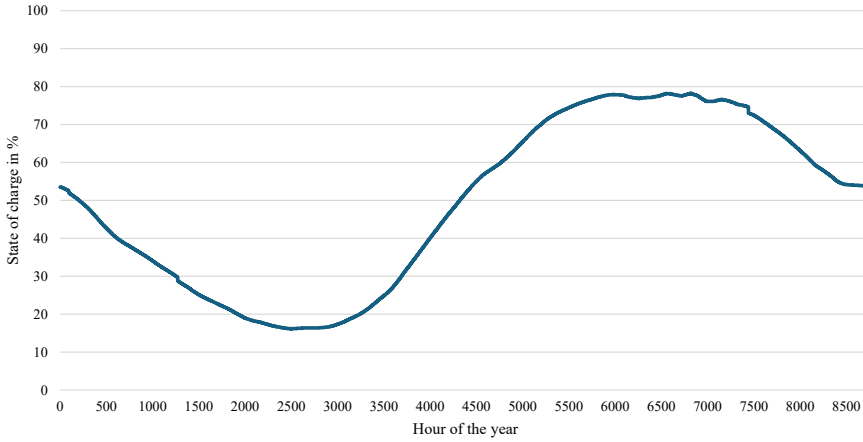


Figure 3.12: The normalized, representative reservoir level profile for seasonal pumped-storage.

profile is shown in Fig. 3.12. This standard profile is then multiplied with the seasonal storage's reservoir capacity to obtain the final reservoir level time series. An exception are storages with really large reservoir capacities, limited turbinning, and often nonexistent pumping capacity. In these instances, only the available inflows can be utilized for turbine operations. This can make it impossible to achieve the fill levels predetermined by the standard profile, leading to infeasibilities. Thus, it is advisable to avoid using the standard profile and instead assume a filling level of 50% as for short-term storages.

3.4 Simplified electricity market model

In order to be able to determine optimal congestion management measures based on a market result, an additional optimization model was implemented that calculates an approximated market result prior to the use of the congestion management model. Additionally, the model can be used in OPF simulations to model countries that shall not be modeled with full grid infrastructure detail (e.g., because not all of the necessary data is available or because of computation time reasons). The model simulates a simplified perfect market by minimizing the generation costs caused by conventional power plants and the costs for load shedding, see Eq. (3.106). Each of the considered countries is modeled as one node, connected to each other by net transfer capacities. Power plants, pumped-storage plants and battery storage systems are modeled unit-wise. The grid infrastructure inside the countries, as well as the start-up costs and ramping limits of the power plants, are neglected. The resulting problem is a linear optimization problem without binary

variables, which ensures fast solvability even for large spatial coverage. The following equations describe the model:

$$\min \sum_{t=0}^T \sum_{g \in G} c_{g,t}^{\text{gen}} P_{g,t}^G + \sum_{t=0}^T \sum_{c \in C} c_{i,t}^{\text{ls}} P_{i,t}^{\text{ls}} \quad (3.106)$$

s.t.

$$\begin{aligned} & P_{c,t}^{\text{RES}} - P_{c,t}^{\text{cur}} - P_{c,t}^{\text{d}} + P_{c,t}^{\text{ls}} - P_{c,t}^{\text{losses}} + \sum_{g \in G_C} P_{g,t}^G - \sum_{k \in C, k \neq c} P_{ck,t}^{\text{exch}} \\ & + \sum_{s \in S_C^{\text{ps}}} (P_{s,t}^{\text{ps,turb}} - P_{s,t}^{\text{ps,pump}}) + \sum_{s \in S_C^{\text{bat}}} (P_{b,t}^{\text{bat,d}} - P_{b,t}^{\text{bat,c}}) = 0 \quad \forall t \in \mathcal{T}, \forall c \in \mathcal{C} \end{aligned} \quad (3.107)$$

$$\underline{P}_g^G \leq P_{g,t}^G \leq \overline{P}_g^G \quad \forall t \in \mathcal{T}, \forall g \in \mathcal{G} \quad (3.108)$$

$$0 \leq P_{c,t}^{\text{cur}} \leq P_{c,t}^{\text{RES}} \quad \forall t \in \mathcal{T}, \forall c \in \mathcal{C} \quad (3.109)$$

$$0 \leq P_{c,t}^{\text{ls}} \leq P_{c,t}^{\text{d}} \quad \forall t \in \mathcal{T}, \forall c \in \mathcal{C} \quad (3.110)$$

$$0 \leq P_{s,t}^{\text{ps,turb}} \leq \overline{P}_{s,t}^{\text{ps,turb}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{ps}} \quad (3.111)$$

$$0 \leq P_{s,t}^{\text{ps,pump}} \leq \overline{P}_{s,t}^{\text{ps,pump}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{ps}} \quad (3.112)$$

$$E_{s,t}^{\text{ps,SOC}} = E_{s,t-1}^{\text{ps,SOC}} - \frac{1}{\eta_s} P_{s,t}^{\text{ps,turb}} + \eta_s P_{s,t}^{\text{ps,pump}} + P_{s,t}^{\text{inflow}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{ps}} \quad (3.113)$$

$$0 \leq E_{s,t}^{\text{ps,SOC}} \leq \overline{E}_s^{\text{ps,SOC}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{ps}} \quad (3.114)$$

$$0 \leq P_{s,t}^{\text{bat,d}} \leq \overline{P}_{s,t}^{\text{bat,d}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{bat}} \quad (3.115)$$

$$0 \leq P_{s,t}^{\text{bat,c}} \leq \overline{P}_{s,t}^{\text{bat,c}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{bat}} \quad (3.116)$$

$$E_{s,t}^{\text{bat,SOC}} = E_{s,t-1}^{\text{bat,SOC}} - \frac{1}{\eta_b} P_{s,t}^{\text{bat,d}} + \eta_b P_{s,t}^{\text{bat,c}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{bat}} \quad (3.117)$$

$$0 \leq E_{s,t}^{\text{bat,SOC}} \leq \overline{E}_s^{\text{bat,SOC}} \quad \forall t \in \mathcal{T}, \forall s \in S^{\text{bat}} \quad (3.118)$$

$$\text{NTC}_{k-c,t} \leq P_{c-k,t}^{\text{exch}} \leq \text{NTC}_{c-k,t} \quad \forall t \in \mathcal{T}, \forall c, k \in \mathcal{C} \quad (3.119)$$

The nodal power balance for each country is given by Eq. (3.107). Power generation comes from both renewable sources and conventional power plants, with the output from renewable sources is adjustable through curtailment. The load is modeled as static, incorporating a variable for load shedding. Additionally, an approximation for the grid losses is included, which is a fixed percentage of the overall load. Pumped-storages, batteries, and exchange flows can function as either generation sources or loads within their respective countries. Equation (3.108) describes the technical limits for conventional power plants, Eqs. (3.109) and (3.110) the upper limits for curtailment and load shedding. Pumped-storages are modeled with Eqs. (3.111) to (3.114),

including limits for the maximum turbinning and pumping power, as well as the calculation of the state of charge for each time step and its limits. The corresponding equations for battery storages are found in Eqs. (3.115) to (3.118), with the main difference that there are no inflows for battery storages. The exchange flow from country c to country k at hour t is limited by the NTC values, as described in Eq. (3.119).

The model does not incorporate endogenous power plant or storage expansion. In order to be able to map future power plant and storage capacities nonetheless, expansion paths from external sources, such as TYNDP 2022 [161, 169] or TYNDP 2024 [162, 170], are used. The data contained therein on available power plant and storage capacities are compared country by country with the capacities already available in the model. Power plants and storage facilities are then added until the target capacity is reached. Typical parameters for the added power plants and storage facilities are used (for gas-fired power plants, for example, an output of 400 MW with an efficiency of 60 %). The addition of individual power plants and storage facilities allows for the calculation of block-specific dispatch.

The results include unit-specific dispatch for power plants and storage systems, state of charge trajectories of storage units, market-based renewable curtailment and forced load shedding, exchange flows between market areas, as well as electricity prices in each market area. The latter are represented by locational marginal prices derived from the dual variables of the optimization problem. These outputs in turn can be used as inputs for subsequent grid calculations.

3.5 Expansion planning model

This section describes an expansion planning model, that identifies expansion candidates for transmission lines, battery storage systems and FACTS based on the results of a previous OPF simulation. The model was developed to determine favorable technical parameters and locations of the mentioned grid expansion elements and analyse their impact on grid operation in a following grid simulation. The model is a heuristic and based on the methodology developed in the Horizon 2020 FlexPlan project [86, 171, 172]. FlexPlan adopts a holistic strategy by first identifying sets of expansion candidates and then determining the optimal expansion result with the aim to minimize capital and operational expenses. This results in a large scale mixed-integer linear programming problem, addressed through decomposition techniques such as Benders decomposition and transmission-distribution separation. Especially the methodology for the identification of expansion candidates regarding flexibilities, storages and transmission lines is of interest for this study. However, this candidate selection model is not open source, so a new tool was developed on the basis of its description and expanded with the integration of FACTS.

3.5.1 Overall methodology

The methodology builds on the results of a previous OPF calculation with a non-expanded configuration. From the OPF outputs, the following key indicators are derived:

- **LMs of the line flow constraints:** These reflect the marginal cost reduction achieved by increasing the transmission capacity of a branch by one unit. Non-zero LM values indicate congestion and quantify potential dispatch cost savings from capacity expansion.
- **LMPs:** In an unconstrained network, LMPs would be uniform across all nodes. However, congestion causes price differences between nodes, with higher sink prices relative to source prices. Larger LMP disparities signal severe congestion and help identify suitable locations for flexibility resources such as storage.
- **PTDFs:** PTDFs describe the sensitivity of line flows to power injections at specific nodes. As they depend on network topology, PTDF values are assumed constant for the course of a year.
- **Power flow directions:** Branch flow calculations provide information on flow orientation and saturation relative to branch ratings.

The AC-OPF employed in this study is non-convex, so the solver typically returns a local rather than a global optimum. As a consequence, the associated LMs of the line-flow constraints and the LMPs are not guaranteed to equal the true marginal values of the global solution: strong duality does not generally hold, a duality gap between the primal and dual problems may exist, and different initializations can lead to different local optima with distinct multiplier sets [173]. Nevertheless, these multipliers remain valuable as local indicators of congestion: a non-zero LM flags a binding branch, and pronounced LMP disparities highlight areas where the network is constrained [174, 175]. Consequently, they can be used to rank lines for capacity expansion, while recognising that they do not constitute globally optimal shadow prices. For the annual study horizon, the OPF computes LMPs, LMs, and power flow parameters, including direction, for all buses and branches across 8760 hourly intervals.

The overall expansion planning methodology is depicted in Fig. 3.13. It starts with quantifying congestions and identifying the lines with the most severe congestions, afterwards the different technology options for expansion are evaluated with respect to their capability to resolve the respective congestion. The result is a ranked list of suitable expansion candidates. Expansion candidates are added from this list in the order they appear until a specified criterion is met. By default, an externally specified number of expansions is used as the termination criterion. However, it would also be possible to use other criteria, for example, to use a fixed investment

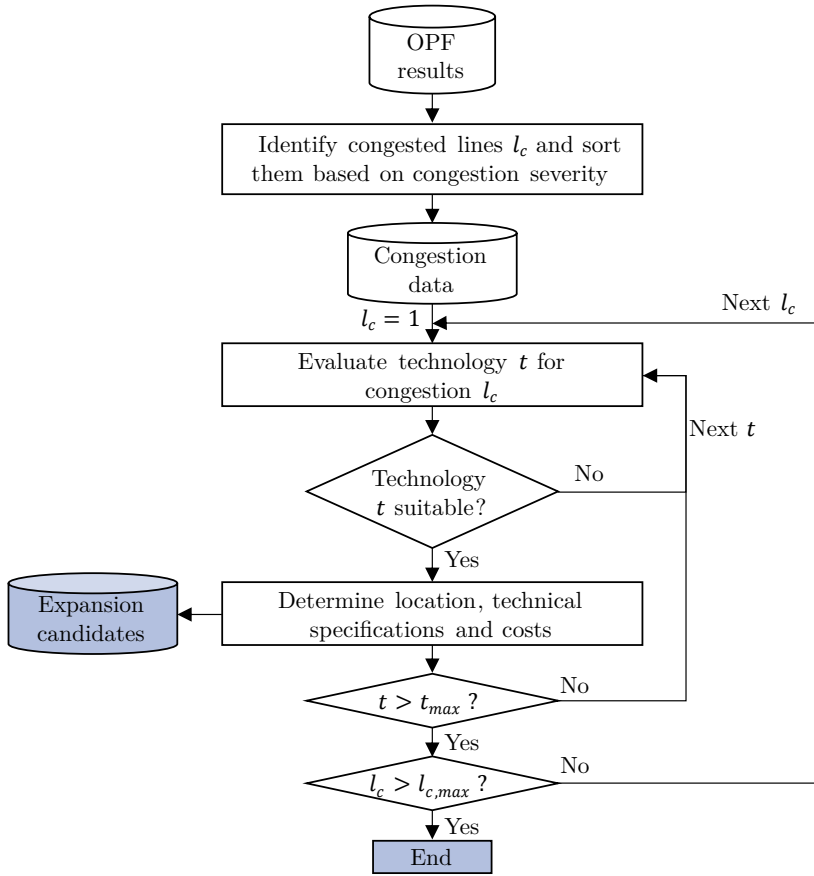


Figure 3.13: Illustration of the overall methodology of the candidate selection for the expansion planning tool.

amount as the expansion limit. The methodology for the quantification of congestion and the evaluation of the different technologies is described in detail in the following sections.

3.5.2 Congestion quantification

The aim is to identify the most severe congestions and suitable expansion candidates (storage, FACTS, transmission lines) to resolve them. To identify congestions, the LM values from the results of the initial OPF calculation are evaluated. First, the average LM value LM_l^{avg} is calculated for each transmission line l of the network.

$$LM_l^{\text{avg}} = \sum_{t=t_0}^{t_\tau} LM_{l,t} \frac{1}{t_\tau - t_0} \quad (3.120)$$

Then, the number of hours line l is affected by a congestion is determined by counting the hours in which the LM value is greater than a threshold ε^{con} :

$$n_l^{\text{occ,con}} = \sum_{t \in \mathcal{T}} \mathbf{1}_{\{LM_{l,t} > \varepsilon^{\text{con}}\}} \quad (3.121)$$

The number of occurrences is then multiplied by the average LM values to calculate the severity score sev_l for each line, which serves as an indicator of both the frequency and intensity of congestion on that line.

$$sev_l = LM_l^{\text{avg}} \cdot n_l^{\text{occ,con}} \quad (3.122)$$

Based on the severity score, the congested lines l_c are ordered, starting with the line with the highest severity score. Based on this ordering, the algorithm identifies suitable expansion candidates to resolve the congestion until a stopping criterion is reached (e.g., a maximum number of expansion candidates or investment volume).

3.5.3 Battery storage systems

The identification of optimal storage locations and the determination of appropriate sizing follow a structured approach, as it is depicted in Fig. 3.14. The process begins with the selection of the most suitable node of the currently assessed congested transmission line. Preference is given to the node with the higher LMP, as this indicates the greatest economic benefit for congestion mitigation. This way, the storage is located "behind" the congestion, which means it can feed energy into the grid in times of congestion and relieve it that way, since less energy has to be transported over the congested transmission line. The storage is charged again in times of no congestion. In addition, the power flow during the congestion scenario must be consistent with the predominant flow direction observed in the majority of congested hours for the line. If a node exhibits higher LMPs in more than 75% of these hours, it is designated as the preferred location for storage. Conversely, if this condition is not met, the location is considered unsuitable for storage deployment.

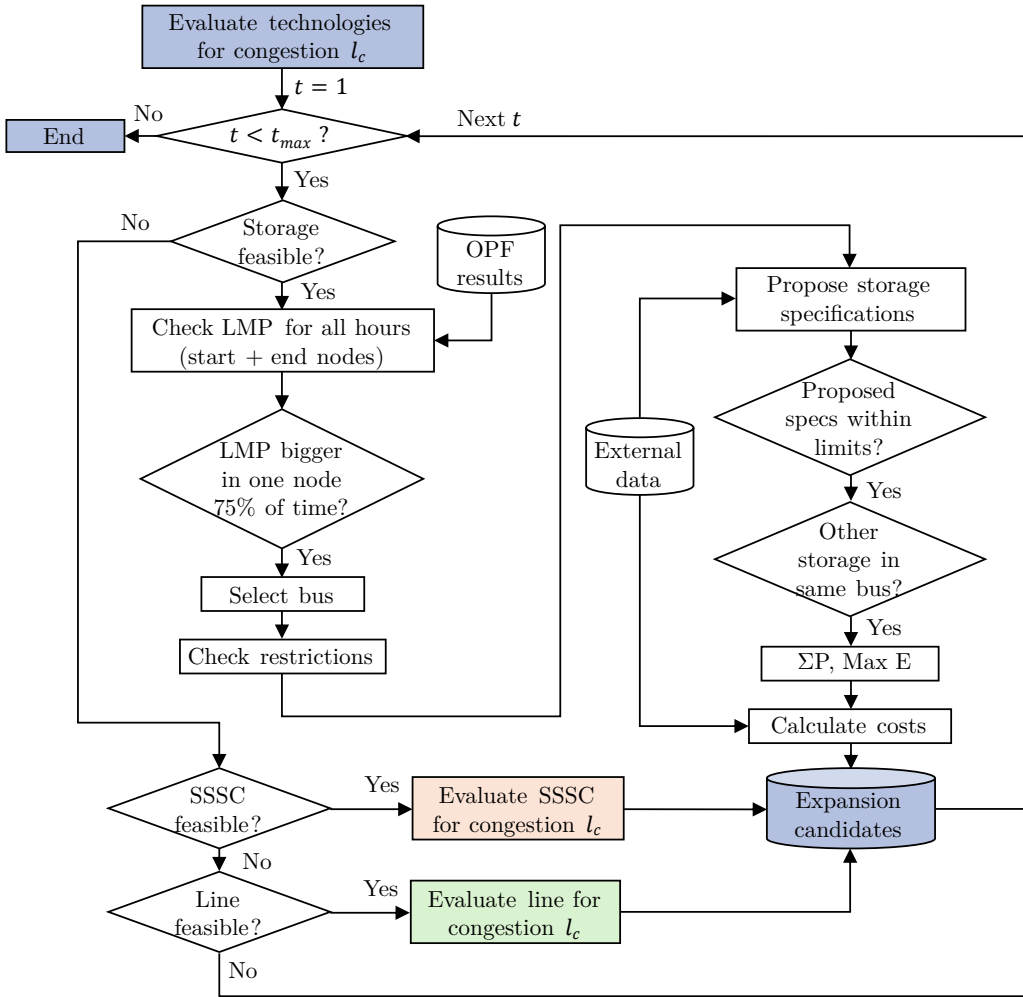


Figure 3.14: Illustration of the candidate selection methodology for battery storage systems.

Once the node is selected, the congestion characteristics of the currently selected line are analyzed to determine which storage technology and properties are appropriate. This analysis includes the yearly number of congestion events, which provides insight into the frequency of potential interventions, and the number of consecutive congested hours, evaluated using statistical measures such as the 75th percentile, which informs the required energy duration.

Based on these findings, the sizing of the storage system is proposed. The power capacity is defined relative to the rated apparent power of the congested transmission line, while the energy capacity

is determined according to the maximum number of consecutive congestion hours identified in the previous step. The cost estimates are then derived from these sizing parameters.

$$P_{s,l_c}^{\text{capa}} = S_{l_c}^N \cdot k_{tech}^{\text{capa}} \quad (3.123)$$

$$E_{s,l_c}^{\text{capa}} = P_{s,l_c}^{\text{capa}} \cdot T_{l_c}^{\text{consecutive}} \quad (3.124)$$

$$C_{s,l_c}^{\text{capex}} = c_{tech}^{\text{MW}} \cdot P_{s,l_c}^{\text{capa}} + c_{tech}^{\text{MWh}} \cdot E_{s,l_c}^{\text{capa}} \quad (3.125)$$

$$C_{s,l_c}^{\text{opex}} = C_{s,l_c}^{\text{capex}} \cdot k_{tech}^{\text{opex}} \quad (3.126)$$

Here, P_{s,l_c}^{capa} is the power capacity of the candidate storage, E_{s,l_c}^{capa} is the energy capacity, k_{tech}^{capa} and k_{tech}^{opex} are predetermined scaling factors depending on the chosen storage technology, $T_{l_c}^{\text{consecutive}}$ is the maximum number of consecutive hours of congestion on line l_c and C_{s,l_c}^{capex} and C_{s,l_c}^{opex} are the related costs.

Special consideration is given to cases where multiple congested lines converge at the selected node. If the lines are parallel, a single storage system is proposed with power equal to the sum of all calculated storage capacities and energy corresponding to the maximum required duration among the lines. In contrast, if the lines originate from different nodes, independent storage systems are recommended to ensure operational flexibility.

3.5.4 FACTS

Power electronic devices such as the SSSC, TCSC and UPFC can be used to control power flows across the network and thus help in resolving congestions. As it is difficult to predict the influence of the FACTS device based on its location in the network ex ante, the congested line itself is chosen for the installation location. This consideration favors the use of SSSCs and UPFCs over TCSCs, as the former are capable of both increasing and decreasing the effective impedance of a transmission line and, consequently, of either reducing or increasing the transmitted power. In contrast, TCSCs are primarily employed to decrease the effective line impedance in order to increase power transfer capability. This functionality is of limited benefit for lines that are already operated close to their thermal limits, since further increases in power flow are typically not feasible under such conditions. The SSSC and the UPFC exhibit nearly identical capabilities with respect to controlling power flows. However, the UPFC entails a more complex device structure and a correspondingly more involved mathematical representation, which results in higher computational effort and longer solution times. For this reason, the following section and

the results presented in this thesis focus on the SSSC. Nevertheless, the expansion logic proposed here can be applied analogously to UPFCs, TCSCs, and even phase-shifting transformers (PSTs).

The voltage rating of the candidate SSSC is determined by a scaling factor k_{SSSC} , the default value is $k_{SSSC} = 10\%$. The higher the scaling factor, the greater the possible impact of the SSSC on the power flow over the line. The power rating S_{SSSC}^N of the candidate SSSC is then calculated on the basis of the SSSC voltage rating V_{SSSC}^N and the current capacity $I_{l_c}^N$ of the congested line. The costs C_{SSSC} are approximated using a fixed cost factor and the power rating of the SSSC.

$$I_{l_c}^N = \frac{S_{l_c}^N}{\sqrt{3} \cdot V_{l_c}^N} \quad (3.127)$$

$$V_{SSSC}^N = k_{SSSC} \cdot V_{l_c}^N \quad (3.128)$$

$$S_{SSSC}^N = V_{SSSC}^N \cdot I_{l_c}^N \quad (3.129)$$

$$C_{SSSC} = c_{SSSC}^{MW} \cdot S_{SSSC}^N \quad (3.130)$$

The process is also depicted in Fig. 3.15.

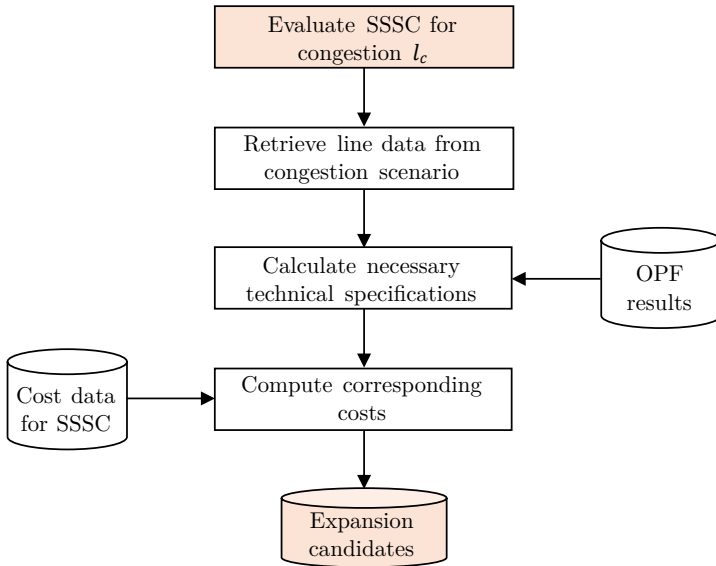


Figure 3.15: Illustration of the candidate selection methodology for SSSC.

3.5.5 Transmission lines

In addition to storages and FACTS, the algorithm is also able to propose expansion candidates for transmission lines. Hereby only already existing connections of two nodes can be expanded, the identification of new connections is not possible. The expansion of a network with a completely new transmission line will have implications on the other lines of the network as well. In the worst case, congestion is just shifted from one line to another. Therefore, the algorithm checks for the implications of the expansion candidate on the surrounding lines based on power transfer distribution factors (PTDF, see Section 2.2.3.6). If necessary, it proposes expansion candidates for heavily negatively affected lines. The approach is explained in more detail below and an illustration is shown in Fig. 3.16

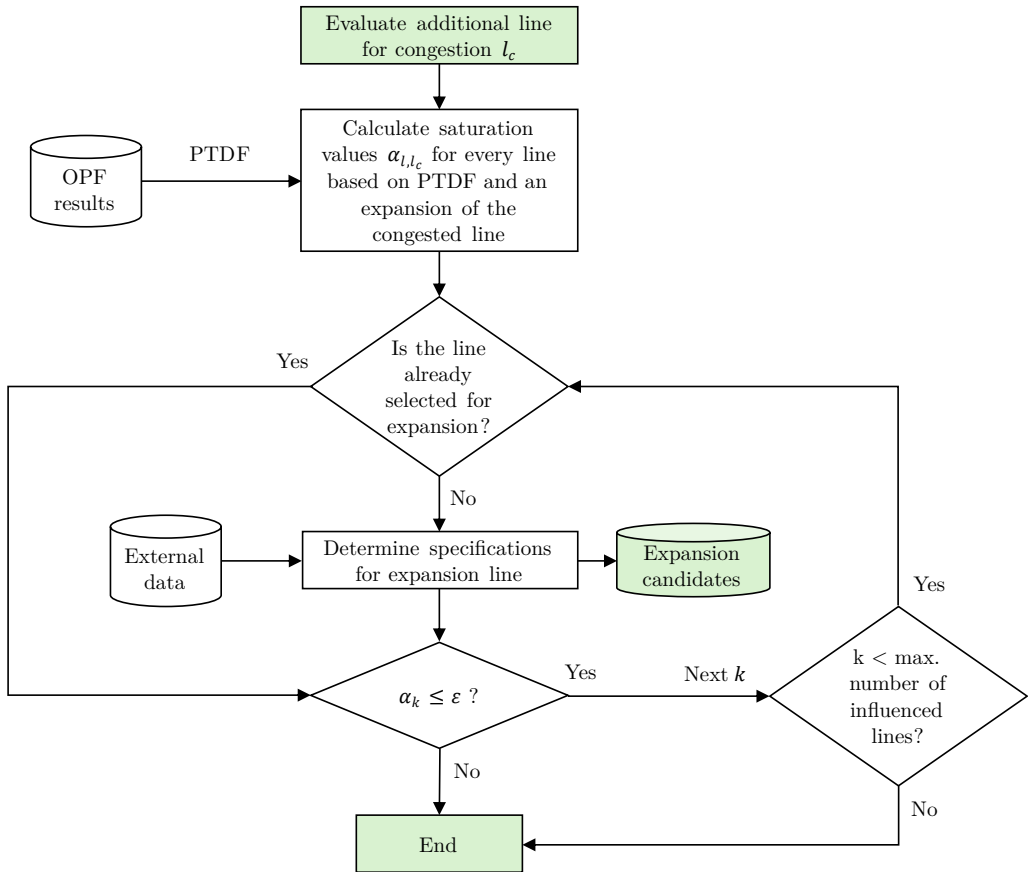


Figure 3.16: Illustration of the candidate selection methodology for transmission lines.

The approach begins by selecting the currently congested line l_c as a mandatory expansion candidate. Building on this, the method evaluates all remaining lines in the network to determine their suitability for reinforcement using a saturation metric derived from the PTDF matrix. For each line l in the system, the saturation percentage α_{l,l_c} with respect to the congested line l_c is computed. The metric combines the sensitivity of line flows to an injection shift between two buses (k_1, k_2) with the available capacity margin on the subset of lines affected by that shift. First, define the column vector $\text{PTDF}_{(k_1-k_2)}$ obtained by subtracting the PTDF column associated with node k_2 from the PTDF column associated with node k_1 :

$$\text{PTDF}_{(k_1-k_2)} = \text{PTDF}_{(:,k_1)} - \text{PTDF}_{(:,k_2)}. \quad (3.131)$$

Let S be the number of nonzero elements in $\text{PTDF}_{(k_1-k_2)}$, and denote by $\text{PTDF}_{(k_1-k_2)}(l_c, 1)$ the entry of $\text{PTDF}_{(k_1-k_2)}$ corresponding to the congested line index l_c .

Construct a diagonal selection matrix $M \in \mathbb{R}^{S \times S}$ from the nonzero elements of $\text{PTDF}_{(k_1-k_2)}$. For the same set of lines included in M , form the diagonal matrices

$$P_l^{\max} \in \mathbb{R}^{S \times S}, \quad P_l^0 \in \mathbb{R}^{S \times S}, \quad (3.132)$$

where $P_l^{\max}$ contains the rated power limits of the selected lines and P_l^0 contains the maximum power flows over the lines from the results of the previous OPF simulation.

With these definitions, the saturation percentage for line l relative to the congested line l_c is computed as

$$\alpha_{l,l_c} = \frac{\text{PTDF}_{(k_1-k_2)}(l_c, 1)}{P_{l_c}^{\max}} M^{-1} (P_l^{\max} - P_l^0), \quad (3.133)$$

where division by $P_{l_c}^{\max}$ normalizes the sensitivity with respect to the capacity of the congested line. In (3.133), the vector $M^{-1}(P_l^{\max} - P_l^0)$ represents the PTDF-weighted capacity margin available along the set of lines impacted by the (k_1, k_2) shift, while the scalar factor $\text{PTDF}_{(k_1-k_2)}(l_c, 1)/P_{l_c}^{\max}$ scales this margin to the congestion reference.

Lines whose saturation value α_{l,l_c} falls below a predefined threshold are considered suitable expansion candidates. These lines, together with the congested line l_c , form the candidate set for reinforcement. To avoid redundant investments, each transmission line may be expanded at most once. Consequently, any line previously selected for expansion is excluded from consideration in subsequent iterations.

For each line in the selected candidate set, we propose the addition of one new circuit with identical electrical and physical characteristics to the existing line (e.g., thermal rating, voltage

level, and impedance and resistance). The investment expenses of each proposed transmission line is then estimated as

$$C_l = \bar{c}_{\text{km}} \cdot \ell_l, \quad (3.134)$$

where ℓ_l is the geographical length of line l and $\bar{c}_{\text{km}}$ denotes the average cost per kilometer for the relevant technology and voltage class.

3.6 Implementation

All the models described in this chapter are implemented in Python. Depending on the chosen time coupling methodology and the user settings, the program makes use of multiprocessing to build the model and/or solve the problems. Here are the most important python packages used in the implementation:

- pandas [176] for data processing and management
- NumPy [177] for data processing and arithmetic data calculations
- pyomo [178, 179] is used for building the model (variables, constraints, objective function, etc.) and as interface to the solver
- pathos [180, 181] as multiprocessing environment
- matplotlib [182] for the visualization of results
- Some functions of PYPPOWER, which is the python implementation of MATPOWER [183], are used for the calculation of nodal admittance matrices, the PTDF matrix, and reordering/-indexing of matrices

For solving the AC OPF problem, the open source solver IPOPT (Interior Point OPTimizer) [155, 156, 184, 185] is used. IPOPT is a large-scale nonlinear programming solver that uses a primal–dual interior point method combined with a filter line-search algorithm to find local optima of twice continuously differentiable objective functions subject to nonlinear constraints. It exploits gradient and Hessian information (either provided or approximated), enabling efficient and robust solution of constrained optimization problems across various modeling environments. For solving the simplified, linear market simulation, the solver gurobi is used, which is a commercial solver that is well-established and widely used for solving large-scale LP and MILP problems. However, the model also allows for the use of open-source solvers such as GLPK [186].

3.7 Modeling framework overview

An overview of the modeling framework developed and applied in this thesis is given in Fig. 3.17. All modules that have been developed and implemented as part of this thesis are explained in the previous sections. The various input data and its sources, as well as the High-RES-O model, which is used to determine regionalized profiles for RES generation and demand, are presented in Chapter 4. A description of the agent-based electricity market model PowerACE can be found in Section 5.3.

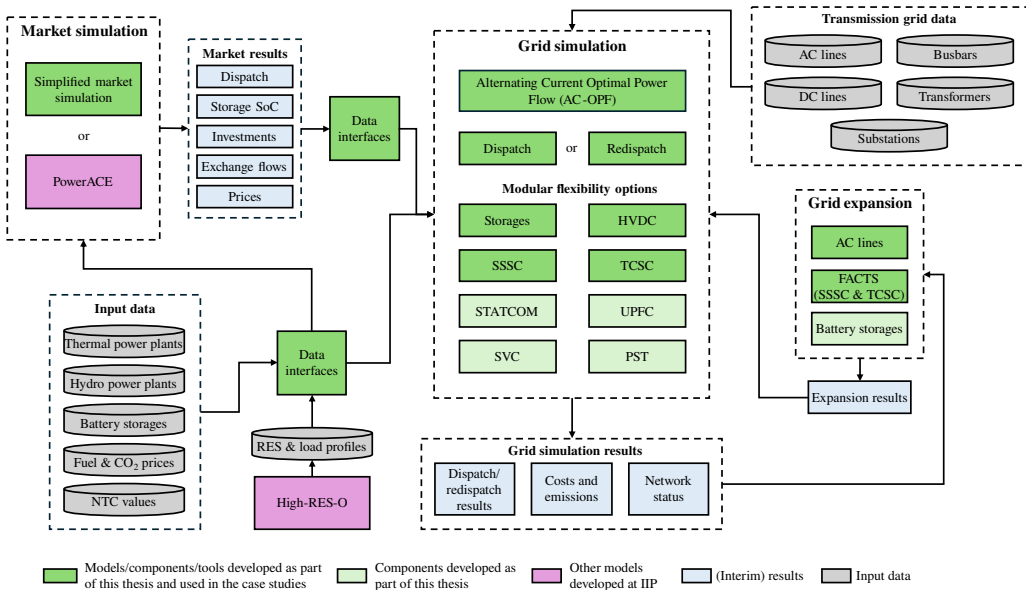


Figure 3.17: Schematic overview of the modeling framework developed as part of this thesis.

4 Data and scenarios

4.1 European electricity transmission grid

This work is based on a data set of the European electricity transmission network developed at IIP in the last decade¹. It was constructed through the systematic consolidation of multiple sources, including topology information (network maps, static grid models, and national grid development plans) and operational resource parameters derived from network data sets. This process was complemented by the integration of geographical coordinates and the completion of missing technical parameters to ensure data consistency and accuracy. The resulting data set covers all central European countries and is based on the TYNDP grid data set, static grid models, and national development plans. In addition, documented expansion projects were incorporated together with their respective commissioning and decommissioning years, enabling a longitudinal analysis of the transmission network on an annual basis.

Since a special focus of this study is set on Germany, in the course of this thesis expansion projects regarding the construction of new AC and DC transmission lines, transformers, substations, the replacement of transmission lines and topology changes from the German national development plan "Netzentwicklungsplan (NEP) 2035 (2021)" [135] were integrated into the data set. To this end, the approximately 250 individual projects in the NEP plan were first transformed into a structured tabular representation and classified into measures related to AC transmission lines, DC transmission lines, and point measures. As the grid development plan is published exclusively as a PDF document and is therefore not readily machine-readable, key information, including line start and end points, construction and decommissioning timelines, and technical line parameters, had to be manually extracted from the respective project descriptions. In a subsequent step, the affected transmission lines, busbars, and substations associated with each measure were mapped to the corresponding elements in the IIP network database, a non-trivial task since there are no universal identifiers in use. Once identified, new and decommissioned network elements were implemented in the database together with explicit construction or decommissioning dates and technical parameters in a transparent and traceable manner. This approach enables the systematic

¹ The author would like to thank the IIP colleagues R. Finck, M. Ruppert and V. Slednev for the joint effort.

activation of specific grid expansion scenarios, such as the NEP 2021–2035, for use in power system simulations. For expansion projects where the exact geographical location is not yet specified, most notably newly planned substations, locations were determined using a best-estimate approach based on the available contextual information.

Table 4.1: Overview of the most important parameters of network elements used in the transmission grid model.

AC lines	DC lines	Transformers	Busbars	Substations
ID	ID	ID	ID	ID
Busbar start	Busbar start	Busbar start	Substation	Name
Busbar end	Busbar end	Busbar end	Voltage lvl [kV]	Latitude [°]
Thermal limit [A]	Voltage lvl [kV]	Nom. volt. start [kV]	Construction year	Longitude [°]
Resistance [Ω]	Capacity [MW]	Nom. volt. end [kV]	Decom. year	Country
Reactance [Ω]	Construction year	Rated power [MW]		Construction year
Susceptance [μF]	Decom. year	Short-circuit volt. [%]		Decom. year
Length [km]		Load losses [kW]		
Construction year		Construction year		
Decom. year		Decom. year		

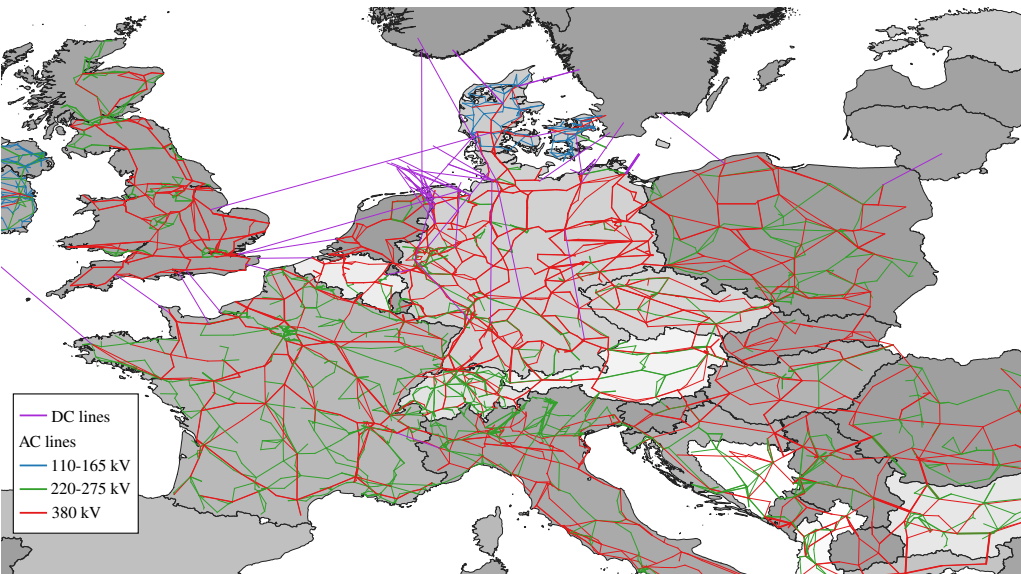


Figure 4.1: Snapshot of the European transmission grid model for the year 2030.

The data set includes substations, busbars, transformers, HVDC connections, and extra-high-voltage AC transmission lines (150 kV and above). The data for transmission lines and transformers comprises information about the start and end points as well as technical parameters that are necessary for power flow simulations, like ohmic and reactive resistance for transmission lines and short-circuit voltage for transformers. Busbar data inherits most importantly the voltage level and the reference to the substation it is located at, and substation data has geographical information. One simplification of the data set is that only one busbar per voltage level is assumed and all transmission lines that start or end at the same substation with the same voltage level are connected to the same busbar. An overview of the most important parameters for each network element mentioned before is given in Table 4.1. For 2030, the entire data set comprises 3144 substations, 5486 busbars, 6545 AC transmission lines, 4412 transformers, and 62 HVDC connections. For Germany alone (including Luxembourg as it is part of the German bidding zone and inclusive cross-border connections to neighboring countries), it is 554 substations, 1111 busbars, 1268 AC transmission lines, 1204 transformers and 44 HVDC connections. A snapshot of the data set for 2030 is shown in Fig. 4.1, with different colors indicating different voltage levels.

4.2 Dispatchable generation units

Dispatchable generation units comprise thermal power plants as well as pump and battery storage systems. For the following analyses, a database representing the currently available generation units is used. Based on this, external scenarios are used to determine future expansions and decommissioning of power plants, thereby enabling modeling of the available generation capacities in future years as well. The external scenarios used in this thesis are the TYNDP 2022 DE scenario [169] and the TYNDP 2024 NT scenario [170]. A third scenario was created by halving the available battery capacity in the TYNDP 2024 NT scenario. This is intended to represent the possibility that not all of the installed battery capacity will participate in the market and to evaluate the benefits of additional available battery capacity for the system.

Further details about the assumed generation capacities of thermal power plants and storage systems are described in the following sections. An overview of the assumed available capacities in the years 2030, 2040 and 2050 and for the three scenario TYNDP 2022, TYNDP 2024 and TYNDP 2024 half battery capacity, broken down by countries (covering Germany and its electrical neighbors) and energy carriers, is given in Fig. 4.2. Tables with the exact capacities are presented in Tables A.1 to A.3 in the Appendix.

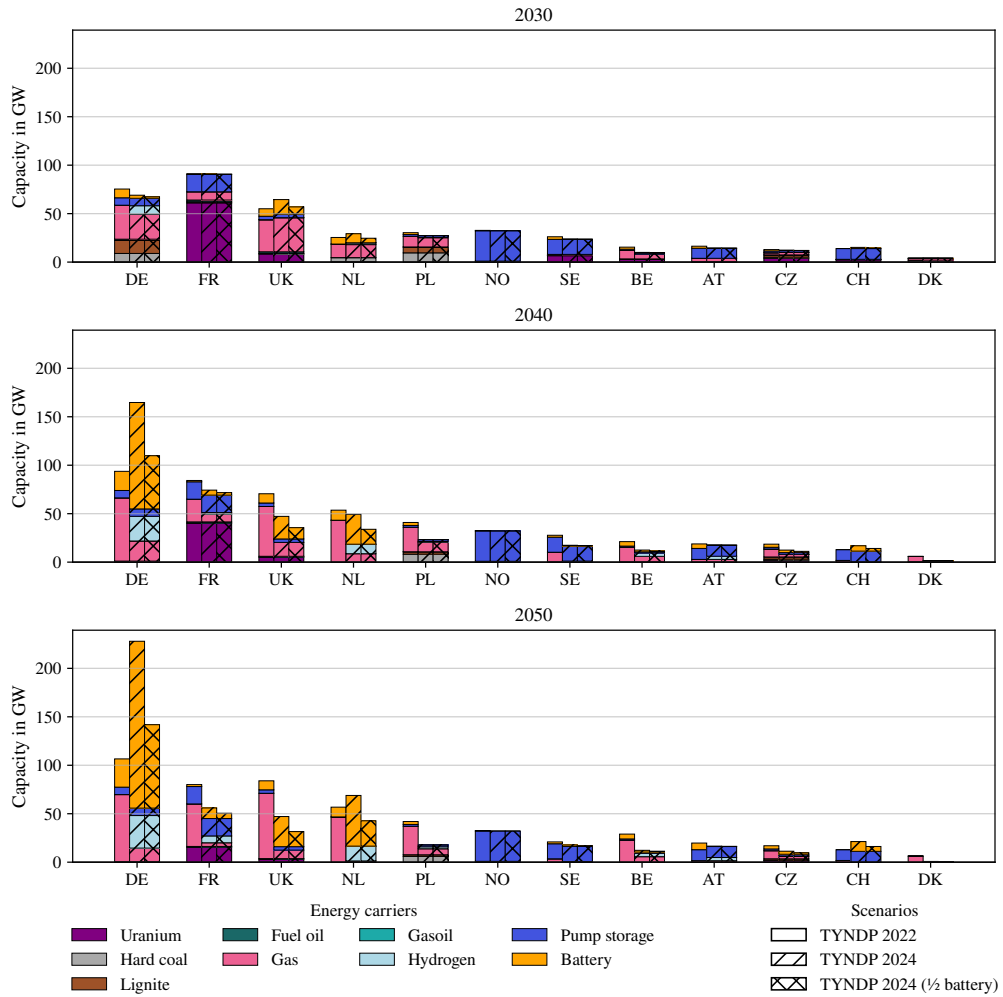


Figure 4.2: Installed capacity of dispatchable power plants (thermal, pump storage and batteries) in Germany and its electrical neighboring countries for the three different scenarios in 2030, 2040 and 2050, broken down by country and fuel type.

4.2.1 Thermal power plants

The data for thermal power plants are taken from an extensive list of power plants available at IIP. The list was originally based on a commercial database, but has been manually updated in recent years based on newsletters, announcements by plant operators, and open source databases such as the Global Energy Monitor [187]. The most important information contained in the list is technical parameters such as the maximum power output, must run constraints, the efficiency and energy carrier information, economic parameters such as the variable and fixed operating costs and the geographical location or grid connection point. In addition, the data includes known decommissioning dates for existing power plants as well as commissioning dates for planned or under construction power plants.

The list only includes specific new construction projects that have already been announced, which means that the power plant portfolio for more distant years, such as 2040 or 2050, is not adequately represented. Therefore, an additional data source for the prediction of available power plant capacities is needed. For this purpose, data from the TYNDP 2022 [169] and TYNDP 2024 [170] is used, which provide information on available power plant capacities broken down by country and energy carrier. For grid modeling, these capacities must be converted into individual power plants with specific technical and economic parameters and geographical locations. This is done using typical plants for the sizing and a brown field approach for the allocation. First, the model calculates the difference in expected available capacity from the scenario information and the available capacity from the power plant list, then determines the necessary number and technical parameters of new power plants and lastly allocates them based on the locations of already decommissioned power plants (preferred, where available) or power plants that are still in operation. For new gas-fired power plants, the typical plant has a capacity of 400 MW and an efficiency of 60 %.

In the TYNDP 2022 scenario, the total capacity of thermal power plants increases moderately from 261 GW in 2030 to 318 GW in 2040 and 333 GW in 2050. In 2030, a relatively balanced mix of gas, coal, and nuclear power plants is expected. From 2040 onward, gas will be the dominant energy carrier for thermal power plants. The capacity for gas-fired power plants is expected to increase from 119.8 GW in 2030 to 252.6 GW in 2040 and 301.5 GW in 2050. Nuclear energy plays a major role only in France and the UK, while coal fired power plants are expected to phase out in all countries besides Poland and Czechia. Hydrogen-fired power plants are not considered in this scenario.

In the TYNDP 2024 scenario, the total capacity of thermal power plants is lower than in the TYNDP 2022 scenario, especially in later years, with 259.0 GW in 2030, 185.5 GW in 2040 and 142.8 GW in 2050. Instead of a rise in installed capacity, a decline is expected from 2030 to

2050, which is compensated by an increased expansion of battery storage systems. As a further difference, hydrogen plays a major role in this scenario, with 44.2 GW installed capacity in 2040 and 64.7 GW in 2050 it gradually replaces natural gas-fired power plants. Lignite, hard coal and uranium are again expected to only play a minor role and even phase out in later years.

4.2.2 Energy storage systems

Pump storage data are based on the approach and results described in [188] which, in turn, is based on a hydropower modeling data set provided by ENTSO-E [189] that uses data from the PAN European Climate Database (PECD). The resulting data set contains unit specific information about pumping and turbinning power, reservoir capacity, and inflow profiles. Complex hydroelectric modeling, such as modeling of power plant or reservoir cascades, is omitted.

The data for battery storage systems is, as for thermal power plants, based on the TYNDP2022 DE and TYNDP2024 NT scenarios [169, 170], which contains aggregated data on available battery power capacities and volumes broken down by country. As with thermal power plants, the number, size and location of the individual new battery storage facilities are determined based on a typical battery size and a brown field approach. A typical battery storage system is defined to have a capacity of 200 MW, a volume of 400 MWh and an efficiency (for charging and discharging respectively) of 95 %. The development of battery capacity in Germany and its electrical neighbors is shown in Fig. 4.2 and Tables A.1 to A.3 in the appendix. In the TYNDP22 scenario, the total battery capacity is expected to increase roughly two-fold from 35.0 GW in 2030 to 71.1 GW in 2050. In the TYNDP24 scenario, the assumed capacities are much higher, rising from 31.1 GW in 2030 to 180.3 GW in 2040 and 283.6 GW in 2050, with 60 % of this capacity located in Germany.

4.3 Renewable energy sources and demand

The scenario data for RES generation and demand is based on the TYNDP 2024 [190, 191]. For 2030, the annual generation and demand values approximately follow the National Trends (NT) scenario, for 2040 and 2050 they are between the annual values of the National Trends (NT) and Distributed Energy (DE) scenarios.

4.3.1 Electricity demand

The annual gross demand for Germany and its electrical neighbors is illustrated in Fig. 4.3 for the years 2030, 2040 and 2050. The scenario assumes a rising demand until 2050, with an annual total gross demand of 2555 TWh in 2030, 2926 TWh in 2040 and 3276 TWh in 2050 for Germany and its electrical neighbors.

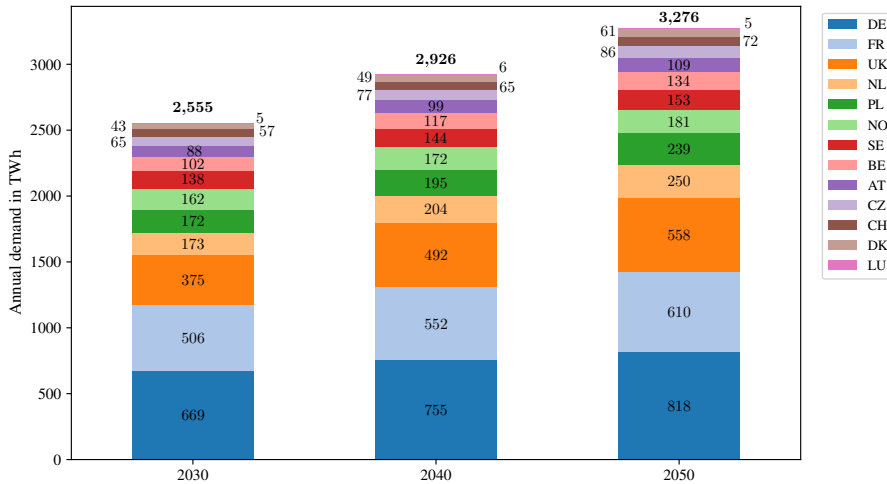


Figure 4.3: Annual demand values for Germany and its electrical neighbors for the years 2030, 2040 and 2050.

Unless specifically otherwise specified in the results section, load shedding is priced with 1000 EUR/MWh.

4.3.2 Renewable energy sources (RES)

The annual potential electricity generation from RES for Germany and its electrical neighboring countries is assumed to be rising from 2292 TWh in 2030 to 3461 TWh in 2040 to 4491 TWh in 2050. Included is generation from PV, onshore and offshore wind turbines, biomass, geothermal energy (the values are so small that they are neglected in the illustrations), run-of-river and inflows into hydro storage power plants (combined into hydro in the illustrations). For 2040 and 2050, these numbers are higher than the total demand, which theoretically enables full coverage of demand through RES. However, the values for the RES generation potential do not take into account any necessary curtailment measures and also the temporal volatility is disregarded. Accordingly, the continued use of conventional power plants may remain necessary in practical system operation.

The distribution of the annual RES generation potential among countries and energy carriers is illustrated in Fig. 4.4 for the years 2030, 2040 and 2050. In Fig. A.1 and Fig. A.2 in the appendix, additionally the aggregated values broken down by country and by energy carrier are provided.

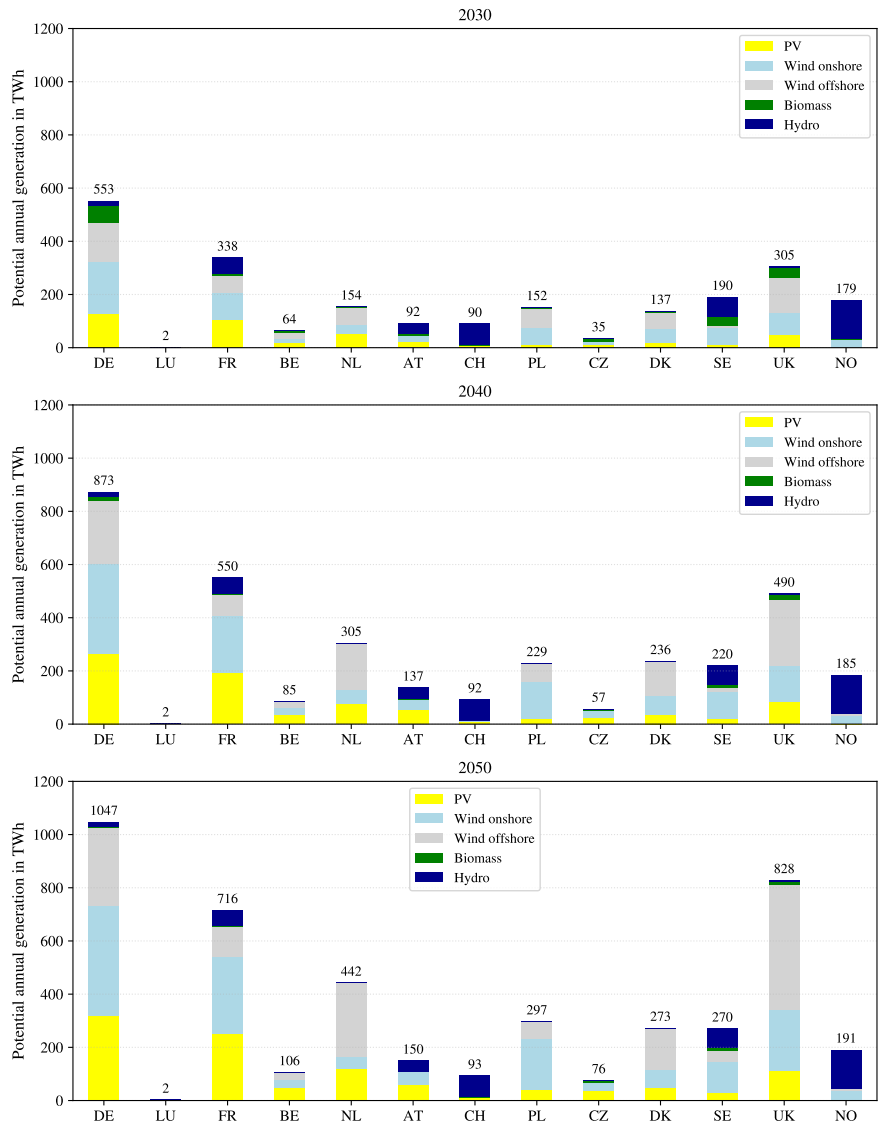


Figure 4.4: Annual potential RES generation for Germany and its electrical neighbors in 2030, 2040 and 2050, broken down by country and energy carriers.

4.3.3 Regionalized time-series data for RES and demand

For the generation and regionalization of time-series, the model High-Res-O [192–194] developed at the Institute for Industrial Production (IIP) was used. The process comprises three main steps: (i) calculation of generation and load profiles, (ii) expansion planning of renewable energy plants, and (iii) regionalization at high-voltage and extra-high-voltage grid nodes.

- (i) The calculation of generation and load profiles is based on a comprehensive data foundation. Wind and PV generation profiles are derived using physical models of the respective technologies combined with meteorological data. For biomass and hydropower, historical profiles are scaled accordingly, while demand profiles are determined using standard load profiles supplemented by statistical and meteorological data. For this study, all generation and demand profiles are based on the weather year 2019.
- (ii) The expansion planning for wind and PV installations is performed through annual optimization aimed at minimizing levelized cost of electricity, taking site-specific conditions into account. For wind energy, plant-specific repowering options are considered. The expansion of other RE technologies is incorporated by scaling to predefined target values.
- (iii) Connection points for large-scale RES plants are often known and can therefore be directly assigned to corresponding grid nodes. For the allocation of decentralized RE units and consumers, Voronoi polygons are generated around high-voltage substations to define uniform reference areas. If the location of decentralized units is known, the assignment is straightforward and unambiguous. However, since consumption and generation profiles are frequently referenced to spatial units such as postal code areas, municipalities, or NUTS-3 regions, overlaying these with Voronoi polygons enables a consistent and transparent mapping to the distribution grid structure. Within each Voronoi polygon, the respective profiles and potentials are assigned to the associated 110-kV substation. When data is available at a higher spatial level, distribution is performed proportionally to land use within the affected polygons. Finally, the time-series generated at the high-voltage level are aggregated to the extra-high-voltage level using a shortest-path algorithm.

Exemplary results of the regionalization for Germany in 2030 can be seen in Fig. 4.5 for RES feed-in and in Fig. 4.6 for demand. While large parts of the generation are located in northern Germany due to high capacities of wind on- and offshore, the demand is mainly located in the south and west, indicating already potential congestions in the transmission grid.

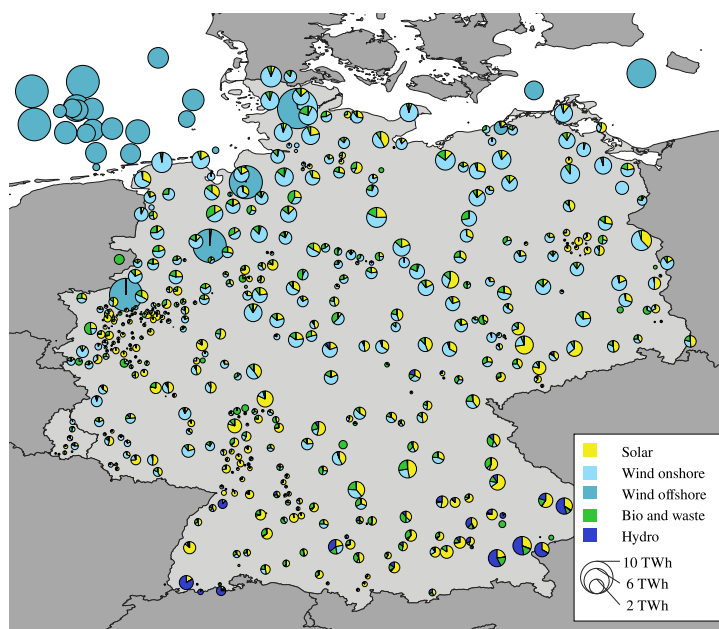


Figure 4.5: Exemplary result of the regionalization of RES generation in Germany for the year 2030. The graphic depicts the annual potential generation of different RES technologies regionalized to transmission grid nodes.

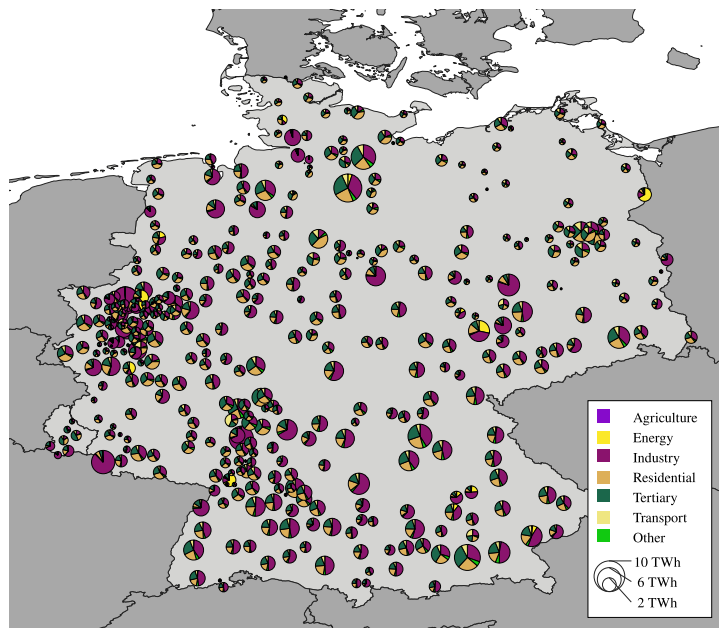


Figure 4.6: Exemplary result of the regionalization of electricity demand in Germany for the year 2030. The graphic depicts the annual load of different demand sectors regionalized to transmission grid nodes.

4.3.4 Cross-border exchange

As described in Section 3.1.8, exchange flows between countries in the active region (countries modeled with the transmission grid) and neighboring countries that are not part of the active region (modeled in a simplified way as a one node system) are constrained in two ways: the capacity of cross-border lines and the NTC values between the two countries. The flows between countries modeled as one node systems are only limited by the NTC. For this study, the NTC values are taken from TYNDP 2024 [195], including exchange capacities currently available and confirmed expansion projects.

4.3.5 Fuel and CO₂ prices

The prices for fuels and CO₂ certificates are taken from TYNDP 2024 [196]. The data set contains values for the years 2030, 2040 and 2050. The data is shown in Table 4.2. For other years, the prices are calculated via linear interpolation. Compared with current market conditions, the price levels assumed in the scenario are relatively low. For instance, the average wholesale day-ahead price of natural gas in Europe amounted to 39.67 EUR/MWh over the first three quarters of 2025 [197]. Nevertheless, the assumed price trajectory remains consistent with the underlying assumptions and outcomes reported in other scenario-based energy system projections [198–200].

Table 4.2: Fuel prices in EUR/MWh, prices for CO₂ certificates in EUR/t. Based on TYNDP 2024 [196].

	Uranium	Hard coal	Lignite	Fuel oil	Natural gas	Gasoil	Hydrogen	CO ₂
2030	6.05	6.40	6.48	33.03	22.64	6.70	63.50	113.4
2040	6.05	5.93	6.48	31.99	20.35	9.76	54.43	147.0
2050	6.05	5.47	6.48	30.96	18.06	14.15	54.43	168.0

5 Results

5.1 Model verification on test case systems

5.1.1 6-bus test system

In order to test and validate the overall OPF model and the models of the technical components (FACTS and PST) and illustrate their functionalities, some calculations were carried out on a 6-bus test case system. In the reference case, the system consists of 6 buses, 6 transmission lines, 1 generator, and 1 load. All lines have the same parameters with $r = 0.01$, $x = 0.04$, and $b = 0.007$, all in p.u. Voltage magnitudes are allowed between 0.9 and 1.1 p.u., and there are no limits on the transmission line capacities. The full description of the test case system is provided in Section A.2. The OPF is calculated with the aim of minimizing generation costs of generator G1 at bus 1 while the demand at bus 6 must be met and the results of the reference case as well as the equivalent circuit diagram of the test system are illustrated in Fig. 5.1.

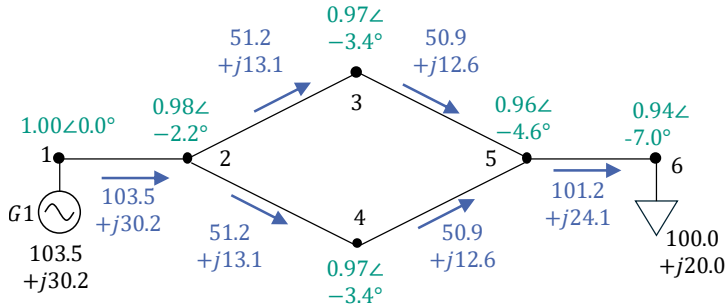


Figure 5.1: Illustration of the 6-bus test case with the initial OPF results. Voltage results (magnitude in p.u., phase angle in degree) are coloured in green, power flows (in MW) in blue.

Basically, the test system consists of two parallel transmission corridors that connect the generation with the load. The difference between the generated real power (103.5 MW) and the load (100 MW) is due to transmission losses. Since all lines have exactly the same parameters, the power flow is evenly distributed across the two corridors with 51.2 MW and 13.1 Mvar each. In

simple terms, real power flows from nodes with higher phase angles to nodes with smaller phase angles, and reactive power flows from nodes with higher voltage magnitude to nodes with smaller magnitude, resulting in decreasing voltage phase angles and magnitudes on the path from bus 1 to bus 6.

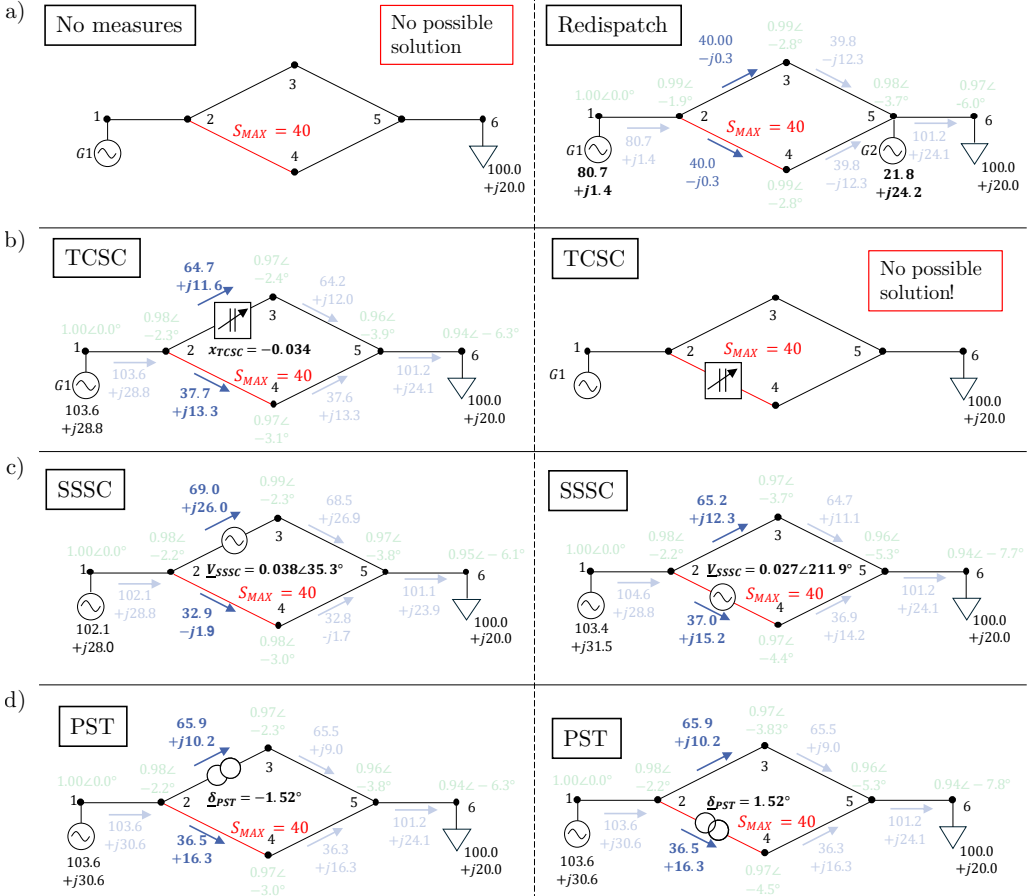


Figure 5.2: Overview of different measures for congestion management to illustrate the effects of different technologies. a) Redispatch, b) use of a TCSC, c) use of a SSSC, d) use of a PST.

For the following analysis, a thermal limit of 40 MVA is assumed for the transmission line connecting buses 2 and 4. This means that one of the two parallel transmission corridors is congested and, without further measures, the reference-case solution becomes infeasible. One possible measure is the use of redispatch. Generator G1 has to reduce its power output to 80.7 MW, and generator G2, which is located behind the congestion at node 5, has to be started and generate

21.8 MW as compensation (see Fig. 5.2a). Since the generation costs of G2 are twice as high as those of G1, this measure results in increased operation costs.

In addition to redispatch, the use of flexible grid elements can help in resolving the congestion, without causing additional costs. The results of the installation of a TCSC are depicted in Fig. 5.2b, once it is installed on the corridor that is not congested and once on the congested one. When installed in a corridor that is not congested, the congestion can be resolved. The TCSC acts as a capacity, decreasing the effective impedance of the corridor, resulting in a higher power flow over this line (64.7 MW) and thus reducing the power flow over the congested branch (37.7 MW). However, when installed on the congested branch, the congestion cannot be resolved. Due to operational limits of the TCSC (the maximum adjustable inductance is lower than the maximum adjustable capacity in the case data), the effective impedance of the line cannot be increased sufficiently to divert sufficient power to the parallel corridor.

The SSSC is more flexible because it is equally effective in increasing and decreasing the power flow. As can be seen in Fig. 5.2c, the SSSC on the line connecting buses 2 and 3 and the SSSC on the line connecting buses 2 and 4 resolve the congestion and produce feasible results, although the resulting power flows are not completely the same. In the first case, the active power flow is distributed 69.0 MW and 32.9 MW over the two corridors, while in the second case it is distributed 65.2 MW and 37.0 MW. The operating points of the SSSC have quite similar voltage magnitudes (0.038 p.u. and 0.027 p.u.) and the phase angle is approximately 180° apart (176.6° to be precise), which makes sense since the SSSC has contrary aims in both cases: in the first one it increases the power flow over the line and in the second one it decreases it.

The PST has an effect similar to that of the SSSC. The installation of a PST on the line connecting buses 2 and 3 as well as the installation on the line connecting buses 2 and 4 leads to feasible results. In contrast to the SSSC, for PST, the resulting power flows over the two corridors are exactly the same for both cases (65.9 MW and 36.5 MW), as can be seen in Fig. 5.2d. In addition, the operating state is exactly symmetric, with 1.52° for both cases, but the sign of the shift differs.

5.1.2 24-bus test system

For this section, we use a modified version of the updated IEEE RTS 24-bus system for electricity market and power system operation studies [201, 202] as a test system. The system consists of 24 buses, 34 branches, 12 conventional generators, 6 wind farms with individual generation profiles, and a demand profile for 8760 hours. The demand profile was obtained by combining the 24-hour profile provided in [201] with a typical daily demand profile for one year. The circuit diagram of the system is shown in Fig. 5.3. Detailed data for the test system can be found in Section A.3. Two scenarios have been analyzed. In the first, the transmission line capacities have been set to 100 %.

In the second, the transmission line capacities have been reduced to 70 %. In the literature, this is often done to consider approximately N-1 security. It also further increases system stress and possible congestion.

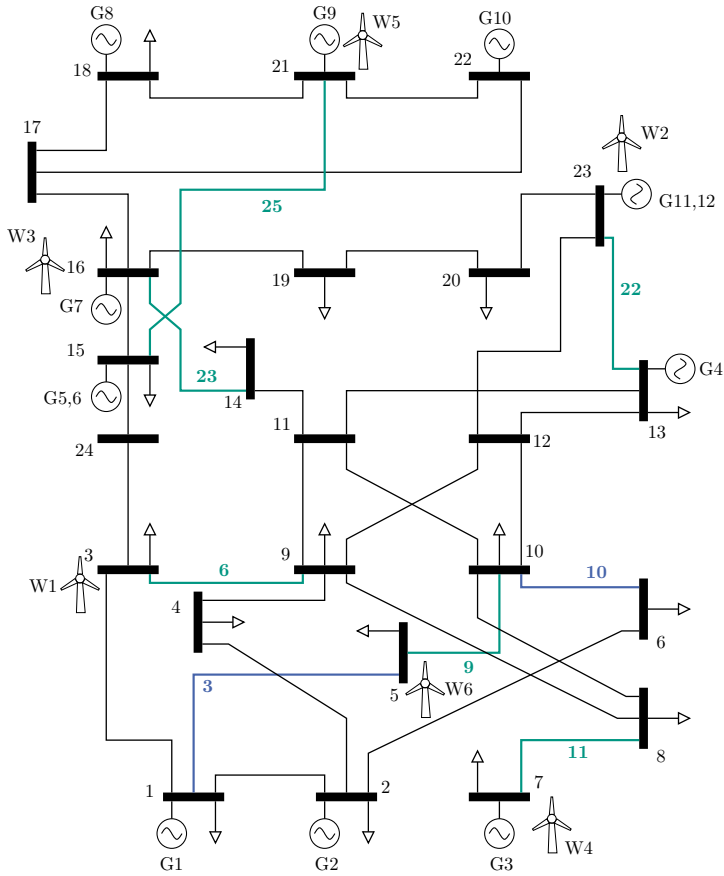


Figure 5.3: Circuit diagram of the 24-bus test system, own illustration after [201]. Lines that are congested in both scenarios (100 % and 70 % transmission capacity) are highlighted in green, lines that are congested only in the 70 % scenario are highlighted in blue.

First of all, three different OPF calculations have been performed: a reference run without any active transmission capacities whose results represent the best possible solution, a run with 100 % capacities and one with 70 % capacities. The aim was to minimize system costs, consisting of the generation costs of thermal power plants and the costs for load shedding (set to 10 000 EUR/MWh). The congested lines are depicted in Fig. 5.3: lines highlighted in green are congested in both scenarios, lines highlighted in blue are only congested in the 70 % scenario. In Fig. 5.4, the transmission lines are ordered according to the congestion severity (see Section 3.5.2)

for both scenarios. We can see that all six congested lines 23, 25, 9, 22, 6 and 11 in the 100 % scenario are also congested in the 70 % scenario, which makes sense, although order is not the same. There are also two more lines with congestion in the 70 % scenario, line 10 (which is even the most congested) and line 3.

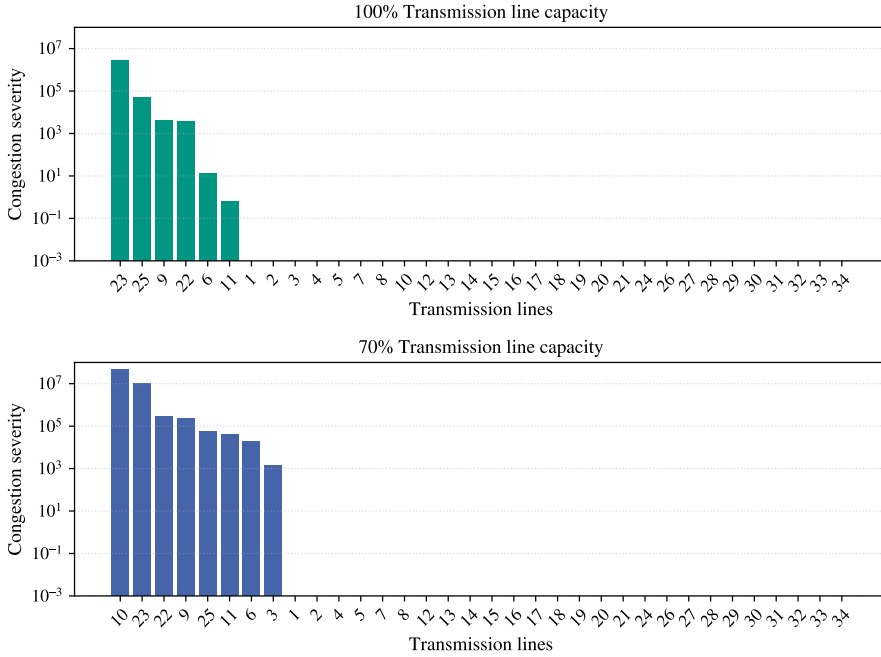


Figure 5.4: Calculated congestion severity for the transmission lines based on the OPF results for the 24-bus test case on a logarithmic scale. Top: results for the scenario with 100 % transmission line capacity, bottom: results for the scenario with 70 % transmission line capacity.

Based on the order of congestion severity, for each scenario, three and six lines are chosen for expansion with an SSSC, respectively. The data for the additional SSSC is shown in Table 5.1. With the additional SSSC, four more calculations are performed. The 100 % scenario with the addition of three and six SSSCs and the 70 % scenario with the addition of three and six SSSCs. An overview of the results of all simulation runs is shown in Fig. 5.5, with the results for the 100 % scenario in the top half and the results for the 70 % scenario in the bottom half. In the figure, the total generation costs of thermal power plants, the total generation values of thermal power plants, RES curtailment, and the loss of load hours (LOLH, number of hours in which load shedding appears) are depicted.

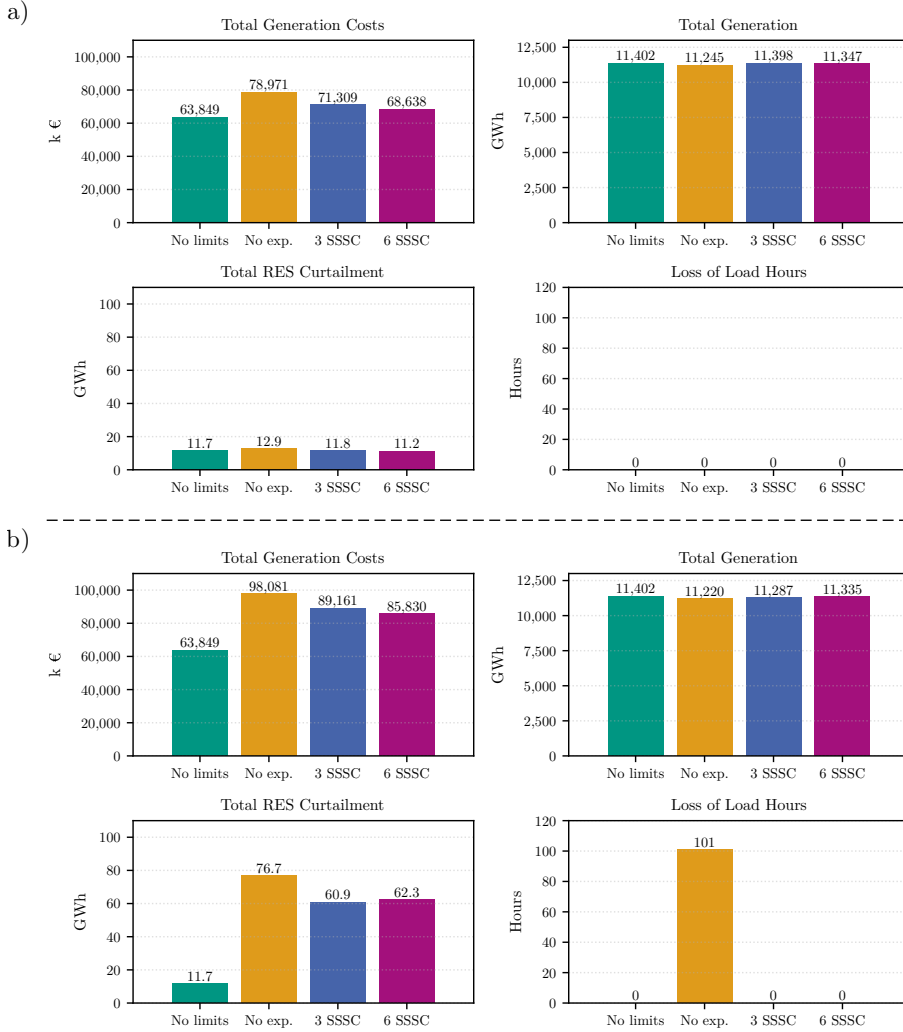


Figure 5.5: Results for different scenarios for the 24-bus test system: Without capacity limits for the transmission line flows, with capacity limits and no expansion, with capacity limits and the expansion of 3 SSSC. In a) the capacity limits are at 100 %, in b) the capacity limits are reduced to 70 % to approximate N-1 security constraints and further increase the stress in the system.

Table 5.1: SSSC expansion for the 100 % and 70 % scenarios.

100% scenario					70% scenario				
SSSC #	Line #	From	To	Vmax kV	SSSC #	Line #	From	To	Vmax kV
1	23	14	16	23.0	1	10	6	10	13.8
2	25	15	21	23.0	2	23	14	16	23.0
3	9	5	10	13.8	3	22	13	23	23.0
4	22	13	23	23.0	4	9	5	10	13.8
5	6	3	9	13.8	5	25	15	21	23.0
6	11	7	8	13.8	6	7	7	8	13.8

Regarding generation costs, it is not surprising that the case without any transmission line capacity constraints has the lowest total costs with 63.8 MEUR. Power flows are not constrained, so all the available power generated by wind farms can be used, and the cheapest conventional power plants generate the remaining needed power. The 11.7 GWh of curtailment is from hours, where the generation of the wind farms is higher than the system load. Since there are no storages in the system, there is no other option than to curtail the excess energy. In the 100 % scenario, the generation costs for the three cases with active transmission capacities are moderately higher, with 79.0 MEUR for the no expansion case, 71.3 MEUR for the case with three SSSCs, and 68.6 MEUR for the case with six SSSCs. The gain from the additional three SSSCs is quite high, with a 11 % reduction in generation costs, while the addition of three more SSSCs (six in total) brings only 4 % additional cost reduction. The values for total generation of thermal power plants, RES curtailment, and LOLH are nearly equally high for all four cases. This means that the differences in costs are solely due to whether cheaper power plants can be used or more expensive ones have to be put into operation instead.

Looking at the results for the 70 % scenario, the generation costs for the three cases with line flow constraints are much higher compared to the 100 % scenario across all three cases, which is no surprise with regard to the 30 % reduction in transmission capacities. Again, the addition of three SSSC reduces the generation costs by approximately 11 %, while the addition of six SSSCs brings only an additional cost reduction of 1.4 % compared to three SSSCs. However, in this scenario, we also see differences in RES curtailment and the LOLH. Without expansion, the RES curtailment is at 76.7 GWh, the addition of three or six SSSCs can reduce it to around 62 GWh. The 101 LOLH in the no expansion case can even be fully mitigated to zero with the additional SSSCs. In Fig. 5.6, the aggregated generation values and corresponding costs of the individual power plants for the 70 % scenario are shown. The shift from plants with lower generation costs in the case without flow constraints to plants with higher costs in the cases with capacity limits is clearly visible, as is the positive influence of the addition of three SSSC.

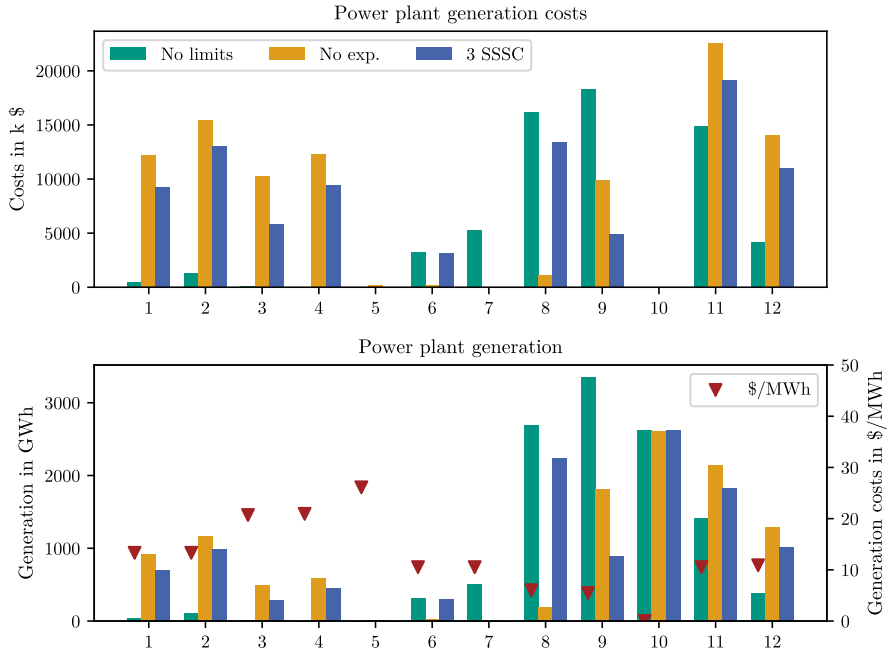


Figure 5.6: Detailed results for thermal power plant generation and costs for the 24-bus test case and the 70 % scenario. Top: total generation costs per power plant. Bottom: Total energy production and generation costs per MWh for each power plant.

The results clearly show the potential of further integrating FACTS (in this case SSSC) in electrical transmission networks. They can help in reducing RES curtailment, the need for load shedding and operation costs in general.

5.2 Case study 1: Future European and German system operation

In this section, different analyses regarding the optimal operation of the European and German electricity system in the years 2030, 2040, and 2050 are carried out. First, Germany and its electrical neighboring countries¹ are considered in a joint simulation, followed by a detailed analysis of system operation and congestion management in Germany, including an assessment of the potential benefits of FACTS. An overview of the countries that are part of the simulations is shown in Fig. 5.7.

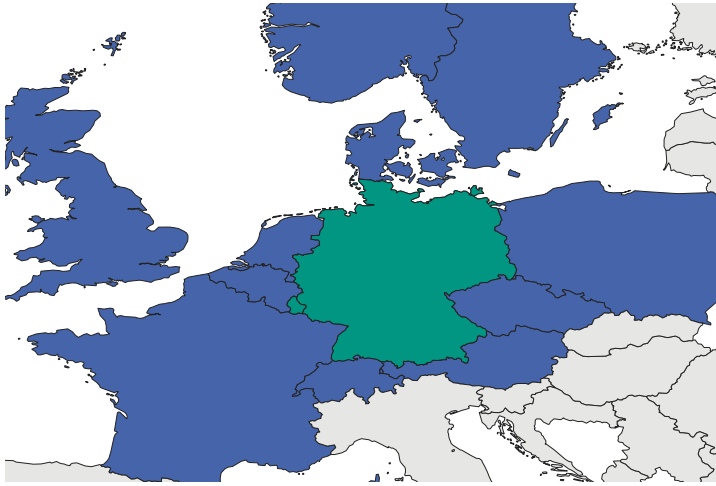


Figure 5.7: Overview of the geographical scope of the simulations. Blue: countries that are part of the simulations. Green: additional in-detail congestion management analysis.

For all the following OPF simulations, the rolling window time coupling approach with optimization windows of 24 hours was used. The state of charge of pump and battery storage systems at the start and end of the optimization periods was fixed to the results of a prior simplified system operation optimization without any grid constraints using the model described in Section 3.4, which was solved in a closed optimization for all hours of the year. For more details on the time coupling methodology, see Section 3.3.

¹ AT, BE, CH, CZ, DK, FR, LU, NL, NO, PL, SE, UK. Since Luxembourg is part of the German market zone and accounts for only a small share of demand and generation, it is considered part of Germany in the following and is not shown separately in the results.

5.2.1 European system operation

5.2.1.1 Insights from simplified market simulations

As a first step, the operation of the electricity system of Germany and its electrical neighbors has been analyzed using the simplified system modeling approach presented in Section 3.4. In this approach, all countries are modeled as one node systems, neglecting all transmission constraints inside a country. Exchange flows between different countries are limited by NTC values. RES and demand are aggregated to country level, whereas power plants and storage systems are modeled unit-wise (with the exception of Norway, where the pump storages are aggregated due to computational issues). System operation is optimized with the objective to minimize overall operation costs, for the scenarios TYNDP 2022, TYNDP 2024 and TYNDP 2024 half battery, each for the years 2030, 2040, and 2050 on an hourly time resolution. The detailed description of the scenarios and further input data can be found in Chapter 4.

The annual generation and demand results are shown in Fig. 5.8. The exact values can be found in Table A.17 in the Appendix. In general, RES are the dominant energy carriers with their share in electricity generation rising from 80 % in 2030 to 90 % in 2040 and nearly 95 % in 2050 across all three scenarios. The generation of thermal power plants is quite similar for all three scenarios in 2030, in 2040 and 2050 some differences can be observed, with higher amounts of conventional generation in the TYNDP 2022 scenario, which is compensated by increased battery storage usage in the two TYNDP 2024 scenarios. In the TYNDP 2024 half battery capacity scenario, we see less battery operation but more generation from natural gas and hydrogen fired power plants than in the TYNDP 2024 scenario, which is due to the reduced battery capacity.

The aggregated generation costs throughout all simulated countries are shown in Fig. 5.9. Since battery and pumped storage operation and generation from RES are not evaluated in terms of costs in the model, only the generation costs of thermal power plants and the costs of load shedding play a role. In 2030, costs are largely similar around 19 000 M EUR across all scenarios, with slightly higher costs in the TYNDP 2024 scenarios, which is due to lower battery and gas capacities than in the TYNDP 2022 and thus an increased usage of coal fired power plants. In 2030 and 2040, the pure generation costs are the lowest for the TYNDP 2024 scenario with 11 500 M EUR for 2040 and 9950 M EUR in 2050, whereas they are the highest for the TYNDP 2022 scenario at 13 500 M EUR in 2040 and 13 700 M EUR in 2050 and for the TYNDP 2024 half battery scenario they lie in between.

Apart from the costs for conventional generation, notably also costs for load shedding are significant in the years 2040 and 2050. In the TYNDP 2022 scenario, no load shedding occurs, indicating that the installed generation capacities are sufficient to reliably cover electricity demand at all

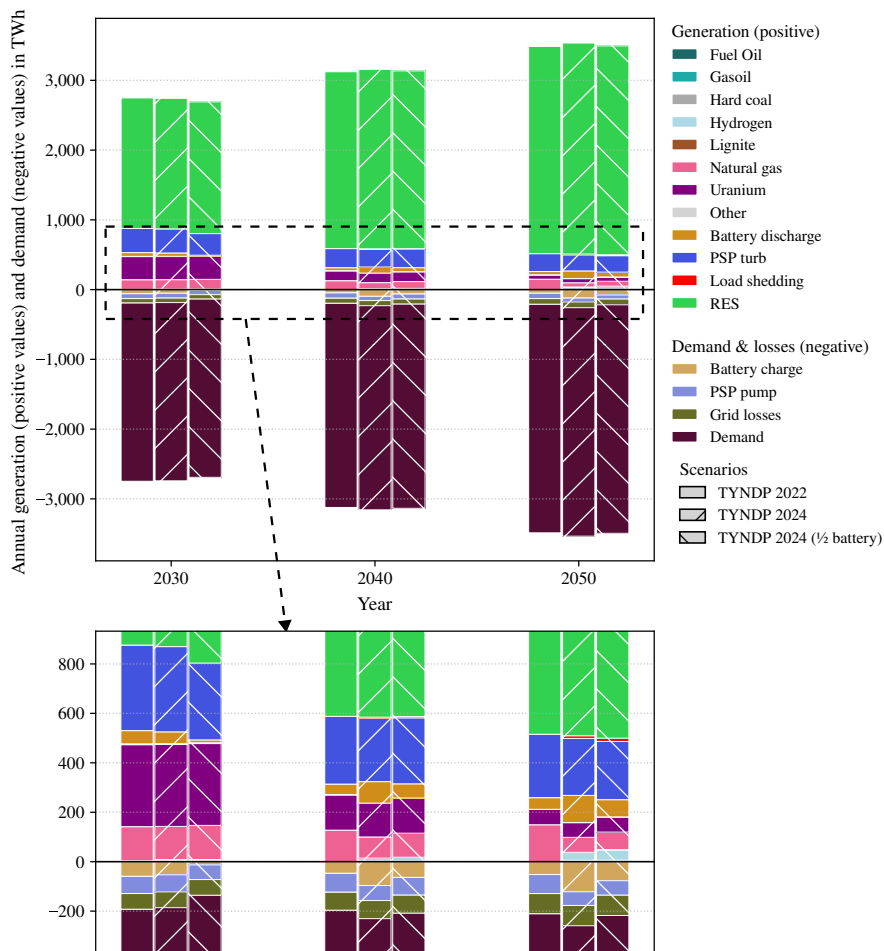


Figure 5.8: Annual electricity generation and demand for Germany and its electrical neighbors for the simplified electricity system operation model.

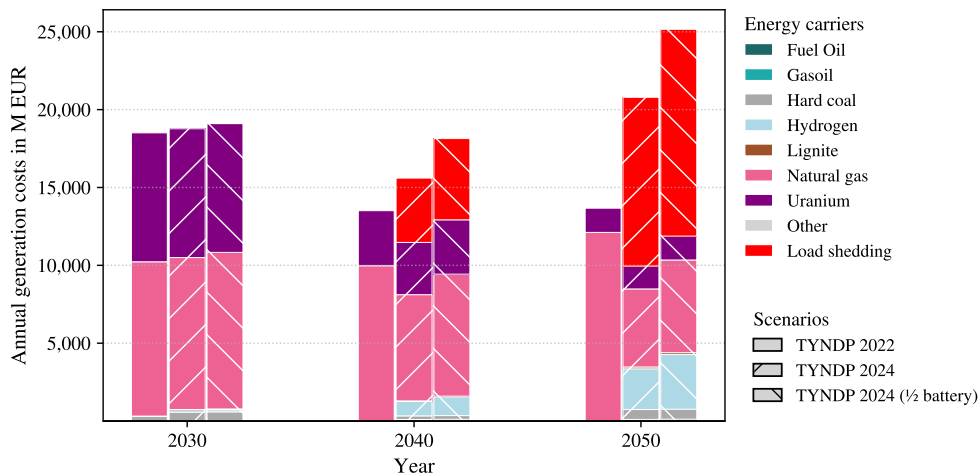


Figure 5.9: Annual system operation costs for Germany and its electrical neighbors for the simplified electricity system operation model.

times. For the TYNDP 2024 and TYNDP 2024 half battery scenario, 4.1 TWh and 5.2 TWh of load shedding are necessary in 2040 and even 10.8 TWh and 13.3 TWh in 2050, which means costs of 4100 M EUR and 5200 M EUR in 2040 and 10 800 M EUR and 13 300 M EUR in 2050 with the assumed load shedding costs of 1000 EUR/MWh. Given the fact that demand side management is not properly integrated in the model and in reality, load shifting will most definitely be possible with costs way below the 1000 EUR/MWh assumed in this study, the resulting costs for load shedding are probably overestimated. Nevertheless, two conclusions can be drawn from this: first, the anticipated generation capacities in the TYNDP 2024 may not be sufficient to meet the demand at all times, although this of course also depends on the anticipated demand scenario. Second, the higher battery capacity in the TYNDP 2024 scenario helps increase the security of supply compared to the TYNDP 2024 half battery scenario, but batteries alone cannot completely replace conventional power plants in this regard. This is specifically the case for so called dark doldrums or Dunkelflauten, in which the generation from wind and solar is minimal over a duration of several days up to a few weeks. In the scenario data of this study, a dark doldrum with a length of approximately 2 weeks can be observed from hour 450 to hour 750 in the used weather year. In the TYNDP 2024 scenario and the year 2040, this period accounts for almost 60% of the load shedding for the entire year, which highlights the potential impact of such dark doldrums on the energy system. The hourly load shedding values for the TYNDP 2024 scenario in 2040 are shown in the Appendix in Fig. A.6.

Looking at the energy exchange between the modeled European countries, cross-border exchange flows consistently hit NTC limits, suggesting that the current interconnector infrastructure is

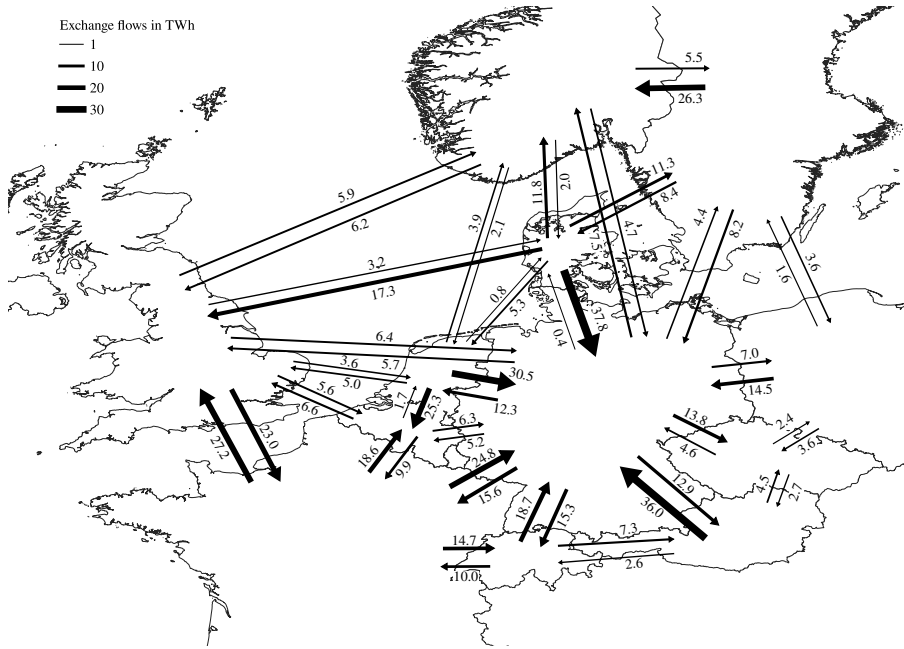


Figure 5.10: Aggregated exchange flows between the modeled countries (including Germany and its electrical neighbors) for the year 2040 and the TYNDP2024 scenario as a result from the simplified system operation optimization.

insufficient for the growing volume of cross-border flows. Expanding the grid could substantially mitigate these limitations and reduce operating costs. Germany, located at the center of the European power system, serves as an important transit country through which large exchange flows are routed. An overview of the aggregated exchange flows resulting for the TYNDP 2024 scenario in 2040 is presented in Fig. 5.10. Germany's location and the associated high volume of exchange flows with its neighboring countries pose additional challenges for its transmission grid, which shall be the focus of the OPF based analyses in the following sections.

5.2.1.2 Insights from OPF simulations

Following the simplified market simulation, OPF calculations were performed to determine optimal dispatch considering the grid infrastructure for the TYNDP 2024 scenario. Germany, Luxembourg, Austria, Switzerland, France, Belgium, Czechia, Poland, Denmark, and the Netherlands are modeled in detail with their transmission grid, Norway, Sweden and the United Kingdom are modeled as simplified one node models.

In Fig. 5.11, the overall generation values and the corresponding costs for 2030 and 2040 are shown compared to the results of the simplified optimization without grid constraints. Regarding generation, the differences seem small at first sight. In the OPF results, less RES generation can be integrated into the system due to grid constraints, which is compensated by a higher share of thermal generation, in particular from hard coal and natural gas. In 2040, additionally, a largely increased usage of battery storages can be observed. This suggests that batteries can be helpful to handle temporary grid congestion and thus reduce grid-related curtailment needs.

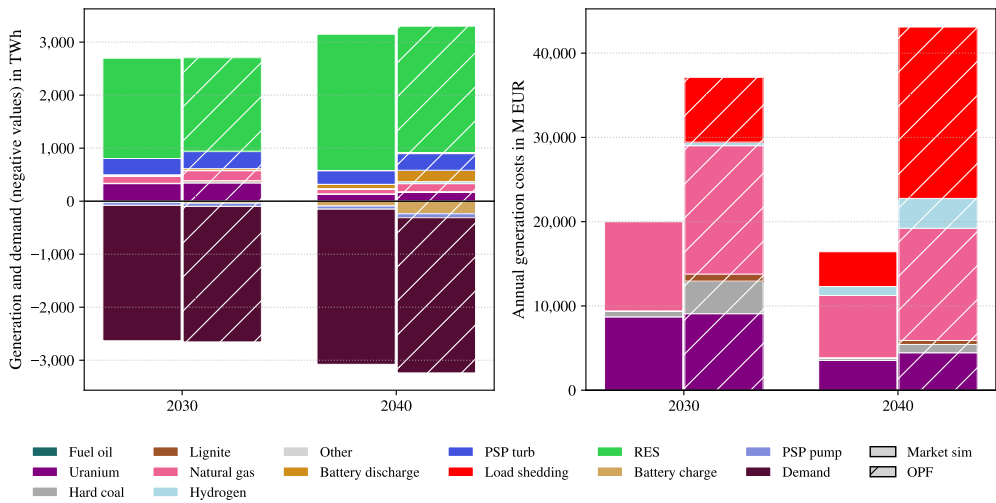


Figure 5.11: Comparison of electricity generation and related costs between the results for the simplified market simulation and the OPF with grid constraints for Germany and its neighbor countries. The results are for the TYNDP 2024 scenario and the years 2030 and 2040.

With regard to costs, the differences to the simplified market simulation are plainly obvious. In 2030, the generation costs are 50 % higher when considering grid constraints, increasing from 20 000 M EUR to nearly 30 000 M EUR with additional costs of 8000 M EUR for load shedding. In 2040, generation related costs are generally lower, but the increase from the market simulation with 12 500 M EUR to the OPF with 23 500 M EUR is nearly 90 %. The additional costs for load shedding are massive in the 2040 OPF results and with 20 000 M EUR are nearly as high as the generation costs. This indicates that especially in 2040, but also to some degree already in 2030, security of supply with regard to transmission adequacy cannot always be guaranteed, and further grid expansion is necessary. Maps with the locations of the necessary load shedding are shown in the Appendix in Figs. A.12 and A.13. It can be seen that most of the load shedding occurs in France and neighboring regions.

The results for the average utilization of AC and DC transmission lines and the distribution of power generation are shown in Fig. 5.12. The generation values are aggregated on NUTS-2 level. The generation results for 2040 are shown in the Appendix in Fig. A.7, as well as the results for RES curtailment for 2030 and 2040 aggregated at NUTS-2 level in Figs. A.8 and A.9 and RES curtailment at the substation level in Figs. A.10 and A.11. Already in 2030, generation is dominated by RES, especially wind onshore and wind offshore, which is produced mainly in regions near the North Sea and Baltic Sea or directly at sea. PV generation is approximately evenly distributed throughout Europe, while hydro power is used mainly in the Alpine region and in Norway and Sweden. France produces most of its electricity with nuclear power plants, coal and gas fired plants are operated mainly in Germany and Poland. Until 2040, the share of RES generation further increases, and the generation of thermal power plants decreases, especially of nuclear power plants. Curtailment drastically increases from 2030 to 2040, with most of it occurring in regions near the coast where high amounts of wind offshore, wind onshore, and PV are generated. The transmission line utilization rates are pretty high across all of the simulated countries, in 2040 even higher than in 2030. This indicates a general high level of stress and congestion in the grid. Especially cross-border DC lines and the DC lines connecting the Northern and Southern part of Germany are constantly operated at their capacity limits, which underscores their importance for the energy system and indicates that further expansion of cross-border infrastructure and connections from the coast to the load centers in the inland might be valuable. The OPF simulation did not converge within a reasonable time and was therefore discarded. The numerical difficulties suggest major problems in balancing generation and demand and indicate more serious gaps in the available transmission infrastructure.

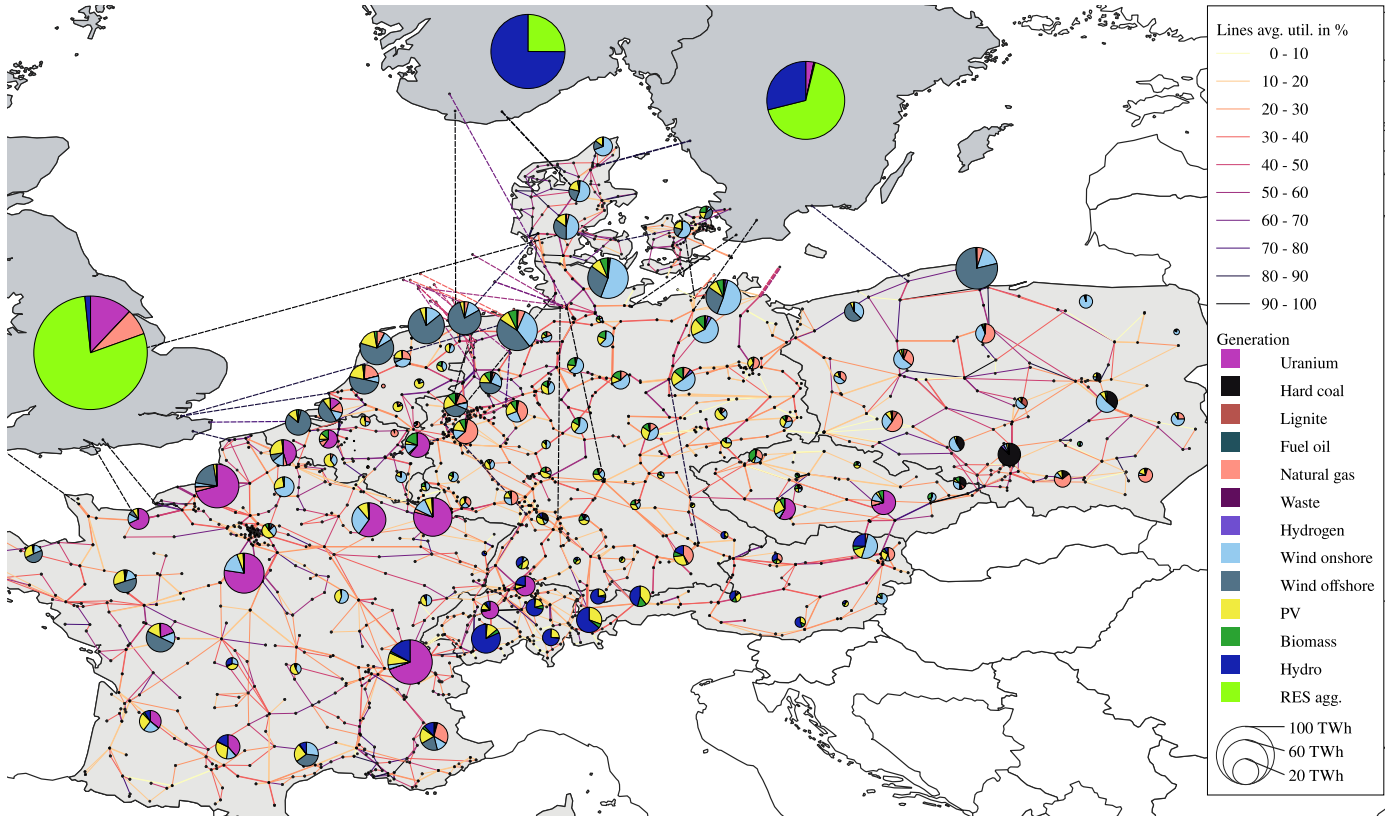


Figure 5.12: Annual generation and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2030 for the TYNDP 2024 scenario. Generation results are aggregated to NUTS-2 level for countries modeled with grid infrastructure (coloured light grey) and to NUTS-0 level for countries modeled as one node systems (darker grey).

5.2.2 Redispatch requirements and costs in Germany

This section analyzes the future need for redispatch measures in Germany. Based on the results of the simplified system operation optimization in Section 5.2.1, the model described in Section 3.2 is used to determine cost optimal redispatch measures for the three scenarios defined before and the years 2030, 2040, and 2050 in an hourly resolution. The model's geographical scope is Germany and exchange flows to neighboring countries are fixed to the corresponding results of the previous simplified simulation.

The results of the redispatch volumes for Germany are shown in Fig. 5.13. For 2030 and 2040, the redispatch requirements are nearly the same with approximately 40 TWh across all three scenarios. In 2050, the redispatch volumes increase to 65 TWh to 75 TWh with higher volumes in the TYNDP 2024 scenario compared to the TYNDP 2022 and TYNDP 2024 half battery scenarios. Negative redispatch consists mainly of RES curtailment, while natural gas (in the TYNDP 2022 scenario) and hydrogen (from 2040 onwards in the TYNDP 2024 scenarios) are the most important sources for positive redispatch. The share of pumped storage is constant and rather small across all years and scenarios. The biggest difference is in the use of batteries, while in 2050 approximately 20 TWh positive and negative redispatch is connected to batteries in the TYNDP 2024 scenario, in the TYNDP 2022 scenario it is only 6 TWh. In return, in the TYNDP 2022 scenario, the use of thermal power plants to generate positive redispatch capacity is slightly higher at nearly 60 TWh in 2050 than in the other two scenarios, at around 50 TWh. Grid-related load shedding occurs across all years and scenarios, with a maximum of 3.2 TWh in the TYNDP 2024 half battery scenario in 2040.

In Fig. 5.14, the corresponding costs are shown. For 2030 and 2040, disregarding costs for load shedding, costs are, as is the case for volumes, pretty similar at 3200 MEUR to 4100 MEUR in all scenarios and for both years with the TYNDP 2024 scenario at the upper end. In 2050, without load shedding, costs rise to 6000 MEUR to 7000 MEUR. Taking load shedding costs into account, the costs reach nearly 10 000 MEUR in the TYNDP 2024 scenario in 2050, which is approximately half of the total generation costs (inclusive load shedding) of the simplified simulation for Germany and all of its neighbors. In 2030 load shedding plays only a minor role, while in 2040 the costs for load shedding rise substantially to 1600 MEUR in the TYNDP 2022 scenario and 3200 MEUR in the TYNDP 2024 half battery scenario.

Again, the costs for load shedding are probably overestimated due to an expected rise in demand side flexibility. Additionally, only expansion projects expected to be commissioned until 2040 are integrated in the grid data, so in later years additional transmission capacities could be available that reduce the redispatch volumes and costs. Nevertheless, the results show that costs related to congestion management and especially redispatch might be even more impactful than the costs

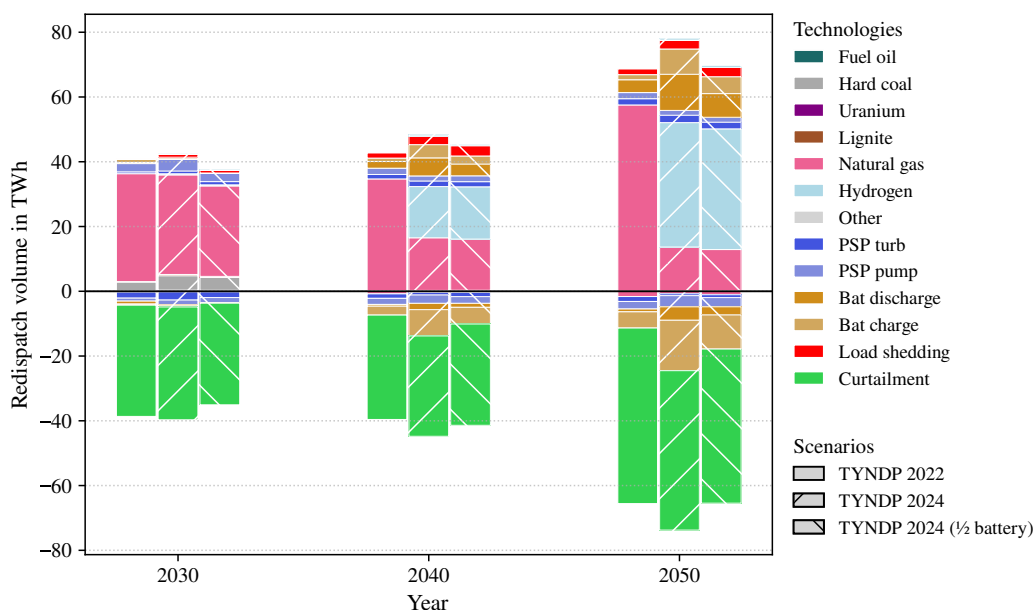


Figure 5.13: Results for the simulated redispatch volumes in Germany for the years 2030, 2040 and 2050 for the TYNDP 2022, TYNDP 2024 and TYNDP 2024 half battery capacity scenarios.

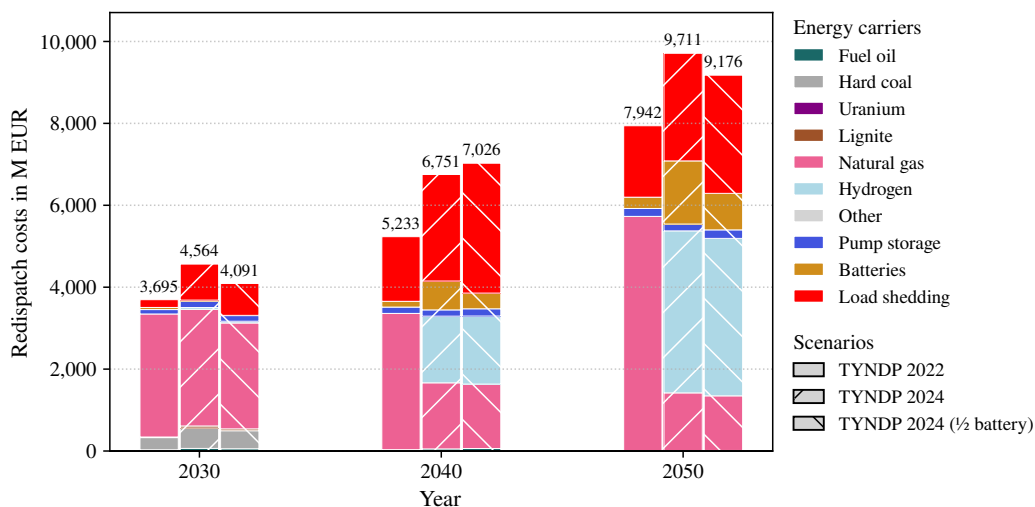


Figure 5.14: Results for the simulated redispatch costs in Germany for the years 2030, 2040 and 2050 for the TYNDP 2022, TYNDP 2024 and TYNDP 2024 half battery capacity scenarios.

related to market-based generation in the future, which is logical given the transition to nearly 100% RES generation.

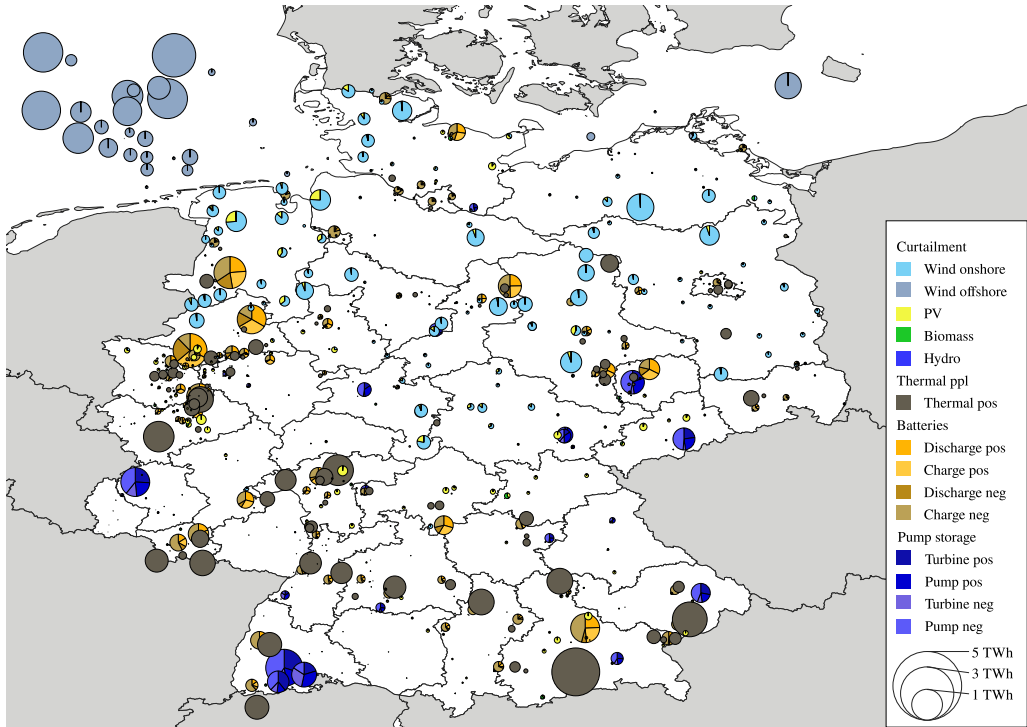


Figure 5.15: Results for the necessary redispatch volumes in Germany for the year 2040 and the TYNDP 2024 scenario, broken down by energy carriers and location.

The locations of the negative (mainly curtailment) and positive (mainly thermal power plants) redispatch volumes for the year 2040 and the TYNDP 2024 scenario are shown in Fig. 5.15. The results for the years 2030 and 2050 are shown in the Appendix in Fig. A.14 and Fig. A.15. Curtailment appears mainly in the northern part of Germany, with wind onshore being the most curtailed technology in 2030 which shifts towards wind offshore in 2040 and 2050. The exact numbers on the negative and positive redispatch volumes per technology are presented in the Appendix in Table A.18. Especially wind energy generated in the North Sea often cannot be integrated into the grid. In contrast, positive redispatch measures by thermal power plants occur mainly in Southern Germany and in the Rhine-Ruhr metropolitan region in the West. This indicates a lack of transmission capacity between the Northern and Southern parts of Germany, even with the grid expansion projects (especially the planned HVDC connections from the north

to the south play an important role) described in the German network development plan [135]. Battery and pumped storage redispatch measures can be observed across all of Germany.

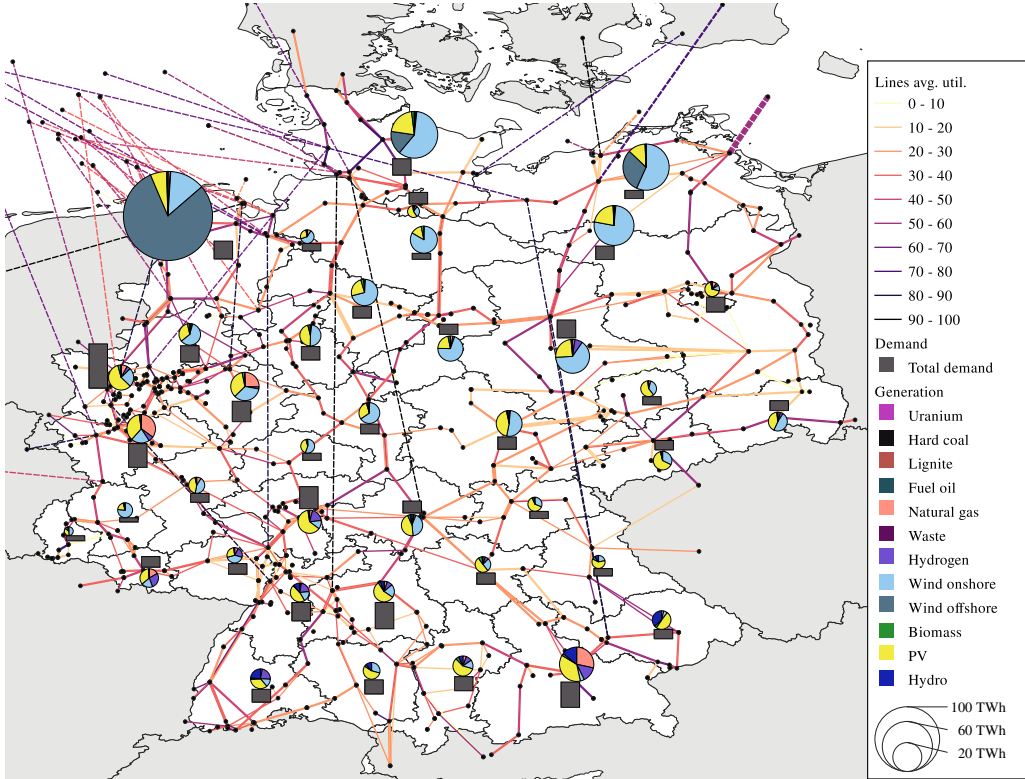


Figure 5.16: Average line utilization of AC and DC (dashed) transmission lines and generation results for Germany broken down by energy carrier and NUTS-2 region after the redispatch simulation for the TYNDP 2024 scenario in 2040.

These conclusions are further reinforced when looking at the line utilization rates, which are shown together with the annual generation and demand volumes (after redispatch, broken down to NUTS-2 level) for the scenario TYNDP 2024 and the year 2040 in Fig. 5.16. The results for 2030 and 2050 are shown in Figs. A.16 and A.17 in the Appendix. Again, the imbalance of high generation in the North and high demand in the South and West is visible, resulting in generally high utilization rates for transmission lines running in a north-south direction. Especially the HVDC lines (dotted in the figure) are constantly operated near or at their capacity limits. On the one hand, this highlights the need for additional transmission capacity, and on the other hand, emphasizes the advantage of HVDC connections, which can be used to transmit power in a highly controllable manner and independently of the other system conditions of the AC grid, whereas

AC lines not always can be used to their limit due to constraints related to voltage limits or other lines in the region.

5.2.3 Impacts of the use of FACTS on congestion management

In this section, the value of FACTS in congestion management is evaluated. Therefore, different numbers of SSSC were added to the system, and optimal redispatch calculations were performed for each configuration. The SSSC was chosen as the focus lies on power flow controlling (series connected) FACTS and it is more flexible than the TCSC and less complex than the UPFC (while maintaining the same or nearly the same capability to control the power flow over the line). The results of the simplified system operation simulation for the year 2030 and the TYNDP 2024 scenario served as a basis for the redispatch calculations. An initial optimization was conducted without any SSSC as the reference case. Based on these results, the locations for additional SSSC were determined using the approach presented in Section 3.5. Calculations were performed with the addition of 10, 20, 30, and 40 SSSCs, the results for redispatch volumes and costs are shown in Fig. 5.17. The number of SSSCs added to the network was specified exogenously.

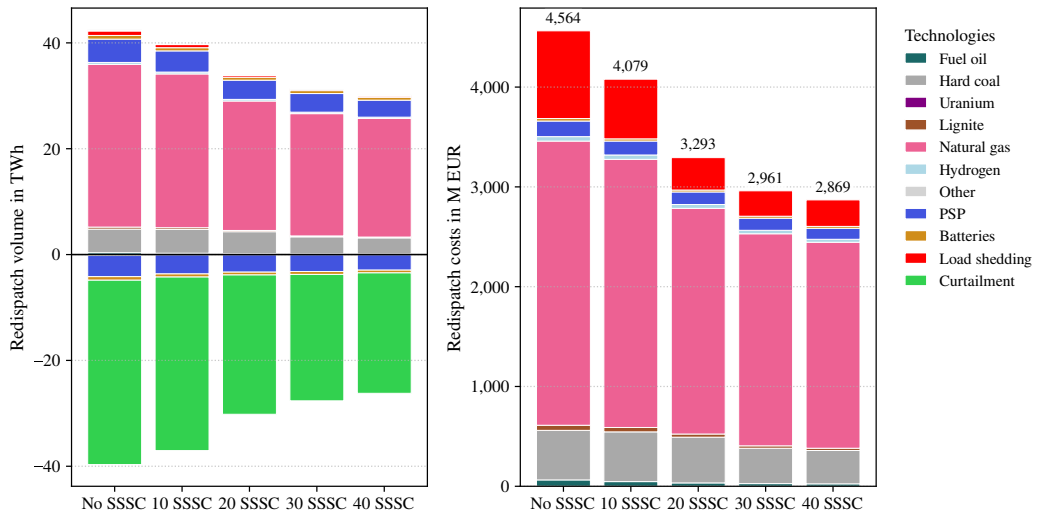


Figure 5.17: Comparison of redispatch volumes (left) and costs (right) in Germany for the reference case and cases with 10, 20, 30 and 40 installed SSSCs in the system. The results refer to the year 2030 and the TYNDP 2024 scenario.

With an increasing number of installed SSSCs, a pronounced reduction in both redispatch volumes and redispatch costs can be observed. Total annual redispatch costs decrease from 4564 MEUR in

the reference case to 4079 M EUR with the installation of 10 SSSCs, 3293 M EUR with 20 SSSCs, 2961 M EUR with 30 SSSCs, and 2896 M EUR with 40 SSSCs. This corresponds to relative cost reductions of 10.6 %, 27.8 %, 35.1 %, and 37.1 %, respectively, indicating diminishing marginal benefits at higher deployment levels. A similar trend is observed when considering redispatch costs excluding forced load shedding. In this case, costs decline from 3685 M EUR in the reference scenario to 3481 M EUR for 10 SSSCs, 2969 M EUR for 20 SSSCs, 2706 M EUR for 30 SSSCs and 2604 M EUR for 40 SSSCs. These values correspond to reductions of 5.5 %, 19.4 %, 26.6 %, and 29.3 %, respectively.

The reduction in redispatch costs is primarily driven by decreased renewable energy curtailment and consequently a reduced need for positive redispatch from conventional thermal power plants, mainly gas-fired units. Annual RES curtailment falls from 34.8 TWh in the reference case to 32.8 TWh with 10 SSSCs, 26.3 TWh with 20 SSSCs, 23.9 TWh with 30 SSSCs, and 22.7 TWh for 40 SSSCs, corresponding to a reduction of approximately 35 %. Even more pronounced effects are observed for forced load shedding. Compared to 879 GWh in the base case, load shedding is reduced by up to 71 %, reaching approximately 254 GWh in the scenarios with 30 and 40 SSSCs. This highlights the effectiveness of SSSCs in alleviating critical congestion and improving supply adequacy in heavily constrained situations.

The cost savings are not linear to the number of devices added. The addition of SSSC 11 to 20 saves an additional 786 M EUR compared to the case with only 10 SSSCs and thus produces a greater benefit in the form of mitigated costs than the addition of SSSC 1 to 10 (485 M EUR) and SSSC 21 to 30 (332 M EUR). The addition of SSSC 31 to 40 brings only 92 M EUR, suggesting that some kind of saturation is reached. These results indicate that massive cost reductions in the redispatch can be achieved by the installation of such devices, although it is not trivial to predict the actual benefit, and reinforcing the most congested lines with power flow controlling devices such as SSSC is not necessarily the optimal strategy in all cases.

The locations of the added SSSC are shown in Fig. 5.18. It is noticeable that the majority is located in the southern and western parts of Germany as well as at some key connections from north to south. These are also the regions where most of the positive redispatch measures have to take place, which already indicates congestion and overall system stress in these regions.

The investment expenses associated with the deployment of SSSCs are difficult to quantify, as publicly available cost data remain scarce. Based on the price assumptions reported in [203], the average investment requirement for one of the 40 SSSCs identified in this study amounts to approximately 25.6 M EUR, with the specific value depending on the nominal rating of the device. For the SSSC configurations examined here, the resulting cumulative investment volumes amount to 166 M EUR for the first 10 devices, 536 M EUR for the first 20, 766 M EUR for the first 30, and 1025 M EUR for all 40 SSSCs.

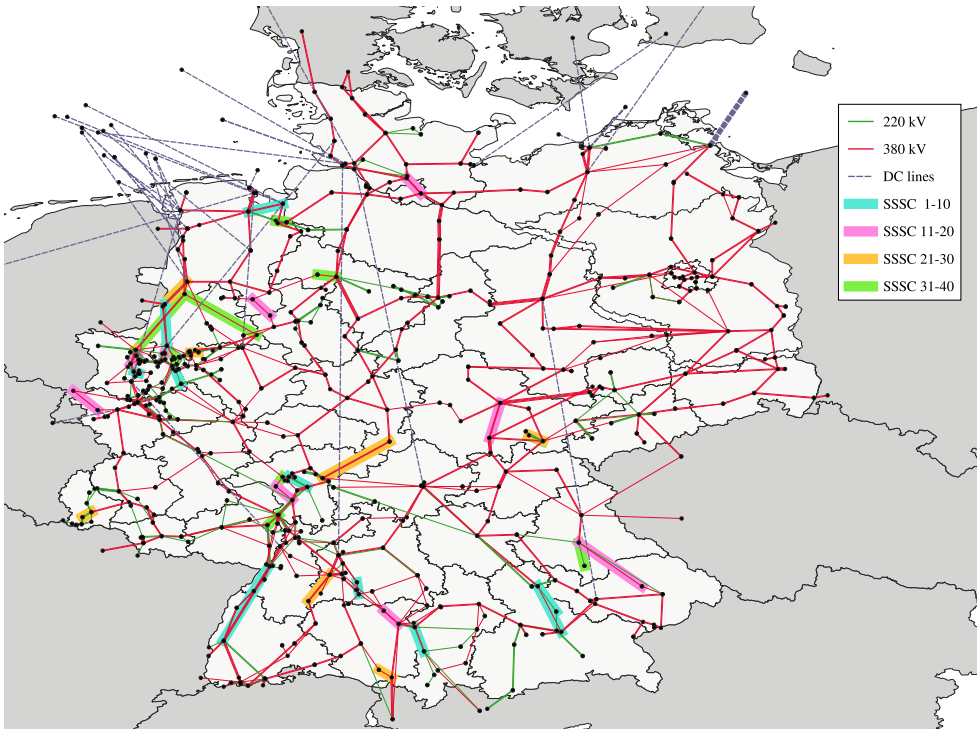


Figure 5.18: Locations of the added SSSC, broken down by the suggested order of installment. The results refer to the year 2030 and the TYNDP 2024 scenario.

When compared to the potential annual system cost reductions achieved through improved power-flow control and reduced redispatch requirements, the associated investment volumes appear modest. Even at higher deployment levels, the cumulative investment expenditures are substantially outweighed by the resulting annual savings, implying short implicit payback periods on a system level. This observation suggests that SSSCs constitute a highly cost-effective congestion-mitigation measure, particularly in systems characterized by frequent structural bottlenecks and high shares of renewable generation. Importantly, this conclusion is not sensitive to the specific cost assumptions adopted in this study. Even under more conservative investment estimates, the relative magnitude of achievable annual redispatch cost reductions continues to exceed the corresponding capital expenditures by a wide margin. Given the long technical lifetime of FACTS devices, which typically spans several decades, the cumulative economic benefits would further increase when evaluated over the full asset lifetime, rendering the present comparison conservative.

At the same time, the strongly diminishing marginal benefits observed at higher deployment levels underline that economic attractiveness does not imply unlimited optimal expansion. While moderate numbers of SSSCs yield exceptionally high economic returns, additional installations beyond a certain point provide substantially lower incremental benefits. This points to the existence of an economically optimal deployment range rather than a monotonic incentive for continued expansion. Consequently, SSSCs should be understood not as a universal substitute for conventional grid reinforcement, but as a targeted complement that can deliver large system benefits when deployed at carefully selected locations.

To further assess the impacts and welfare gains of other transmission expansion options, the results of a reference case without any grid expansion are compared to several alternative expansion scenarios. Specifically, the deployment of 10 SSSCs, 10 TCSCs implemented in two different technical configurations, and the construction of 10 additional transmission lines installed in parallel to selected congested lines are considered. The identification of these congested lines again follows the expansion planning algorithm described in Section 3.5 and is identical across all expansion scenarios. Redispatch calculations are subsequently carried out using the same underlying market outcomes as in the reference case. The resulting annual redispatch costs associated with each expansion technology are presented in Fig. 5.19.

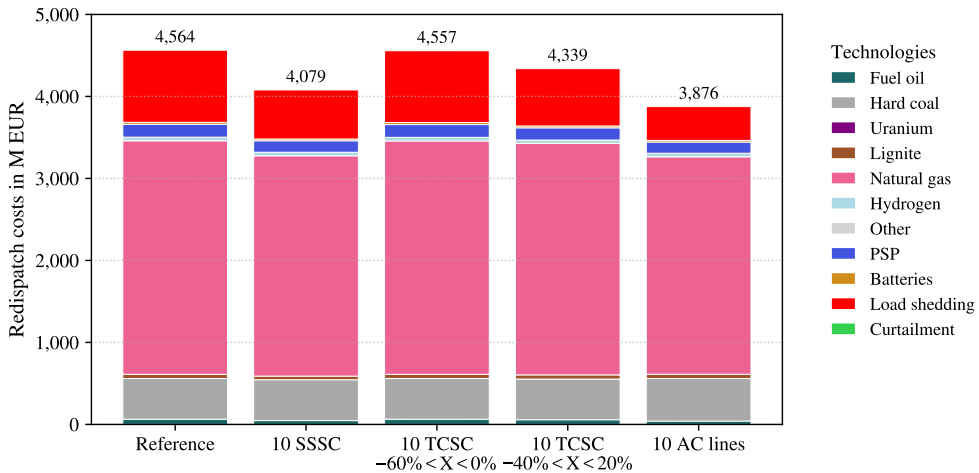


Figure 5.19: Comparison of redispatch costs in Germany for the reference case and cases with additionally installed SSSCs, TCSCs, and AC transmission lines in the system. The results refer to the year 2030 and the TYNDP 2024 scenario.

For TCSCs, the achieved cost reductions are relatively small. In the configuration in which the TCSC can only be operated in a capacitive mode, i.e., can only reduce the effective line reactance,

the resulting cost savings are close to zero. This can be explained by the applied expansion logic, which selects transmission lines for reinforcement that are already operated close to their thermal limits. A reduction in the effective line reactance increases the power flow on the affected line, which is counterproductive in such situations, as further loading is typically not feasible. Consequently, an alternative expansion strategy would be required to enable the effective use of TCSCs under these conditions. In the configuration that also allows for an increase in the effective impedance, modest cost reductions can be achieved. By contrast, the scenario with ten additional SSSCs results in redispatch cost reductions of nearly 500 M EUR. This effect is further exceeded by the scenario involving the construction of ten additional transmission lines, which yields cost savings of close to 700 M EUR. However, the required investment expenses for the ten new transmission line, amounting to approximately 1000 M EUR, based on cost estimates from the German network development plan [204], are substantially higher in comparison.

Overall, the results highlight the significant potential of FACTS devices, particularly SSSCs, to reduce system operation costs at comparatively low investment effort, while underscoring the importance of prioritization and marginal benefit assessment in transmission planning. From an economic perspective, power-flow-controlling devices emerge as a highly attractive option for mitigating congestion in the short to medium term, especially when compared to capital-intensive line expansion projects. At the same time, the magnitude of the calculated cost savings should be interpreted with caution. The modeling framework neglects several remedial actions that are already available to transmission system operators in current practice, such as transmission switching and the operation of existing FACTS devices or phase-shifting transformers. This simplification may lead to an overestimation of baseline redispatch costs and, consequently, to an overstatement of the absolute savings potential attributed to additional expansion measures. In addition, a substantial share of the computed cost reductions is driven by avoided forced load shedding. Since future energy systems are expected to exhibit higher levels of demand flexibility and a broader set of demand-side management options, none of which are explicitly represented beyond forced load shedding in the model, the resulting load-curtailment costs are likely overstated relative to real-world system operation.

5.2.4 Comparison with optimal dispatch considering grid constraints

This section aims to estimate the costs that could be saved in system operation if grid restrictions were included in the optimization from the outset. To this end, the costs resulting from the simplified market simulation in Section 5.2.1 and subsequent redispatch calculations for Germany in Section 5.2.2 are compared with the results of an OPF calculation, in which an optimal

dispatch is calculated taking grid restrictions into account. It is important to note that in both the redispatch simulation and the dispatch OPF calculation only Germany is modeled with its grid infrastructure and the resulting transmission restrictions. In the redispatch simulation, exchange flows to neighboring countries were fixed based on the results of the simplified market simulation, while for the dispatch OPF the European neighbors are modeled as a single node system without taking intra-zonal grid restrictions into account. Nevertheless, the results described below refer to the aggregated costs of all modeled countries, which could of course look different if all the countries were modeled in all details regarding grid constraints.

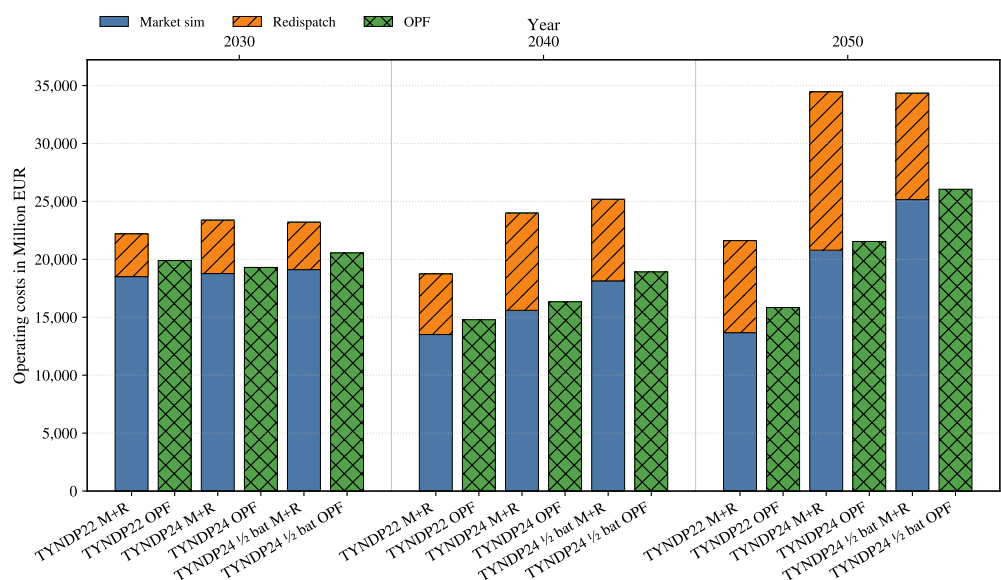


Figure 5.20: Annual system operation costs for Germany and its neighbors. M+R: Simplified market simulation for all considered countries, followed by a redispatch calculation for only Germany. OPF: Dispatch OPF taking grid constraints into account for Germany, simplified one node modeling approach for neighboring countries.

The costs for the simplified market and following redispatch simulations and the dispatch OPF simulations are presented in Fig. 5.20 for all three scenarios and the years 2030, 2040 and 2050. It is evident that enormous amounts of redispatch costs could be saved if grid restrictions are already taken into account when determining dispatch and RES curtailment. The spatial distribution of RES generation and curtailment in particular is crucial to how well the resulting dispatch is compatible with grid constraints. With an optimized allocation of RES curtailment and use of available storage capacities, the additional costs caused by grid constraints can be nearly completely mitigated, as the results for the TYNDP 2024 scenario show. This strengthens the assumption that including grid-related constraints or incentives in market design could drastically

reduce system operation costs and thus increase social welfare. In the next section, two such approaches are introduced and discussed.

5.3 Case study 2: Effects of market-based approaches to internalize grid constraints

In this case study two market-based approaches with the aim to reduce redispatch and overall system costs were examined: dividing Germany into multiple price zones and the introduction of dynamic grid fees. For this purpose, the OPF model presented in this thesis was coupled with the agent based electricity market simulation model PowerACE [122, 205–207], which has been developed and used at IIP for nearly 20 years. PowerACE is a bottom-up, long-term simulation model with a focus on the day-ahead market considering European market coupling. Market participants are modeled as agents with individual behaviors, who can submit sell and ask bids to the day-ahead market and also make investment decisions. The coupled day-ahead market is cleared for the 24 hours of the next day with an hourly resolution, using a market clearing algorithm based on EUPHEMIA [114]. After each year, the agents make investment decisions based on a net present value approach. The results include, for example, electricity prices, power plant and storage dispatch, and investment decisions.

To couple PowerACE with the OPF model, an interface was developed that imports and processes the results from the market simulation (most importantly, dispatch results) and ensures a harmonized input data base. In the redispatch optimization, only additional system costs are considered in the objective function, while potential revenues are deliberately excluded. This design choice ensures that the redispatch formulation represents a corrective post-market adjustment and avoids any re-optimization of the original market outcome.

5.3.1 Bidding zone review of the DE-LU market zone

The idea behind the division of Germany into multiple price zones is to better align economic signals in the day-ahead market with physical grid constraints and thus reduce congestion management needs and costs [122, 208]. Multiple price zones with limited exchange capacities would lead to regional differences in the wholesale electricity price, incentivizing production in regions where there is a lack of generation instead of regions with a surplus of available energy. As a result, in theory less electricity needs to be transported from generation centers to load centers, reducing the likelihood of grid congestion. In this case study, the configurations of three and five price zones in Germany and the impacts on market results and grid operation are analyzed.

5.3.1.1 Methodology

One of the biggest challenges in developing different market zone configurations is determining the geographical extent or location of the individual zones while ensuring a robust configuration over multiple years or decades, since repeated reconfiguration is not feasible in practice. In this study, the zones are not defined by geographical boundaries but by mapping the nodes of the transmission network data set to the price zones. The mapping is determined using a modified k-means clustering algorithm, which was developed as part of a bachelor's thesis at KIT [209]. A detailed description of the clustering algorithm can be found in Section A.6.1.

The objective of the algorithm is to define price zones that are stable over time and have low intra-zonal congestion. Stability refers to a consistent zonal configuration across all hours of the considered years, which is, in this case, the time span from 2030 to 2050. A start date in the future is chosen because such a regulatory measure would require a considerable amount of time to implement. Low intra-zonal congestion is achieved by grouping nodes with similar LMPs, as large differences in LMPs usually indicate underlying transmission constraints. The LMP values are determined by previous OPF calculations for the German transmission network for the years 2030, 2035, 2040, 2045, and 2050. Each node is described by a multi-dimensional LMP time series vector, and the clustering algorithm partitions nodes into k zones by minimizing the within-cluster LMP variance, while enforcing a geographic constraint to ensure spatially compact bidding zones. In this case study, configurations with three and five price zones are analyzed.

The resulting clusters for the configurations with three and five price zones are shown in Fig. 5.21. In the three-zone configuration, cluster DE1 is located in the northern and eastern part of Germany, cluster DE2 includes the south, and cluster DE3 covers the western part of Germany. In the configuration with five price zones, cluster DE1 covers only the north-eastern and eastern part of Germany, while cluster DE3 from the three-zone configuration is divided into clusters DE3 and DE5. In this configuration, DE3 covers north-western and northern Germany, and DE5 covers North Rhine–Westphalia and Hesse in the west. Cluster DE2 in the south is split into cluster DE2, covering Bavaria, and cluster DE4, covering the regions of Baden–Württemberg, Rhineland-Palatinate, Saarland, and Luxembourg.

After determining the clusters, thermal power plants, storage systems, RES generation, and demand are allocated to the price zones based on their locations. For the market simulation, NTC constraints for the exchange flows between the newly created German price zones are estimated based on the transmission lines connecting the zones and also the NTCs between Germany and its neighboring countries have to be allocated to the new market areas. The initial NTC values are based on the TYNDP 2022 [169], and the resulting NTC values involving the German market zones are shown in the Appendix in Tables A.19 and A.20. Afterwards, the market simulations

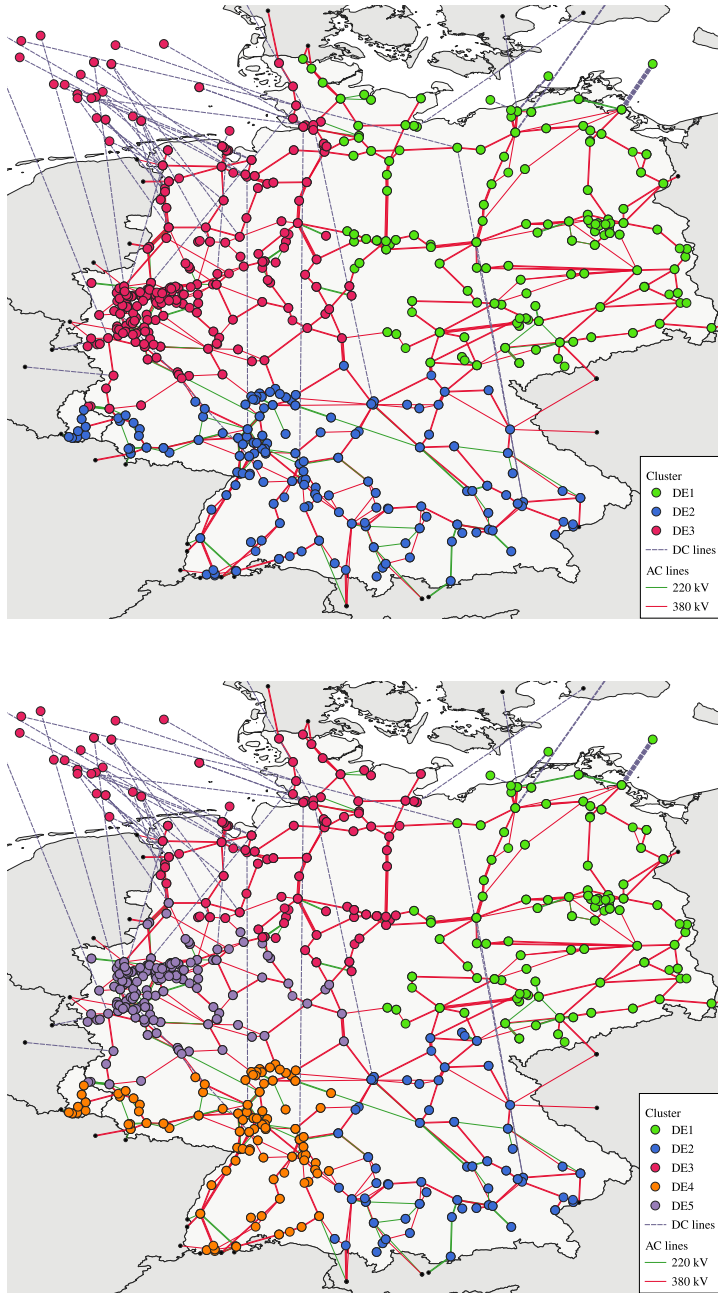


Figure 5.21: Resulting node clusters when dividing Germany into three (top) or five (bottom) price zones.

are run using PowerACE. The simulation horizon spans from 2025 to 2050, starting with the joint DE-LU bidding zone. The separation into distinct bidding zones is introduced in 2030. The day-ahead simulation is conducted on an hourly basis for each year within the time horizon, with investment decisions allowed after each simulation year. The results concerning the day-ahead market² as well as investment decisions for new power plants and storages serve as input for the grid simulations to determine the necessary redispatch volumes and costs. Redispatch calculations are performed for the years 2030, 2040, and 2050. The main results of the market and grid simulations are presented in the following section.

5.3.1.2 Results

First, the market outcomes are examined. The annual electricity generation results per energy carrier for Germany (aggregated over all German price zones) for the different price zone configurations and the years 2030, 2040 and 2050 are shown in Table 5.2.

Table 5.2: Annual, aggregated generation and load results for Germany for different market zone configurations broken down by energy carriers.

Year	Scenario	Generation [TWh]							Load [TWh]			
		Hard coal	Lignite	Oil	Gas	Waste	Storages	RES	Imports	Storages	Exports	Demand
2030	1 Zone	15	23	-	45	12	19	456	129	24	77	597
	3 Zones	15	30	-	39	12	18	436	139	28	59	602
	5 Zones	15	30	-	41	11	18	431	139	27	55	602
2040	1 Zone	-	-	-	22	1	21	663	103	31	105	673
	3 Zones	-	-	-	24	1	27	638	110	37	84	679
	5 Zones	-	-	-	27	1	28	625	112	36	78	679
2050	1 Zone	-	-	-	22	1	38	747	91	57	113	730
	3 Zones	-	-	-	28	2	48	720	97	71	91	734
	5 Zones	-	-	-	32	2	41	700	101	58	84	734

The results show less RES generation when more price zones are introduced, which is no surprise given the additional transmission constraints for the exchange between German price zones. The reduced generation from RES in the three- and five-zone configurations is compensated for by a higher generation from thermal power plants (mainly gas), increased imports from other European countries and less exports. Furthermore, an increased usage of storages in Germany can be observed.

² RES generation per market zone, unit specific thermal power plant and storage dispatch, wholesale electricity prices and exchange flows

The higher dependence on conventional energy carriers and imports generally leads to higher wholesale electricity prices, as shown in Fig. 5.22. The huge price spike from 2040 to 2041 is caused by a forced transition from natural gas to hydrogen as fuel for all gas fired power plants (the assumed fuel prices are shown in Table A.21 in the Appendix). The transition is only modeled by a change in fuel price and not a change in energy carriers, this is why it is not seen in the generation values but in the prices.

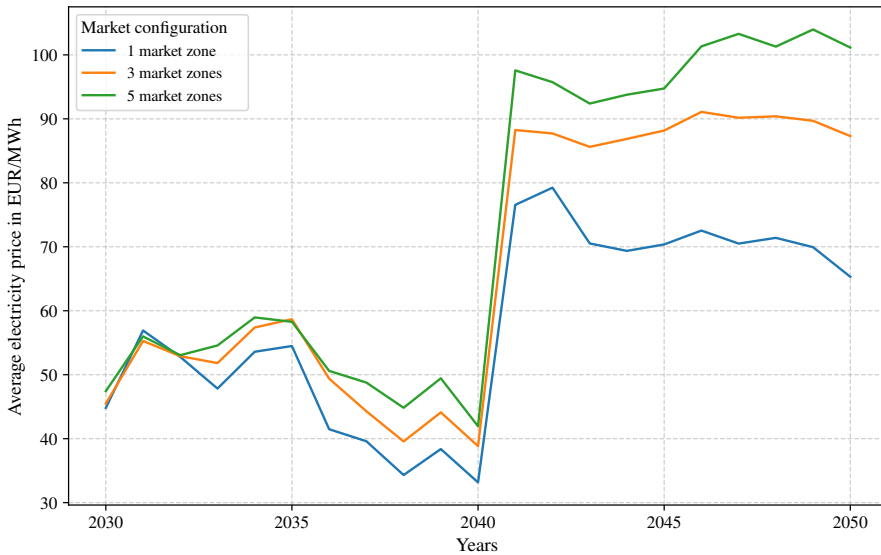


Figure 5.22: Average yearly prices (average over all German market zones) for the analyzed market zone configurations.

Although the market results are not favorable for the market split configurations, the results of the redispatch calculations show a different picture. The necessary redispatch volumes are depicted in Fig. 5.23 and the corresponding costs in Fig. 5.24. The assumed positive effects of the market zone split are visible in both volumes and costs. In 2030, redispatch costs drop by two thirds from 3100 M EUR to 946 M EUR in the configuration with three market zones and 759 M EUR for five market zones. For 2040 and 2050, the reduction in costs is not quite as high, but with a nearly 60 % cost reduction in 2040 and an approximately 40 % to 50 % cost reduction in 2050 still very considerable. The cost reduction mainly results from reduced RES curtailment and thus a reduced need for generation from gas fired power plants in return. Additionally, load shedding can be mitigated by approximately 50 %.

It is also notable that the redispatch costs for the configurations with three and five price zones are fairly similar for 2030 and 2040, while in 2050 the redispatch costs (including forced load

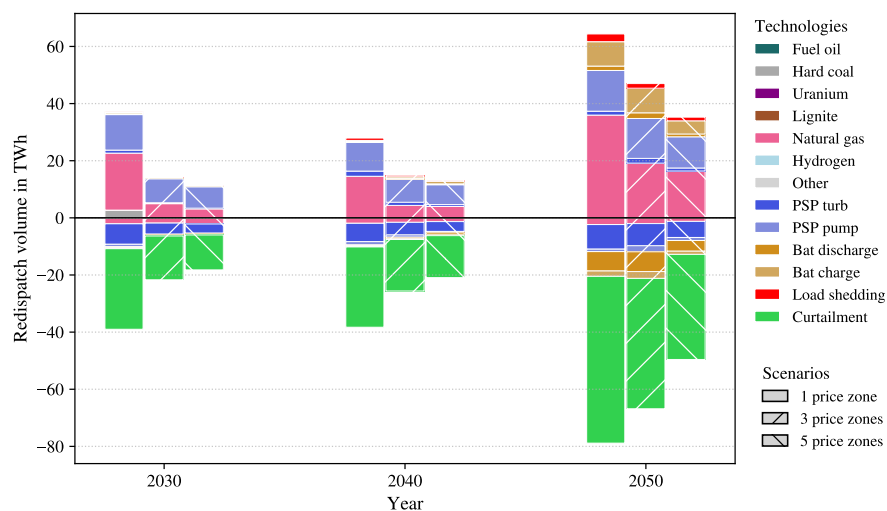


Figure 5.23: Resulting redispatch volumes for the years 2030, 2040 and 2050 for the three different market zone configurations in Germany.

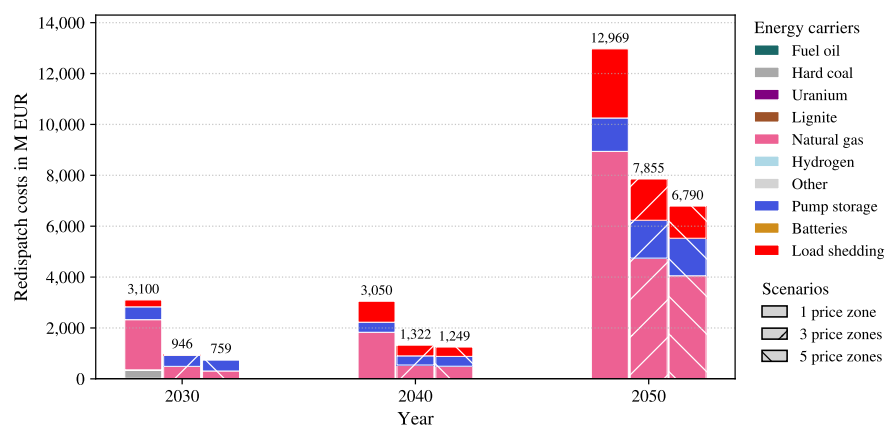


Figure 5.24: Resulting redispatch costs for the years 2030, 2040 and 2050 for the three different market zone configurations in Germany.

shedding) for the five-zone configuration are 13.5 % lower than for the three-zone configuration. The wholesale electricity market prices are noticeably higher for five price zones than for three price zones. From an economic perspective, the three zone configuration therefore seems to be more favorable. The results also show that configurations with multiple price zones have complex economic impacts. While costs for redispatch might decrease, wholesale electricity prices and general generation costs might rise. Therefore, it is not possible to make a general statement about which configuration brings the most benefit. Additionally, the results in this case study are highly dependent on the assumptions made about input data such as fuel prices, grid expansion, and the configuration of the bidding zones. Nevertheless, the results show that a split of the German market zone might have positive effects on economic welfare, but the design of the market zone configuration is crucial, and further research is needed to explore these impacts in more detail.

5.3.1.3 Discussion

The comparison with existing studies reveals both consistencies and notable differences. The ENTSO-E Bidding Zone Review [3] investigates the year 2025 and reports average electricity-price differences between zones of 4 EUR/MWh to 8 EUR/MWh. Their analysis predicts a 50 % reduction in redispatch costs when the market is divided from a single to two zones, yet no further significant savings for three, four, or five zones. For the German split into two, three or four market zones, the study estimates annual redispatch savings of roughly 600 M EUR in 2025. In contrast, the results of Knörr et al. [124] indicate that the total cost savings, including redispatch expenses, remain small for any zonal split between two and five zones also focusing on 2025. Although both works analyse the same target year and employ comparable zone configurations, the magnitude of the reported savings differs markedly. Fraunholz et al. [122] demonstrate that congestion volumes shrink considerably after a market split in the short term, but that the optimal zonal arrangement identified for 2020 quickly becomes outdated due to dynamic factors such as grid reinforcement, renewable energy expansion, and new power-plant investments. Glynos et al. [208] arrive at a different conclusion: while market splits may alleviate congestion over longer horizons, short- to medium-term results often indicate persistent or even increased congestion levels. Their analysis considers different two-zone configurations for each target year, which, however, differ substantially from the configurations derived in this thesis. In the results of Zinke [210] redispatch costs reduced can be reduced by 50 % to 70 %, resulting in cost savings of over 2 bn EUR in 2025 and even 4 bn EUR in 2030.

Overall, the results of the present thesis point to larger potential savings in redispatch costs than those reported in the literature, yet they follow the same qualitative and quantitative trend as the Bidding Zone Review [3] and Zinke [210]. Direct comparison is, however, often limited by the differing reference years, scenario assumptions, and methodological choices across studies.

The zone layout and the assumptions for the resulting exchange capacities also have substantial influence on the results. In this thesis, the exchange capacities are calculated rather conservatively, which should lead to less redispatch needs compared to higher exchange capacities. Moreover, the spatial allocation of market-based curtailment has an influence on congestion and, consequently, redispatch costs, as well. Scenario inputs such as RES capacities, demand development, and fuel-price trajectories also exert a considerable influence on the outcomes.

Besides limitations arising from scenario assumptions regarding renewable energy generation, demand development, and fuel prices, further limitations of the case study stem from modeling simplifications. Redispatch operations involving battery storage are represented without any associated costs, and the redispatch model does not account for unit-commitment constraints such as start-up costs, minimum up- and downtimes, or ramping limits, which may lead to an overly flexible representation of conventional generation. Furthermore, the market simulation does not incorporate flow-based market coupling to determine exchange flow capacities. In addition, demand-side flexibility is not covered in the market as well as the redispatch model, which could overstate redispatch requirements and costs.

5.3.2 Introducing dynamic grid fees

In this case study, the effects of dynamic, spatio-temporal grid fees on the market and grid operation shall be analyzed. The grid fees are designed in such a way that they take potential congestions into account and thus create incentives that should lead to a market outcome that is more compatible with the physical limitations of the transmission grid, thereby reducing redispatch costs. For this purpose, the OPF model presented in this thesis is again coupled with the market simulation model PowerACE. The methodology and results of the approach are discussed in the following sections.

5.3.2.1 Methodology

Methodologically, the approach begins with solving an OPF dispatch to obtain locational marginal prices at each network node for each simulated time step. This calculation is embedded in the PowerACE workflow and executed daily for the next 24 hours before the PowerACE day-ahead simulation. The LMPs are converted to a nodal grid fee component, which captures both congestion-related and loss-related cost signals. The resulting grid fees, varying across both time and location, are then assigned to individual generation units based on their location and integrated into their variable generation costs within PowerACE. Market agents rely on these adjusted variable costs when generating their daily bids in the wholesale electricity market. After

market clearing in PowerACE, the resulting dispatch is transferred back into the OPF model, which performs another grid simulation based on the dispatch to determine necessary redispatch measures. An overview of the methodology is given in Fig. 5.25.

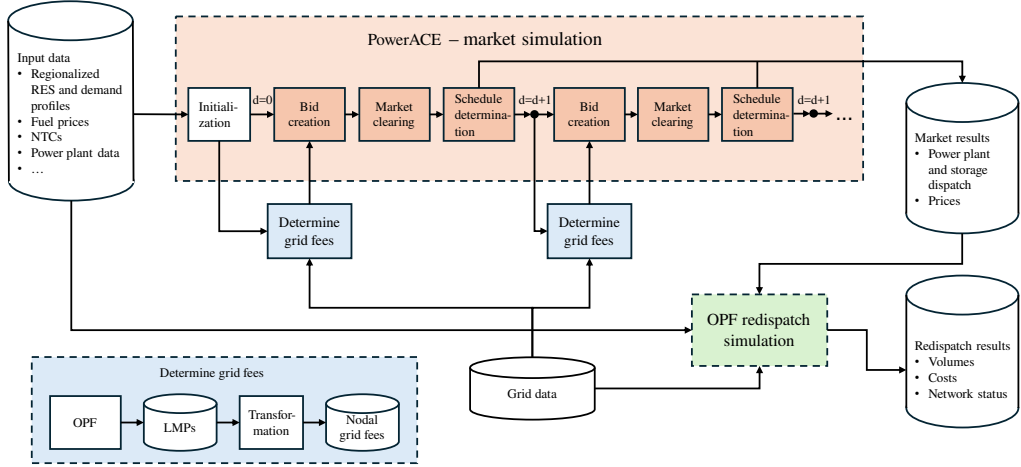


Figure 5.25: Overview of the methodology for the integration of dynamic grid fees.

To determine the dynamic grid fees from the LMPs, a median based approach is used. For each time step t of the upcoming 24 hours, the median $\tilde{p}_t$ of all LMPs is calculated.

$$\tilde{p}_t = \text{median}_{i \in I} \{p_{i,t}^{\text{LMP}}\} \quad (5.1)$$

Low LMPs are typically a sign of a surplus of available energy generation, whereas high LMPs are a sign of a lack of available energy, both caused by grid constraints. Therefore, for nodes with a low LMP an incentive to reduce generation (or increase demand) and for nodes with a high LMP an incentive to increase generation (or reduce demand) should be set. This is realized by introducing grid fees with opposite signs $m_{i,t}$. Since in this study only grid fees for generators are considered and consumers are neglected, grid fees for nodes with an LMP lower than the median generally have a positive sign and grid fees for nodes with an LMP higher than the median have a negative one. By introducing a parameter τ that defines what quantile of nodes should be assigned a grid fee, nodes with LMPs near the median may be excluded.

$$p_t^{\text{low}} = Q_\tau(p_{i,t}^{\text{LMP}}), \quad p_t^{\text{high}} = Q_{1-\tau}(p_{i,t}^{\text{LMP}}), \quad m_{i,t} = \begin{cases} +1, & p_{i,t}^{\text{LMP}} \leq p_t^{\text{low}} \\ -1, & p_{i,t}^{\text{LMP}} \geq p_t^{\text{high}} \\ 0, & \text{otherwise} \end{cases} \quad (5.2)$$

Further, the nodes are ordered by their LMPs and the amplitude of their grid fee $s_{i,t}$ is determined based on their rank in the order, with the LMPs farther from the median translating to the higher grid fees (in the negative or positive direction), while the LMPs close to the median imply only small surcharges or even no grid fees at all. The levels of the grid fees are graded into $2 \cdot n$ discrete steps (n steps for positive and negative values each) based on the quantiles $Q_{k,t}^+$ (if the LMP is lower than the threshold p_t^{high}) and $Q_{k,t}^-$ (if the LMP is higher than the threshold p_t^{low}) in which the LMP of the respective network node is located and a maximum grid fee value S_{max} . Mathematically, the quantiles are defined as follows:

$$Q_{k,t}^+ = Q_{\frac{k}{n}}(\{p_{i,t}^{\text{LMP}} \mid m_{i,t} = +1\}), \quad k = 0, \dots, n \quad (5.3a)$$

$$Q_{k,t}^- = Q_{\frac{k}{n}}(\{p_{i,t}^{\text{LMP}} \mid m_{i,t} = -1\}), \quad k = 0, \dots, n \quad (5.3b)$$

The grid fee is determined on the basis of the quantile and the median:

$$s_{i,t} = \begin{cases} A_{k_{i,t}^+}, & p_{i,t}^{\text{LMP}} \leq p_t^{\text{low}} \text{ and } Q_{k_{i,t}^+-1,t}^+ < p_{i,t}^{\text{LMP}} \leq Q_{k_{i,t}^+,t}^+, \\ -A_{k_{i,t}^-}, & p_{i,t}^{\text{LMP}} \geq p_t^{\text{high}} \text{ and } Q_{k_{i,t}^--1,t}^- < p_{i,t}^{\text{LMP}} \leq Q_{k_{i,t}^-,t}^-, \\ 0, & p_t^{\text{low}} < p_{i,t}^{\text{LMP}} < p_t^{\text{high}}. \end{cases} \quad (5.4)$$

with the price levels:

$$A_k = S_{\text{max}} \left(1 - \frac{k}{n}\right), \quad k = 0, \dots, n-1. \quad (5.5)$$

The simulation is carried out for a scenario based on the year 2025 with different configurations of τ and S_{max} . The spatial scope of the market simulation is Germany and its geographical neighbors³, and the redispatch simulation is run for Germany with fixed exchange flows to the other countries from the market simulation. NTC values, fuel and carbon prices are based on TYNDP 2024 [162, 196]. For RES generation, demand, thermal power plants and pumped storage plants, the same input data as in the previous sections are used (see Chapter 4 for details). The data for battery storages is based on the European Energy Storage Inventory published by JRC [211]. In addition to the thermal power plants that participate in the electricity market, grid

³ DE, AT, BE, CH, CZ, DK, FR, LU, NL, PL

reserve power plants are added as an additional generation option only for Germany and only for the redispatch calculation. The power plant data for the grid reserve is taken from data published by the German Federal Network Agency [212]. The operating costs for grid reserve power plants are set to 1000 EUR/MWh, to ensure that these plants are only used if the generation of other sources is not sufficient. As a last option for the redispatch model, load shedding is enabled at a cost of 10 000 EUR/MWh.

5.3.2.2 Results

First, we take a look at the results of the market simulation with different configurations regarding the dynamic grid fees. In addition to a reference case without any grid fees, configurations with $\tau \in \{0.1, 0.5\}$ ⁴ and $S_{\max} \in \{1.0, 5.0\}$ are tested. The resulting wholesale electricity market prices for Germany are shown in Fig. 5.26.

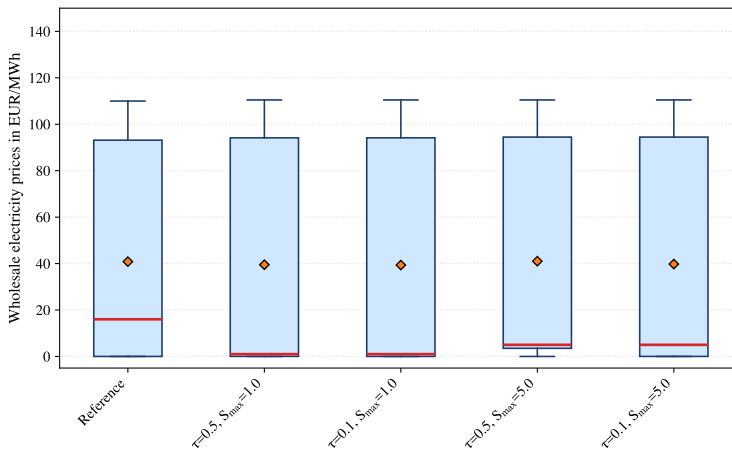


Figure 5.26: Wholesale electricity prices resulting from the market simulation for the different dynamic grid fee configurations.

The price distribution is generally very similar across all configurations. The median (red line) is the highest for the reference case with 16 EUR/MWh, for the configurations with $S_{\max} = 1.0$ and $S_{\max} = 5.0$ it is at 1 EUR/MWh and 5 EUR/MWh, respectively. Although the difference appears substantial at first glance, closer inspection shows that all configurations share a very

⁴ $\tau = 0.5$ means that 50 % of nodes are assigned a positive network fee and 50 % are assigned a negative one, so all nodes are affected. For $\tau = 0.1$, only the 10 % of nodes with the highest and lowest LMPs are assigned a fee, so a total of 20 % of network nodes is affected.

similar overall price distribution, including the characteristic step around the median. What changes between the configurations is not the shape of the distribution, but the exact ordering of a few values around the midpoint. Since the median is defined as the middle element of the ordered price series, even small shifts in the rank of individual prices can cause the numerical median to move, despite the underlying distributions remaining nearly identical. The average (yellow diamond) is around 40 EUR/MWh for all configurations with variations in the area of ± 1 EUR. Therefore, in terms of market prices, no major effects or drawbacks are observed.

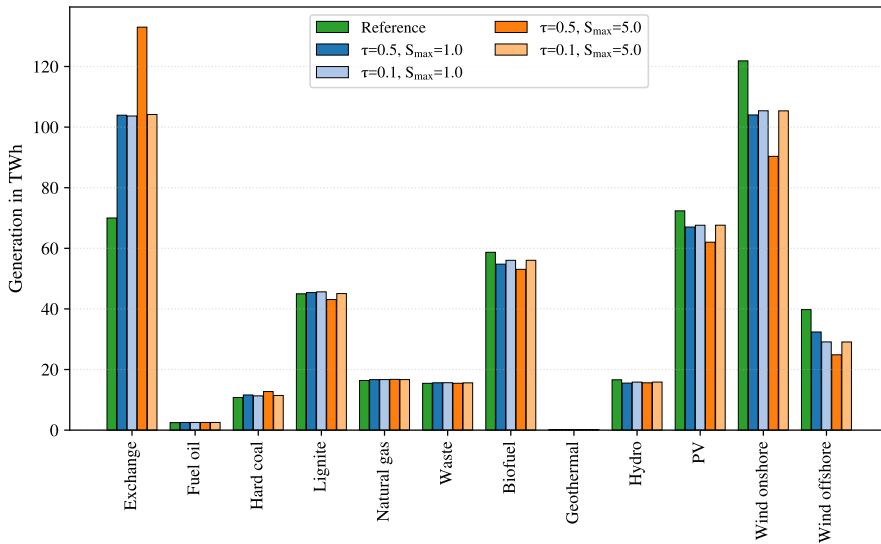


Figure 5.27: Annual generation values per energy carrier resulting from the market simulation for the different dynamic grid fee configurations.

In Fig. 5.27 the resulting annual generation values per energy carrier are presented. Here, greater differences can be observed. Compared to the reference case, all dynamic grid fee configurations lead to lower generation from RES, especially wind onshore and wind offshore, which is compensated by substantially higher net imports. The highest net imports result for the $\tau = 0.5, S_{\max} = 0.5$ configuration with 133 TWh compared to 70 TWh in the reference case. This shift can be explained by the bidding behavior of RES plant operators in PowerACE: RES operators make their supply bids with marginal costs, which are usually zero. When positive grid fees are applied, the marginal costs increase, and so do the prices for the bids, reversely for negative grid fees. Because the methodology assigns positive tariffs to roughly half of the nodes and negative tariffs to the other half, and since grid fees apply only to Germany, the market clearing algorithm first accepts all negative bids from German agents. After that, it becomes

more cost-effective to import RES generation from abroad at zero cost than to procure RES from German operators whose bids reflect positive grid fees. Extending the approach to other European countries could mitigate this effect.

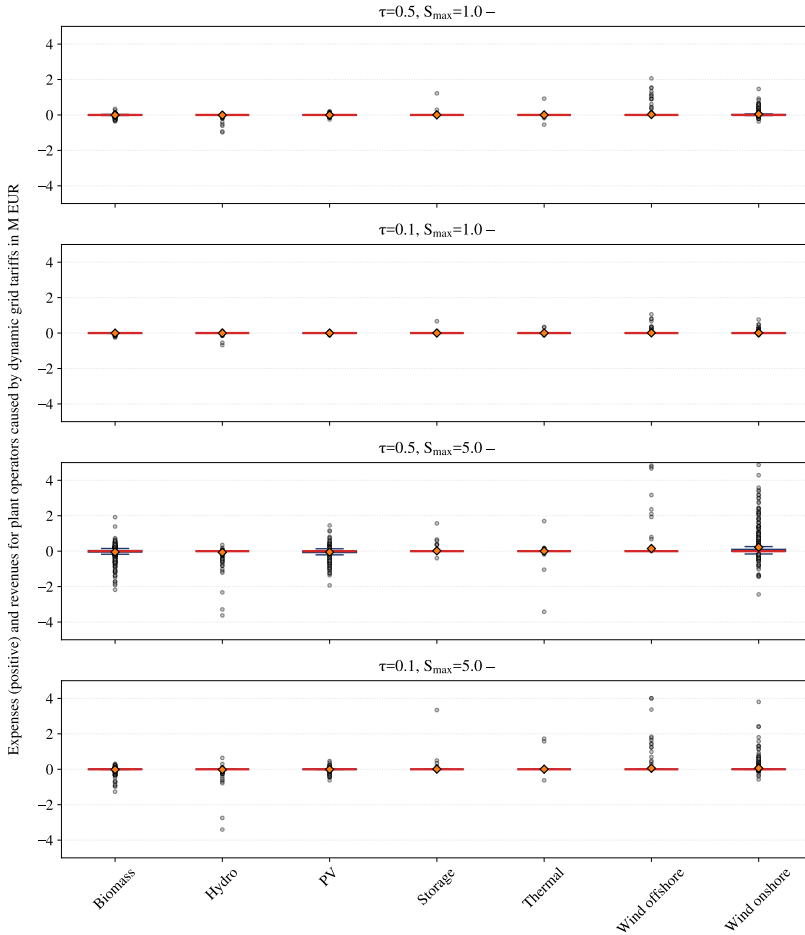


Figure 5.28: Distribution of costs (positive values) and revenues (negative values) for plant operators caused by the different dynamic grid fee configurations.

In addition to general market implications, the effects on single plant operators are of interest. In Fig. 5.28 the annual expenses or revenues for each network node caused by the grid fees are depicted. It is evident that there are winners and losers, but overall the additional revenues and costs are relatively balanced, as can be seen from the aggregated values shown in Fig. 5.29. In general, wind onshore and wind offshore plant operators are more affected by additional costs, while

operators of biomass, hydro, and PV plants can even achieve net gains in some configurations. In the $\tau = 0.1, S_{\max} = 1.0$ configuration the net sum of additional expenses and revenues is very small with just 9 MEUR and the distribution is also close to zero for most network nodes, which means that the goal of a cost-neutral regulation is achieved fairly well. In contrast, the configuration $\tau = 0.5, S_{\max} = 5.0$ implies additional net costs of more than 100 MEUR for plant operators, and also the distribution between network nodes and technologies is very heterogeneous.

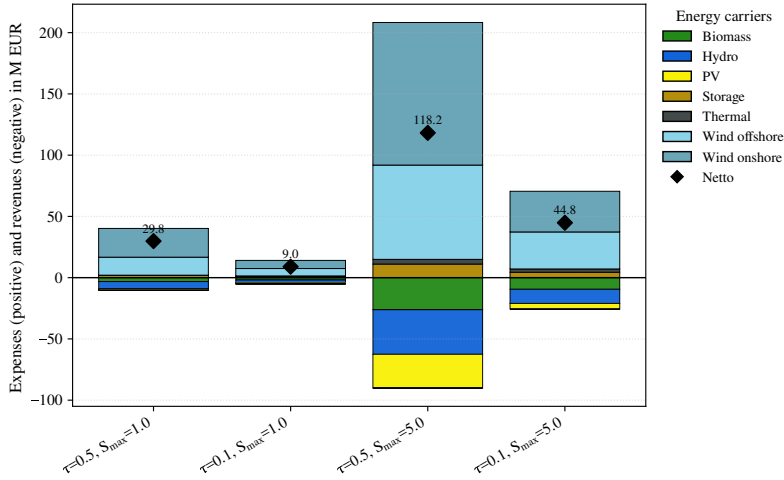


Figure 5.29: Aggregated costs (positive values) and revenues (negative values) for plant operators caused by the different dynamic grid fee configurations.

Lastly, the effects on the redispatch requirements are evaluated. The volumes resulting from the redispatch calculations after the market simulations with the different dynamic grid fee configurations are shown in Fig. 5.30 and the corresponding costs in Fig. 5.31. We see a massive decline in both redispatch volumes and costs, which is mainly caused by reduced RES curtailment⁵. Interestingly, the resulting costs are fairly even for all configurations with around 700 MEUR to 800 MEUR, which equals a cost reduction of around 40 % compared to the reference case. The lowest costs are achieved for the $\tau = 0.5, S_{\max} = 5.0$ configuration and the highest, except for the reference case, for the $\tau = 0.1, S_{\max} = 5.0$ configuration. An overview of the distribution of the redispatch measures for the reference case and the $\tau = 0.1, S_{\max} = 1.0$ configuration is given in Fig. 5.32.

⁵ Wind (onshore and offshore) is affected the most with a reduction in curtailment of around 50%.

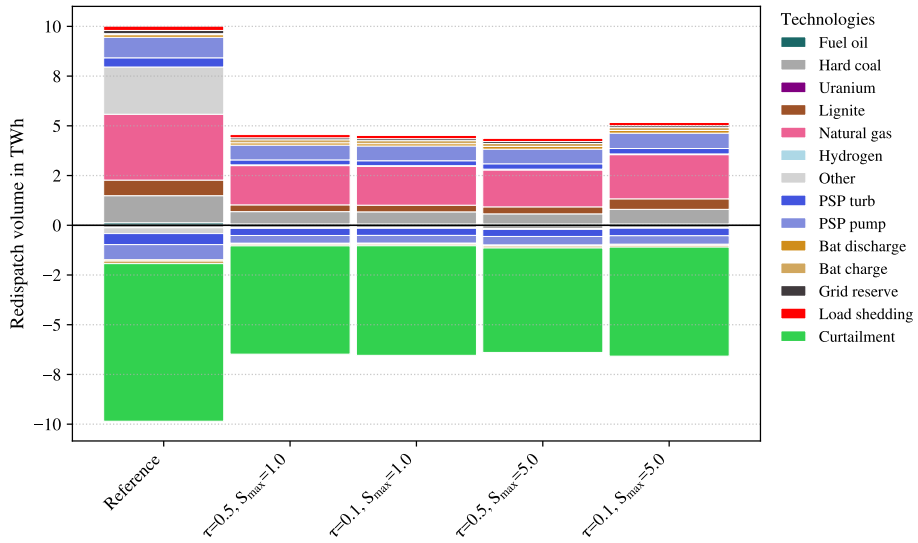


Figure 5.30: Results for the annual redispatch volumes for the different dynamic grid fees configurations.

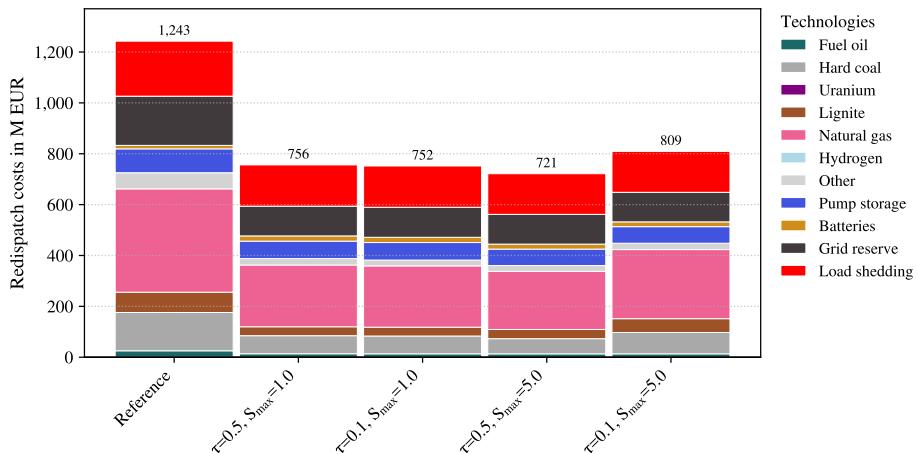


Figure 5.31: Results for the annual redispatch costs for the different dynamic grid fees configurations.

Combining the results of the market and the redispatch simulation, it seems that with the $\tau = 0.1, S_{\max} = 1.0$ configuration remarkable cost savings can be obtained with regard to the redispatch requirements with only minimal effects on the market result (apart from increased imports). Although a higher amplitude (high $S_{\max}$) and a broader application (high τ) of the tariff can deliver slightly larger cost reductions for the redispatch, such configurations also exert a stronger influence on the market and on individual market participants. Therefore, a balanced and rather cautious design appears to be most appropriate following the results of this case study.

5.3.2.3 Discussion

Overall, dynamic grid fees with both temporal and locational differentiation show a tangible potential to reduce redispatch volumes even at relatively moderate tariff levels. The primary mechanism underlying this effect is a reduction in grid-related curtailment, combined with a partial reallocation of curtailment decisions from grid-driven interventions toward market-based responses. In the simulated scenarios, the impact of such tariffs on wholesale electricity prices remains limited overall. Nevertheless, the resulting cost burden for individual generators may become non-negligible if grid fees are set at high levels, particularly for assets frequently exposed to congestion.

Across all scenarios, simulated electricity prices are generally lower than observed historical levels. Several factors may contribute to this outcome, including a potential overestimation of renewable energy generation in the scenario data, comparatively lower fuel price assumptions, and the neglect of power-plant unavailabilities due to outages or maintenance. In addition, the market model assumes that thermal power plant operators bid the must-run capacities of their units at zero marginal cost, which further depresses price levels. These modeling choices tend to increase price-setting occurrences of renewable energy sources and may therefore influence both price formation and dispatch outcomes.

The simulations further indicate an increase in net electricity imports under dynamic grid-fee regimes. This effect can be attributed to the fact that in the case study dynamic grid fees are implemented only within the German market, while neighboring market areas remain unaffected by such locational price signals. As a result, relative price distortions arise at the borders, incentivizing additional imports into Germany. This finding suggests that uncoordinated national implementation of dynamic grid fees may lead to cross-border distortions, underscoring the need for harmonized, or at least well-aligned, European regulatory frameworks when introducing locational pricing elements.

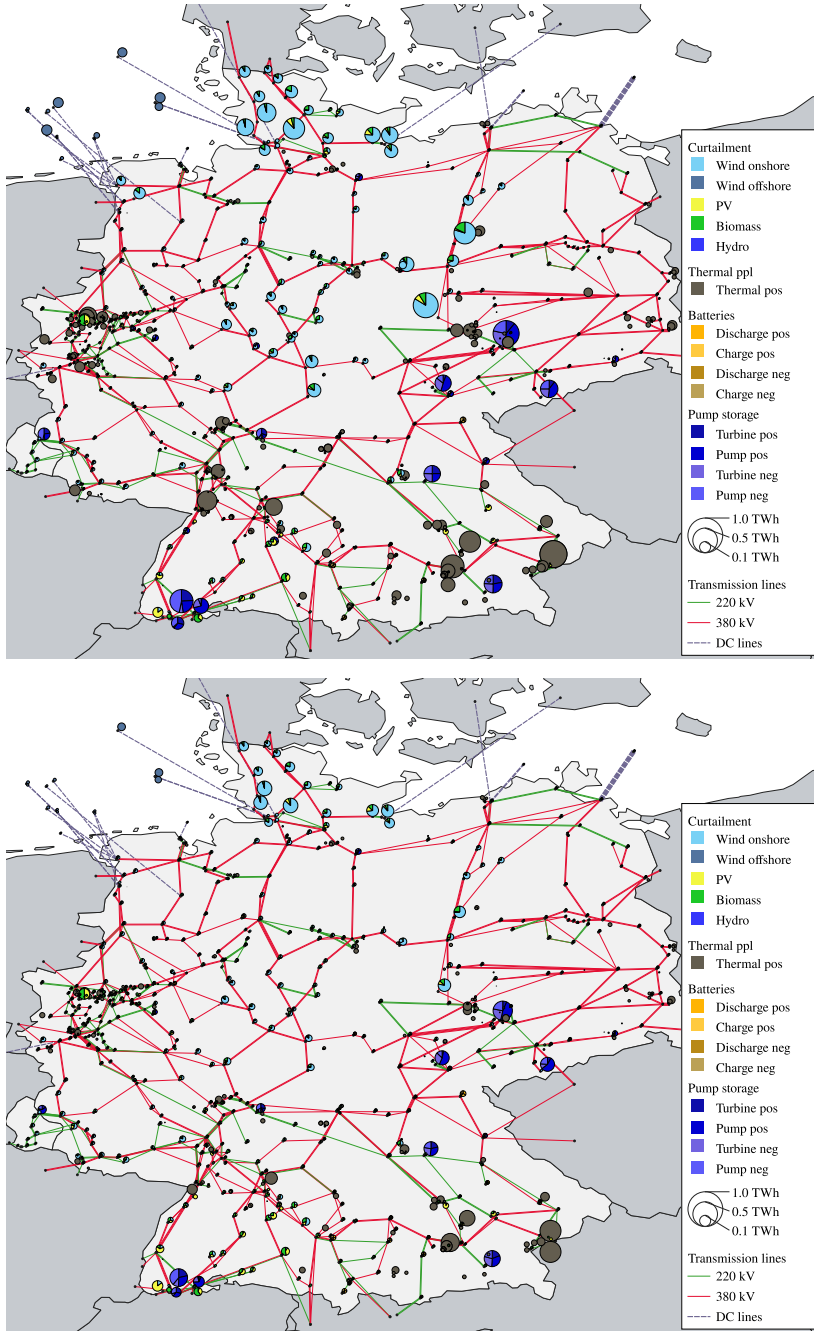


Figure 5.32: Comparison of the results for redispatch volumes and distribution for the reference case (top) and the $\tau = 0.1, S_{\max} = 1.0$ configuration (bottom).

Finally, the effectiveness of dynamic grid fees in reducing grid-related curtailment is particularly pronounced in system states where renewable energy sources are price-setting. As renewable capacities are expected to grow substantially in future years, this condition is likely to become increasingly prevalent, thereby strengthening the relevance of dynamic grid fees as a congestion-mitigation instrument.

6 Conclusion

6.1 Summary

In this thesis, an OPF model suitable for large-scale simulations of power systems with a focus on the transmission grid has been developed. Its purpose is to calculate the optimal operating state of the system under consideration of network and other system constraints. The model is based on an AC power flow formulation and inherits detailed component models of standard components as well as flexible network elements such as FACTS. Further specifications are the consideration of dynamics for storage systems with different time coupling methodologies, the consideration of exchange flows to systems outside of the core modeling region, detailed operating cost models and the ability to be either used to calculate the optimal dispatch or to calculate optimal redispatch measures based on a prior market simulation. Consequently, interfaces have been developed to couple the model to external market models such as PowerACE.

The developed model is first applied to standard test cases to verify and evaluate the modeling approach. The results demonstrate the functionality of the model and its components and show the potential of flexible grid elements in alleviating grid congestions, and thus reduce the costs for system operation.

Afterwards, several case studies are conducted in which the model is applied to large-scale real-world systems. The first case study begins with an examination of system operation and related costs within the European context in the years 2030, 2040, and 2050, followed by a detailed assessment of future redispatch requirements in Germany. In this framework, the potential benefits of FACTS for system operation are evaluated, using the SSSC as an example. The results indicate that redispatch requirements will increase drastically compared to current levels, and that FACTS devices can contribute substantially to mitigating the associated costs. In this case study, the installation of 40 SSSCs can help reduce redispatch costs by approximately 30 %. The second case study investigates the impact of market-based instruments designed to better internalize grid constraints in market outcomes, illustrated by a bidding-zone split and the introduction of temporally and spatially differentiated network tariffs in Germany. While the results again indicate substantial potential for reducing redispatch costs, the impacts on market outcomes are

non-negligible and must be carefully taken into account when designing and implementing such regulatory instruments.

6.2 Discussion and outlook

Model-level contributions

This work presents a highly customizable AC Optimal Power Flow (AC-OPF) framework that is demonstrably applicable to large-scale, real-world power system studies. The model integrates detailed device-level representations for Flexible AC Transmission Systems (FACTS) and phase-shifting transformers (PSTs), enabling a systematic assessment of advanced power-flow control options in operational settings. Beyond feasibility analyses, the framework supports both optimal dispatch and optimal redispatch formulations contingent on prior market-clearing results, thereby providing an explicit link between market outcomes and network feasibility. This coupling is essential for quantifying the cost and location of corrective actions implied by unconstrained market schedules. To facilitate experimentation across a range of planning and operational questions, the framework includes a simplified market representation as well as a heuristic for expansion planning. The resulting tool chain allows users to explore sensitivities with respect to renewable capacity pathways, interconnector build-out, controllability options, and storage portfolios while considering network assumptions. The architecture is deliberately modular so that additional component models and extensions can be easily integrated, extending the framework's utility for future case studies and methodological refinements.

System-level insights from the case studies

Regarding the results for the market and grid simulation of the European¹ power system, the case studies indicate that security of supply risks may materialize, particularly during Dunkelflauten (extended periods of low wind and solar availability). Under such conditions, residual load is elevated, and relying exclusively on variable renewables and storage may be insufficient. While battery energy storage systems reduce system operation costs through peak shaving and congestion relief, the results show that additional battery capacity cannot fully substitute for firm conventional resources, especially during prolonged scarcity events. This indicates that some combination of conventional capacity and/or demand flexibility may be necessary to avoid involuntary load shedding in the future.

¹ Germany and its electrical neighbors: AT, BE, CH, CZ, DE, DK, FR, LU, NL, NO, PL, SE, UK

Spatial patterns are equally consequential. A substantial share of electricity is expected to be generated by wind turbines in the regions along the North and Baltic Sea coasts, necessitating reliable transfer to inland load centers. Grid constraints are projected to intensify as renewable penetration rises. Cross-border exchange plays a pivotal role in mitigating scarcity, with indications that expanding interconnection capacity would be beneficial for both enhancing security of supply and reducing system costs. HVDC corridors are particularly valuable because they can be operated with greater controllability relative to AC lines and are less coupled to regional voltage conditions or congestion. Overall, further grid expansion appears warranted.

A comparison of the scenario assumptions used in this study with recent empirical data reveals both consistencies and notable deviations. For Germany, gross electricity production in 2025 amounted to approximately 508 TWh, with renewables accounting for about 58 % of total generation [213]. By contrast, the grid-fee scenario applied in this study assumes a slightly lower gross production of 485 TWh, combined with a higher renewable share of 65 %. While total generation therefore remains broadly comparable, the assumed degree of renewable penetration exceeds current levels. At the European level, the differences are more pronounced. The scenario underlying this study assumes gross electricity demand of 2555 TWh with a renewable share of 77 % for Germany and its electrical neighbors in 2030. In comparison, observed values for 2024 indicate gross electricity production of around 1984 TWh and a renewable share of approximately 59 % [214–217]. This implies an assumed increase in electricity demand of about 29 % from 2024 to 2030, a trend that has not been observed in recent years, where electricity demand in the EU has remained broadly stable or has even declined in certain periods and countries. Consequently, the demand assumptions in the applied scenario may be on the high side. In contrast, the assumed strong expansion of renewable generation capacities appears more consistent with recent developments. According to Eurostat data [214], the share of renewable electricity generation in the EU-27 increased from approximately 33 % in 2019 to around 48 % in 2025, indicating a rapid and sustained structural shift in the European electricity mix .

With respect to redispatch costs, the simulation results obtained in this thesis are broadly consistent with empirical values reported for redispatch measures involving conventional power plants [121]. This comparability arises from the fact that renewable energy curtailment is not monetized in the present analysis and that holding costs for reserve power plants are likewise excluded. In 2024, redispatch costs associated with conventional generation amounted to approximately 1.2 bn EUR (see Fig. 2.4), a value that closely aligns with the redispatch costs calculated for the 2025 reference case in this study (cf. Section 5.3.2). Within Germany, the results suggest that redispatch costs are likely to increase as renewable capacities and spatial imbalances grow. For 2030 and 2040, annual costs of around 4 bn EUR are predicted, disregarding costs for forced load shedding and grid reserve capacities. This number is about four times higher than the respective costs in 2024. For 2030, this goes in line with a report by the European Joint Research Centre from 2024 [218],

where the results predict an increase in redispatch volumes in Europe of the factor five from 2022 to 2030 and of factor ten from 2022 to 2040. The difference in 2040 could stem, on the one hand, from the fact that the redispatch costs in this study apply only to Germany, whereas the JRC study includes all European countries. On the other hand, this study explicitly considers planned expansion projects, some of which are scheduled for completion between 2030 and 2040, whereas the JRC study adopts an approach in which transmission capacities are increased by a flat factor.

Curtailment is concentrated in northern regions, primarily affecting onshore and offshore wind, reflecting both locational concentration of supply and downstream network bottlenecks. Existing HVDC north–south links alleviate congestion but are frequently operated near their capacity limits, implying that additional transfer capability would be beneficial. A comparison of the results from market simulations and subsequent redispatch optimization with optimal dispatch calculations that incorporate network constraints shows that internalizing grid constraints earlier in the decision chain can materially reduce total system costs. In particular, the allocation of RES curtailment is crucial for reducing the need for redispatch measures in power systems with a high share of spatially volatile renewable generation. Overall, this points toward a combination of grid reinforcement, targeted controllability, and market-design measures.

On the controllability side, FACTS devices show promising potential to steer power flows, reduce congestion, and lower redispatch volumes and costs. By integrating 40 Static Synchronous Series Compensators (SSSC) into the German transmission grid, in the case study, the redispatch costs could be reduced by 1081 M EUR which is equivalent to 29 % and forced load shedding even by 71 %, while investment expenses are modest with approximated 1025 M EUR. However, the cost savings are not linear to the number of devices added and the positive effect seems to diminish with higher number of installed devices. From a transmission planning perspective, these results carry two important implications. First, SSSCs seem to represent a highly cost-effective alternative or complement to conventional grid expansion, particularly for alleviating structural congestion in the short to medium term. Second, the allocation of such devices cannot be derived solely from static congestion indicators. The fact that reinforcing the most congested lines does not always maximize economic benefits highlights the importance of system-wide interactions and shifting power-flow patterns, which may alter congestion dynamics once initial interventions are implemented.

While the calculated cost savings from the deployment of additional FACTS devices or new transmission lines appear large relative to the required investment expenditures, these results should be interpreted with caution. The modeling framework abstracts from several remedial actions that are already available to transmission system operators in current practice, such as transmission switching and the operation of existing FACTS devices or phase-shifting transformers. Neglecting these measures may lead to an overestimation of baseline redispatch costs and, consequently, to an

overstatement of the absolute savings potential associated with the considered expansion options. In addition, a significant portion of the computed cost reductions is attributable to decreases in forced load shedding costs. In future energy systems, however, the share of flexible demand is expected to increase, and a broader set of demand-side management options will likely be available. Since demand-side flexibility beyond forced load shedding is not explicitly represented in the model, load curtailment is captured in a highly stylized manner, which may result in an overestimation of the associated costs compared to real-world system operation.

From a market-design perspective, two different approaches are tested within the case study. A bidding-zone split can reduce redispatch by aligning locational price signals with network scarcities. The results show that a significant reduction of redispatch costs is possible, which is, however, accompanied by higher wholesale prices, warranting careful welfare assessment. In addition, as a permanent reconfiguration of price zones is not feasible in practice, robust market zones must be defined over long time horizons, which is challenging regarding the uncertainties connected to influencing factors like RES capacity expansion, demand projection or fuel prices. Dynamic (temporal and locational) grid fees also exhibit potential to reduce redispatch costs, even at modest levels, primarily by reducing grid-related curtailment and reallocating part of curtailment to market-driven responses. Price effects appear limited in the tested settings, yet cost impacts on individual plant operators could be non-negligible if tariff levels are set too high. The simulations, which introduced dynamic grid fees only for Germany, further indicate higher net imports under such tariffs and the given modeling assumptions, suggesting that coordinated European regulation may be required to avoid cross-border distortions. Importantly, the effectiveness of dynamic grid fees in reducing grid-related curtailment is greatest when RES are price-setting, a condition expected to become more prevalent in future years as renewable capacities are expected to increase.

Limitations

Concerning the OPF model, several limitations have to be mentioned. First of all, demand-side management (DSM) is not represented in detail in the model, although it probably will play a substantial role in future power systems. Extending the model with a richer DSM formulation incorporating flexibility potential and related costs is an important aspect to be addressed in future work. Furthermore, N-1 security is not explicitly modeled. Instead, a 70 % transfer capacity approximation is employed as a tractable proxy, which might lead to under- or overestimating transmission capacities. Although explicitly modeling N-1 constraints is computationally costly, it may be worth expanding the model with this option if only to be able to model shorter extreme periods with precision. Another complex and computationally challenging model expansion would be the integration of transmission line switching, which would bring binary variables with it. In the grid model used in this thesis, each substation inherits only one busbar for each voltage level, and all transmission lines with the same voltage level located at that substation are connected

to the same busbar. In reality, there are several busbars for each voltage level at a substation and the TSO has multiple options on how to connect them to each other, resulting in changes in the grid topology. This possibility is not implemented in the model presented in this thesis. Furthermore, the siting of new gas/hydrogen plants and battery storages follows a naïve brownfield approach, where sites are chosen based on decommissioning dates of power plants that are still active or have already shut down. This implies that only existing sites can be considered for the location of new plants. Different siting patterns or the possibility of determining new and possibly better locations would possibly alter network flows, generation values, and costs. The AC OPF formulation and the application of the model on real-world transmission systems lead to large-scale, nonlinear, and non-convex optimization problems that are challenging to solve. Solvers using interior point methods, like IPOPT that is used in this thesis, are only able to find local optima, so global optimality cannot be guaranteed. This means that in theory, better solutions in terms of optimality, and thus operation costs, could be possible.

Regarding the case studies, a number of assumptions and simplifications were necessary. Generation capacities, renewable energy profiles, and demand trajectories are taken from external scenario assumptions or derived from other models, and only a single scenario for renewable generation and demand is analyzed. Alternative assumptions regarding these inputs could therefore lead to substantially different outcomes. The geographical scope covers Germany and its electrical neighbors, primarily for computational tractability. A broader scope would likely affect congestion patterns, costs, and cross-border flows. Furthermore, the analysis focuses exclusively on the transmission grid and does not account for congestion in the distribution network, which may increasingly constrain system operation and induce additional redispatch requirements in real-world power systems. The results are also sensitive to the assumed grid data and line parameters. Given the absence of an officially validated and transparent transmission-network dataset, it is not possible to conclusively verify the correctness of these inputs, which introduces additional uncertainty into the analysis. Although a model to determine power-plant unavailabilities based on historical statistics is implemented, it was not activated for the simulations presented. Including unavailabilities would potentially influence market results, redispatch, and adequacy metrics. Finally, in the OPF simulations, the year with its 8760 hours is partitioned into 24-hour optimization windows, with storage state of charge boundary conditions linked to a prior simplified optimization. While a 168-hour test run suggests minimal differences relative to 24-hour windows, longer horizons may still alter results in specific stress periods or storage-driven intertemporal patterns.

Outlook

Methodologically, future work could investigate advanced solving approaches, such as decomposition methods like ADMM [219, 220] and ALADIN [13] or time-series aggregation (e.g., typical days or weeks), to manage computational complexity and reduce computation times without losing

critical temporal dynamics. Currently, the model's solving time for a time period of one year and with the consideration of time-coupling constraints typically lies between a few hours and several days, depending on the geographical scope. The integration of FACTS also implies additional complexity, which further increases the computation time. A linearized or convexified implementation could also be helpful to get results with less accuracy but faster computation times, which could be necessary, e.g., when simulating a set of multiple scenario assumptions or even pursuing a Monte Carlo approach. Beyond steady-state operation, future extensions could also incorporate transient system behavior and stability aspects. Such an enhancement would enable the assessment of dynamic phenomena, including fault-induced disturbances and transient stability limits, thereby broadening the applicability of the framework to security-oriented analyses. The integration of dynamic line rating would enable to capture weather-dependent influence on transmission capacities and may reveal additional flexibility in congested corridors. The expansion-planning model currently endogenizes new transmission lines, battery storage systems, and SSSC. Other flexible network elements remain exogenous and could be incorporated in subsequent extensions.

On the infrastructure and data side, it is advisable to update the transmission grid databases for Germany and adjacent European systems with newly announced expansion projects and to try to install a database concerning FACTS devices and PST, which has been proven to be difficult. The robustness of the findings should be reassessed under broader and updated scenario sets for generation capacity and demand, ideally including enhanced DSM representations and alternative siting strategies for new thermal and storage assets.

Regarding the market-based approaches, further research should be carried out, especially in terms of the dynamic grid fees. It would be interesting to test the approach for future years and different configurations or even methodologies for the grid fee calculation as well as to include more countries. Further, more emphasis could be set on modeling and analyzing the behavior of plant operators concerning their bidding strategies when dynamic grid fees are implemented.

Synthesis

Overall, the evidence supports a complementary strategy combining targeted grid reinforcement, deployment of controllability (e.g., FACTS, HVDC), and market instruments that better reflect locational and temporal network conditions. Joint implementation of these measures can reduce redispatch needs and total system costs while maintaining security of supply in a high-renewables European power system. The presented framework provides a credible basis for quantifying the trade-offs among these levers and for stress-testing policy or investment proposals under consistent network physics and market assumptions.

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A Appendix

A.1 System modeling input data

Table A.1: Available dispatchable generation capacities in GW in the TYNDP 2022 scenario [161].

Year	Fuel	DE	FR	UK	NL	PL	NO	SE	BE	AT	CZ	CH	DK
2030	Uranium	–	–	61.1	8.3	0.5	–	–	6.6	3.0	–	3.9	2.5
	Hard coal	8.9	1.1	0.6	4.1	9.5	–	–	0.2	–	–	1.2	2.0
	Lignite	–	13.3	–	–	5.9	–	–	–	–	2.3	–	–
	Fuel oil	1.4	1.8	1.6	–	–	0.1	0.3	0.3	0.3	0.4	–	–
	Natural gas	35.1	8.5	33.1	14.0	10.9	0.9	0.9	8.7	3.5	2.2	0.3	1.8
	Hydrogen	–	–	–	–	–	–	–	–	–	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	10.4	1.8	11.1	–
	Battery	9.0	0.6	7.7	6.8	2.0	0.4	2.6	2.1	2.1	1.5	–	0.1
2040	Uranium	–	40.3	5.1	–	–	–	–	–	–	–	1.9	–
	Hard coal	–	–	–	–	8.2	–	–	0.1	–	–	1.1	0.4
	Lignite	–	–	–	–	2.4	–	–	–	–	2.3	–	–
	Fuel oil	1.1	1.3	0.9	–	0.1	–	0.2	0.2	–	–	–	–
	Natural gas	65.2	23.4	51.4	43.2	25.3	0.9	9.9	15.0	2.8	8.2	1.8	5.4
	Hydrogen	–	–	–	–	–	–	–	–	–	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	11.3	1.8	11.1	–
	Battery	19.8	1.4	9.6	10.4	3.1	0.3	2.0	4.6	4.6	3.2	–	0.1
2050	Uranium	–	15.5	3.2	–	–	–	–	–	–	–	1.9	–
	Hard coal	–	–	–	–	6.0	–	–	–	–	–	–	–
	Lignite	–	–	–	–	1.7	–	–	–	–	1.5	–	–
	Fuel oil	0.5	0.8	0.5	–	–	–	–	–	–	–	–	–
	Natural gas	69.3	43.9	67.4	46.7	29.4	0.9	3.5	22.7	1.6	8.4	1.8	6.2
	Hydrogen	–	–	–	–	–	–	–	–	–	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	11.3	1.8	11.1	–
	Battery	29.2	2.0	9.3	10.1	3.0	0.3	1.9	5.0	6.9	3.3	–	0.2

Table A.2: Available dispatchable generation capacities in GW in the TYNDP 2024 scenario [170].

Year	Fuel	DE	FR	UK	NL	PL	NO	SE	BE	AT	CZ	CH	DK
2030	Uranium	–	–	61.1	8.3	0.5	–	–	6.6	3.0	–	3.9	2.5
	Hard coal	–	8.9	1.1	0.6	4.1	9.5	–	0.2	–	–	1.2	2.0
	Lignite	13.3	–	–	–	–	5.9	–	–	–	–	2.3	–
	Fuel oil	1.4	1.8	1.6	–	0.1	–	0.1	0.3	0.3	0.4	0.1	–
	Natural gas	25.7	8.5	35.2	13.4	9.6	0.9	0.9	4.8	3.5	2.5	0.3	1.8
	Hydrogen	8.8	–	–	–	1.9	0.1	–	–	–	–	–	–
	Pump storage	7.7	18.0	3.6	–	–	1.9	31.3	15.5	1.3	10.4	1.8	11.1
	Battery	3.2	0.5	15.1	9.3	–	–	0.3	0.6	0.1	0.6	1.2	0.2
2040	Uranium	–	40.3	5.1	–	–	–	–	–	–	1.9	–	–
	Hard coal	–	–	–	–	8.2	–	0.1	–	–	1.1	–	0.4
	Lignite	–	–	–	–	2.4	–	–	–	–	2.3	–	–
	Fuel oil	1.1	1.3	0.9	–	0.1	–	0.2	0.2	–	–	–	–
	Natural gas	20.7	8.1	14.3	8.7	9.8	0.9	0.8	5.7	2.8	2.7	0.2	1.0
	Hydrogen	25.4	1.6	3.6	9.7	0.8	–	–	3.4	3.3	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	11.3	1.8	11.1	–
	Battery	109.8	5.2	23.3	30.8	–	–	0.8	1.8	0.2	2.6	5.6	0.2
2050	Uranium	–	15.5	3.2	–	–	–	–	–	–	1.9	–	–
	Hard coal	–	–	–	–	6.0	–	–	–	–	–	–	–
	Lignite	–	–	–	–	1.7	–	–	–	–	1.5	–	–
	Fuel oil	0.5	0.8	0.5	–	–	–	–	–	–	–	–	–
	Natural gas	14.1	3.8	8.8	1.3	6.2	0.9	0.7	5.7	1.6	2.7	0.1	0.6
	Hydrogen	33.6	7.0	–	15.2	2.0	–	–	3.4	3.3	0.2	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	11.3	1.8	11.1	–
	Battery	172.2	10.9	31.1	52.3	–	–	1.5	1.8	0.4	3.1	10.1	0.2

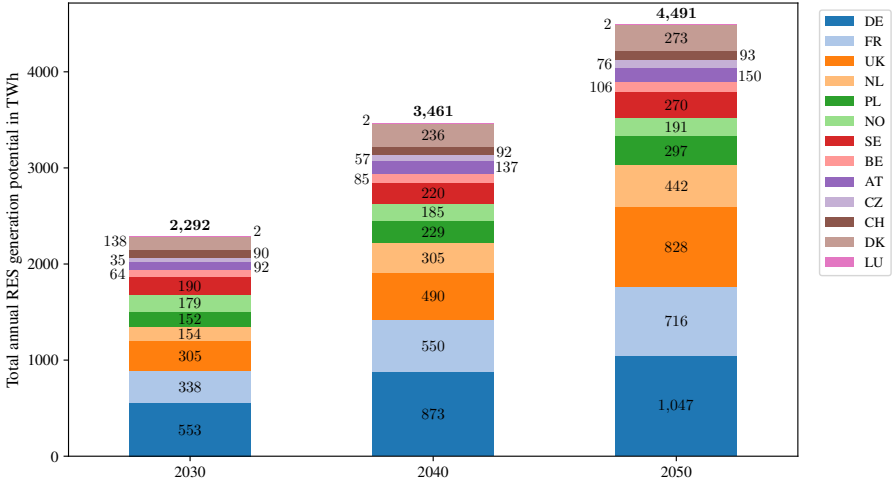
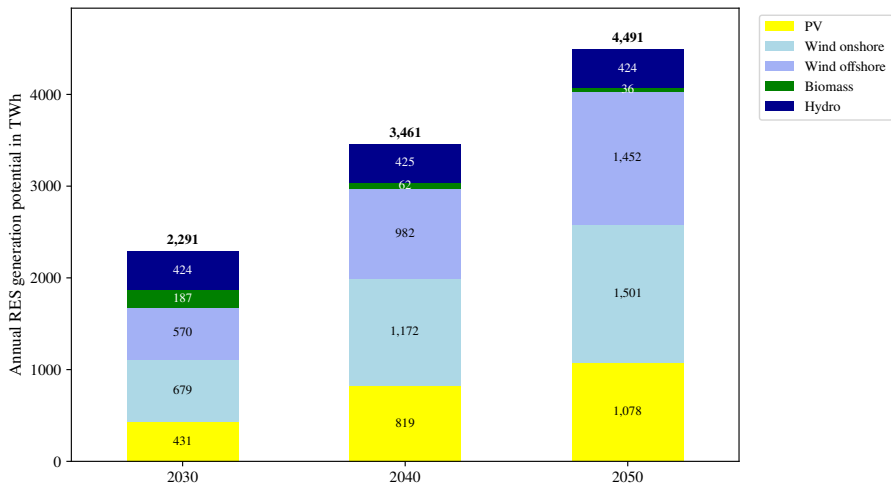


Figure A.1: Annual total potential RES generation Germany and its electrical neighbors in 2030, 2040 and 2050, broken down by countries.

Table A.3: Available dispatchable generation capacities in GW in the TYNDP 2024 half battery capacity scenario [170].

Year	Fuel type	DE	FR	UK	NL	PL	NO	SE	BE	AT	CZ	CH	DK
2030	Uranium	–	61.1	8.3	0.5	–	–	6.6	3.0	–	3.9	2.5	–
	Hard coal	8.9	1.1	0.6	4.1	9.5	–	–	0.2	–	1.2	–	2.0
	Lignite	13.3	–	–	–	5.9	–	–	–	–	2.3	–	–
	Fuel oil	1.4	1.8	1.6	–	0.1	0.1	0.3	0.3	0.4	0.1	–	–
	Gas	25.7	8.5	35.2	13.4	9.4	0.9	0.9	4.8	3.5	2.5	0.3	1.8
	Gasoil	–	–	–	–	–	–	–	–	–	–	–	–
	Hydrogen	8.8	–	–	1.9	0.1	–	–	–	–	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	10.4	1.8	11.1	–
	Battery	1.6	0.2	7.5	4.7	–	–	0.1	0.3	–	0.3	0.6	0.1
2040	Uranium	–	40.3	5.1	–	–	–	–	–	–	–	1.9	–
	Hard coal	–	–	–	–	8.2	–	–	0.1	–	1.1	–	0.4
	Lignite	–	–	–	–	2.4	–	–	–	–	2.3	–	–
	Fuel oil	1.1	1.3	0.9	–	0.1	–	0.2	0.2	–	–	–	–
	Gas	20.7	8.1	14.3	8.7	9.8	0.9	0.8	5.7	2.8	2.7	0.2	1.0
	Gasoil	–	–	–	–	–	–	–	–	–	–	–	–
	Hydrogen	25.4	1.6	–	9.7	0.8	–	–	3.4	3.3	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	11.3	1.8	11.1	–
	Battery	54.9	2.6	11.7	15.4	–	–	0.4	0.9	0.1	1.3	2.8	0.1
2050	Uranium	–	15.5	3.2	–	–	–	–	–	–	–	1.9	–
	Hard coal	–	–	–	–	6.0	–	–	–	–	1.5	–	–
	Lignite	–	–	–	–	1.7	–	–	–	–	–	–	–
	Fuel oil	0.5	0.8	0.5	–	–	–	–	–	–	–	–	–
	Gas	14.1	3.8	8.8	1.3	6.2	0.9	0.7	5.7	1.6	2.7	0.1	0.6
	Gasoil	–	–	–	–	–	–	–	–	–	–	–	–
	Hydrogen	33.6	7.0	–	15.2	2.0	–	–	3.4	3.3	–	–	–
	Pump storage	7.7	18.0	3.6	–	1.9	31.3	15.5	1.3	11.3	1.8	11.1	–
	Battery	86.1	5.5	15.5	26.2	–	–	0.8	0.9	0.2	1.6	5.0	0.1

**Figure A.2:** Annual potential RES generation for Germany and its electrical neighbours in 2030, 2040 and 2050, broken down by energy carriers.

A.2 6-bus test case data

Table A.4: Generator data in the matpower case format [221]. Generator 2 is only available in the redispatch case.

bus	Pg	Qg	Qmax	Qmin	Vg	mBase	status	Pmax	Pmin
1	100	0	127.5	-127.5	1	100	1	170	0
5	100	0	127.5	-127.5	1	100	1	170	0

Table A.5: Bus data in the matpower case format [221].

bus_i	type	Pd	Qd	Gs	Bs	area	Vm	Va	baseKV	zone	Vmax	Vmin
1	3	0	0	0	0	1	1	0	230	1	1.0	1.0
2	1	0	0	0	0	1	1	0	230	1	1.1	0.9
3	1	0	0	0	0	1	1	0	230	1	1.1	0.9
4	1	0	0	0	0	1	1	0	230	1	1.1	0.9
5	1	0	0	0	0	1	1	0	230	1	1.1	0.9
6	1	100	20	0	0	1	1	0	230	1	1.1	0.9

Table A.6: Branch data in the matpower case format [221]. For the reference case, rateA for the third branch is also set to 0 (meaning no thermal limit).

fbus	tbus	r	x	b	rateA	rateB	rateC	ratio	angle	status	angmin	angmax
1	2	0.01	0.04	0.007	0	0	0	0	0	1	-360	360
2	3	0.01	0.04	0.007	0	0	0	0	0	1	-360	360
2	4	0.01	0.04	0.007	40	0	0	0	0	1	-360	360
3	5	0.01	0.04	0.007	0	0	0	0	0	1	-360	360
4	5	0.01	0.04	0.007	0	0	0	0	0	1	-360	360
5	6	0.01	0.04	0.007	0	0	0	0	0	1	-360	360

Table A.7: Generator cost data in the matpower case format [221].

model	startup	shutdown	n	c(n-1)	c(n-2)	c(n-3)
2	0	0	3	0.013	10	0
2	0	0	3	0.026	20	0

Table A.8: SSSC data for the 6-bus case. Depending on the case the branch index is changed from 1 to 2.

branch	$V_{\min}$	$V_{\max}$	$\theta_{\min}$	$\theta_{\max}$
1	0.0	0.05	0	2π

Table A.9: TCSC data. Depending on the case the branch index is changed from 1 to 2.

branch	$x_{\min}$	$x_{\max}$
1	-0.05	0.01

Table A.10: PST data. Depending on the case the branch index is changed from 1 to 2.

branch	position	$\vartheta_{\min}$ ($^{\circ}$)	$\vartheta_{\max}$ ($^{\circ}$)
1	0	-20	20

A.3 24-bus test case data

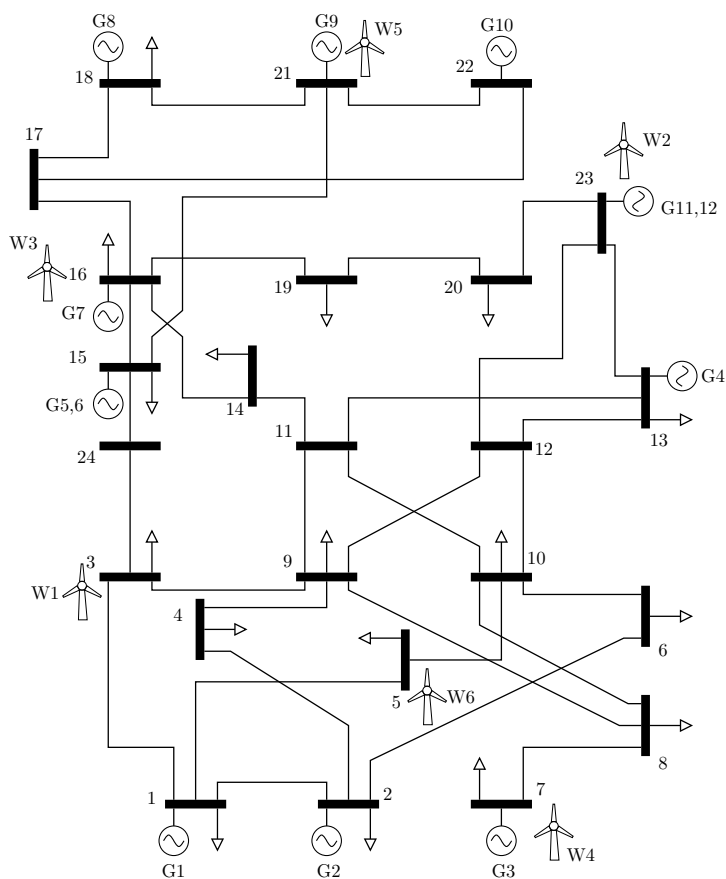


Figure A.3: Circuit diagram of the 24-bus test case system. Own illustration after [201].

Table A.11: Bus data for the 24-bus test case.

Bus #	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin	Bus #	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
1	108	22	0	0	138	1.05	0.95	13	265	54	0	0	230	1.05	0.95
2	97	20	0	0	138	1.05	0.95	14	194	39	0	0	230	1.05	0.95
3	180	37	0	0	138	1.05	0.95	15	317	64	0	0	230	1.05	0.95
4	74	15	0	0	138	1.05	0.95	16	100	20	0	0	230	1.05	0.95
5	71	14	0	0	138	1.05	0.95	17	0	0	0	0	230	1.05	0.95
6	136	28	0	-100	138	1.05	0.95	18	333	68	0	0	230	1.05	0.95
7	125	25	0	0	138	1.05	0.95	19	181	37	0	0	230	1.05	0.95
8	171	35	0	0	138	1.05	0.95	20	128	26	0	0	230	1.05	0.95
9	175	36	0	0	138	1.05	0.95	21	0	0	0	0	230	1.05	0.95
10	195	40	0	0	138	1.05	0.95	22	0	0	0	0	230	1.05	0.95
11	0	0	0	0	230	1.05	0.95	23	0	0	0	0	230	1.05	0.95
12	0	0	0	0	230	1.05	0.95	24	0	0	0	0	230	1.05	0.95

Table A.12: Technical data of conventional generating units.

Unit #	Bus #	Pmax	Pmin	Qmax	Qmin	mBase	status
1	1	152	30.4	10	0	100	1
2	2	152	30.4	10	0	100	1
3	7	350	75	60	0	100	1
4	13	591	206.85	80	0	100	1
5	15	60	12	6	0	100	1
6	15	155	54.25	80	-50	100	1
7	16	155	54.25	80	-50	100	1
8	18	400	0	200	-50	100	1
9	21	400	0	200	-50	100	1
10	22	300	150	16	-10	100	1
11	23	310	108.5	80	-50	100	1
12	23	350	100	150	-25	100	1

Table A.13: Cost coefficients of conventional generating units. The operating costs are calculated by $\sum_{i=0}^{n-1} c_i \cdot (P_g)^i$

n	c_{n-1}	c_{n-2}	c_0
3	0	13.32	0
3	0	13.32	0
3	0	20.70	0
3	0	20.93	0
3	0	26.11	0
3	0	10.52	0
3	0	10.52	0
3	0	6.02	0
3	0	5.47	0
3	0	0.00	0
3	0	10.52	0
3	0	10.89	0

Table A.14: Technical data of the transmission lines.

Line #	From #	To #	r p.u.	x p.u.	b p.u.	Fmax MVA	Line #	From #	To #	r p.u.	x p.u.	b p.u.	Fmax MVA
1	1	2	0.0026	0.0139	0.4611	175	18	11	13	0.0061	0.0476	0.0999	500
2	1	3	0.0546	0.2112	0.0572	175	19	11	14	0.0054	0.0418	0.0879	500
3	1	5	0.0218	0.0845	0.0229	175	20	12	13	0.0061	0.0476	0.0999	500
4	2	4	0.0328	0.1267	0.0343	175	21	12	23	0.0124	0.0966	0.2030	500
5	2	6	0.0497	0.1920	0.0520	175	22	13	23	0.0111	0.0865	0.1818	250
6	3	9	0.0308	0.1190	0.0322	175	23	14	16	0.0050	0.0389	0.0818	250
7	3	24	0.0023	0.0839	0.0000	400	24	15	16	0.0022	0.0173	0.0364	500
8	4	9	0.0268	0.1037	0.0281	175	25	15	21	0.0032	0.0250	0.2060	400
9	5	10	0.0228	0.0883	0.0239	175	26	15	24	0.0067	0.0519	0.1091	500
10	6	10	0.0139	0.0605	2.4590	200	27	16	17	0.0033	0.0259	0.0545	500
11	7	8	0.0159	0.0614	0.0166	175	28	16	19	0.0030	0.0231	0.0485	500
12	8	9	0.0427	0.1651	0.0447	175	29	17	18	0.0018	0.0144	0.0303	500
13	8	10	0.0427	0.1651	0.0447	175	30	17	22	0.0135	0.1053	0.2212	500
14	9	11	0.0023	0.0839	0.0000	400	31	18	21	0.0016	0.0130	0.1090	1000
15	9	12	0.0023	0.0839	0.0000	400	32	19	20	0.0026	0.0198	0.1666	1000
16	10	11	0.0023	0.0839	0.0000	400	33	20	23	0.0014	0.0108	0.0910	1000
17	10	12	0.0023	0.0839	0.0000	400	34	21	22	0.0087	0.0678	0.1424	500

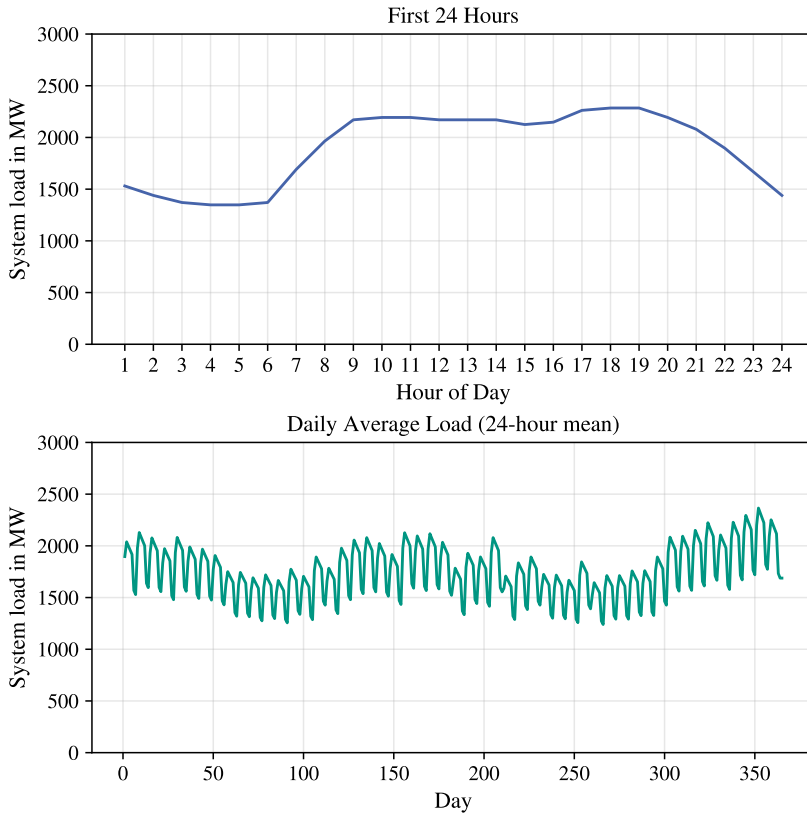


Figure A.4: Illustration of the hourly (left: example for the first 24 hours) and daily (right: daily average) load profile.

Table A.15: Node location and distribution of the total system demand.

Load #	Node	% of system load	Load #	Node	% of system load
1	1	3.8	10	10	6.8
2	2	3.4	11	13	9.3
3	3	6.3	12	14	6.8
4	4	2.6	13	15	11.1
5	5	2.5	14	16	3.5
6	6	4.8	15	18	11.7
7	7	4.4	16	19	6.4
8	8	6.0	17	20	4.5
9	9	6.1			

Table A.16: Wind farm data for the 24-bus case.

Wind farm	Node	Capacity (MW)
1	3	420
2	23	315
3	16	455
4	7	245
5	21	175
6	5	420

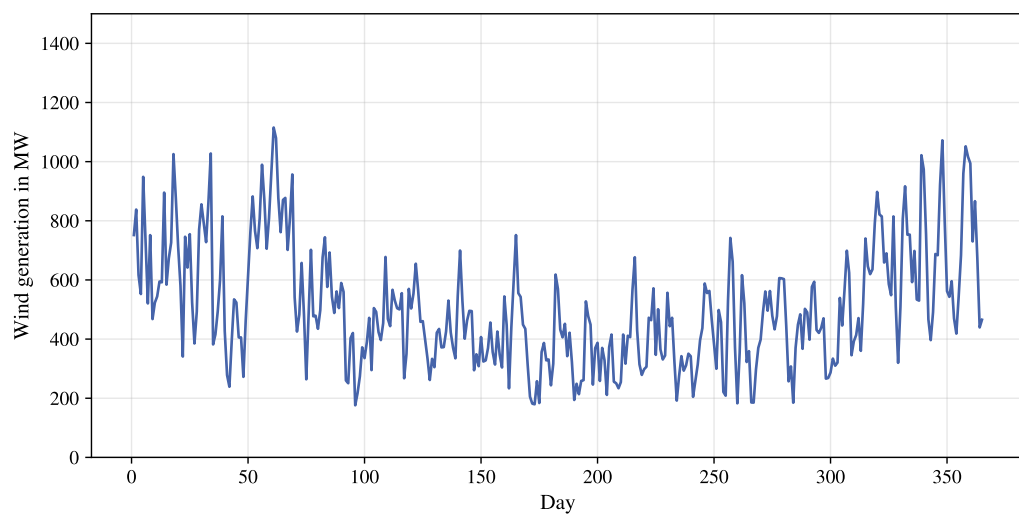


Figure A.5: Daily average of the total potential wind generation.

A.4 Complementary data and results for the European system analysis

Table A.17: Electricity generation and demand results in TWh for 2030, 2040 and 2050 for the three scenarios.

	2030			2040			2050		
	TYNDP22	TYNDP24	TYNDP22 1/2 bat	TYNDP22	TYNDP24	TYNDP24 1/2 bat	TYNDP22	TYNDP24	TYNDP24 1/2 bat
Demand	-2554.9	-2554.9	-2554.9	-2926.3	-2926.3	-2926.3	-3275.7	-3275.7	-3275.7
Grid losses	-63.9	-63.9	-63.9	-73.2	-73.2	-73.2	-81.9	-81.9	-81.9
PSP turb	346.0	344.9	310.7	274.0	256.6	267.0	256.5	230.6	235.5
PSP pump	-69.5	-69.0	-59.5	-76.5	-60.8	-71.8	-76.9	-55.6	-58.9
Load shedding	0.0	0.0	0.0	0.0	4.1	5.2	0.0	10.8	13.3
Battery discharge	53.6	47.9	11.6	42.6	87.1	57.6	47.1	109.7	69.5
Battery charge	-59.4	-53.1	-12.9	-47.2	-96.5	-63.8	-52.2	-121.6	-77.0
RES	1871.5	1870.8	1887.7	2535.2	2572.1	2547.8	2971.3	3025.2	2993.8
Other	3.2	3.4	3.3	1.3	1.2	1.3	0.3	0.2	0.2
Uranium	331.8	331.3	331.0	142.5	135.6	140.9	62.3	59.6	61.5
Hard coal	3.3	6.4	6.8	0.0	2.1	2.2	0.0	5.0	5.0
Lignite	0.3	0.5	0.5	0.0	0.3	0.3	0.0	0.7	0.8
Fuel Oil	0.0	0.0	0.0	0.0	0.6	0.7	0.0	0.6	0.7
Natural gas	137.9	134.4	138.1	127.5	85.6	97.3	149.3	60.7	71.0
Hydrogen	0.0	1.4	1.5	0.0	11.5	14.8	0.0	31.5	42.1

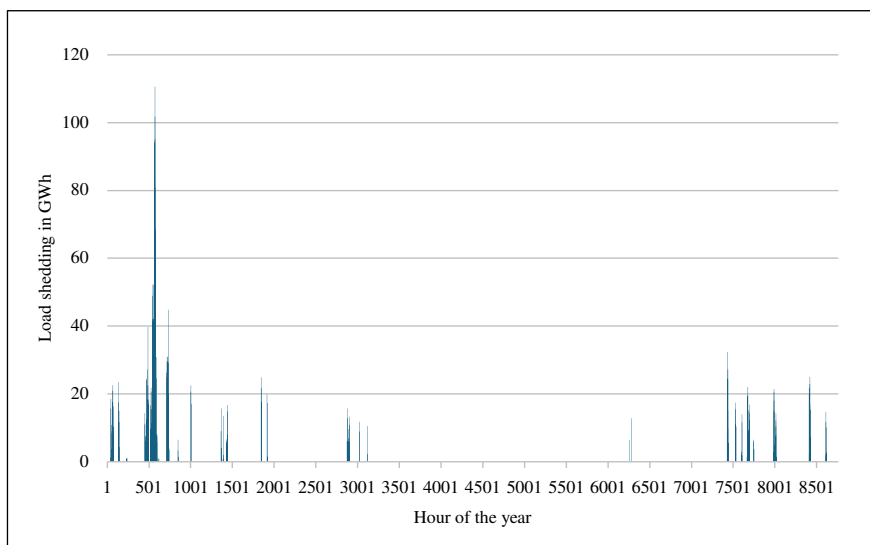


Figure A.6: Hourly load shedding results (aggregated across all modeled countries) for the TYNDP 2024 scenario in 2040.

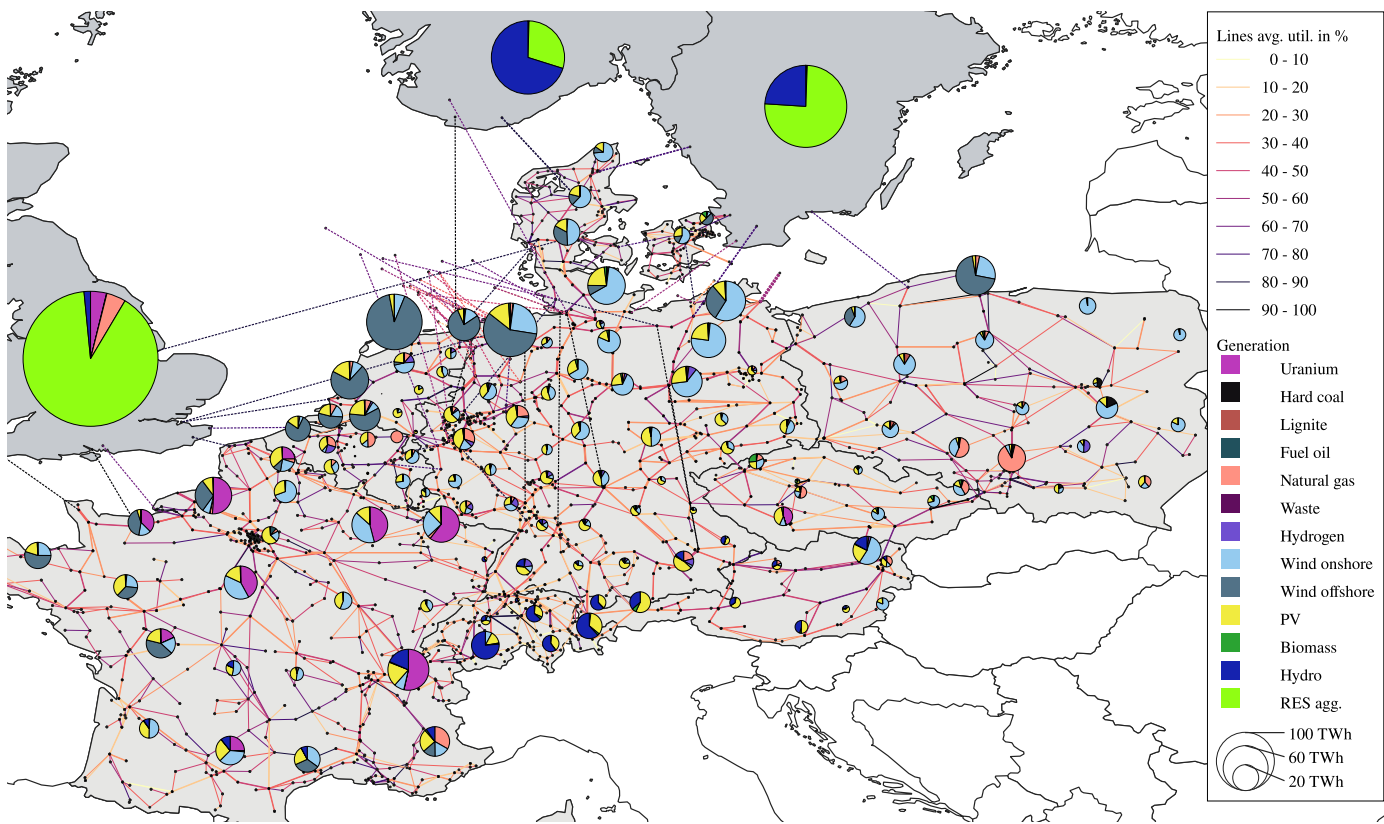


Figure A.7: Annual generation and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2040 for the TYNDP 2024 scenario. Generation results are aggregated to NUTS-2 level for countries modeled with grid infrastructure (coloured light grey) and to NUTS-0 level for countries modeled as one node systems (darker grey).

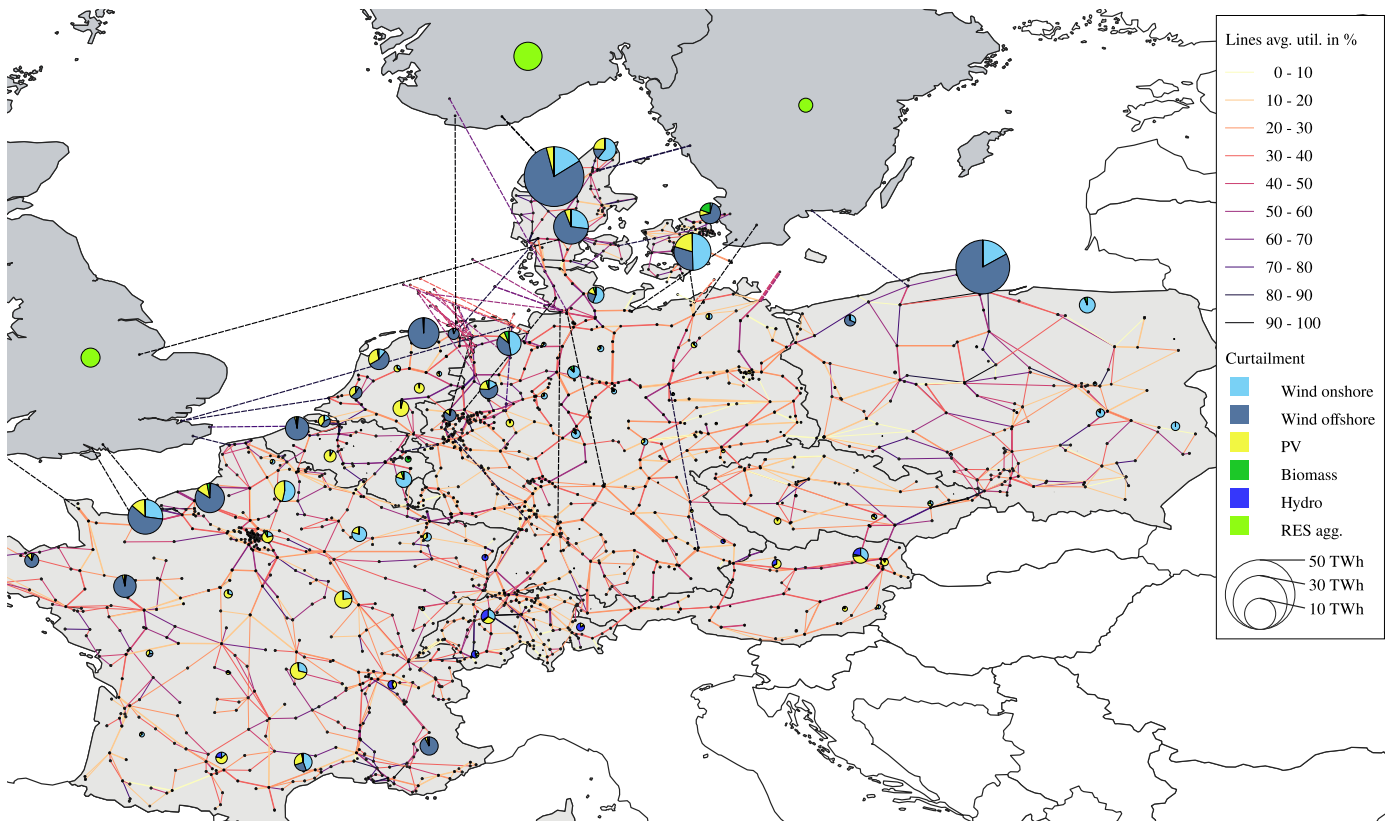


Figure A.8: Annual RES curtailment and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2030 for the TYNDP 2024 scenario. Curtailment results are aggregated to NUTS-2 level for countries modeled with grid infrastructure (coloured light grey) and to NUTS-0 level for countries modeled as one node systems (darker grey).

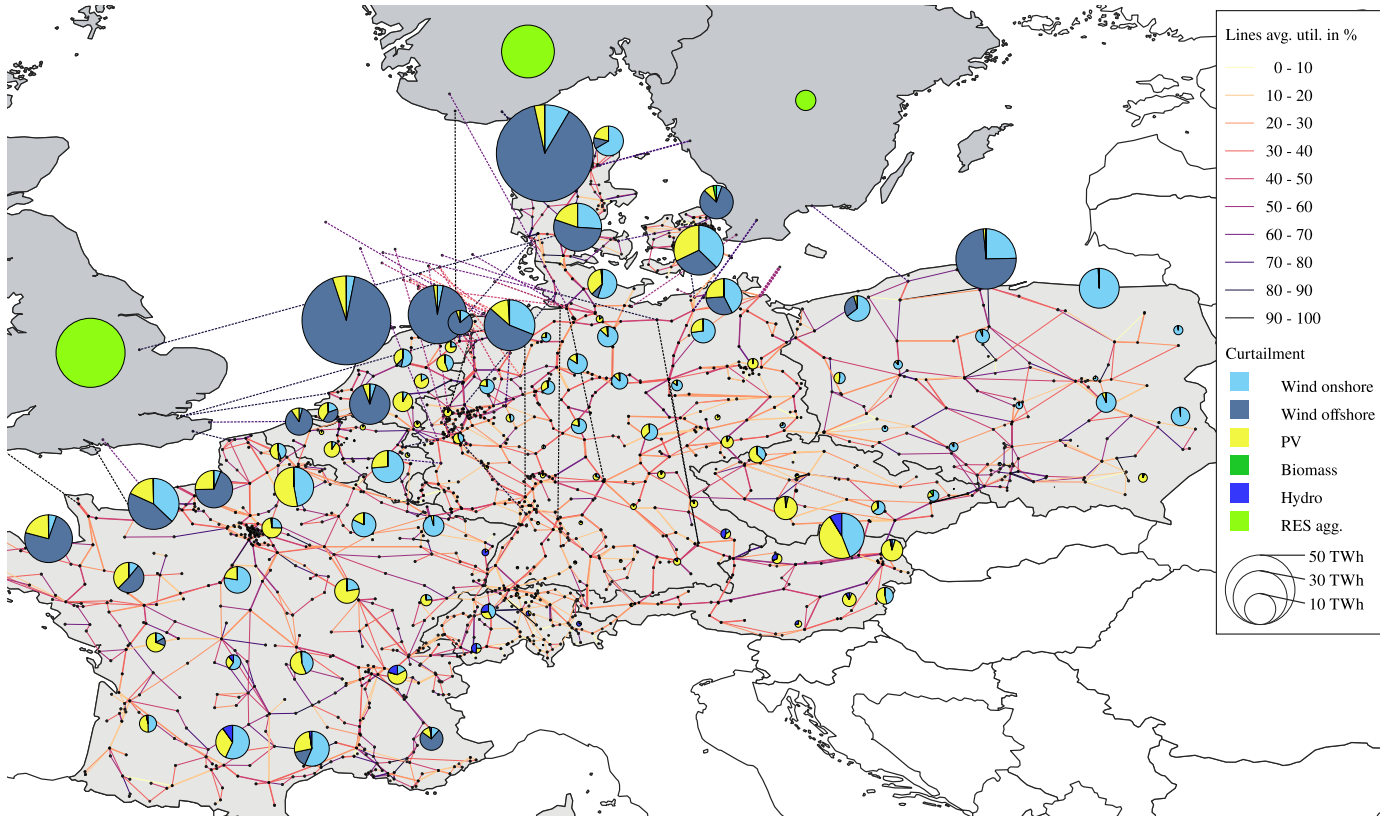


Figure A.9: Annual RES curtailment and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2030 for the TYNDP 2024 scenario. Curtailment results are aggregated to NUTS-2 level for countries modeled with grid infrastructure (coloured light grey) and to NUTS-0 level for countries modeled as one node systems (darker grey).

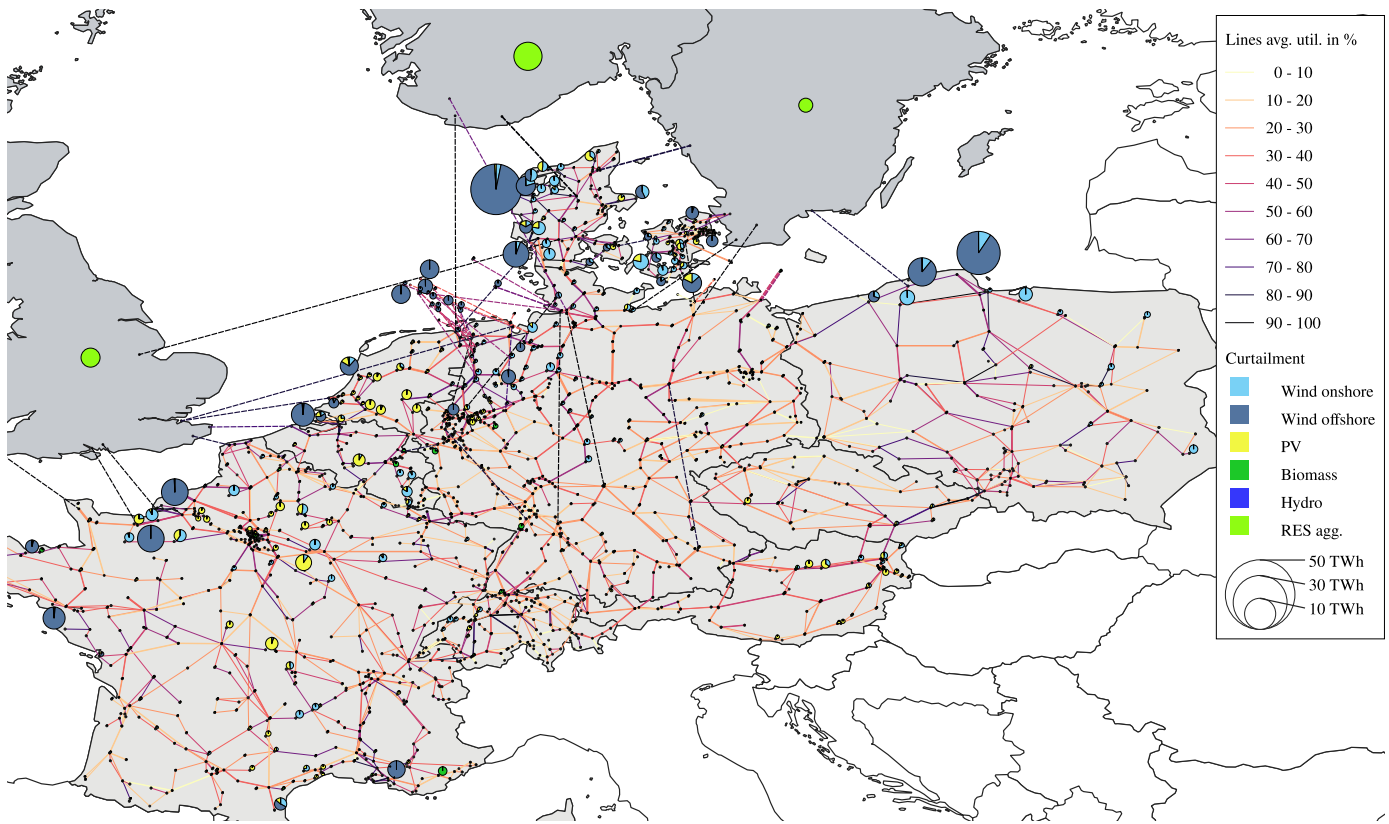


Figure A.10: Annual RES curtailment and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2030 for the TYNDP 2024 scenario. Curtailment results are shown at substation level for countries modeled with grid infrastructure (coloured light grey) and aggregated to NUTS-0 level for countries modeled as one node systems (darker grey).

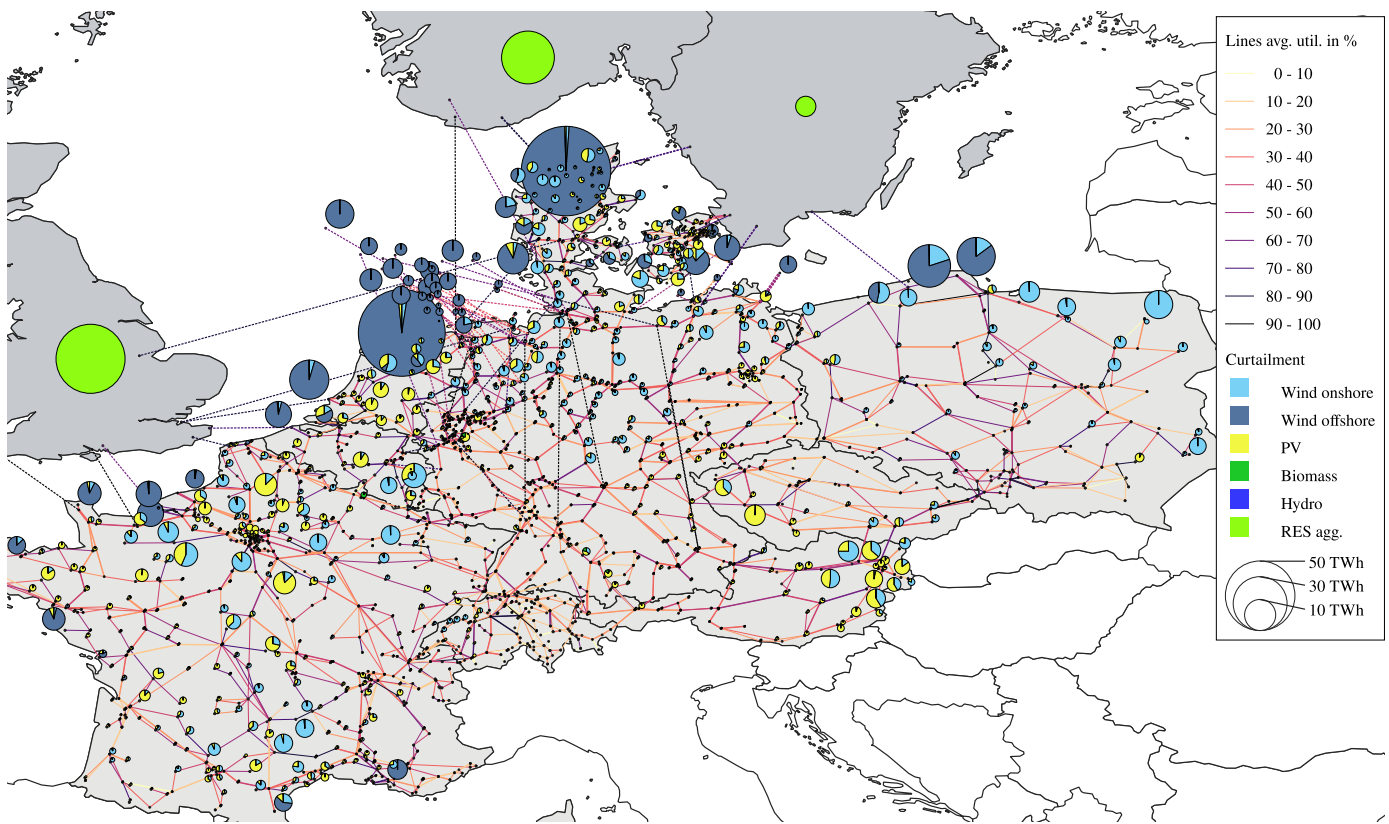


Figure A.11: Annual RES curtailment and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2040 for the TYNDP 2024 scenario. Curtailment results are shown at substation level for countries modeled with grid infrastructure (coloured light grey) and aggregated to NUTS-0 level for countries modeled as one node systems (darker grey).

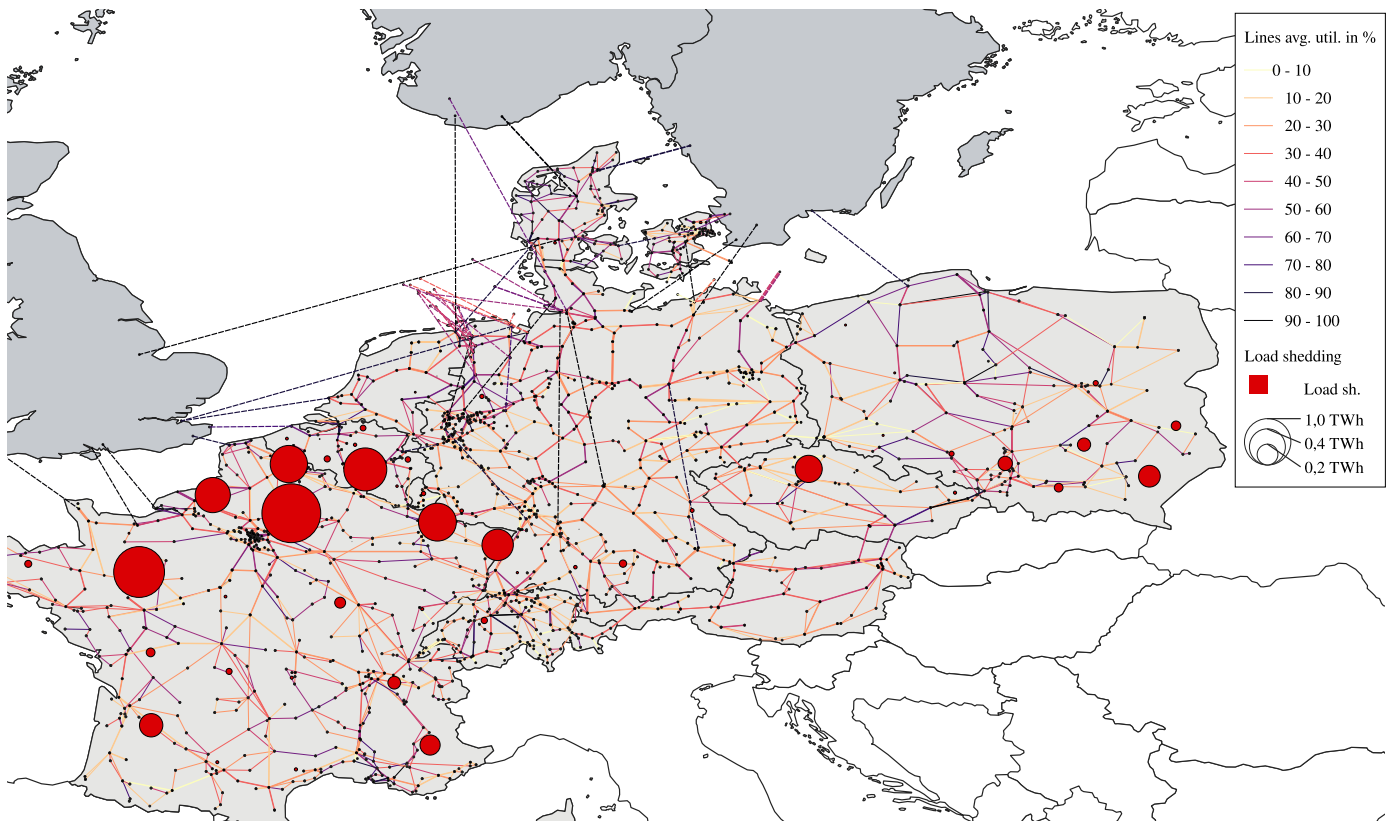


Figure A.12: Annual load shedding and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2030 for the TYNDP 2024 scenario. Load shedding results are aggregated to NUTS-2 level for countries modeled with grid infrastructure (coloured light grey) and aggregated to NUTS-0 level for countries modeled as one node systems (darker grey).

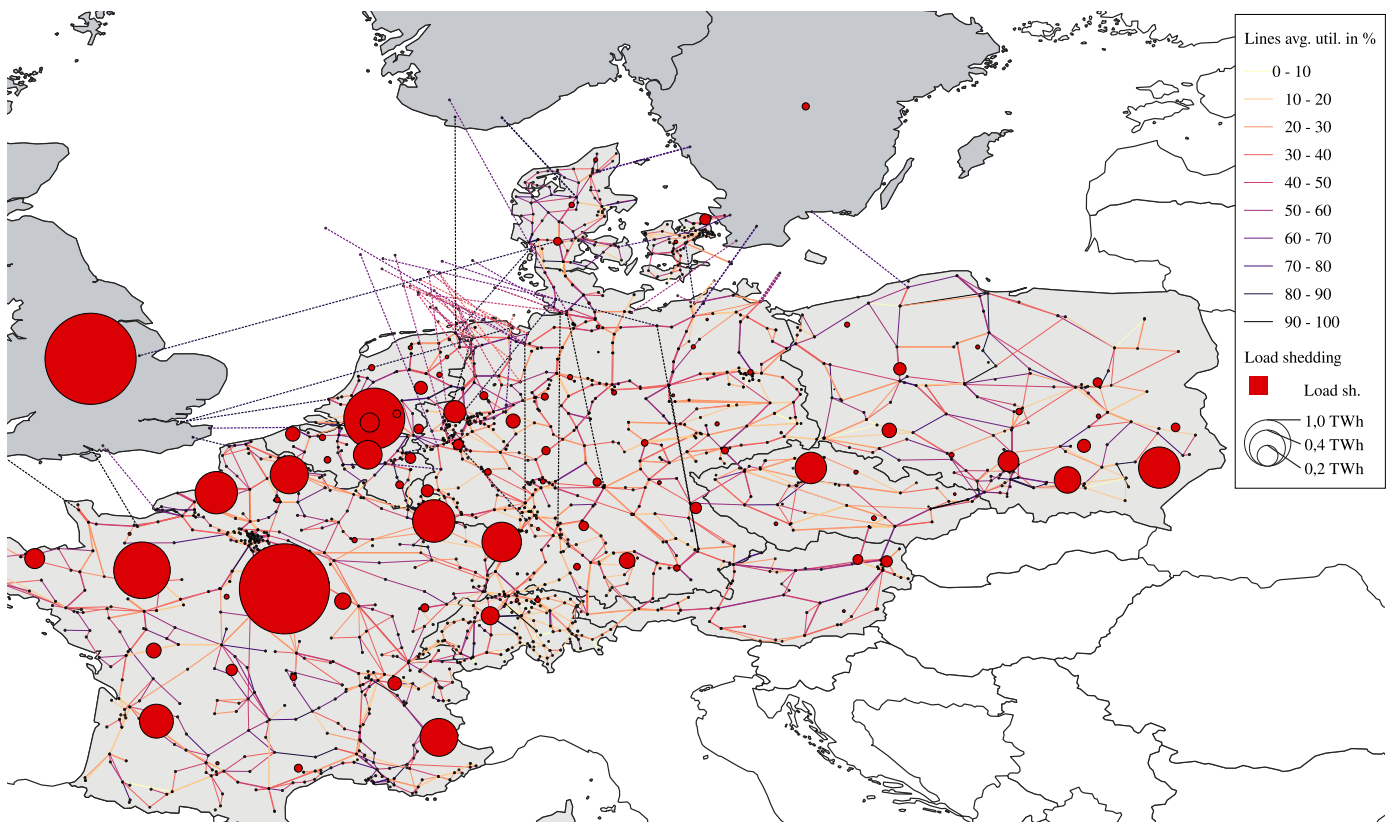


Figure A.13: Annual load shedding and average AC (solid lines) and DC (dashed lines) line utilization results for the OPF simulation of Germany and its electrical neighbors in 2040 for the TYNDP 2024 scenario. Load shedding results are aggregated to NUTS-2 level for countries modeled with grid infrastructure (coloured light grey) and aggregated to NUTS-0 level for countries modeled as one node systems (darker grey).

A.5 Complementary data and results for the congestion management simulations for Germany

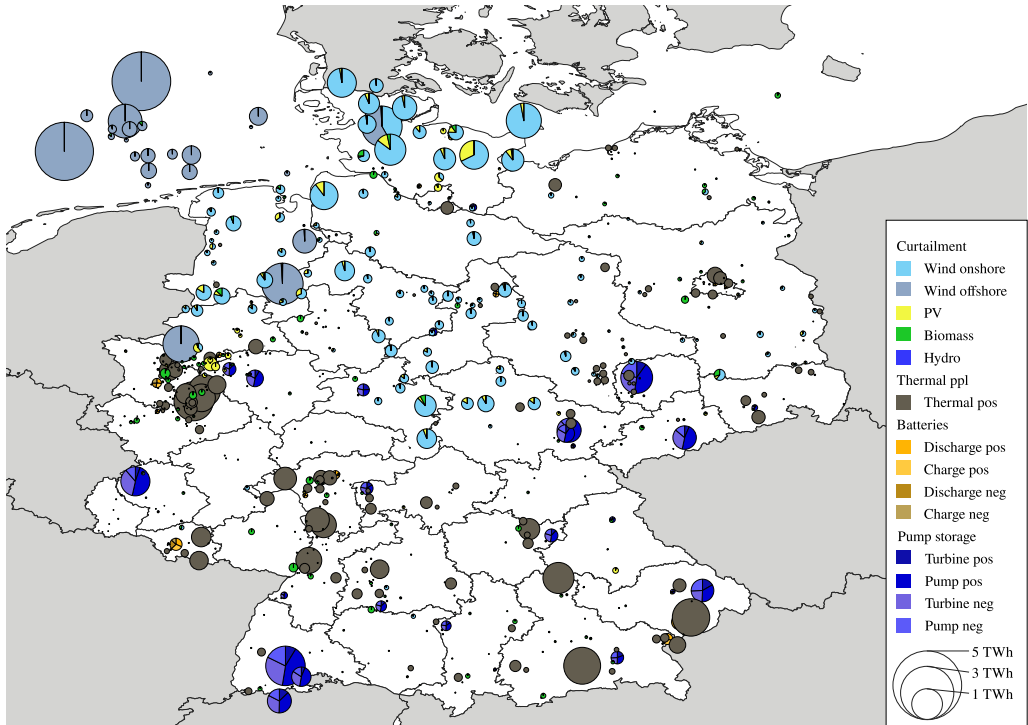


Figure A.14: Results for the necessary redispatch volumes in Germany for the year 2030 and the TYNDP 2024 scenario, broken down by energy carriers and location.

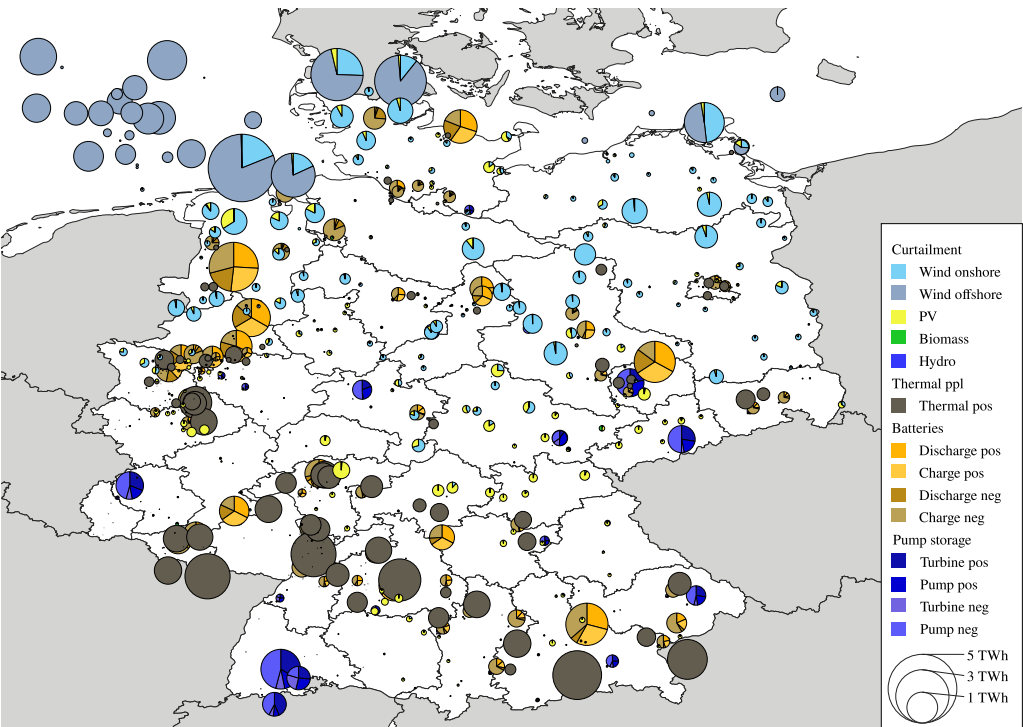


Figure A.15: Results for the necessary redispatch volumes in Germany for the year 2050 and the TYNDP 2024 scenario, broken down by energy carriers and location.

Table A.18: Results for the redispatch and curtailment volumes in TWh for Germany across the three scenarios and the years 2030, 2040 and 2050.

	2030			2040			2050		
	TYNDP22	TYNDP24	TYNDP24 1/2 bat	TYNDP22	TYNDP24	TYNDP24 1/2 bat	TYNDP22	TYNDP24	TYNDP24 1/2 bat
Uranium pos	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uranium neg	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hard coal pos	2.7	4.5	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Hard coal neg	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lignite pos	0.1	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0
Lignite neg	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel oil pos	0.2	0.3	0.3	0.2	0.3	0.3	0.0	0.0	0.1
Fuel oil neg	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural gas pos	33.3	30.7	27.9	34.5	16.3	15.8	57.5	13.6	12.8
Natural gas neg	-0.2	-0.2	-0.2	-0.8	-0.3	-0.3	-1.6	-0.8	-1.1
Hydrogen pos	0.0	0.4	0.3	0.0	15.8	16.2	0.0	38.4	37.3
Hydrogen neg	0.0	0.2	0.2	0.0	0.4	0.4	0.0	0.5	0.6
Other pos	0.2	0.2	-0.1	0.7	1.0	0.9	0.4	0.5	0.5
Other neg	0.0	-0.4	-0.2	0.0	-0.8	-0.5	0.0	-1.0	-0.6
PS turbine pos	0.6	0.8	1.0	1.4	1.7	1.6	1.9	2.3	2.0
PS turbine neg	-1.9	-2.5	-1.8	-1.4	-0.8	-1.3	-1.5	-0.6	-0.9
PS pump pos	2.6	3.6	2.5	1.9	1.6	1.8	1.9	1.5	1.5
PS pump neg	-0.9	-1.5	-1.6	-1.9	-2.6	-2.1	-2.3	-3.4	-2.8
Bat charge pos	1.0	0.5	0.1	1.0	4.1	2.5	1.6	7.8	5.2
Bat charge neg	-0.3	-0.3	-0.1	-2.8	-8.1	-5.1	-5.0	-15.6	-10.5
Bat discharge pos	0.3	0.2	0.1	2.1	5.6	3.6	4.0	11.2	7.3
Bat discharge neg	-0.9	-0.4	-0.1	-0.5	-1.9	-1.2	-0.9	-4.2	-2.5
PV curtail	-2.2	-2.2	-2.0	-1.4	-2.3	-1.7	-1.7	-5.1	-4.0
Wind onsh curtail	-14.5	-15.2	-13.5	-11.6	-9.7	-10.8	-16.6	-15.7	-15.8
Wind offsh curtail	-15.8	-15.5	-14.0	-18.9	-18.7	-18.5	-35.7	-28.2	-27.6
Hydro curtail	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Biomass curtail	-1.7	-1.8	-1.7	-0.3	-0.2	-0.3	-0.1	-0.1	-0.1
Load shedding	0.2	0.9	0.8	1.6	2.6	3.2	1.7	2.6	2.9

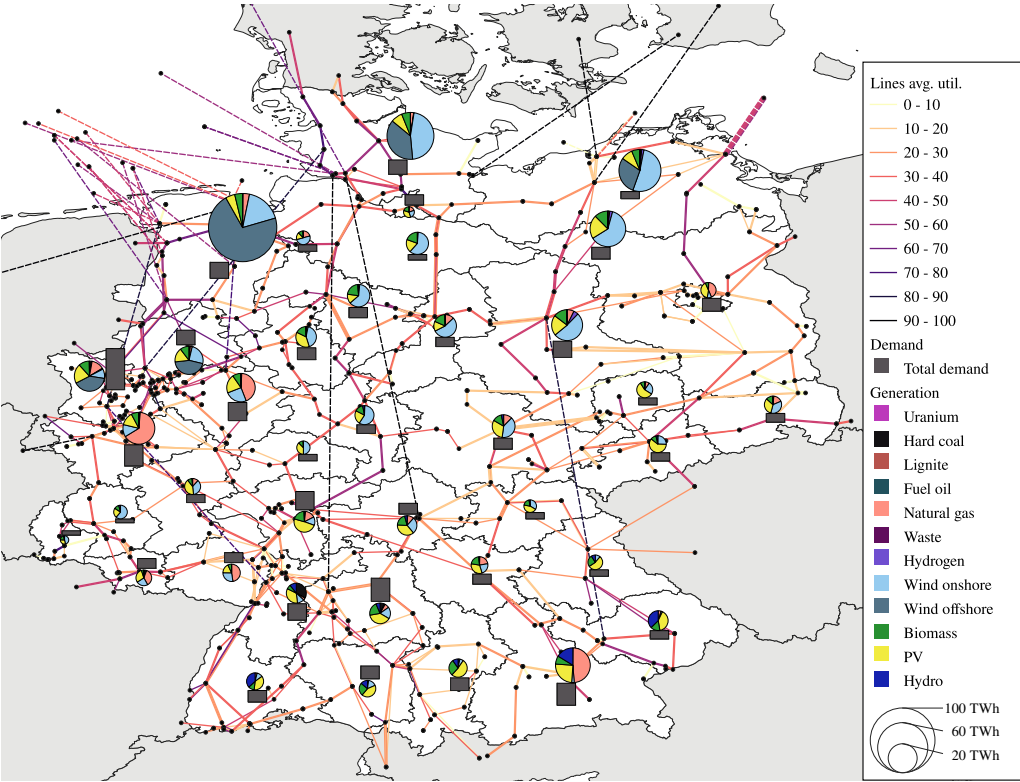


Figure A.16: Average line utilization of AC and DC (dashed) transmission lines and generation results for Germany broken down by energy carrier and NUTS-2 region after the redispatch simulation for the TYNDP 2024 scenario in 2030.

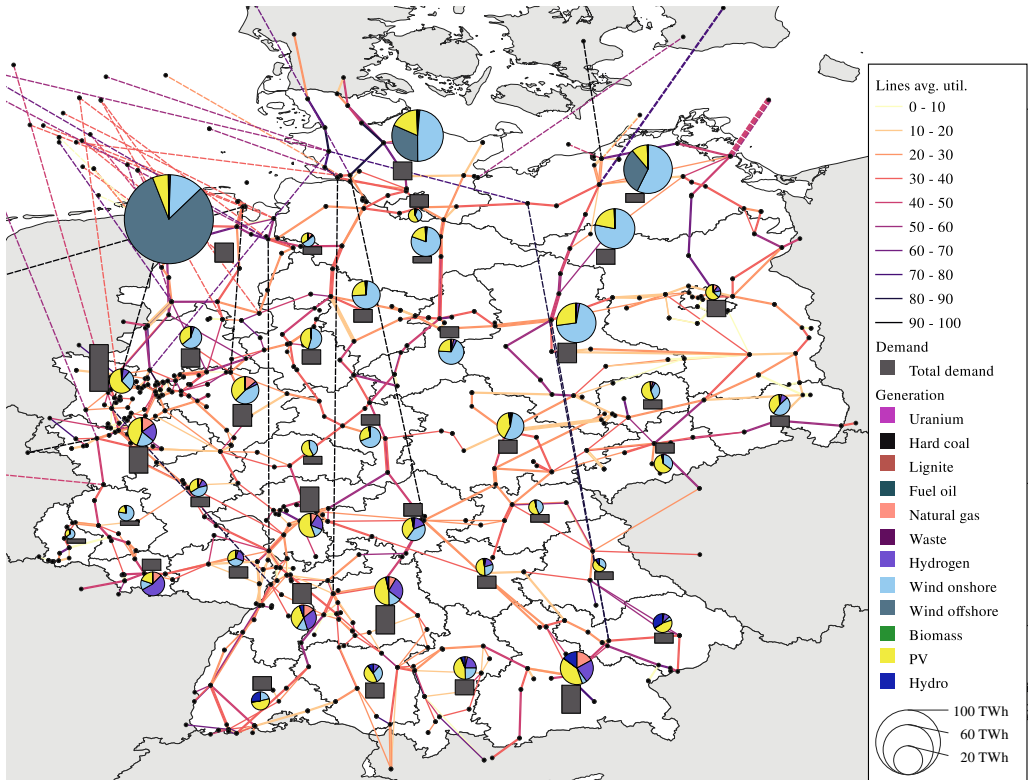


Figure A.17: Average line utilization of AC and DC (dashed) transmission lines and generation results for Germany broken down by energy carrier and NUTS-2 region after the redispatch simulation for the TYNDP 2024 scenario in 2050.

A.6 Complementary data and results for the German bidding zone review

A.6.1 Description of the clustering methodology

The modified k-means clustering algorithm used for the identification of a suitable split of the German market zones was developed as part of a bachelor's thesis at KIT [209] and follows the guidance of the ACER Bidding Zone Review [3, 222]. The algorithm employs a modified k-means clustering approach to partition transmission grid nodes into internally coherent, congestion-aware bidding zones. The objective is to generate zonal configurations that remain stable over time while minimizing intra-zonal congestion. The clustering operates on time series of locational marginal prices (LMPs, see Section 2.2.3.5), which inherit information about underlying network constraints and thus serve as a suitable basis for the clustering.

Classic k-means is selected due to its computational efficiency, deterministic convergence, and suitability for unsupervised learning tasks [223–226]. The algorithm partitions a dataset in $\mathbb{R}^N$ into k clusters by minimizing the intra-cluster variance. Starting from an initial set of centroids, each data point is assigned to the nearest centre, after which the centroid is updated. This iterative process continues until the assignments converge. However, the standard formulation of k-means assumes convex cluster structures and is sensitive to initialization, which limits its ability to produce spatially coherent clusters, which is an essential requirement in the context of this application. To address these shortcomings, the input data are pre-processed to improve stability, and geographical coordinates are incorporated as additional features, weighted by a geo factor α . This modification directs the clustering towards zones that are both similar in locational marginal prices and geographically contiguous. By tuning α and assessing the resulting partitions, the configuration that minimizes average intra-zonal LMP variance is identified, achieving a balance between economic homogeneity and spatial coherence.

Each grid node i is represented by a feature vector with three components:

$$x_i = \left[\frac{LMP_i}{\mu_{LMP}}, \alpha \cdot \text{lat}_i, \alpha \cdot \text{lon}_i \right] \quad (\text{A.1})$$

where $LMP_i \in \mathbb{R}^{8760}$ is the hourly LMP vector for node i in a given scenario year, μ_{LMP} is the mean of LMPs across all nodes and hours and lat_i , lon_i are the node's geographic coordinates. A grid search over $\alpha \in \{0, 25, \dots, 1000\}$ is used to determine the value that minimizes average intra-zonal LMP variance for each target number of clusters k . The resulting clusters are evaluated

both quantitatively (via intra-zonal variance) and qualitatively (via spatial inspection of zonal maps).

To ensure temporal consistency across the modelling horizon, the clustering is first applied only to nodes that exist in all scenario years (2030–2050). Nodes that appear or disappear due to infrastructure changes are subsequently assigned to the nearest cluster centroid using a hybrid metric based on LMP correlation and spatial distance, preserving methodological consistency without distorting cluster structure. The final output is a cluster identifier for each node for the selected value of k , which forms the basis for the zonal configuration used in subsequent simulations.

A.6.2 Scenario data and results

Table A.19: Calculated NTC values involving German market zones for the 3 zones configuration. The NTCs are considered symmetrical for both flow directions. The original NTC values are based on TYNDP 2022 [169].

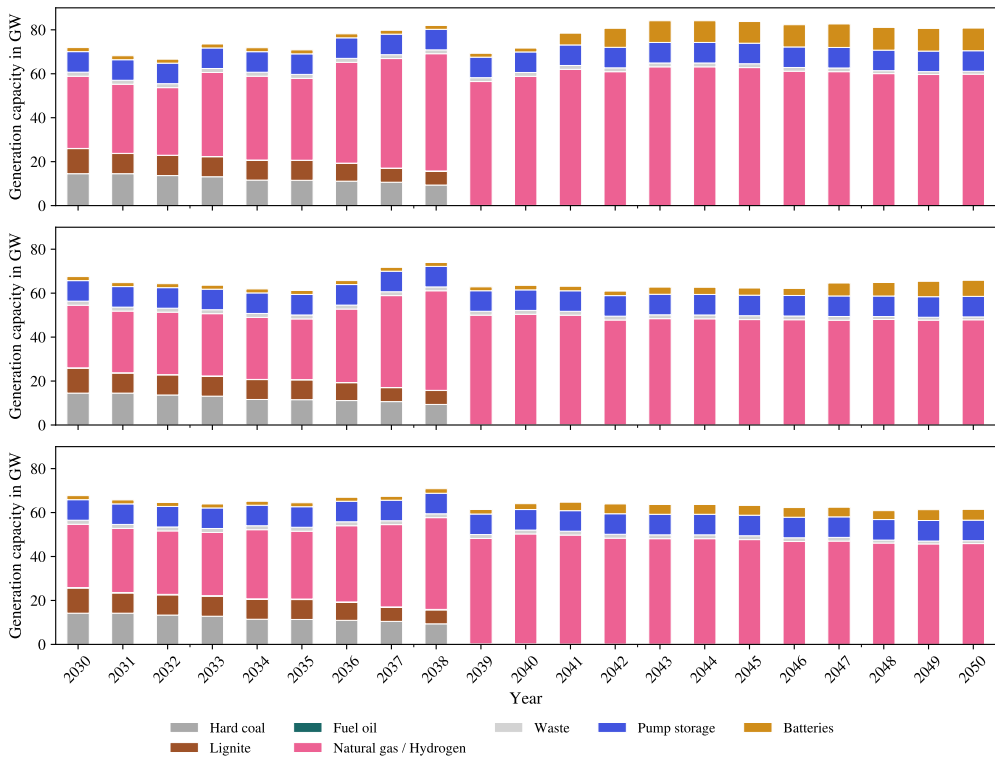
2030			2040			2050		
From	To	NTC [MW]	From	To	NTC [MW]	From	To	NTC [MW]
DE1	CZ	788	DE1	CZ	788	DE1	CZ	1050
DE1	DK	3268	DE1	DK	3268	DE1	DK	3268
DE1	PL	2000	DE1	PL	2000	DE1	PL	2000
DE1	SE	1315	DE1	SE	2015	DE1	SE	2015
DE1	DE2	6331	DE1	DE2	7331	DE1	DE2	7331
DE1	DE3	9782	DE1	DE3	12571	DE1	DE3	12571
DE2	AT	6900	DE2	AT	7500	DE2	AT	8500
DE2	BE	231	DE2	BE	130	DE2	BE	130
DE2	CH	3600	DE2	CH	3600	DE2	CH	3600
DE2	CZ	712	DE2	CZ	712	DE2	CZ	950
DE2	FR	4800	DE2	FR	4800	DE2	FR	4800
DE2	DE1	6331	DE2	DE1	7331	DE2	DE1	7331
DE2	DE3	12025	DE2	DE3	14999	DE2	DE3	14999
DE3	BE	769	DE3	BE	870	DE3	BE	870
DE3	DK	1832	DE3	DK	1832	DE3	DK	1832
DE3	NL	5000	DE3	NL	5000	DE3	NL	5000
DE3	NO	1400	DE3	NO	1400	DE3	NO	1400
DE3	DE1	9782	DE3	DE1	12571	DE3	DE1	12571
DE3	DE2	12025	DE3	DE2	14999	DE3	DE2	14999

Table A.20: Calculated NTC values involving German market zones for the 5 zones configuration. The NTCs are considered symmetrical for both flow directions. The original NTC values are based on TYNDP 2022 [169].

2030			2040			2050		
From	To	NTC [MW]	From	To	NTC [MW]	From	To	NTC [MW]
DE1	CZ	788	DE1	CZ	788	DE1	CZ	1050
DE1	DK	309	DE1	DK	309	DE1	DK	309
DE1	PL	2000	DE1	PL	2000	DE1	PL	2000
DE1	SE	700	DE1	SE	1400	DE1	SE	1400
DE1	DE2	7141	DE1	DE2	8141	DE1	DE2	8141
DE1	DE3	3752	DE1	DE3	6726	DE1	DE3	6726
DE1	DE5	987	DE1	DE5	987	DE1	DE5	987
DE2	AT	6788	DE2	AT	7378	DE2	AT	8362
DE2	CZ	712	DE2	CZ	712	DE2	CZ	950
DE2	DE1	7141	DE2	DE1	8141	DE2	DE1	8141
DE2	DE3	1000	DE2	DE3	1000	DE2	DE3	1000
DE2	DE4	6901	DE2	DE4	6901	DE2	DE4	6901
DE3	DK	4791	DE3	DK	4791	DE3	DK	4791
DE3	NL	1217	DE3	NL	1898	DE3	NL	1898
DE3	NO	1400	DE3	NO	1400	DE3	NO	1400
DE3	SE	615	DE3	SE	615	DE3	SE	615
DE3	DE1	3752	DE3	DE1	6726	DE3	DE1	6726
DE3	DE2	1000	DE3	DE2	1000	DE3	DE2	1000
DE3	DE4	1000	DE3	DE4	2000	DE3	DE4	2000
DE3	DE5	15769	DE3	DE5	20437	DE3	DE5	20437
DE4	AT	112	DE4	AT	122	DE4	AT	138
DE4	BE	231	DE4	BE	130	DE4	BE	130
DE4	CH	3600	DE4	CH	3600	DE4	CH	3600
DE4	FR	4800	DE4	FR	4800	DE4	FR	4800
DE4	DE2	6901	DE4	DE2	6901	DE4	DE2	6901
DE4	DE3	1000	DE4	DE3	2000	DE4	DE3	2000
DE4	DE5	8375	DE4	DE5	8375	DE4	DE5	8375
DE5	BE	769	DE5	BE	870	DE5	BE	870
DE5	NL	3783	DE5	NL	3102	DE5	NL	3102
DE5	DE1	987	DE5	DE1	987	DE5	DE1	987
DE5	DE3	15769	DE5	DE3	20437	DE5	DE3	20437
DE5	DE4	8375	DE5	DE4	8375	DE5	DE4	8375

Table A.21: Assumed fuel prices in EUR/MWh for the market zone split analysis.

Energy carrier	2030	2040	2050
Uranium	1,69	1,69	1,69
Hard coal	12,4	9,7	15,0
Lignite	6,48	6,48	6,48
Fuel oil	49,61	355,48	355,48
Natural gas	27,5	26,4	100,0
Hydrogen	120,0	110,0	100,0

**Figure A.18:** Resulting generation capacities (excluding RES) for the different market zone configurations in Germany.