Techno-economic assessment of market coupling regimes in future electricity systems

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Abstract

Flow-based market coupling is the target model for European electricity markets. It enables increased exchange compared to the previously used net transfer capacity approach but might lead to increased congestions during grid operation, when minimum capacities are enforced. Therefore, considering the transmission grid becomes imperative in analysing the (future) European electricity markets. Market coupling and grid curtailment are determining factors for both the economic viability of investments in renewable energy sources and their actual share in the power mix. Given the delay in grid expansion, a comprehensive understanding of the interdependencies between market clearing and congestion management in the European electricity market is essential to foster effective investments and create an efficient market design.

In this thesis, an integrated framework is developed to investigate the impact of flow-based market coupling on market prices and the revenue potential of renewables. To this end, detailed transmission grid data is collected and processed for the existing and future grid in central Europe to simulate flow-based market coupling and the subsequent grid operation. The market model covers the coupled wholesale markets of 48 European bidding zones with a detailed representation of over 2000 thermal power plant units and includes (demand) flexibility providers such as demand response, power-to-heat and e-mobility applications. The approach leverages a highly detailed renewables expansion planning model that enables the simulation of (future) feed-in and demand profiles based on state-of-the-art weather reanalysis. Finally, a method is proposed to integrate approximate flow-based exchange limits in traditional market models that allows simulating market coupling more adequately while retaining the benefits of such models, such as a faster runtime and reduced memory requirements.

After quantifying the impacts of an expanded flow-based region and the effects of minimum exchange capacities introduced by the Clean Energy Package of the European Commission, the developed framework is applied to analyse the difference between the use of flow-based constraints and net transfer capacities for market coupling in highly flexible future energy systems with respect to prices, market values and curtailment needs. The results show that solar PV is most affected. With market value differences between -26 % and 56 %, the market coupling regime can determine the economic (non)viability of renewable projects. The reduction of CO_2 emissions in the market domain is more than outweighed by the increased activation of fossil power plants through re-dispatch.

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June 2024
Rafael Finck

Contents

Appendix

1 Introduction

Flow-based market coupling (FBMC) is the target model for the European internal electricity markets. Since its introduction into the day-ahead markets of Central Western Europe (CWE) in 2015 and the extension to Core Capacity Calculation Region (CCR) in 2022, it has proven to enable larger exchange capacities compared to the previously applied Net Transfer Capacity (NTC) approach [CWE15]. The intensified efforts to integrate Europe's electricity markets are determining factors in the evaluation of investment projects in Renewable Energy Sources (RES), such as solar photovoltaic (PV) or wind parks, or flexibility-providing technologies (for instance, energy storages such as batteries) and thus are pivotal for the successful energy transition. In this thesis, an approach is developed to analyse the impact of (Flow-based) market coupling in the market domain and during grid operation and quantify the economic consequences for market participants.

1.1 Background and motivation

For market participants and political decision-makers alike, the physically fed-in (renewable) energy is decisive, in addition to the market outcome, which makes an integral consideration of market and grid events necessary. Although FBMC enables an improved integration of the physical grid state in the market coupling, the drive toward more market integration represents a potential stress factor for the grids within the bidding zones. Driven by the urgency of the transition to a low-carbon energy system, governments are compelled to escalate their renewable energy goals. This transition is intrinsically linked to the expansion and modernisation of the electric grid, a requirement that is not without its challenges.

Delays in grid expansion become a determining variable in scenario analysis, as demonstrated for the case of Germany in Fig. 1.1, where grid expansion developed a delay of about 7 years over a period of 14 years. In the third quarter of 2023 about 20 % of the planned grid expansion had been realised (~2 700 km) and the German grid development plan 2037/2045 in version 2023 foresees an additional need of 25 723 km until 2045 [Bun24a]. Understanding the impact of the grid expansion state on electricity market results and simulation models becomes therefore imperative for researchers and practitioners alike, but is neglected in most economic studies, where reference NTC exchange limits (also from scenarios) are assumed, and thus a timely realisation of the expansion measures of the grid is not called into question.

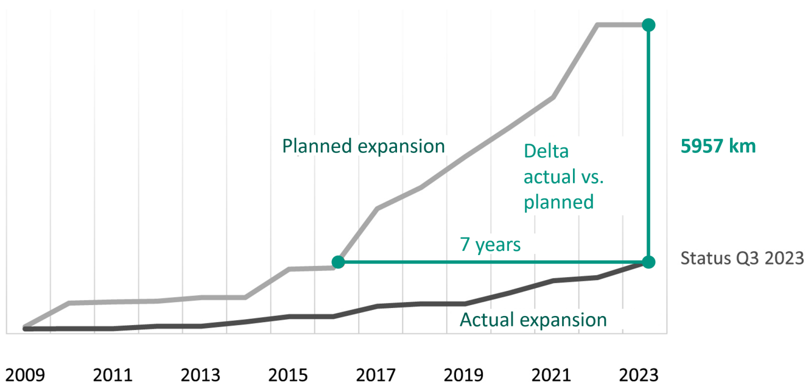

Figure 1.1: Delay of grid expansion measures in German EnLAG and BBPlG between 2009 and 2023. Source: Bundesrechnungshof, Monitoringbericht 2010, Netzausbaumonitoring 2013-2023 [Bun24b].

Furthermore, with increasing shares of intermittent RES, the utilisation of the grid becomes increasingly determined by weather conditions. It is not economically feasible to expand the grids to a stage where every kW of renewable energy generated can be transported. The German regulator Bundesnetzagentur states that even the complete grid with all expansion measures proposed by the four German Transmission System Operators (TSOs) for 2037 would contain numerous congestions, as shown in Fig. 1.2.

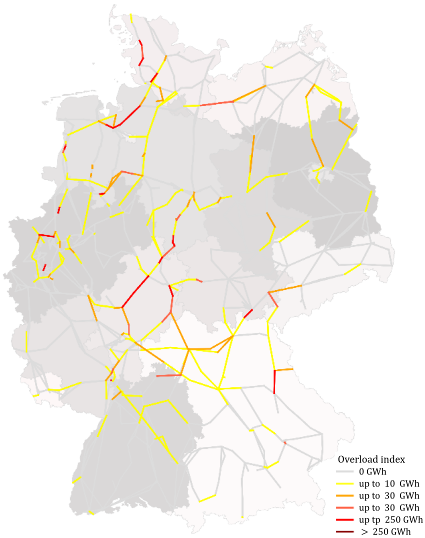

Figure 1.2: Remaining overloads in the German grid development plan scenario B 2037 if all expansion measures proposed by the TSOs were implemented. Source: Confirmation of the grid development plan 2037/2045, [Bun24a].

A relief for the transmission grid can be found in optimised operations, for instance, in the form of weather-dependent current limits on overhead lines (also called Dynamic Line Rating (DLR)). This allows for higher transmission in hours with high wind speeds that are correlated with the system's transmission needs (due to high wind power infeed). Moreover, the integration of DLR into existing transmission overhead lines offers the advantage of potentially fast(er) implementation than traditional grid expansion measures.

This optimising approach is planned to be implemented or is already in use by many European TSOs. Figure 1.3 shows the planned and present use of dynamic line rating in the German 380 kV grid by the four German TSOs. Therefore, consideration of this flexibility becomes also important for market studies, where coupling constraints are determined by the prevalent grid conditions at the time of market clearing; and to determine the final capacity factors of RES after curtailment.

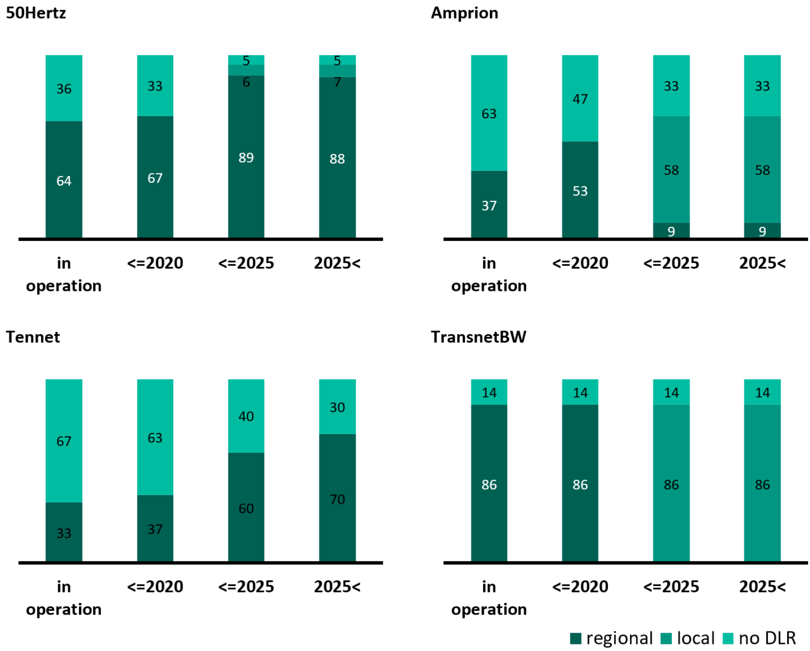

Figure 1.3: Share of DLR utilisation as of 2019 and planned by the for German TSOs for the 380 kV grid in %. Source: 'Monitoringbericht 2019 von Bundesnetzagentur und Bundeskartellamt', [Bun20]

A key challenge for (market) analyses of the future energy system is thus to incorporate this inherent uncertainty with regard to the grid state into the investigation and to develop ways of integrating the optimisation potential from the (flexible) grid restrictions into the market considerations.

1.2 Aim and structure of the thesis

The aim of this thesis is to quantify the influence of market coupling on the market clearing, prices and grid operation and the resulting revenue opportunities for RES and flexibility providers. To this end, it is necessary to develop an approach that allows taking into account the above-mentioned circumstances in an integrated manner. This approach consists of a market model which is capable to integrate FBMC in a future energy system and derive Flow-based (FB) exchange capacities based on detailed fundamental grid expansion scenarios for the transmission grids in the bidding zones of the Core CCR. In addition, the approach must be able to model (and integrate into the market coupling) future flexibilities that will necessarily be present in the electricity system with high shares of RES, such as (seasonal) storage, battery storage, flexibility potential from electric vehicles and home storage, but also increased demand flexibility, for example, from price-sensitive heat pumps or electrolysers. This forms the basis for analyses, which can compare FBMC with static NTC approaches, as they are used in most economic studies to sensitise stakeholders to potential differences.

Based on these market results, consistent grid simulations can be performed and the necessary congestion management in the transmission grid can be determined, to quantify the impacts on the actual feed-in of RES and flexibility providers.

Market and grid analyses are embedded in the European market design and regulatory context. In addition, the dynamics of the electricity markets depends on market developments in the commodity and emission allowances markets. Chapter 2 provides the fundamental background for the thesis with respect to these aspects, introducing the different segments of the wholesale market for electricity and how the limited exchange capacities are allocated among them. Furthermore, the methodological foundation for the grid simulations and FBMC is presented.

As future systems will largely depend upon weather-induced phenomena, being it the generation of renewable energy sources or the weather-dependent flow limits of overhead lines, a detailed spatio-temporal processing of meteorological data is necessary combined with technical models of the respective technology. These aspects, including the (temperature-dependent aspects of) electricity demand profiles, are described in Chapter 3.

The following Chapter 4 presents the core modules developed in the approach, the wholesale electricity market model, the transmission grid model and the module for calculating the Flow-based (FB) coupling constraints. Furthermore, a method is described that should make it possible to determine dynamic bidirectional exchange limits based on the FB results and thus to calculate an approximation of the FBMC in NTC-based models.

In Chapter 5, the data basis for the grid and market models is described, one part describing historical data (sources) for validation and backtesting purposes, and another part introducing the input data for future scenario analyses.

The results of these analyses are presented in Chapter 6, which start with a validation study of the grid simulation and the evaluation of parameter choices in the congestion management simulation on the resulting volumes. Thereafter, the impact of minimum exchange capacities introduced by the Clean energy for all Europeans package (CEP) on market prices and exchanges are analysed, as well as the effects of an expansion of the FB region towards Core CCR. The model-based studies are completed by a quantitative analysis of the impacts of market coupling regimes on congestion management volumes and the earnings potential of renewables and flexibility providers in a scenario with high shares of renewables.

Chapter 7 draws the essential conclusions from the scenario results, critically reflects on the developed approach and closes with an outlook for future research.

2 Foundations of electricity markets and electricity grids

In this chapter, the important foundations and context for the dissertation are presented. Section 2.1 provides an overview of the current market design in the European electricity system with respect to markets and grid operation. This is followed by Section 2.2, which details how different market segments are coupled and how zonal electricity markets can be modelled. Section 2.3 introduces the markets for commodities which are of relevance in the context of energy system modelling, followed by Section 2.4, which presents the structure of the European Electricity grid and lays out modelling approaches and concepts which are important for the presented approach. Flow-based market coupling (FBMC) is introduced in Section 2.5 with concepts and methodology in Section 2.5.1 and as a research subject in 2.5.2. Section 2.5 has already been published in large parts in [Fin21].

2.1 Fundamentals of energy economics in Europe

This section describes the fundamental market design and regulatory framework, respectively, of markets for electricity and electricity grids. Since the liberalisation, the transformation and trade of electrical energy are partly organised in competitive markets, while other parts remain monopolised and regulated.

Markets for electricity

Wholesale markets are where electricity suppliers, sales companies and large (industrial) consumers trade electricity. They can be classified into exchange-based markets, where transparent and standardised products are traded, and Over-The-Counter (OTC) markets, where market participants can negotiate more flexible individual contract conditions, which serve both parties better than the products available at exchanges. The different segments of wholesale markets can be described by their proximity to the physical exchange of electricity. Futures markets (standardised products on exchanges) and forward markets (traded OTC) serve market participants primarily through financial derivatives to hedge against price risks or speculate on future price movements. Spot markets consist of the day-ahead market, where electricity can be traded the day before delivery, and the intraday market, where trades can be made until close to real time (5 minutes before delivery in some markets). The day-ahead market is, with regard to liquidity (today), the most important market and is used as a price reference for a large share of the traded electricity. It also allows efficient scheduling of generation units. The intraday market, on the other hand, allows adjustments in these schedules following forecast errors of Renewable Energy Sources (RES), the demand and unplanned outages of power sources.

Ancillary services markets are different in the way that there usually is a central counter party, the grid operator(s). In balancing markets, grid operators acquire capacity and energy reserves outside the spot markets to ensure the necessary balance of supply and demand in the grid after markets have closed. Other ancillary services include functions such as e.g. black start capability and reactive power provision. Ancillary services have traditionally been offered by generators, but more providers, such as demand response, are included in the procurement as technical solutions become available. The last market segment is related to investment incentives in generation capacity or to keep existing capacity available. As additions to generation capacity depend on private investments, incentives are created to achieve political goals such as security of supply and the integration of new (not yet competitive) technologies. For flexible generation sources, which can provide *secure capacity* (i.e., they are dispatchable), this is often achieved through capacity mechanisms, for instance reserves or capacity markets. To promote the diffusion of new technologies, this often includes support schemes, as they are present in many European countries for various intermittent RES, such as feed-in tariffs or market premiums. Finally, retail markets are where (small and medium-sized) end consumers procure their electricity, usually in the form of standardised contracts. This segment is of high relevance to incentivise flexible reaction of consumers to electricity spot prices, which to this day is mostly not the case due to two factors. First, today's end consumer contracts in the vast majority of cases do not differentiate in price (on an hourly basis) with respect to the wholesale market prices and second, end consumer prices contain to a large degree cost, which are not dependent on the market price for electricity but consist of grid fees, taxes, etc., which reduces the steering effect prices could have on consumption.

The European market design employs a zonal market model with so-called Bidding Zones (BZNs). Within these BZNs, physical restrictions of market transactions (from the electricity grid) are neglected, as under normal network conditions sufficient transmission capacity is available.

Electricity grids

The electricity transmission networks form natural monopolies, where competition would not be efficient. These networks are therefore owned and operated by monopolists and are regulated accordingly. In European markets, the operation of the grid follows the closing of the market, when the bids of the suppliers and consumers have been cleared on the exchanges or OTC. This is often described as self-dispatched or self-scheduled markets in contrast to centrally dispatched market design (which is explained in the following paragraph). Therefore, the grid operators have the role of ensuring a secure grid operation given the market outcome. Grid operators can be divided into TSOs, which own and operate the grids that mainly transport electricity over large distances, and Distribution System Operators (DSOs), which manage the lower voltage parts of the grids where electricity is (traditionally) distributed from the transmission grid to end consumers. With the widespread dissemination of Renewable Energy Sources, these grids often collect energy and feed it into the transmission grid. As zonal markets do not account for intra-zonal network constraints, situations can occur in which the market dispatch schedule is not feasible for secure grid operation. Grid operators are tasked to ensure grid adequacy; this includes maintenance of grid infrastructure, as well as the adaptation for (future) transport needs, especially in the context of the transition towards RES through grid optimisation, reinforcement and expansion. As grid expansion is facing delays due to resistance in the population and lengthy authorisation procedures, grid operators have the possibility to intervene in the market schedules and reduce generation causing a grid congestion, while increasing generation on the other side of the congestion by means of re-dispatch. However, not for all congestions, infrastructure measures like grid expansion are cost efficient, so in energy systems with high shares of decentralised, intermittent electricity sources, re-dispatch likely remains an efficient adequacy instrument and can be integrated into the grid expansion planning[1].

Alternative market design - central dispatch
A different approach to efficient resource allocation is the centralised dispatch with an Independent System Operator (ISO) also often referred to as Regional Transmission Organisation (RTO), as it is applied in many (North) American electricity markets. Here generators are dispatched by a centralised unit, which also publishes obligatory guidelines for cost calculations (fuel costs, start-up costs, no-load costs, etc.). A prominent example is Pennsylvania-New Jersey-Maryland (PJM) Interconnection, a RTO in the United States. The challenges faced in both systems are very similar, leading to also very similar solutions (day-ahead market and real-time market), capacity markets and ancillary services markets. A major difference is the formation of prices, where in ISO systems Locational Marginal Prices (LMPs) determine the contribution margin of the generators at each node of the network and indicate the scarcity

[1] In the German context, TSOs can assume peak shaving (through re-disaptch) of up to 3 % of the yearly forecasted infeed for wind onshore and solar PV in the expansion planning [50H22b], the European legislation allows for up to 5 % [Eur19a]

or surplus of supply or flexibility. The European markets, consist of BZNs, which in most cases comprise the member states.[2] A detailed comparison of self-dispatched and centrally-dispatched markets is presented in [Ahl18]. A comparative overview of the market segments in the standard European and US market design is presented in Fig. 2.1.

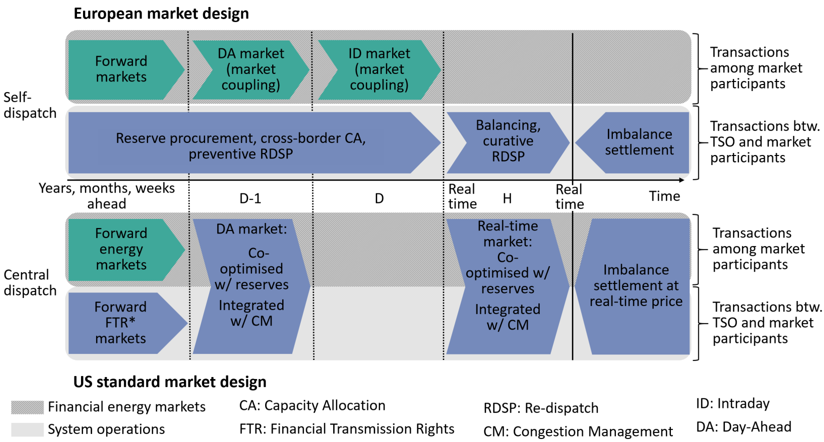

Figure 2.1: Different market segments of wholesale markets and respective role of transmission system operator in the European and US-American standard electricity market design[Roq18][a]

[a] The distinction between capacity allocation and congestion management is not always clear in the literature. At times capacity allocation is also referred to as ex-ante congestion management and re-dispatch is sometimes referred to as curative congestion management (see also [Web22].

Market coupling

A key feature of liberalised European markets for electricity has been the ongoing integration through market coupling, which aims at efficient use of physical transmission capacities for electricity trade to maximise social welfare. Current efforts to market coupling in the different market segments are

[2] Notable exceptions being Norway, Sweden, Denmark and Italy, which all have more than one BZN, and the Germany_Luxembourg BZN or the Irish Single Electricity Market (SEM), where more than one country form a common bidding zone.

further described in Section 2.2. The first approach to market integration followed the auction of explicit transmission rights to market players (which still exists, e.g., for long-term markets). It has since been replaced more and more by implicit allocation, where TSOs calculate the available transmission capacities and provide these to the electricity exchanges. Market coupling is then performed by means of optimisation, best known in the case of the day-ahead markets through the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) algorithm, which is jointly maintained by the European electricity exchanges (see Section 2.2).

The European market design is subject to ongoing changes induced by either the European Commission or individual member states. A comprehensive compilation of European regulation regarding the electricity markets can be found in [Mee20]. Some recent examples are the redesign of the German balancing market in November 2020, the introduction of *Redispatch 2.0* since March 2022 and the German Easter Package from July 2022, increasing targets for RES expansion. Another example is the implications of the Russian invasion of Ukraine in early 2022, leading to unprecedented price levels for natural gas in Europe, but also elevated price levels of coal, oil and CO_2 certificates. This, in turn, led to newly introduced policies, from price caps, discussed in several European countries, to a discussed redesign of price determination mechanisms away from marginal pricing. These changes are accompanied by the first telltales of materialising climate change in the form of more regular extreme events (floods, but more importantly for the energy system droughts and heatwaves, resulting in emptier than usual hydro reservoir and river levels). Additionally, state interventions in the market occur regularly, for example, the renationalisation of the French quasi-monopolist Électricité de France (EDF), or the regulatory shutdown of the German nuclear fleet and some older lignite power plants.

Relevance in the scope of the dissertation

The main objective of the developed framework is to depict how prices are determined in interconnected electricity markets. Prices are conceptualised as the point where demand and supply intersect in all energy markets. It is essential to take into account the balancing markets, as they limit the electricity supply accessible to spot markets.

2.2 Coupled European markets for electricity

Simulating the coupling of European electricity markets represents the heart of the framework developed in this thesis. This section describes the status of integration and market coupling in the different market segments for electricity, followed by a section on how these markets can be modelled as optimisation problems, to lay the foundation for the following chapter, where the developed model is described in detail.

2.2.1 Coupled long-term markets

Forward Capacity Allocation (FCA) regulation [Eur16], which came into force in October 2016, makes the integration of the FB allocation methodology also obligatory for long-term allocation of capacities. FB allocation methodology is scheduled to be launched in late 2024 for the first yearly auction for 2025 for the CCRs Core[3] and Nordic[4]. Long-term transmission rights are offered in explicit auctions on a platform operated by the Joint Allocation Office (JAO). Due to the large uncertainty regarding future generation and load patterns,

[3] Core CCR consists of the borders between BZNs Austria (AT), Belgium (BE), Croatia (HR), Czech Republic (CZ), France (FR), common BZN of Germany (DE) & Luxembourg (LU), Hungary (HU), the Netherlands (NL), Poland (PL), Romania (RO), Slovenia (SI) and Slovakia (SK), involving 16 TSOs and 10 Exchanges.

[4] Nordic CCR covers the power systems of Finland (FI), Norway (NO), Sweden (SE) and Denmark (DK)

as well as the availability of transmission lines for which transmission rights need to be guaranteed, the implementation of the FB methodology is complex and not without disadvantages. [ENT23a] lists as potential challenges from the implementation of FB allocation (which clears all bidding zone borders at the same time as the possibility that at certain borders no capacity will be offered, as other borders are more efficient) longer time requirements for the calculation of capacities due to increased methodological complexity and increased collateral requirements by participating market participants, which might hinder competition.

Within the bidding zones, the power exchanges offer a typical range of long-term products in form of power futures, which market participants can use to hedge against price risks in the commodity or electricity spot markets. Standard contracts cover yearly, quarterly or monthly but also shorter maturities, for example, day, weekend or week futures. The EEX German Power Future for instance is available as base load or peak load contract, can be traded at European Energy Exchange (EEX) between 8:00 am and 6:00 pm and is defined in quantities of 1 MW, prices can be defined in euros and cents. The contract covers the physical fulfilment and includes cash settlement [EEX24a]. More complex financial instruments include spread futures that allow to hedge against the price difference between bidding zones and options, that are financially settled and thus allow to hedge against price risks without physical delivery obligations. Options at EEX include Equity Styled Options, where the option premium is paid up front, and Futures Styled Options, where the premium is paid when the contract expires [EEX24b].

2.2.2 Single day-ahead market: European market clearing algorithm EUPHEMIA

Guidelines for cross-zonal capacity allocation and congestion management are defined in [Eur15]. For the day-ahead time frame, this process is called Single Day-Ahead Coupling (SDAC). SDAC was introduced in 2014 in the northwestern and southwestern European CCRs[5], [6] as well as in the 4M market coupling[7]. In the following years, more bidding zones joined: Italy (IT) and Slovenia (SI) in 2015, Croatia (HR) and the market zones of the single electricity market on the island of Ireland (SEM) in 2018, Greece (GR) in 2020 and Bulgaria (BG) in 2021. In 2021, the GB bidding zones exited SDAC following the Brexit, while 4M market coupling zones were integrated with the other zones. The method of market coupling is called Price Coupling of Regions (PCR), where the technical solution used in the day-ahead time frame and for intraday coupling is EUPHEMIA. After being in used since 2015 in CWE[8], Flow-based market coupling, which is described in more detail in Section 2.5, was implemented for the borders of the Core capacity allocation region. The constraints on exchanges at the other borders follow the Available Transfer Capacity (ATC) model[9] [ENT21b].

Furthermore, TSOs can and have introduced additional constraints that must be respected during capacity allocation to maintain the transmission system within the operational security limit and have not been translated into cross-zonal capacity or are needed to increase the efficiency of capacity allocation.

5 Including Belgium (BE), Denmark (DK), Estonia (EE), Finland (FI), France (FR), Germany (DE), Austria (AT), Great Britain (GB), Latvia (LV), Luxembourg (LU), the Netherlands (NL), Norway (NO), Poland (PL), Sweden (SE), Portugal (PT) and Spain (ES).

6 DE, AT and LU formed a single bidding zone until October 2018, when AT was split from DE/LU.

7 Czech Republic (CZ), Hungary (HU), Romania (RO) and Slovakia (SK).

8 CWE covers the borders of NL, BE, FR, DE/AT/LU

9 The NTC/ATC model follows the definitions of transfer capacities by the European Transmission System Operators (ETSO), the predecessor organisation to ENTSO-E [ETS00], [ETS01]. It relies on the Total Transfer Capacities (TTC), the 'maximum exchange programme between two areas compatible with operational security standards [defined in each TSO's grid code], applicable at each system if future network conditions, generation and load patterns were perfectly known in advance'. From these TTC, a security margin is deducted to account for 'unintended deviation of physical flows during operation due to the physical functioning of load-frequency regulation[,] emergency exchanges between TSOs to cope with unexpected anbalanced situations in real time [or] inaccuracies, e.g. in data collection and measurements'. The result is the Net Transfer Capacitiy (NTC), the ' maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions.' This NTC can be allocated in different time frames / market segments. After each phase of the allocation procedure, the Available Transmission Capacity (ATC) 'is the part of NTC that remains available,[...] for further commercial activity'.

As of 2023, this includes hourly flow ramping constraints on individual lines, hourly flow ramping limit on line sets, net position allocation constraints, virtual areas limiting the total allocation on a set of borders and line set capacity constraints published on a yearly basis by the European Network of Transmission System Operators for Electricity (ENTSO-E) (e.g. [ENT23b]) and on the transparency platform.

As it is fundamental to European market coupling the basic features of EUPHEMIA are briefly introduced, a detailed description is available in the public description [NEM20].

Supply and demand orders from market participants are collected by the Nominated Electricity Market Operators (NEMOs) active in the European bidding zones. NEMOs are the organisations tasked with the execution of the single day-ahead or single intraday market. This is mainly taken over by electricity exchanges. The Agency for the Cooperation of Energy Regulators (ACER), the European regulator, maintains a list of designated NEMOs for each market. In some cases like the German, Danish and Polish BZNs, there are several NEMOs active in competition, while other markets are only covered by a single monopolistic NEMO like Czech Republic, Italy, or Greece. These bids are then submitted to the algorithm EUPHEMIA. It solves[10] the welfare maximisation problem as a master problem and several sub-problems to provide all the necessary output needed by market participants. In the master problem, the optimal (integer) solution with the objective of maximising social welfare is searched for regarding the rejection and acceptance of demand and supply bids. Social welfare is hereby defined as the sum of consumer surplus, producer surplus and congestion rent. As the problem contains integer variables, the market clearing price cannot be directly derived from the solution of the problem. Thus, following the initial solution of accepted and rejected

[10] PCR is operated in 2024 by nine power exchanges: EPEX Spot, GME, HenEX, Nasdaq, Nord Pool, OMIE, OPCOM, OTE and TGE. The process is based on a jointly operated platform, but data are managed decentralised at the exchanges. Orders and electricity network constraints are shared anonymised among the exchanges through the *PCR Matcher and Broker service* [Epe24a], [Epe24b].

bids, the price determination sub-problem is solved. In some cases, there exists no solution for the price, which satisfies the condition that bids are only accepted when they are in or at the money. In these cases, additional cuts (i.e., constraints) are added to the initial problem and the acceptance of bids is adjusted [NEM20].

EUPHEMIA allows for four different order types depending on the local market rules: (Aggregated) hourly orders, complex orders, which include minimum income condition orders and load gradient orders, block orders, which can be linked block orders, exclusive groups of block orders or flexible hourly orders and finally merit orders and Prezzo Unico Nazionale (PUN)[11] [NEM20]. Not all types are relevant in all markets, for instance, Nord Pool, as of 2023, supports four types of orders for day-ahead trading, which are [Nor24]:

- **Single hourly orders** comprise the largest share of day-ahead bids. They can be either price-dependent (where at least two price volume pairs are used to create a piecewise linear curve through interpolation) or price-independent (where a volume is defined at a minimum or maximum price for all hours).
- **Block orders** are orders in which bids for multiple hours are linked together and are accepted or rejected jointly (partly). Block orders can be linked together or made curtailable where the acceptance ratio is defined equally amongst the hourly bids of a block order. Furthermore, profile blocks can be defined, with varying volumes asked or bid.
- More complex bidding strategies can be created with **exclusive groups** of block bids, from which only one block can be activated.
- Finally, **flexible orders** are block orders, where the starting point is not defined in the order but calculated by the algorithm.

Market participants can also combine these order types to realise their trading strategy.

[11] PUN is the single price which consumers in Italy pay (except pumped hydro storage power plants and importers) although there are several BZNs. As suppliers receive the clearing price in these zones, the PUN is determined by a subproblem in EUPHEMIA.

The geographical resolution of the market clearing is bidding zones, where the outcome is a single clearing price in each BZN for each time period. Furthermore, the Net (Export) Position (NP) for each BZN is obtained from EUPHEMIA's solution.

Once an integer solution is found for the acceptance of bids and a resulting market clearing price has been determined for each bidding zone, two more problems are solved. The first is the PUN search problem, which is a speciality of the Italian market. Finally, the volume indeterminacy problem is solved, which arises if there are several solutions for the acceptance of bids, net positions, or flows at the same market clearing price. To ensure a transparent outcome, EUPHEMIA follows a set of volume indeterminacy rules [NEM20].

In addition to constraints on bids (list of bid types), the problem is constrained by network constraints, which are provided by TSOs and ensure that the exchange flows determined by the market clearing result in feasible power flows in the transmission grid. These constraints can be either ATC constraints, i.e. bidirectional limits on the exchange between zones, FB constraints (explained in more detail in Section 2.5), or hybrid being a combination of ATC and NTC [NEM20].

Furthermore, constraints can be defined on intertemporal deltas of flows (hourly) and NPs (hourly and daily), so-called ramping limits. These are also relevant for the High-Voltage Direct Current (HVDC) interconnectors between the market zones (see the previous paragraph). The constraints on exchanges can also account for losses and tariffs on the power flow in case the interconnector is operated by a private company, so flows are only allocated in case the price difference is above the relevant price delta threshold to be economically feasible. Due to the limitations of ATC constraints to represent the meshed reality of transmission grids, grouped (ramping) constraints can be defined on borders, which has been used, for instance, on the borders of Germany, Poland and Czech Republic [NEM20], [ENT23b].

2.2.3 Single intraday coupling

The capacity allocation and congestion management guidelines also require market coupling for intraday markets [Eur15]. European NEMOs have been working on the implementation of the regulation in the Cross Border Intraday (XBID) project, which continues in the Single Intra-Day Coupling (SIDC). The goal is to make intraday trading more efficient by promoting competition, increasing liquidity, making it easier to share energy generation sources and facilitating to account for unexpected changes in consumption and outages. With increasing generation from intermittent renewable energy sources, the need for closer to real-time trading increases, in consequence also the importance of the intraday market. XBID introduced a continuous trading platform for cross-border intraday trades. Since 2022, it covers 25 countries[12]. SIDC is based on a common IT system that allows the matching of supply and demand bids across borders, as long as transmission capacity allows, through a common order book. Due to different regulatory requirements, SIDC includes explicit allocation of capacity (FR-DE/LU and HR/SI borders) and implicit allocation of both energy and capacity. Bids are continuously cleared, where the highest buy price is matched to the lowest sell price. After the orders have been matched, they are removed from the order book, and the available transmission capacity is reduced accordingly. In August 2023, the minimum order size can be defined between 100 kW and 999 MW, with prices ranging from -9 999 €/MWh to 9 999 €/MWh. Depending on the bidding zone, products include 15, 30 min or hourly bids or even blocks of several hours. As in the day-ahead market, TSOs can and have defined ramping constraints on individual borders or sets of borders. As of 2023, for the SIDC, TSOs have defined constraints in bidding zones of the following countries: Denmark, Norway, Sweden, Poland, Finland, Estonia and Lithuania. These constraints are published on the ENTSO-E transparency platform. Since its introduction, the importance of cross-border intraday trading has increased significantly. The development of the trades since the third quarter of 2018 is shown in Fig. 2.2 [ENT24].

[12] EU without Ireland, Malta and Cyprus, including Norway

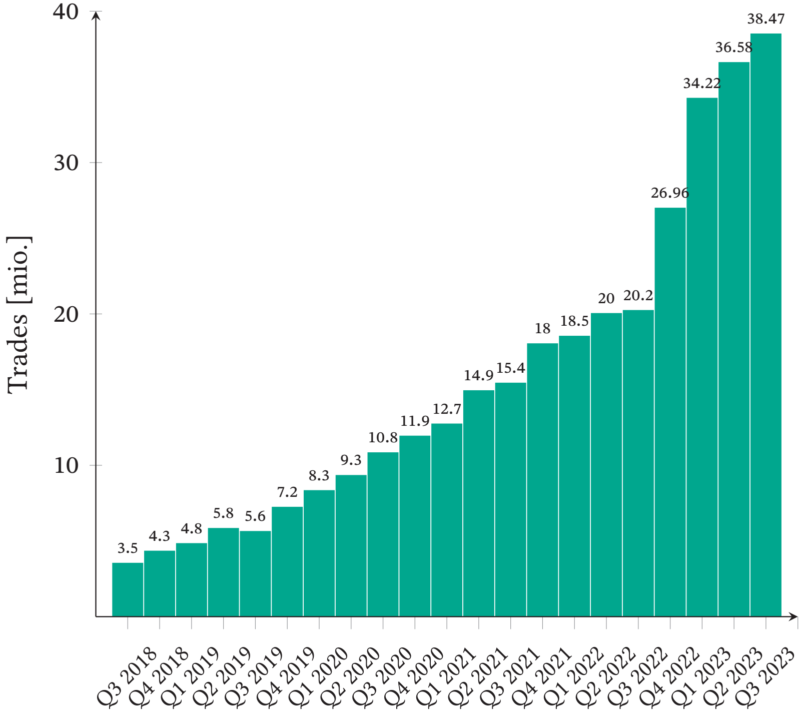

Figure 2.2: Number of trades through SIDC per quarter from introduction in June 2018 until third quarter of 2023 [ENT24].

2.2.4 Coupled balancing markets

The commission also published guidelines for electricity balancing, including targets for to integrate new players such as demand response and RES, but also addressed the issue of sharing resources between market areas by means of coupled markets. Balancing regimes and markets differ with respect to requirements in terms of response time, degree of automation and provisioning time and therefore for different products and time frames[13], several cross-border projects have been initiated by TSOs to implement the guideline.

The International Grid Control Cooperation (IGCC) launched in 2010 includes 27 TSOs as of 2023 and allows the connected TSOs to avoid simultaneous activation of frequency restoration reserves in opposite directions by imbalance netting. The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO), launched in June 2022, allows the exchange of Automated Frequency Restoration Reserve (aFRR) bids among 26 connected TSOs. As of October 2023, operational members are the TSOs of DE, CZ, AT and IT. The Manually Activated Reserve Initiative (MARI) platform, launched in late 2022, enables the exchange of bids for Manually Frequency Restoration Reserve (mFRR) between TSOs. Although all EU TSOs are project members, as of 2023 the platform is operational for the TSOs of DE and CZ. The Trans-European Replacement Reserves Exchange (TERRE) has been in full operation since 2021 and enables the coordinated activation of Replacement Reserves (RR) among seven TSOs[14] [ENT23a].

Beyond these solutions required by the electricity balancing guideline, TSOs have engaged in voluntary solutions for cross-border cooperation in balancing markets. The TSOs of Nordic CCR have decided to introduce a market for aFRR capacity in 2022, the TSOs of DE and AT have been engaged in an aFRR cooperation since 2017, which was extended by the Allocation of Cross-zonal Capacity and Procurement of aFRR Cooperation Agreement (ALPACA) that also includes the TSO of CZ. For Frequency Containment Reserve (FCR), the voluntary FCR cooperation has been in place since 2017 and as of 2023 includes 12 TSOs[15] [ENT23a].

[13] For a detailed description of the specifics of the balancing market segments, the interested reader is referred to the textbook literature, e.g., [Web22].

[14] As of 2023, the TSOs of CZ, FR, IT, PL, PT, ES, CH are project members, (the TSO of HU and ENTSO-E have observer status and the TSOs of NO and SE as well as Amprion have joined the project to obtain intellectual property rights to the technical solution.) Until the expected connection of the TSO of PL in 2024, the TSOs of ES, PT, FR, CH and IT exchange products on the platform, while CZ operates in island mode.

[15] FCR cooperation involves the TSOs from AT, BE, CH, CZ, DE, DK, FR, NL and SI.

2.2.5 Sequential allocation of transmission capacities

Through the different technical platforms that allocate products in different market time units to the same physical transmission capacities, a solution for capacity management needs to be found. Until 2024, this issue will be addressed by the individual TSOs, which have to maintain the information about the capacity allocated among the different time frames (long-term, day-ahead, intraday, balancing markets). The TSOs develop a common capacity management module, which is scheduled to keep track of the allocation in a centralised way. In particular, the limits for cross-zonal capacity after the intraday time frame are send to the replacement reserves platform. After the optimisation on the RR platform, the resulting flows are transferred to the mFRR platform, where again an optimisation is run for reserve activation. Afterwards, the results are sent to the common IT platform for aFRR and Imbalance Netting (IN), where the reserve activation is again optimised. Figure 2.3 shows the sequence of transmission Capacity Allocation (CA) in the balancing markets [ENT23a].

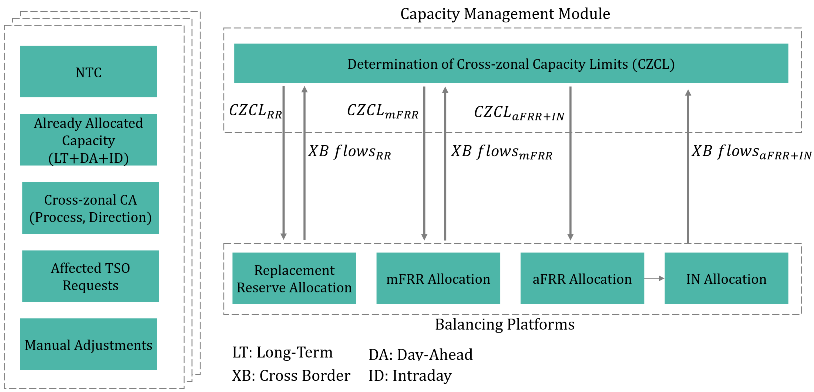

Figure 2.3: Sequence in which total available transfer capacities are allocated in the different (balancing) market domains, after being partially allocated to the long-term, day-ahead and intraday domain [ENT23a].

2.2.6 Liquidity of the different market segments

Over the years, the different segments of power markets have shifted in relevance. Market segments closer to real time have gained importance for market participants and hence liquidity has increased and the importance of exchange executed contracts has increased, if not in volume, at least in importance as a relevant reference market. Indeed, electricity contracts (including) power purchase agreements are often indexed to the day-ahead market or other liquid products at the exchanges, where prices are made transparent, as a reference. Higher volumes of the forward markets compared to the spot markets are due to a relatively high churn rate, i.e. energy is traded multiple times before it is consumed[16]. Hence, the traded volumes at the (forward) markets are much higher than the electricity, which is finally physically generated, transported and consumed.

The volume of contracts traded on the European forward markets at EEX in 2021 was 4 568 TWh compared to 629 TWh traded at the spot markets. The day-ahead market is again much larger than the intraday market [EEX23]. For example, in Nord Pool in 2021, 963 TWh were traded at European spot markets, of which the Nordic and Baltic day-ahead market accounted for 722.5 TWh (~75 %), while the Nordic intraday markets only accounted for 25.18 TWh (~2.6%) [Nor22]. At EEX in 2022, intraday products accounted for 134.6 TWh (~21.9 %) compared to a total of 616 TWh traded at the spot markets [EPE23].

Although the role of exchanges has increased, most of the electricity in the European markets it procured through (OTC) contracts. However, the distinct markets show different characteristics; e.g., in the Nordic markets, the majority is cleared on exchanges, while the UK markets are almost exclusively relying on OTC contracts. In Germany, the most liquid market in Europe by far, between 20 % and 30 % are cleared at the exchanges, while OTC contracts account for the rest of the electricity traded [Eur23a].

[16] Churn factors in the European markets vary, with the highest values appearing in Germany with >7 (2017-2021) [ACE22]

The changing nature of the market share of these different segments, as well as the inherent price dynamics, are beyond the scope of most long-term market models. Usually, the total electricity demand is cleared in a single (deterministic) mechanism, which is used to clear all the physical electricity demand, while accounting for exchange capacity potential, dispatch of intertemporal flexible resources, and so on.

2.2.7 Models of the wholesale electricity markets

Various modelling approaches are employed to navigate the complex interplay of market dynamics, each exhibiting unique characteristics in terms of complexity and computational burden. These can originate from different sources, which include but are not limited to the spatial and temporal scope and resolution of the model, the inclusion of discrete decisions through binary variables or integrity constraints on variables, e.g., for storages. The representations of the electricity grid also cover a wide range, from a zonal market setup with bidirectional NTC limits to a nodal grid representation with Alternating Current (AC) power flow equations and finally the inclusion of contingency cases to ensure secure operation. Each type of model, ranging from linear models to advanced machine learning approaches, offers unique insights and comes with its own set of advantages and limitations.

Linear models, often used for economic dispatch, simplify the market by assuming linear relationships between variables [Xia10]. These models are computationally efficient, making them suitable for large-scale system analysis including seasonal storages (such as hydro reservoirs) with time-coupling constraints [Web05].

Unit commitment models introduce a higher level of detail by incorporating technical constraints of power plants, such as minimum up and down times and ramping rates [Bjø08]. When combined with economic dispatch, these models offer a more nuanced understanding of operational decisions, especially in day-ahead and reserve markets, through the explicit consideration of start-up and shutdown decisions [Bru17]. However, the binary nature of the decision variables in these models increases the computational complexity.

Often, myopic setups are used where relatively small market time units are solved to optimality, in rolling windows over the entire period [Ata18].

Optimal Power Flow (OPF) models, with both Direct Current (DC) and AC representations, provide an advanced grid representation, including line capacities and losses. DC OPF simplifies the AC power flow equations, enhancing computational feasibility while sacrificing some accuracy [Rui08]. AC OPF, in contrast, offers a more precise representation of the physical flow of electricity, also accounting for voltage levels and reactive power provision.

Stochastic models, which incorporate randomness and uncertainties in market conditions, can be applied to all the above approaches. These variants are useful in simulating scenarios with, e.g. variable renewable energy generation and fluctuating demand, enhancing the models' robustness in risk assessment and decision-making processes [Mös10].

Statistical models and in recent years increasingly machine learning approaches have been introduced, especially in the short-term forecasting of market prices [Lag21]. While their forecast quality can be much higher than that of fundamental models, these models lack the explanatory qualities of fundamental models, especially in the context of transitional scenarios of the energy system.

Agent-based models [Rin16], [Wei08] are another class of models and allow for adaptive behaviour modelling of and interaction among agents. System dynamics models another one that allows to account for complex feedback loops [Ahm16].

Relevance in the scope of the dissertation

Spot markets form the heart of the developed framework. Balancing markets, while not the focus, impact the results because reduced capacity is available, compressing the merit order, with special significance in scarce situations.

2.3 Commodity markets - European natural gas, oil and hard coal markets

Wholesale markets also exist for natural gas. As gas-fired power plants are to play an important role as transition and backup technology, providing secure capacity, prices for natural gas are also important for energy markets. Prices for (hard) coal are important for the shrinking fleet of coal-fired power plants in Europe. Besides some countries, which produce their own hard coal for the power sector, where the cost basis is relevant, most coal for the European energy sector is imported and thus depends on (global) markets. The same is true for oil derivatives, which play a minor role for some oil-fired power plants. Some power plants can (in addition to their main fuel) also burn oil derivatives as a substitute. Finally, all fossil power plants above 50 MW fall under the European Union Emission Trading System (EU ETS), so the price of certificates, which can also be traded on markets, is important for the formation of prices on the European electricity markets. For lignite, which is almost exclusively sourced at the location where it is used, there are no liquid markets. Uranium, on the other hand, is traded, but due to the possibility of missuse, it is not open to many players and prices are not formed on liquid markets.

2.3.1 Markets for natural gas

In Europe there are several hubs and virtual balancing points for natural gas: The Title Transfer Facility (TTF), a virtual trading hub in the Netherlands and the National Balancing Point, a virtual trading hub in the United Kingdom, being the most liquid [Hea12]. Besides these, there are many other regional trading hubs. For instance, EEX offers trade on the following hubs: the Central Europe Gas Hub Virtual Trading Point (CEGH VTP) in Austria, Czech Virtual Trading Point (CZ VTP), Exchange Transfer Facility (ETF) in Denmark, Punto di Scambio Virtuale (PSV) in Italy, Point d'échange de gaz (PEG) in France, PVB in Spain, Trading Hub Europe (THE) in Germany as well as Zeebrugge Hub (ZEE) and Zeebrugge Trading Point (ZTP), both in Belgium.

A large amount of European natural gas demand used to be delivered by pipelines from Russia. In light of the Ukraine war, this has changed dramatically, putting pressure and focus on the import capacity of Liquified Natural Gas (LNG). At most hubs, gas is traded in €/MWh and contracts cover 1 MW. The hubs differ in the type of contract they offer. There is also a divergence between the prices.

Long historical price time series are not openly available, the EEX publishes the *Neutral TTF index*, a cumulation of traded contracts around the delivery day for the last 60 trading days. Historic spreads in wholesale gas prices and average prices are published by the European Commission in the *Quarterly Report reports on European Gas Wholesale Markets*[17], which include multiple hubs per country and provide information on wholesale prices and prices for industrial customers.

More than in the electricity markets, futures are important in the gas markets. Day-ahead markets exist for instance for TTF, but the short-term future products (front month, front quarter) are much more common and tradable on several exchanges as standardised contracts (e.g. at Intercontinental Exchange (ICE), Chicago Mercantile Exchange (CME) or EEX). In some markets LNG plays a significant role for the gas supply, while other markets almost completely rely on pipeline gas, e.g. from Norway or Russia. In the aftermath of the Russian invasion of Ukraine, the import of Russian pipeline gas has been significantly reduced in Europe.

2.3.2 Markets for hard coal

Besides natural gas, hard coal and oil derivatives play a relevant role in the electricity mix of some European countries. With some exceptions, most of the hard coal used in the power sector is imported from outside of Europe, and therefore prices are subject to dynamic global markets. Similar to TTF or National Balancing Point (NBP) for gas, there is a standardised reference for imported hard coal in northwest Europe, which serves as a reference point for

[17] https://energy.ec.europa.eu/data-and-analysis/market-analysis_en

most trade contracts. This reference is the API 2 price assessment published by Argus media as the average of the *Argus CIF*[18] *ARA*[19] *price assessment* and the *IHS McCloskey NW Europe Steam Coal marker*. Based on this reference, futures and options are available on exchanges that cover time frames from the front month to several years into the future with declining liquidity.

2.3.3 Oil derivatives in the power sector

In some countries, in southern Europe, fuel oil has some relevance for power generation. Trades are conducted directly between sellers and buyers, so there is no transparent exchange price available. As with hard coal information providers, like *S&P Global Commodity Insights*, offer a price assessment for low-sulphur fuel oil, which serves as a reference for contracts. Against these reference indices, futures products are available for financial hedging on the exchanges.

2.3.4 Markets for emission certificates

Since it's introduction in 2005, the EU ETS has been an (important[20]) aspect of variable costs for fossil power generation. Currently, the system is in the fourth trading phase (2021-2030). Emissions have to be covered with emission allowances, which can be obtained in auctions (in the case of Germany once a week) and traded on the secondary market, where also futures products are available for financial hedging. In scope of the *fit for 55* package by the European Commission, the emission cap was tightened to reduce the emissions covered by EU ETS by 61 % by 2030, compared to 2005 [Eur23b].

[18] CIF: price for the import of a good which includes cost, insurance and freight.

[19] ARA: Antwerpen, Rotterdam, and Amsterdam.

[20] Especially between 2013 and 2017 prices for CO_2 were so low that the 'importance' for price formation can be questioned.

Relevance in the scope of the dissertation

- Regional gas prices are relevant for price dynamics between regions, especially if new-built (gas-fired) power plants make the energy mix in countries more similar (other technology choices (lignite, coal) are no longer desirable, nuclear of limited appeal).
- Coal and oil prices are of lesser importance for future scenarios but highly relevant for back-testing
- CO_2 prices are of high relevance to determine the cost of fossil generation.

2.4 Transport of electricity

The electricity traded on the markets needs to be physically transported from generation to demand. This happens in the electrical grid. This section introduces the voltage levels in use in Europe, explains how the power flows in the grid can be described mathematically, and how grid operation can be modelled. It concludes on the necessity of and processes for grid expansion.

2.4.1 Voltage levels in Europe

The electricity grid can be characterised into two domains, the transmission grid, where large amounts of energy are transported over a significant geographical distance at extra-high voltage levels, and the distribution grid, where electricity is transformed to lower voltage levels and spread among consumers. In (Central) Europe, the transmission domain consists of the extra high voltage levels of 220/225 kV[21] and 380/400 kV, which is operated by the TSO. In some eastern European countries older 750 kV lines exist, which

[21] The indicated voltage levels refer to phase-to-phase voltage.

are typically operated at 400 kV or out of service. Large power generators feed into the transmission grid, through which the energy is transported to substations close to demand centres, where it is transformed to lower voltage levels. The distribution domain contains the high voltage level (typically 110 kV or 150 kV), medium voltage level (1 kV - 35 kV), and low voltage level (< 1 kV). Consumers and smaller power generators are usually connected to the distribution grid, according to the maximum power demand (e.g. large wind farms are connected to 110 kV, while households are connected to low-voltage grid at 400 Volt). Table 2.1 shows used voltage levels in Europe, and applicable operational limits.

Table 2.1: Voltage limits in the European transmission grid [Eur17a].

Synchronous area	Voltage range (110 kV - 300 kV)	Voltage range (300 kV - 400 kV)
Continental Europe	0.9 pu - 1.118 pu	0.9 pu - 1.05 pu
Nordic	0.9 pu - 1.05 pu	0.9 pu - 1.05 pu
Great Britain	0.9 pu - 1.1 pu	0.9 pu - 1.05 pu
Ireland and Northern Ireland	0.9 pu - 1.118 pu	0.9 pu - 1.05 pu
Baltic	0.9 pu - 1.118 pu	0.9 pu - 1.097 pu

2.4.2 Power flow in meshed electricity grids

The power flows in a three-phase alternating current system such as the European electricity system can be described using a set of nonlinear equations. Some reasonable assumptions, which are briefly covered in the following, allow for a simplification of the problem, which makes it easier to solve. In steady-state operation, the three phases of the power grid are usually balanced, i.e. the power flow is shared equally between lines, which allows for building of a mathematical model based on the one-line diagram of the positive sequence component [Oed11]. Unbalanced power flows, e.g. in case of a fault, can be analysed using the method of symmetrical components. Furthermore, assuming that no transient changes in the currents or voltages of the system occur, both can be described with sinusoidal functions with time-invariant amplitude, frequency, and initial phase, which allows them to be represented as phasors. Therefore, the power flow problem can be solved using algebraic equations instead of differential equations in the time domain. The complex power in a three-phase system results to [Oed11]:

$$\underline{S} = 3\underline{U}\underline{I}^*, \tag{2.1}$$

where * denotes complex conjugation. Another step of simplification is the use of the per-unit (pu) system, where the relevant parameters are expressed relative to a common base in the power system, which reduces the numeric scale and makes it easier to solve the problem computationally. The state of the power system at each node i can be expressed in terms of voltage angle θ_i, voltage magnitude V_i, net real power injection P_i and net reactive power injection Q_i. The power systems buses or nodes are divided into three groups, depending on the known and unknown variables at the respective bus. At busses without generation, P and Q are assumed to be known, they are called PQ busses. A generation bus is selected as a slack bus, where V and θ are set as reference values. At the slack bus, a large generator is needed, which can balance the system load. For all other (generator) buses, it is assumed that P and V are known (see Table 2.2), therefore they are referred to as PV nodes [Oed11].

Table 2.2: Node categories and variables for power flow calculation [Oed11].

Node type	Known variables	Unknown variables
Slack	θ,V	P,Q
PQ	P,Q	θ,V
PV	V,P	Q,θ

The problem is to identify the unknown variables, which can be achieved by solving a system of nodal power balance equations. This includes the active power balance given by Eq. (2.2a) for each PV node except the slack bus and the reactive power balance Eq. (2.2b) for the PQ nodes.

$$P_i = \sum_{k=1}^{N} |V_i||V_k|(G_{i,k}\cos(\theta_{i,k}) + B_{i,k}\sin(\theta_{i,k})), \quad \forall i \in N \tag{2.2a}$$

$$Q_i = \sum_{k=1}^{N} |V_i||V_k|(G_{i,k}\sin(\theta_{i,k}) - B_{i,k}\cos(\theta_{i,k})), \quad \forall i \in N \tag{2.2b}$$

G_{ik} and B_{ik} represent the real and imaginary part of the admittance matrix Y_{BUS} at row i and column k respectively and θ_{ik} represents the voltage angle difference between nodes i and k. This set of equations can be solved by several methods, of which the most widely used is the Newton-Raphson method [Oed11]. The set of equations Eq. (2.2) is also known as AC power flow equations. Once the solution for the power flow is found, the remaining unknowns can be found by utilising the remaining equations.

This nonlinear, nonconvex representation of power flows in an AC network can be simplified: In normal operation conditions in high- and extra-high voltage grids, voltage angle differences between neighbouring buses are usually small. θ_{ik} becomes close to 1 and consequently $\cos\theta_{ik} \approx 1$ and $\sin\theta_{ik} \approx \theta_{ik}$. Moreover, voltage magnitude differences are assumed to be small, therefore, in per unit terms, all very close to 1, which results in $|V_i||V_k| \approx |V_i|^2 \approx 1$. Finally, typically in transmission grids, the resistance of a circuit is much lower than the reactance ($R << X$). With $g = \frac{r}{r^2+x^2}$ and $b = \frac{-x}{r^2+x^2}$, a reasonable simplification is $g \approx 0$ and $b \approx \frac{-1}{x}$. With these simplifying assumptions, the reactive power flow vanishes, and a reduced representation of the active power flows remains [Web22]:

$$P_i \approx \sum_{k=1}^{N} B_{i,k}\theta_{i,k}, \quad \forall i \in N. \tag{2.3}$$

These DC power flow equations form the basis for the linearised Power Transfer Distribution Factors (PTDFs), which indicate the approximate flows from a node injection to a defined sink at a (set of) slack bus(es) through the network. The PTDF of node n with respect to l^{th} line i,k,l between nodes i and k as defined as:

$$ptdf^{n}_{i,k,l} = \frac{\Delta P_{i,k,l}}{\Delta P_n}, \quad \forall n \in N, \quad \forall (i,k) \in H, \quad \forall l \in L, \tag{2.4}$$

where H is the set of lines, connecting nodes. Slack-dependent PTDFs can also be used to calculate the slack-independent PTDFs of a line i,k,l for the power flow between two nodes n and m.

$$\begin{gathered} ptdf^{n \to m}_{i,k,l} = ptdf^{n}_{i,k,l} - ptdf^{m}_{i,k,l}, \\ \forall n \in N, \quad \forall m \in N, \quad \forall (i,k) \in H, \quad \forall l \in L \end{gathered} \tag{2.5}$$

In the context of zonal electricity markets, PTDFs can also be used to approximate the flows on particular grid elements (e.g. interconnectors). For this calculation, in addition to the grid information, the distribution of power sources and sinks in each market zone has to be known or assumed. These distribution factors are referred to as Injection Shift Keys (ISKs) or, in the context of FBMC as Generation Shift Keys (GSKs) [Van16]. The partial flow resulting from the zonal injections on a particular line (with respect to a slack distribution) can then be expressed as:

$$partFlow^{z}_{i,k} = \sum_{n=1}^{N^z} ptdf^{n}_{i,k} \cdot gsk_{n,z} \cdot injMW_{n,z}, \quad \forall (i,k) \in H, \quad \forall z \in Z. \tag{2.6}$$

where N^z are all nodes in zone z, $injMW_{n,z}$ is the injection at bus n of zone z in MW and Z is the set of market zones. Naturally, the sum of all shift keys in one zone needs to equal one:

$$\sum_{n=1}^{N^z} gsk_{n,z} = 1 \quad \forall z \in Z. \tag{2.7}$$

Analogously, the partial flow resulting from an exchange from zone A to zone B can be calculated using the nodal PTDFs and GSKs, which define how the delta in the zonal injection is distributed between the zonal nodes.

$$\begin{aligned} partFlow_{i,k}^{z_1 \rightarrow z_2} = partFlow_{i,k}^{z_1} - partFlow_{i,k}^{z_2}, \\ \forall (i,k) \in H, \quad \forall z_1 \in Z, \quad \forall z_2 \in Z \end{aligned} \tag{2.8}$$

2.4.3 Optimal power flow

In many real-world problems it is not sufficient to obtain the state of the electricity grid given known input conditions, but it is rather necessary to combine these technical constraints with an (economic) objective to obtain, e.g., an optimal dispatch solution for generators in a nodal electricity market. If the power flow equations are combined with such an objective function, the resulting problem is referred to as OPF problem. In the classic form, the variable cost of the generation units are included in the objective and the problem is solved to find a solution for the grid constrained economic dispatch [Fra16]:

$$\min \sum_{i \in G} C_i(P_i^G), \tag{2.9a}$$

$$s.t. \quad P_i = \sum_{k=1}^{N} |V_{\text{i}}||V_{\ k}|(G_{i,k} \cos(\theta_{i,k}) + B_{i,k} \sin(\theta_{i,k})) \quad \forall i \in N, \tag{2.9b}$$

$$Q_i = \sum_{k=1}^{N} |V_{\ i}||V_{\ k}|(G_{i,k} \sin(\theta_{i,k}) - B_{ik} \cos(\theta_{i,k})) \quad \forall i \in N. \tag{2.9c}$$

Additional constraints are defined on active and reactive limits of generators, voltage magnitude and angle limits at busses.

$$p_i^{G,min} \leq p_i^G \leq p_i^{G,max} \quad \forall i \in G, \tag{2.9d}$$
$$q_i^{G,min} \leq q_i^G \leq q_i^{G,max} \quad \forall i \in G, \tag{2.9e}$$
$$v_i^{min} \leq v_i \leq v_i^{max} \quad \forall i \in N, \tag{2.9f}$$
$$\theta_i^{min} \leq \theta_i \leq \theta_i^{max} \quad \forall i \in N. \tag{2.9g}$$

Most recent OPF formulations also include limits on the power flows across branches

$$h_f(\theta_f, V_f) = |F_f(\theta_f, V_f)| - F_{max} \leq 0, \quad \forall f \in N, \tag{2.9h}$$
$$h_t(\theta_t, V_t) = |F_t(\theta_t, V_t)| - F_{max} \leq 0, \quad \forall t \in N, \tag{2.9i}$$

where the flow limits depending on the formulation can be (real) power flows, expressed in MW or MVA or current magnitude limits.

Some authors divide the decision variables of the problem into control variables (active and reactive power generation of the generators and if included other devices like voltage regulation transformers and phase shifters) and state variables (voltage magnitudes and angles) [Cap16].

Depending on the formulation, OPFs can be applied to solve various problems that arise in operation for TSOs, such as reactive power dispatch, minimising the cost of shunt capacitor deployment, optimising voltage controls and procurement of distributed active power reserves [Cap16]. The scope of the problem also depends on whether time-coupling constraints, unit commitment constraints, or topology changes are included to extend the problem formulation in Eq. (2.9).

2.4.4 Security constrains

Power systems have to be operated in a secure state, which ensures that any single contingency remains within save operating conditions (also referred to as n-1 criterion). To account for this, the problem in Eq. (2.9) can be extended for additional constraints and variables [Cap16], [Fra16]. For a set of relevant contingency states C, the optimal solution also has to satisfy:

$$P_i^c = \sum_{k=1}^{N} |V_{\mathrm{i}}^c||V_k^c|(G_{i,k}^c \cos(\theta_{i,k}^c) + B_{i,k}^c \sin(\theta_{i,k}^c)) \quad \forall i \in N, \tag{2.10a}$$

$$Q_i^c = \sum_{k=1}^{N} |V_i^c||V_k^c|(G_{i,k}^c \sin(\theta_{i,k}^c) - B_{i,k}^c \cos(\theta_{i,k}^c)) \quad \forall i \in N, \tag{2.10b}$$

$$h_f^c(\theta_f^c, V_f^c) = |F_f^c(\theta_f^c, V_f^c)| - F_{max}^c \leq 0 \quad \forall f \in N, \tag{2.10c}$$

$$h_t^c(\theta_t^c, V_t^c) = |F_t^c(\theta_t^c, V_t^c)| - F_{max}^c \leq 0 \quad \forall t \in N, \tag{2.10d}$$

$$p_i^{G,min,c} \leq p_i^{G,c} \leq p_i^{G,max,c} \quad \forall i \in G, \tag{2.10e}$$

$$q_i^{G,min,c} \leq q_i^{G,c} \leq q_i^{G,max,c} \quad \forall i \in G, \tag{2.10f}$$

$$v_i^{min,c} \leq v_i^c \leq v_i^{max,c} \quad \forall i \in N, \forall c \in C, \tag{2.10g}$$

$$\theta_i^{min,c} \leq \theta_i^c \leq \theta_i^{max,c} \quad \forall i \in N, \forall c \in C, \tag{2.10h}$$

$$|p_i^{G,c} - p_i^G| \leq \Delta p_i^{G,c} \quad \forall i \in G, \forall c \in C, \tag{2.10i}$$

$$|q_i^{G,c} - q_i^G| \leq \Delta q_i^{G,c} \quad \forall i \in G, \forall c \in C, \tag{2.10j}$$

where in addition to the system equations for the contingency states, also the transition from normal operation to contingency operation for the control variables has to be feasible.

In the context of economic studies on the European power system that frequently span multiple years with an hourly resolution and are therefore commonly performed using the DC formulation, contingencies are often only considered with regard to branch outages. The OPF is then solved for preventive security, which ensures that the dispatch solution for generators is also feasible in the event of any single line outage. However, these problems are still too large to be solved with reasonable resources, and several approaches to dealing with the problem have been suggested in the literature: The simplest case is the application of a security factor on the branch flow limits, which serves as a proxy for explicit contingency modelling. [Hob22] find that in a simulation of congestion management (CM) in the German transmission system a deduction of line capacity by 30 % leads to similar results in yearly aggregates of re-dispatch and renewable curtailment, but results in geographically different activation of resources. In highly meshed areas of the grid, more congestion management measures are necessary when applying the deduction factor compared to a model version that includes an explicit line outage simulation [Hob22]. Another approach is contingency filtering with the goal of identifying a subset of critical contingencies and then identifying some contingencies that dominate a number of others and are potentially binding in the solution [Cap07], [Jah18], [Bou05].

Similarly to the use in linearised formulations of the power flow, linearised factors can also be derived for contingency analysis [Gul07]. Line Outage Distribution Factors (LODFs) describe the effect of the outage of one line on the power flows of the other lines in the system. The $lodf_{i,k}$ of line i with respect to line k describes the percentage of the present power flow over line k, which will be observed on line i in the case of an outage of line k. Using these LODFs and PTDFs (described in Section 2.4.2), the post-contingency effect of an exchange between two nodes/zones in the grid can be calculated. Analogous to the PTDF, which describes the partial flow over a line given a nodal injection, the Outage Transfer Distribution Factor (OTDF) $otdf_{i,k}^{n}$ describes the partial flow over line i with respect to an injection at node n under the outage of line k

$$\begin{gathered} odtf_{l_1}^{n} = ptdf_{l_1}^{n} + lodf_{l_1,l_2} \cdot ptdf_{l_2}^{n}, \\ \forall l_1 = (i,k) \in H, \quad \forall l_2 = (i,k) \in H, \quad \forall n \in N. \end{gathered} \tag{2.11}$$

The power flow over line i under the contingency c (outage of line k) can then be approximated to

$$\begin{gathered} flow_{i}^{c=l_2} \approx flow_{l_1} + lodf_{l_1,l_2} \cdot flow_{l_2}, \\ \forall l_1 = (i,k) \in H, \quad \forall l_2 = (i,k) \in H. \end{gathered} \tag{2.12}$$

When power flows and contingencies of the branches in the power system are approximated with PTDFs and OTDFs, the OTDF-Matrix for each identified relevant contingency forms an additional set of inequalities, which constrain the optimal solution in the OPF [Jia09].

2.4.5 Congestion management

Given the European market design of self-dispatched power plants, which is determined by auctions at the electricity exchanges, the resulting market solution does not ensure a secure grid operation as only very limited grid constraints are accounted for. Therefore, the grid operator, mainly the TSOs is responsible for ensuring a secure grid operation given the market schedule for power plant operation. Due to the fact that grid expansion and market zone layout are not in perfect alignment with renewable generation, congestions occur in the network and have to be relieved by remedial actions. These include re-dispatch of market power plants, i.e., the increase (positive re-dispatch) or decrease (negative re-dispatch) of the scheduled generation of power plants, curtailment of renewable energy sources, and the activation of grid reserves. Given the rapid deployment of RES in Germany and the delay of planned grid expansions, re-dispatch has become a common phenomenon in Germany, while most other control areas have not (yet) encountered similar levels of market interventions. Figure 2.4 shows the development of necessary congestion management in the four German control areas between 2013 and 2022.

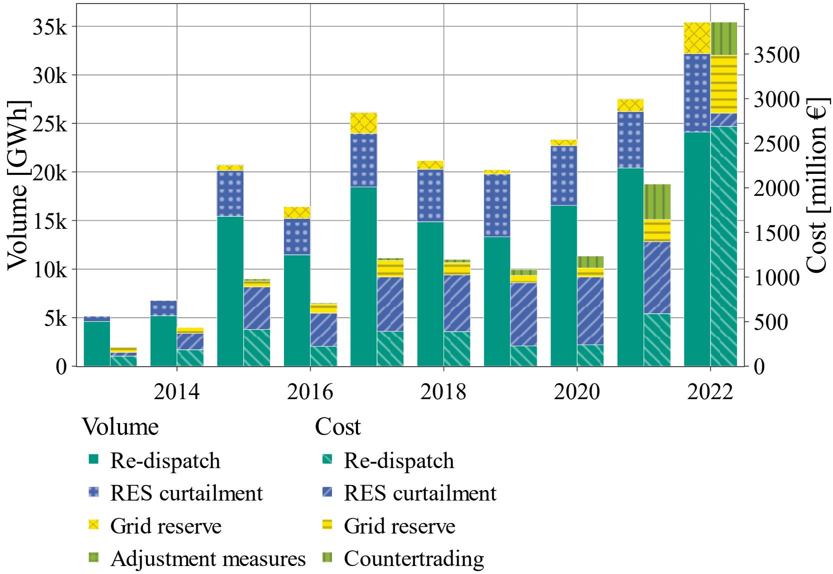

Figure 2.4: Development and volumes and cost for congestion management measures in Germany between 2013 and 2022. (Source: [BDE23],BNetzA).

In some cases, the grid operators also define operation bands for certain power plants in advance, which ensure grid security, e.g. in Poland. Given the growing amount of congestion management (CM) measures in Germany, processes have been continuously developed to curb the increasing costs. The increasing number of CM measures and therefore the increasing amounts of energy and cost affected, on the one hand, and regulatory requirements (prioritisation of renewable dispatch) and court decisions on the other hand have shaped the process. The current state called *Redispatch 2.0* aims at standardised and more efficient processes, covering all generation units above 100 kW. The legislative basis is covered by three German laws (Netzausbaubeschleunigungsgesetz Übertragungsnetz (NABEG) [Deu11], Erneuerbare-Energien-Gesetz (EEG) 2021 [Deu14] and Energiewirtschaftsgesetz (EnWG) [Deu05]), but the details are not clearly laid out. On 28 April 2015, the Oberlandesgericht

Duesseldorf decided that charging energy storages (pumping of pumped hydro storages) must not be forced to participate in the re-dispatch process. Following three decisions of Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen (BNetzA)[22], remuneration for re-dispatch by the German TSOs follows the detailed recommendations of the German Association of Energy and Water Industries (Bundesverband der Energie- und Wasserwirtschaft (BDEW)) [BDE18], [BDE20a], [BDE20b]. The remuneration is subject to ongoing adjustments, with the BNetzA aiming to establish binding remuneration regulations for all market participants in the next regulation period (2024- 2029). This process started in September 2023 with decision *BK6-23-241*.

Also introduced with the *Redispatch 2.0* regulation was the integration of RES in the re-dispatch process. As congestions are mainly caused by RES generation, naturally, the adjustment of RES feed-in is the most efficient way to relieve grid congestion. However, to encourage investment into RES, their dispatch is prioritised by law. To comply with the RES feed-in prioritisation, and still efficiently include RES into the re-dispatch process, BNetzA has defined a minimum factor, which is used to calculate the proxy cost, at which RES are included in the re-dispatch optimisation process[23]. This 'threshold' price is calculated based on the average cost for positive re-dispatch and average revenues from negative re-dispatch according to the following formula:

$$Proxy\_cost_{EE} = (minFact \cdot (C_{posRD} - C_{negRD})) - C_{posRD}, \qquad (2.13)$$

where the minimum factor ($minFact$) is set to 10 by BNetzA, C_{posRD} are the yearly average cost for positive re-dispatch and C_{negRD} are the average revenues calculated by the TSOs.

[22] *BKG-20-059* in November 2020, and *BK6-20-060* and *BK-20-061* in March 2021.
[23] The procedure is based on the study 'Entwicklung von Maßnahmen zur effizienten Gewährleistung der Systemsicherheit im deutschen Stromnetz' [Eco18].

Table 2.3 shows the average cost for positive and negative re-dispatch excluding prioritised electricity and the calculatory prices assumed for RES curtailment and grid reserve dispatch in *Redispatch 2.0* by the German TSOs[24]. Combined Heat and Power (CHP) power plants were included in *Redispatch 2.0* until Summer 2022, when a law[25] was passed, which excluded CHP power plants that can not produce heat with other means from the process.

Table 2.3: Cost basis and calculatoric prices for RES and grid reserves in *Redispatch 2.0* [€/MWh][Net24].

Year	Positive re-dispatch	Negative re-dispatch	RES	Grid reserve
2023 / 2024	222.00	-142.23	575.7	476.5
2022 / 2023	216.99	-128.5	667.89	385.88
2021 / 2022	88.1	-20.23	590.6	251.09

The cost incurred by the TSOs for congestion management are charged to the electricity consumers through grid fees. This makes the determination of re-dispatch volumes and especially cost essential for evaluating welfare effects. In the European market design with market operation largely independent of intra zonal grid congestions, market integration and bidding zone layouts decisions can increase welfare in the market domain, but induce welfare losses in the form of re-dispatch cost, hence these effects should always be considered jointly.

2.4.6 Grid expansion

While re-dispatch can achieve grid adequacy in the short-term and operational domain, from a welfare perspective it is inferior to other solutions, namely adequate bidding zone layout and grid expansion. As a certain size

[24] Values are valid from 1^{st} October to 30^{th} September.

[25] The *Gesetz zur Bereithaltung von Ersatzkraftwerken zur Reduzierung des Gasverbrauchs im Stromsektor im Fall einer drohenden Gasmangellage durch Änderungen des Energiewirtschaftsgesetzes und weiterer energiewirtschaftlicher Vorschriften* [Deu22b] was passed on 8 July 2022.

of bidding zone comes with advantages, such as liquidity and less volatile prices, a zonal market design where generation investment is organised in a liberalised market will most likely lead to grid congestions, when large numbers of renewable sources have to be integrated. As these expansion goals are the consequence of political targets with respect to the decarbonisation of the energy sector and, in particular, the electricity sector and legally binding, grid operators have to ensure long-term grid adequacy by strengthening and extending the grid infrastructure in such a way that it can accommodate the generation capacity and demand to be expected in the future. As grid expansion projects tend to require several years to be completed, the grid operator has to rely on scenario-based assumptions regarding the concrete realisation of the political goals. In Germany with four TSOs and control zones and even more in the European context, this requires coordination between grid operators and regulators, which is organised in grid development plans. This usually takes the form of National Grid Development Plans (NDPs) like the German Grid Development Plan (NEP), where scenario assumptions and grid expansion measures are proposed by the TSOs and confirmed by the German regulator BNetzA. The European perspective is addressed with the Ten-Year Network Development Plan (TYNDP) published by ENTSO-E, where on the one hand national plans are compiled into the national trends scenario, which depicts the TSOs' current view on grid development. On the other hand, the TYNDP aims at providing a European vision in the form of scenarios, based on EU goals and legislation such as the fit for 55 package or the green deal where a cost-efficient European decarbonisation is modelled in a top-down approach. Both NDPs and TYNDP rely on external scenarios regarding macroeconomic development and long-term outlook for fossil fuel prices and CO_2 prices, such as the World Energy Outlook (WEO) published yearly by the International Energy Agency (IEA).

There is a vast body of literature on the subject of transmission expansion planning [Lum16], [Hem13], traditionally driven by the growing energy demand over time, while assuming a price inelastic demand profile. With the decarbonisation efforts and resulting transition of the power system toward renewable generation, this focus has shifted, even further so due to the growing flexibility of demand through the electrification of the transport and heating sector, which will introduce significant demand response potentials to the future system. Market-driven demand flexibility could be available from e.g., electric vehicles (controlled charging, Vehicle-to-Grid (V2G)), heat pumps at household or district heating level, utility-size battery storage systems, or flexibility of industry processes. Demand response sources may also include prosumer systems such as PV-Battery systems where depending on the regulatory incentives, the owner may be either operating the system to optimise self-consumption of the PV electricity or optimise feed-in with respect to the spot market price. [Mot24] provide a recent survey of optimisation models for power system operation and expansion planning that consider demand flexibility. For network expansion planning, they distinguish between transmission expansion planning, joint generation and transmission expansion planning, and transmission planning under uncertainty, which they further divide into stochastic programming and robust optimisation. In the European system where companies owning generation assets are unbundled from the grid operators, joint generation and transmission expansion planning is not the appropriate approach. Additionally, operational reality forces TSOs not only to consider optimal green-field network topology, but rather optimal brown-field solutions, where data availability and quality is in many cases problematic. Furthermore, intermediate states during transformations have to be secure and feasible with regard to voltage stability and reactive power provision, which usually is not covered by optimisation approaches that rely on the DC representation of the power system.

NDPs usually rely on scenarios to account for uncertainty. However, in many cases, for example, the NEP, only one deterministic scenario which incorporates political goals is modelled in full detail over the entire time horizon to derive necessary grid expansion. Robustness of certain expansion measures is then derived ex post, when these measures prove necessary in multiple of the analysed scenarios. Finally, due to the lengthy process of grid expansion and the necessity for regulatory approval, much of the grid expansion in the European countries is predetermined until within the 2030s, which makes the model-endogenous expansion study out of scope for many economic studies of the mid-term European electricity system. Thus, many studies rely on the external set of grid expansion measures as defined in the NDPs and the TYNDP.

With the introduction of FBMC, it has also found its way into the grid expansion processes e.g., the NEP. However, as FBMC relies on explicit knowledge of the future grid topology, in the current version of the NEP[26] it is only applied in the lead scenario and in the earlier of the two planning years, due to uncertainty with regard to the grid expansion state in the European neighbours.

Additionally, ACER can authorise merchant lines in Europe that are exempted from certain aspects of regulation. Realised projects include several interconnectors, for example, BritNed between GB and NL and Estlink linking Estionia and Finland [Rub15], [Lum16].

Relevance in the scope of the dissertation

- (Optimal) power flow forms the basis for the grid analyses in the thesis and is also necessary for FB contraint calculation.
- Linearised (DC) formulation speed up calculation and mimic real procedures (FBMC)
- Security constraints necessary to include for realistic simulation of grid operation
- Parameters in OPF determine closeness to reality
- To model realistic scenarios, comprehensive grid expansion data is necessary

[26] Second draft of NEP 2037/2045, version 2023.

2.5 Flow-based market coupling

Section 2.5 has already been published in large parts in [Fin21].

FBMC was introduced in the Central Western Europe (CWE) region in 2015 to better account for the limitations of the physical electricity network in the clearing procedure of the market. The goal is to increase cross-border capacities, promote supplier competition, increase grid security and minimise prices across in the market zones [Nex21]. This section revisits the methodology and important concepts of FBMC to provide the reader with context for the following literature review and the remainder of the thesis.

2.5.1 Methodology

For the calculation of FBMC the information gap that arises from the zonal market design in the European electricity markets has to be closed. Due to the separation of electricity suppliers and grid operators accompanied by the clearing of anonymous bids at the energy exchange, the grid operators cannot know which power plants participate in additional commercial exchange and thus how much the grid infrastructure is loaded. For the necessary calculation of available transmission capacities, grid operators have to approximate the market outcome to forecast the grid utilisation. This approximation is called the base case, which consists of the forecasted demand, supply, exchange position, and grid topology.

In the European market design, bidding zones are regarded as (almost) free from congestion. This limits the grid elements, which are considered in market clearing to restrict commercial exchanges. The relevant elements are identified with linearised sensitivity factors, the PTDFs . Only lines and transformers, which are affected by cross-border exchanges above a certain threshold (often 5 %, e.g. [CRE17]) are included. This selection threshold is called the PTDF threshold for the remainder of the thesis. Because the market outcome has to result in a secure grid operation, possible grid outages, which reduce the available capacity on the lines, are considered. Only a limited number of contingencies have a critical impact on the grid, threatening security. Contingency screening is performed to identify the most relevant outages, which are then included as additional constraints. The relevant grid elements are called Critical Network Elements under a Contingency (CNECs) . In this thesis, outage constraints are included in the FBMC if the line loading in the outage simulation lies above a certain threshold referred to as CNEC threshold.

Without the information on which bid at the energy exchange is linked to which generator and thus unable to exactly determine the effect of commercial exchanges on the network elements, grid operators have to develop strategies to approximate the impact of trade results on the grid. This is achieved by assigning linear participation factors to generators, which distribute the delta in the NP of a market zone to the generators most likely to participate in this change, the GSKs.

Having determined the relevant grid elements to incorporate in the market coupling and having forecasted the effects of a change in net position on power flows, grid operators must determine the Remaining Available Margin (RAM) on these grid elements, which can be used for commercial exchanges. Due to the meshed nature of the European transmission grid, even in situations with balanced NPs, CNECs are loaded to a certain degree. The RAM is the remaining capacity, deducting the physical transmission capacity by loop and transit flows and a security factor to account for uncertainties in the FB calculation process, the Flow Reliability Margin (FRM).

Within the CEP [Eur19a], the regulator has introduced a minimum share of physical capacities that need to be made available for commercial exchange, the so-called Minimum Remaining Available Margin (minRAM). These minimum capacities were introduced in 2020, but allowed for derogations so they only come into full use in the year 2025.

2.5.2 State of research

The body of literature on FBMC has been growing in recent years and is summarised in Table 2.4. It can be classified into three groups with respect to the scope of the analysis, all of which provide important insights into different aspects of FBMC, which are presented below.

Table 2.4: Literature overview on articles covering FBMC.

Reference	Scope and conclusion
Category I: Conceptual work on stylised examples or reduced temporal resolution	
[Kur10]	Analysis of market power in zonal power markets with FBMC constraints.
[Mek12]	Propose an algorithm for the integration of phase shifting transformers into FBMC. The impacts are evaluated on a stylised 3-zone example system.
[Mar13]	Analyse the impacts of GSK strategy and FRM on the outcome of FBMC in a stylised system representing CWE with changing zonal configurations. Smaller zones reduce the uncertainty of the FRM. GSKs should reflect best available forecast.
[Sch13]	Compare FBMC and NTC market coupling in a stylised system. FBMC generally offers superior competition for scarce capacity compared to NTC market coupling. Scarcity of transmission capacity has to be represented by zones to be subject to market allocation.
[Sor13]	Present a FBMC model for Czech republic, Slovakia and Hungary, which is evaluated for the first week of 2012. Complex bids are included in a MIQP formulation.
[Hag14]	Present a framework for power system extension considering FBMC. The approach is tested in a 3-node system and then extended to a 200-bus representation of the European transmission system.
[Bjo18]	Analyse FBMC on stylised 3, 6 and 24 bus grids for single hours. The identified increased social welfare in the market results comes at the cost of higher re-dispatch.
[Fel19b]	The basic concepts of FBMC and sensitivities of certain parameter variations are analysed on a stylised 4-node example. A framework for FBMC in CWE region is presented.

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Reference	Scope and conclusion
[Bye20]	Compare different approaches for the base case, re-dispatch and market clearing on a 3-zone system for one month. The base case resembling the nodal result leads to lowest system cost.
[Lan20]	Present an approach for integrating grid constraints in the spot market evaluated on a stylised central European region (29 nodes) labelled FBMC. The article highlights the importance to integrate FBMC in market and grid analyses instead of NTC market coupling to have a more adequate representation of physical constraints.
[Pop20]	Propose the integration of nodal information for some generators in the spot market to relieve critical branches. The approach is evaluated on a two zone, 6 node system.
[Sch20]	Present an open-access model including a test network for experiments with the FB methodology.
[Fel21]	Compare FBMC to a nodal market clearing in a stylised single hour, 4-node system. Conclude that the closer the approximation of the base case is, the lower the welfare losses by FBMC are, compared to nodal pricing.
[Hen21]	Present a FBMC framework for a 3 area, 96-bus system. In this setup the impact of minRAM are investigated. Different re-dispatch schemes and the resulting implications on welfare are analysed.
[Wei21b]	Formulate a probabilistic FBMC, which includes uncertainty in RES generation in the FRM in a 118-bus system. The reduced exchange in the probabilistic day-ahead market clearing proves more robust against real-time deviations than deterministic FBMC.
Category II: Reduced temporal or spatial scope of real-world systems /Analysing specific aspects (mainly in CWE)	
[van16]	Presents the key concepts of FBMC as applied in the CWE and identify challenges with regard to the transparency of the process.
[Die17]	Analyses the impact of different GSK Strategies on the market outcome for the CWE region in 16 time steps. The different strategies have significant impact on line flows; however, the reduced temporal resolution limits the possibility to generalise results.

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Reference	Scope and conclusion
[Fin18]	Compare the impact of six different GSK strategies on market outcome in CEE region for a scenario in 2020. Results show that the difference compared to NTC market coupling is larger than the impact the GSK strategies have on the energy mix in the investigated zones.
[Seb18]	Analyse the impact of three GSK strategies in the grid of Belgium and highlight the possible impacts on the FB domain.
[Fel19a]	Price zone configuration for market coupling in CWE and Switzerland is investigated under FBMC. Improved bidding zones can reduce re-dispatch needs by over 90 %. New zones reduce producer rents in Germany and outside CWE, while increasing it in France.
[Mat19]	Compare different level of minRAM in the CWE region on market results and resulting congestions in the grid. Although increased minRAM increase welfare in the market results, the FB results no longer represents physical reality in the grid making additional remedial actions necessary.
[Bo20]	FBMC is applied in the Nordic area with exogenous FB parameters from 2017 for scenario years 2020, 2022 and 2022 with increased wind generation. Price differences between zones are reduced and FBMC allows Nordic to export more energy.
[Kri20]	Qualitative comparison of FB and NTC market coupling. Summary of historic parallel runs and implications for practitioners. Highlights the difficulties to understand and replicate FBMC for traders as well as the necessity to develop models, which are capable of replicating FB market fundamentals in the medium/long-term.
[Mak20]	Compare NTC and FB market coupling for several zonal combinations on South Eastern Europe utilising the Common Grid Model of this region. A single day is analysed considering the interconnectors as critical branches. Larger trading capacities are offered under FBMC than NTC market coupling.

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Reference	**Scope and conclusion**
[Sch21a]	Analyse three levels of minRAM in the CWE region in combination with three different GSK strategies. Due to computational burden, only two weeks of 2016 are analysed. For all analysed scenarios, the welfare gains in the market are more than offset by losses in the congestion management. The unequal share of welfare effects between consumers and producers is highlighted. Largest welfare effects are reported for increased minRAM from 20 % to 45 %.
[Sch21b]	Historic CNECs are matched to model data and additional constraints added to the problem to resemble historic flows. Afterwards, different GSKs are evaluated for FB market coupling for one week in 2018 for CWE FBMC. The potential beneficial effect of GSKs on the size of the FB domain is highlighted with the remark that for the welfare evaluation re-dispatch cost have to be included in the analysis.
[Wei21a]	Constructs a 2020 and 2030 scenario for CWE based on open data and compare different minRAM with regard to market effects and welfare including congestion management.
[Zad21]	Propose a clustering approach for FB domains to incorporate FBMC into adequacy studies.
Category III: Frameworks for comprehensive system analysis considering FBMC	
[Car20]	Present a detailed FBMC model for the Italy North CCR for the year 2017 with real-world grid data. The approach resembles CWE FBMC. Results show higher import and lower prices in Italy compared to NTC market coupling.
[Mat17]	Present a framework to include security constraints efficiently into FBMC in large power systems. Additionally, a linearisation of GSKs over time is proposed to reduce computational complexity.
[Mar18]	Investigate the effect of an extended FB region (adding Denmark West, Poland, Czech Republic, Hungary, Slovenia, Slovakia and Italy North to CWE).The NTCs in the scenario lead to larger re-dispatch needs than FB results, while the extended FB region increases price convergence and results in a slight shift in NPs.
[Wyr18]	Propose a FBMC framework and evaluate it in a 2025 scenario for an extended Core CCR without the consideration of contingencies.

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Reference	Scope and conclusion
[Wyr19]	Analyse the impact of different base case methods on the market outcome for FBMC at the German borders (except Switzerland). An NTC approach performs better, if NTCs are appropriately selected, while power flow analysis at zero NPs allows incorporating the explicit grid expansion state. Due to an applied minimum capacity, results do not differ much.

The first group mainly incorporates conceptual work on FBMC ([Kur10], [Mek12], [Mar13], [Sch13], [Sor13], [Hag14], [Lan20], [Pop20]) and fundamental research of parameter choice such as base case calculation ([Bye20], [Fel21], minimum capacities ([Hen21]) or FRM ([Wei21a]) in the FBMC methodology. Research is carried out primarily on stylised systems or with reduced spatial or temporal resolution, but provides important insights on what to keep in mind when applying FBMC to real-life scenarios. Although a qualitative conclusion can be drawn from the results, quantitative interpretation remains difficult due to the difference from real-world systems.

The second group covers analyses of FBMC on real-world systems but with reduced temporal or spatial scope. Most of the research in this group covers the analysis ([van16], [Kri20]) or simulation of (historic) FBMC results in the CWE region ([Die17], [Fel19a], [Mat19], [Sch21a], [Sch21b], [Wei21a]). Some articles look at different subregions, where the effects of FBMC are analysed, e.g. [Fin18], who analyse different GSK strategies in the CEE region, [Mak20], who compare FBMC to NTC market coupling in several zonal combinations in South Eastern Europe, and [Bo20], who compare FBMC and NTC market coupling in the Nordic region. [Zad21] propose a clustering approach for the FB domain in the CWE region.

A key insight from groups one and two is that the base case and GSKs need to match the realisation as closely as possible for FBMC to have a cost-efficient result (e.g. [Mar13]. For GSK strategy, *pro rata* seems to be a common understanding of good fit ([Fel21], [Sch20]). This follows the same idea of a close match of GSKs and base case with the realisation. Hence, GSKs based on the specific base case seem reasonable. Some authors raise awareness that the analysis of cost effectiveness and welfare impacts should not be limited to the analysis of market results, but should incorporate congestion management, which is necessary to ensure secure grid operation ([Sch21b], [Fel21]).

The third group of research consists of more comprehensive frameworks, which are able to analyse the effects of FBMC in full-scale, consistent energy system scenarios, including an explicit grid representation with expansion path, power plant, and RES (de-) commissioning with hourly resolution as well as the relevant methodological variety necessary for quantitative analysis of FBMC in the wider European context. [Car20] present a detailed FBMC model for the Italy North CCR and while the real Common Grid Model for this region is used, the framework considers a reduced FB region not covering the Core CCR and is limited to historical data. [Mat17] present a framework to include security constraints in the FBMC methodology efficiently in large-scale power systems, but are limited in scope to the CWE region. [Mar18] analyse the effect of an increased FB region, which includes Italy North and Denmark West but misses Croatia and Romania not resembling the Core CCR. [Wyr18] cover the Core CCR but neglect security constraints. [Wyr19] analyses the effect of base case methods in a focus region that covers Germany and its electric neighbours. To the best of the author's knowledge, no framework has been presented, which is capable of covering FBMC with an hourly resolution and accounting for security constraints, with a nodal representation of the Core CCR including consistent scenario information regarding grid expansion, power plant fleet and demand development. Such a framework is necessary to adequately assess the quantitative implications of FBMC on European electricity markets in the near future after the extension of the FB region to the Core CCR. The framework developed in this thesis is capable of these requirements and of quantifying the implications of FBMC for several scenarios in CWE and Core CCRs.

3 Modelling weather impacts in energy systems with high shares of renewable energy sources

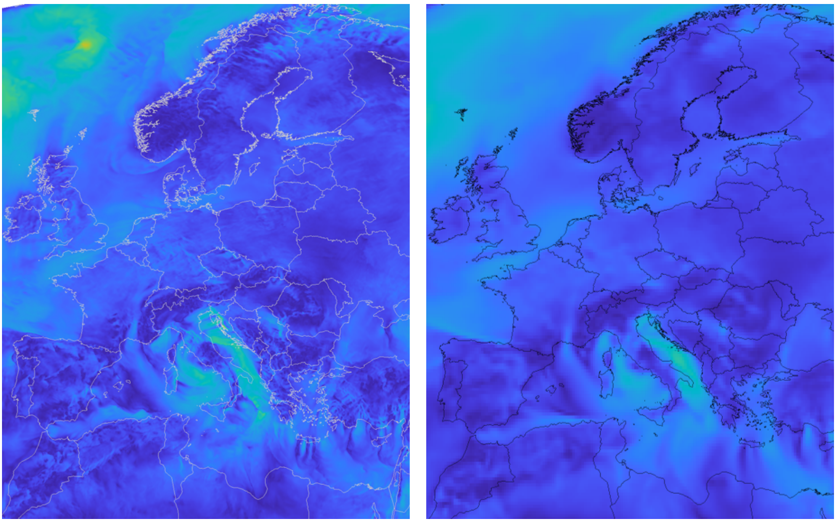
Historically, in a demand following (European) energy system, the main influences of weather were the temperature dependence of demand (depending on the predominant heating technology and in southern countries the cooling in summer), the availability of water in hydro power plants following precipitation, and potential restrictions on the cooling of power plants, which depend on rivers. With some notable exceptions (temperature-dependent load in France during cold winter or the heavily water-reliant Nordic power markets), the impact was rather small. The rapid dissemination of weather-dependent Renewable Energy Sources (RES) such as solar PV and wind power plants and the ongoing electrification of the heating sector will dramatically increase the relevance of weather information and data for the energy system. This chapter introduces data sources for numerical weather and climate information and describes the parameters used in the developed approach in Section 3.1. Furthermore, a short overview of how RES infeed and demand profiles, as well as thermal limits for the electricity grid can be derived based on this information is presented in Section 3.2. The section on demand profiles (Section 3.2.4) has been partially published in the final project report for the VERMEER project [Nit23].

3.1 Meteorological data for energy system analysis: Reanalysis, numerical weather prediction and (regional) climate models

Weather information is available on different time scales. Measured historic data from weather stations operated by the national weather service provide data with different and potentially limited temporal and spatial coverage. Numerical Weather Prediction (NWP) models of different scope and resolution[27] provide short-term forecasts globally or for a region up to a few weeks into the future, historical forecasts can also be of interest. Finally, reanalysis data sets such as MERRA-2 [Gel17] and ERA5 [Her23], [ECM23a] combine historical forecasts with measured observations to produce the most complete picture of the past climate and weather. For analyses of the European energy system, ERA5 is especially suitable because it is a relatively new product, calibrated to Europe in particular, covers a wide temporal range (1940-present) and is openly available. [Jou20] evaluate different data sets for wind speed and their predictive power for wind park generation and find that ERA5 (global, 30 x 30 km) outperforms MERRA-2 (global, 60 x 60 km) in the evaluated case (wind parks in France), although it underestimates wind speeds especially in mountain areas. Furthermore, regional models like AROME (France, 1.3 x 1.3 km) and COSMO-REA6 (Continental Europe, 6 x 6 km) [Han24], [Bol15], [Fra18], [Wah17] perform better in regions with complex topology. Figure 3.1 gives an overview of the resolutionof COSMO-REA6 based on the COSMO-EU model, covering the greater European area with a resolution of roughly 6x6 km and ERA5, which is a global model, but displayed here for Europe. The wind speed

[27] For instance, the German Weather Service (DWD) publishes the NWP data open on it's portal for the ICON-EU model covering Europe and the ICON-D2 model (COSMO-EU and COSMO-D2 were the operational regional model used by DWD until 30.11.2016. They were superseded by the ICON-EU and ICON-D2 model) covering Germany and surrounding areas, météo France operates the global ARPEGE model and a regional forecast model AROME, which is tailored to France.

for a single hour in 2012 at 100 m is shown. The higher resolution of COSMO-REA6 shows, especially in areas with more complex topology, where the difference in wind speeds becomes most obvious. Although these data sets represent the same content, naming conventions and variable definition may differ and need to be observed when utilising the data for simulation. As often with meteorological data sets, they are stored in efficient binary data formats like netcdf, grib, or grib2. In recent years, toolboxes have become available to process these data formats also in nonspecialised software like python. As meteorological data sets tend to be large, efficient processing is essential. [Sch23b] provide a large set of tools to work with climate and numerical weather data without the need to load complete files into physical memory.



(a) COSMO-REA6 **(b)** ERA5

Figure 3.1: Resolution of reanalysis model at the example of wind speed above Europe COSMO-REA6 (left) and ERA5 (right) at 100 meters for 1 February 2012, 12:00.

For long-term energy system analysis, climate simulations are also of interest, as they may offer insights into changing weather patterns or shifting probabilities for extreme weather events. However, due to the great (model) uncertainty, analyses should always be performed on an ensemble of model combinations of global models and regional models, which makes the inclusion into energy system analysis, where weather is only one source of uncertainty, an even more challenging task. [Ben21] provide some guidelines on the distinction between climate and weather models, as well as the utilisation and interpretation of regional climate projections in the context of the European Coordinated Regional Downscaling Experiment (EURO-CORDEX) initiative [Jac20].

Table 3.1 gives an overview of the most relevant parameters for the simulation of infeed from solar PV and wind turbines exemplary for the ERA5 dataset.

Table 3.1: Era-5 parameter for modelling wind and pv park output [ECM23b]

Parameter	**paramId**	**Short-Name**
Eastward component of the 10 m wind. It is the horizontal speed of air moving towards the east, at a height of 10 metres above the surface of the Earth, in metres per second.	165	10u
Northward component of the 10 m wind. It is the horizontal speed of air moving towards the north, at a height of 10 metres above the surface of the Earth, in metres per second.	166	10v
Eastward component of the 100 m wind. It is the horizontal speed of air moving towards the east, at a height of 100 metres above the surface of the Earth, in metres per second.	228246	100u
Northward component of the 100 m wind. It is the horizontal speed of air moving towards the north, at a height of 100 metres above the surface of the Earth, in metres per second.	228247	100v

continued on next page

Parameter	paramId	Short-Name
Temperature of air at 2m above the surface of land, sea or in-land waters in Kelvin. 2m temperature is calculated by interpolating between the lowest model level and the Earth's surface, taking account of the atmospheric conditions.	167	2t
Pressure of the atmosphere on the surface of land, sea and in-land water in Pascals. It is a measure of the weight of all the air in a column vertically above the area of the Earth's surface represented at a fixed point.	134	sp
Amount of solar radiation (also known as shortwave radiation) that reaches a horizontal plane at the surface of the Earth. This parameter comprises both direct and diffuse solar radiation. This parameter is accumulated over a particular time period which depends on the data extracted. The units are joules per square metre (Jm^{-2}).	169	ssrd
Amount of direct solar radiation (also known as shortwave radiation) reaching the surface of the Earth. It is the amount of radiation passing through a horizontal plane, not a plane perpendicular to the direction of the Sun. This parameter is accumulated over a particular time period which depends on the data extracted. The units are joules per square metre (Jm^{-2}).	228021	fdir
Fraction of diffuse solar (shortwave) radiation with wavelengths shorter than 0.7 µm reflected by the Earth's surface (for snow-free land surfaces only).	16	aluvd
Fraction of direct solar (shortwave) radiation with wavelengths shorter than 0.7 µm reflected by the Earth's surface (for snow-free land surfaces only).	15	aluvp

continued on next page

Parameter	paramId	Short-Name
Amount of solar radiation (also known as short-wave radiation) that reaches a horizontal plane at the surface of the Earth (both direct and diffuse) minus the amount reflected by the Earth's surface (which is governed by the albedo). This parameter is accumulated over a particular time period which depends on the data extracted. The units are joules per square metre (Jm^{-2}).	176	ssr

3.2 Spatially and temporally high-resolution input time series for energy system models with nodal grid representation

For historical analysis and simulation of European power markets, multiple data sources are available, the most powerful probably being the transparency platform operated by ENTSO-E. For most Bidding Zones (BZNs), hourly and in part subhourly time series are available for the generation of RES and demand profiles. This is sufficient for Net Transfer Capacity (NTC) market simulations. However, for transmission grid simulations (or simulations of Flow-based market coupling (FBMC)), the spatial resolution needs to be higher, namely on the grid node level, which are substations or buses in the case of the transmission grid. [Rav22] compare the methods from eight models of the German transmission grid to obtain the nodal RES generation and demand profiles and classify them into top-down and bottom-up methods. The former aim at distributing the available aggregated profiles to the grid regions; the latter aim to simulate the fundamental sources for the profiles at the grid nodes and adjacent areas and aggregate these at the relevant level. The issue with top-down approaches for renewable generation is that even though regional information about the installed capacity might be available[28], the regional feed-in depends on the local weather conditions, so the information to produce nodal profiles is missing. For future scenarios, the additional problem arises that new-built (renewable) power plants are not likely to follow the historic distribution, especially when the installed capacity approaches the regional installation potential. This fact, combined with technological progress, especially in the case of wind turbines, makes the use of historical profiles unsuitable for future scenario analysis.

For demand, the situation is somewhat different, due to the fact that for a large enough number of consumers of the same type, aggregated consumption can indeed be approximated with standard load profiles. An approach that is also applied in daily power system operation. Aggregated historic profiles can be decomposed into sectoral profiles and spatially distributed according to social, demographic and economic factors. Similarly to RES, the diffusion of future technology impacting the demand side (e.g. heat pumps, electric vehicles, etc.) is difficult to account for in a top-down approach. For instance, heat demand varies with local temperature and demand profiles for electric vehicles might differ between regions. An additional problem arises through the desired market participation of some of these new applications to provide flexibility to the system, which can only be properly modelled in the presence of market prices, i.e. the dispatch decision of such flexibilities needs to be included as a variable in the market simulation instead of a parametric, static (price-inelastic) demand profile. Often, the chosen modelling approach is a hybrid one, with 'conventional' electricity demand following historic or generic profiles, while for price sensitive demand flexibilities, the energy demand is distributed according to statistical features, and the dispatch decision is modelled explicitly in the market and/or grid simulation.

For many NWP data sets (including ERA5), the highest temporal resolution available is hourly. This also fits to the market time unit in the most liquid market segment of electricity spot markets in most market zones and market

[28] For instance, in Germany, the market data register, Marktstammdatenregister (MaStR), lists all generation assets connected to the German electricity grid with capacity and location.

places, the day-ahead market. Hence, the temporal resolution of many electricity market and transmission grid models is also chosen to be one hour. This is a compromise between the effects in weather phenomenon, which especially in the case of wind speed show large volatility in the subhourly domain, data availability and the computational burden which come along with deailed studies for the European market and grid.

For the power flow simulation, the generation of RES and demand time series need to be available (per type) for every grid node. For the optimisation, additional parameters and degrees of freedom need to be defined, also at the grid node or unit level. For future scenarios, input data usually have a spatial resolution of countries or BZNs to reflect international or national political goals and scenarios for RES share in the energy mix; or more generally to comply with decarbonisation goals. Consequently, methods and workflows need to be available that break down these aggregated figures and distribute them to the nodes of the model. In recent years, some publicly available data sets have emerged such as scenario data from the project *eXtremOS* hosted by Forschungsstelle für Energiewirtschaft (Ffe). The drawback of these data is, that they are scenario specific, limiting the scope of analysis and the privately hosted data can be subject to unavailability or discontinuiation. The alternative is to develop tool chains, which can break down scenario framework numbers into input data with adequate resolution. The tool used in this work is the HighResO (HighResO) model [Sle17], [Sle18]. The input data preparation can be divided into two domains.

Allocation and expansion planning

For RES this task covers the distribution of scenario capacities to optimal or good locations that are then connected to a specific grid node. For demand, load scenarios have to be identified or developed for conventional load. Furthermore, the method needs to output how many new consumers are installed, of what type and where (E-mobility, heat pumps, installation of (district) heating networks, electrolysers, etc.).

Profile generation
Future RES generation cannot be derived from historical profiles, as the distribution of RES installations changes over time. More importantly, technical conditions are subject to dramatic change, most notably for wind turbines. Moreover, the historical data is determined by the historic weather year, which might not be suitable for the research question at hand. A solution can be to create bottom-up feed-in profiles for RES installations (historic and new-built, optimally allocated) based on numeric weather data. Similar problems arise on the demand side for new applications that have an intrinsic use profile, but could react flexible to e.g. price signals. Especially in the latter case, there is ongoing research with regard to acceptance of such business models, as well as the technical implementation of signals necessary to trigger desired reactions. Moreover, with the electrification of heating applications, consistent temperature modelling becomes more relevant. As profile information is more important for the operational simulations performed in this thesis, the methodology to produce them including the relevant data sources is described in the following sections.

3.2.1 Data sources for weather-based time series

The input time series for RES, demand and dynamic thermal ratings of overhead lines are generated using the HighResO model, mainly developed by Slednev and Ruppert [Sle17],[Sle18]. For the model, the input data sources have been extended to utilise multiple publicly available input sources for weather data. The model is capable of processing the input data from the COSMO model of the DWD, especially the output data from the high-resolution reanalysis system COSMO-REA6, which covers continental Europe with a resolution of 6 km and the period 1995 to 2019, as well as the published data set for COSMO-REA2 for 2007 to 2013 covering Central Europe. In addition, the model can use input data from the global ERA5 model operated by the European Centre for Medium-Range Weather Forecasts (ECMWF), with a resolution of 31 km, dating back until 1940. Finally, the model can incorporate input from the operational numerical weather prediction of DWD, the ICON-EU and the ICON-D2 model. The remainder of this section gives a short overview of how the weather model output can be used for modelling wind turbine and solar PV cell power generation time series.

3.2.2 Calculation of wind power feed-in from weather models

The wind turbine model follows rather simple assumptions. The power output depends upon the effective wind speed at hub height as well as the turbine-specific power curve. The power curve information is stored in the institute's wind turbine data base that is continuously updated for existing wind park projects. The future installed capacity and the corresponding power curves are based on the expansion HighResO model. Given the relevant power curve for each turbine, the effective wind speed can be calculated as a function of wind speed at a reference level, pressure, temperature, altitude, roughness length, hub height, and some constants. The starting point is the wind speed at a given reference level from one of the numerical weather programmes, e.g. ERA5. For the ERA5 model, wind speeds can easily be obtained on 10 m and 100 m above ground. In the planetary boundary layer, the log wind profile can be used in neutral atmospheric conditions to describe the vertical distribution of wind speeds. Wind speed also depends on the roughness length z_0. The roughness length is determined by the terrain. For land cover classification, the 44 European CORINE land cover classes are used, which have a resolution of up to 1 ha [EEA24]. The corresponding roughness length is determined according to [McK15]. Given the hub height hh, surface roughness z_0 and reference heights 10 m hl and 100 m hu above ground ,two height correction factors for the wind speed can be determined following the wind log profile:

$$factor_l = \frac{\ln \frac{hh}{z_0}}{\ln \frac{hl}{z_0}} \tag{3.1}$$

$$factor_h = \frac{\ln \frac{hh}{z_0}}{\ln \frac{hu}{z_0}} \tag{3.2}$$

Extrapolation from these two reference wind speeds are combined using the proximity of the hh to the reference levels for hub heights below 100 m:

$$wspd_{hh} = wspd_{hu} \cdot factor_h \cdot \alpha + wspd_{hl} \cdot factor_l \cdot (1 - \alpha) \tag{3.3}$$

with

$$\alpha = \frac{hh - hl}{hu - hl}. \tag{3.4}$$

For hub heights above 100 m, the extrapolation from the higher level is used. The calculated wind speed at hh is then corrected for air density using temperature, pressure, and altitude information. The temperature and pressure for 2 meters above ground are obtained from the NWP. The altitude is taken from GTOPO30 [Ear17], with an approximate resolution of 1 km. To determine the pressure at hh, the barometric formula and a temperature lapse rate of $-0.0065\frac{K}{m}$ is used:

$$p(h1) = p(h_0)\left(1 - \frac{a\Delta h}{T(h_0)}\right)^{\frac{Mg}{Ra}}, \tag{3.5}$$

with

$$a = -\frac{dT}{dh} = 0.0065\frac{K}{m}, \tag{3.6}$$

where R is the universal gas constant, g is gravitational acceleration and M the mean molar mass of the atmospheric gas.

The adjusted pressure and temperature are used to calculate the air density at hh under the assumption of dry air:

$$\rho_{hh} = \frac{p_{hh}}{T_{hh} R_s} \tag{3.7}$$

where R_s is the specific gas constant of dry air. Given the air density at the hub height, instead of scaling the power curve from the norm density, where it is known to the site condition, the impact of the specific air density conditions is used to correct the effective wind speed at hh, following IEC 61400-12[IEC22]:

$$wspd_{eff} = wspd_{hh} \cdot df \tag{3.8}$$

with

$$df = \sqrt[3]{\frac{\rho_{tt}}{\rho_0}}. \tag{3.9}$$

3.2.3 Calculation of solar PV feed-in from weather models

Similarly, the calculation of solar PV cells and parks is performed. Due to the fundamental difference regarding project planning and operation, solar PV generation is grouped into rooftop installations and ground-mounted installations. Rooftop solar PV is characterised by a lower kW_{peak} capacity and a higher relative cost. More importantly, the slope and azimuth of the PV modules are in many cases determined by the roof orientation and slope. [Pep21] find that the majority of rooftop solar PV installations between 2014 and 2021 in Germany (82 %) had less than 10 kW_{peak} installed. Ground-mounted installations are usually larger in size and capacity and the orientation is matched to local conditions. While in 2000, 61 % of solar installations in Germany had a southward orientation, alternative orientations gained in importance leaving 42 % with southward orientation in 2019. In the year 2019, 7 % of installed systems had an eastern orientation, 9 % a western orientation and 6% an east-west orientation. Moreover, there is a trend visible from the data from relatively large inclination angles towards smaller inclination angles, with installations with tilt[29] smaller than 20 degrees increasing their share from around 10 % in 2010 to almost 20 %. Correspondingly, installations with a tilt between 20 and 40 degrees saw a decline from 63 % in 2010 to 54 %. In 2019, three-quarters of the installed system had a capped maximum feed-in at below 70 % of installed capacity. The remaining systems are capable of remote-controlled curtailment [Pep21].

To address these uncertainties and in the absence of exact data, the slope and azimuth of PV installations in the model are drawn generically from a distribution, guided by the following assumptions. The Photovoltaic Geographic Information System (PVGIS) [Šúr05] provides optimal azimuth and tilt for solar PV installations as all year optimum, i.e. maximum yield with fixed azimuth. For ground-mounted installations, southward orientation is assumed due to more freedom in the planning and focus on maximum yield. Accordingly, the slope is equivalent to the optimum in PVGIS for each country. For rooftop installations, the azimuth is drawn from a Gaussian distribution with expected value μ of 180°and standard deviation σ of 50°. The tilt is drawn from a distribution following the optimal tilt angle given in PVGIS. For the simulation of the power output a standard PV module from PV_LIB's database is used - the BP Solar BP 3220N [Hol18]. The calculation makes use of the PV_LIB toolbox from Sandia National Laboratories. The calculation steps are described in the following. As for wind, the starting point is the weather parameters taken from the numeric weather programmes. As input the variables surface net solar radiation NHI, total sky direct solar radiation at surface DHI and surface solar radiation downwards GHI are used. For each time step, the sun's azimuth, zenith angle, and apparent zenith angle have to be calculated. This is done using the *pvl_spa* function [San18d], which uses the time stamp, exact location of each PV module as well as pressure and temperature at each location. From the zenith angle of the Sun $SunZen$, the direct normal irradiation

[29] Tilt and angle of inclination are used as synonyms here.

is calculated:

$$DNI = \frac{DHI}{\cos(SunZen)}. \tag{3.10}$$

The angle of incidence AOI between the tilted surface of the PV modules and the beam of the sun for each module and time step can be calculated as a function of the module's slope and azimuth as well as the sun's zenith angle and azimuth, using the *pvl_getaoi* function [San18a]. The irradiation resulting from direct sky radiation $SkyDirect$ is then calculated as:

$$SkyDirect = DNI \cdot \cos(AOI). \tag{3.11}$$

Apart from the $SkyDirect$, the diffuse irradiation resulting from refraction in the atmosphere and reflection from clouds, as well as reflection from the ground needs to be taken into account. Given the surface solar radiation downwards, the modules slope and the grounds albedo, the diffuse radiation from the ground $GroundDiffuse$ can be calculated with the function *pvl_grounddiffuse* [San18b]. The diffuse irradiation from the sky is the delta of global and direct radiation:

$$DDI = GHI - DHI, \tag{3.12}$$

which - given the modules slope - is used to calculate the effective irradiation on the module resulting from diffuse sky radiation $SkyDiffuse$ with the function *pvl_isotropiocsky* [San18c]. The total diffuse irradiation amounts to:

$$E_{diff} = SkyDiffuse + GroundDiffuse. \tag{3.13}$$

The cell temperature is calculated using the Sandia Cell Temperature Module and temperature data from the numeric weather programme. Combined with the calculated figures E_{diff} and $SkyDirect$ and several parameters (specific to PV cells), this forms the input for the Sandia PV Array Performance Model, which yields the DC output of the cell at the maximum power point. PV_Lib also provides functions to obtain the AC power output, which include additional losses, e.g. stemming from the converter.

3.2.4 Nodal (weather-dependent) demand profiles

Section 3.2.4 has been partially published in the final project report for the project VERMEER [Nit23].

To ensure a data set of weather-dependent feed-in and demand profiles that is as consistent as possible, the approach to determining electricity demand profiles and regionalisation described in [Sle17] and [Rav22] has been further developed as part of the VERMEER project [Nit23], particularly with regard to temperature-dependent processes. Based on the sectoral and process-specific electricity demand structure of the Ten-Year Network Development Plan (TYNDP) 2022, each final electricity demand process was regionalised on the basis of existing preliminary work and external toolboxes and data sets, in particular *hotmaps* [Hot19], [Pez19] and *eXtremOS* [Gum21]. If necessary, the demand profile was adjusted accordingly for each weather year in the observation horizon (1985-2022). A temperature-specific adjustment was made primarily for heating and cooling processes in space heating and district heating, as well as for heat pump processes. The demand structure is divided into the sectors households, trade, commerce, services, industry, transport, agriculture, energy sector, and others. For household and industrial demand, a further subsectoral breakdown is made into single-family, two-family, and multifamily households and the various industrial sectors. At process level, a differentiation is made for the residential and tertiary sectors in terms of demand for electrical applications and electricity demand for cooking, heating, and cooling purposes, whereby a distinction is also made between various processes for the provision of hot water, space heating and space cooling. In the case of industry, a distinction is made between low-temperature processes, steam processes, and other heating and cooling processes in addition to the demand for electrical applications. In the transport sector, electricity demand is differentiated according to transport modes (air, road, rail and waterways), with road-based transport being further differentiated. In addition to final energy demand, electricity-based applications for meeting demand in district and local heating systems are also taken into account, whereby a distinction is also made between hot water and space heating-related demand from households and businesses, as well as low-temperature and steam process-related demand from industry, analogous to final energy supply. Finally, all demand profiles are aggregated by sector and totalled per network node.

3.2.5 Weather-dependant current limits of overhead transmission lines

Dynamic line rating has long been established in the engineering domain. In operational practice it may follow a 'hands-on' approach, which can be applied to individual overhead lines and relies on local observations and measurements. This is however not feasible for expansion planning or for the evaluation of the potential of dynamic line rating in larger power systems on the transmission capacity (and hence also on the market results). The costs of comprehensive measurements are too high for a potential analysis and for the integration into expansion studies, there is often a lack of knowledge about the exact route along which such measurements would have to be carried out. The availability of highly temporal and spatially resolved weather data and the steadily increasing processing power of modern computers have made model-based analyses possible. Two prominent examples are the approach of the IEEE standard for calculating the current-temperature relationship of bare overhead conductors [IEE12] and the CIGRE approach formulated in two technical brochures [CIG02] and [CIG14]. Several studies compare these standards; for example [Arr15] compare the predicted values to measurements of a 132 kV conductor over the course of one year and conclude that while the standards provide similar results, they both have shortcomings in situations with low wind speeds and wind direction approaching 90°. ENTSO-E summarised (then current) TSO practices in [ENT15]. In the following, the IEEE standard is used and the formulae and assumptions are briefly explained.

The IEEE model is based on the steady-state heat balance of the conductor, that is, the sum of heat losses equals the sum of heat gains [IEE12].

$$q_c + q_r = q_s + I^2 R(T_c), \tag{3.14a}$$

$$I = \sqrt{\frac{q_c + q_r - q_s}{R(T_c)}}, \tag{3.14b}$$

where q_c is the heat loss rate per unit span because of convection in watts, q_r is the heat loss rate per unit span because of radiation in watts, q_s is the heat gain rate per unit span from sun in watts, I is the conductor current in Ampere, T_c is the conductor's surface temperature in degree Celsius and $R(T_c)$ is the AC resistance of conductor at temperature $T_c \Omega$.

The convection heat loss q_c in $\frac{W}{m}$ is approximated differently, depending on the wind speed [IEE12]. At high wind speeds q_c becomes

$$q_{c,high} = K_{angle} \cdot 0.754 \cdot \left(\frac{D \rho_f V_w}{\mu_f}\right)^{0.6} \cdot k_f \cdot (T_c - T_a), \tag{3.15a}$$

at low wind speeds q_c is calculated as

$$q_{c,low} = K_{angle} \cdot \left[1.01. + 1.35 \cdot \left(\frac{D \cdot \rho_f \cdot V_w}{\mu_f}\right)^{0.52}\right] \cdot k_f \cdot (T_c - T_a). \tag{3.15b}$$

In the absence of wind, the heat loss occurs through natural convection

$$q_{c,still} = 3.645 \cdot \rho_f^{0.5} \cdot D^{0.75} \cdot (T_c - T_a)^{1.25}, \tag{3.15c}$$

where D is the conductor diameter in millimetres, ρ_f is the air density in kg/m^3, V_w is the speed of air stream at conductor in $\frac{m}{s}$, μ_f is the air viscosity in $Pa \cdot s$, k_f is the thermal conductivity of ambient air at temperature $\frac{T_c+T_a}{2}$ in $\frac{W \cdot °C}{m}$, $R(T_c)$ and T_c as in Eq. (3.14) and T_a the ambient air temperature in ℃. The standard recommends using the higher value of Eqs. (3.15a) and (3.15b) at any wind speed and the maximum value of Eq. (3.15) at low wind speeds as a conservative approach.

The wind direction factor K_{angle} above is defined as

$$K_{angle} = 1.194 - \cos(\theta) + 0.194 \cos(2\theta) + 0.368 \sin(2\theta), \tag{3.16}$$

where θ is the 'wind angle' between the wind's direction and the overhead line's direction.

The radiation heat loss q_r in $\frac{W}{m}$ of the overhead line is calculated as

$$q_r = 17.8 \cdot D \cdot \epsilon \left[\left(\frac{T_c + 273}{100} \right)^4 - \left(\frac{T_a + 273}{100} \right)^4 \right], \tag{3.17}$$

where ϵ is the emissivity of the conductor and T_c and T_a as in Eq. (3.15).

The solar radiation rate q_s based on a model for direct solar irradiation. However, when using numerical weather data, this parameter is usually available and does not need to be calculated.

$$q_s = \alpha \cdot Q_{se} \cdot \sin(\theta) \cdot A', \tag{3.18}$$

where α is the solar absorptivity of the conductor, Q_{se} is the solar heat flux in $\frac{W}{m}$, θ is the effective angle of incidence of the solar rays with the conductor in degrees and A' is the area of conductor in $\frac{m^2}{m}$. [IEE12] includes a simplified model to obtain Q_{se} and θ based on the hour of the year and latitude of the conductor. When the model is used in combination with numerical weather data, Q_{se} can be derived directly from these data.

Finally, the Joule heat gain q_j in watts due to power flow through the conductor results to

$$q_j = I^2 R(T_c), \tag{3.19}$$

whith I and $R(T_c)$ as in Eq. (3.14).

4 Concept and model

This chapter introduces and describes in detail, the developed wholesale market model, the approach for modelling the transmission grid as well as the model to derive Flow-based (FB) coupling constraints and to integrate them into the market simulation. The developed tool chain builds on and extends a number of existing data structures and models in use at the chair of energy economics, mainly it depends on regionalised demand and Renewable Energy Sources (RES) infeed profiles, which are derived from the HighResO model [Sle17], [Sle18] and the data and methods described in Chapter 3. At the core of the developed approach are the electricity wholesale market model module, the Flow-based market coupling (FBMC) module, the grid simulation module and the Dynamic Line Rating (DLR) module. The market model takes RES feed-in and demand time series from the HighResO model, where the RES expansion planning is performed and infeed as well as demand profiles are calculated for a given scenario and specific weather year(s). The market model uses various other inputs, among which the master data of the power plants, the hourly (un-)availability of the power plants, regional and subannual fuel prices and CO_2 prices are the most important. Moreover, flexible hydro power plants and other flexible units, which are modelled as storages, are included in the model. In case the market clearing is modelled with FBMC, the base case is calculated with the market module, and the FB constraints are fed back into the market coupling from the FBMC module. The FBMC module has access to all the input data for the market module and receives additional data from the grid data base and the DLR module where, based on the weather information and grid topology, scenario-specific dynamic thermal ratings for the overhead lines are calculated. During FB calculation, Optimal Power Flow (OPF) simulations are necessary, which are performed using the grid simulation module, which in turn can use outputs from all the other modules to simulate OPFs in different modes, for example, to simulate congestion management (CM) based on a market result with DLR. The data flows and interdependencies of the different modules are shown in Fig. 4.1.

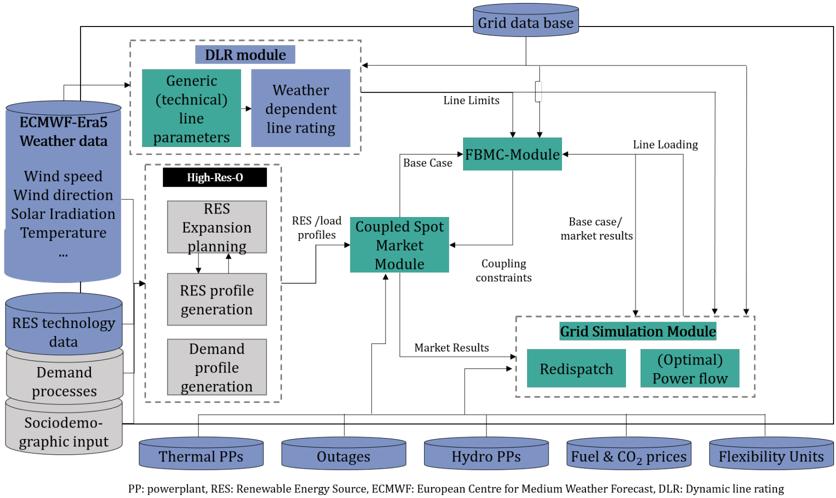


Figure 4.1: Integration of the developed tool chain in the existing model and data ecosystem at the chair of energy economics.

The first section - Section 4.1 - describes the market model and details the mathematical formulation. Section 4.2 describes the transmission grid model, covering the relevant simplifications and tools used and developed, and describes the relevant model variants used in the modelling of FBMC and CM. In Section 4.3 the developed method for calculating the Flow-based market coupling constraints and the relevant calculation steps, parameters and input data are described. Section 4.4 outlines the parameters used to calculate weather-dependent thermal ratings for overhead lines based on IEEE 738-2012 and weather data from ERA5. Finally, Section 4.5 illustrates how and under which conditions the FBMC results can be used to derive dynamic bilateral exchange constraints for the use in Net Transfer Capacity (NTC)-based market models.

4.1 Market model

The market model is formulated as a linear optimisation problem. Quantities and prices of demand and supply bids are exogenous parameters of which the accepted share is optimised. Market clearing prices are derived from the dual variables of the zonal energy balances indicating the price of a marginal change in the supply and demand equilibrium in each market. In the simplest variant of the model, each generator offers the total available capacity at variable cost, resembling a competitive market. The framework includes the possibility to split this capacity into several bids with different (exogenous) price levels to model bidding behaviour. The model simulates the spot markets in an hourly resolution, mainly due to the resolution of the underlying data. Due to the missing uncertainty in demand and renewable infeed realisation, it resembles a real-time market, which centrally clears all supply and demand bids. Although, this makes the explicit modelling of a balancing activation unnecessary, the allocated capacity to the balancing markets is included as an exogenous demand, which reduces the available generation capacity in the spot markets.

4.1.1 Overview and objective

An overview of the market simulation for NTC and FBMC is shown in Fig. 4.2. Hourly time series for RES infeed and demand from HighResO form the basis for the supply bids for renewable power plants and the demand bids. Based on the fuel and CO_2 prices, power plant master data (e.g. installed capacity and efficiency), outages, revision and maintenance, thermal must-run constraints[30] and the balancing market participation, the supply bids for the thermal power plants are calculated. For seasonal storage plants such as hydro reservoir and pumped hydro storage power plants with natural inflow, the

[30] Must-run is modelled by introducing bids with the relevant capacity for the respective generator at a competitive price, which makes the dispatch of this capacity very likely. The prevalence of 'must-run' capacity is scenario dependent, with, e.g., the TYNDP 2022 not foreseeing any thermal must run after 2030.

dispatch is the result of a yearly simulation, with the 8 760 hours of the year linked with storage constraints. The start and end storage volumes are determined by either external start and end values or are constrained to be equal.

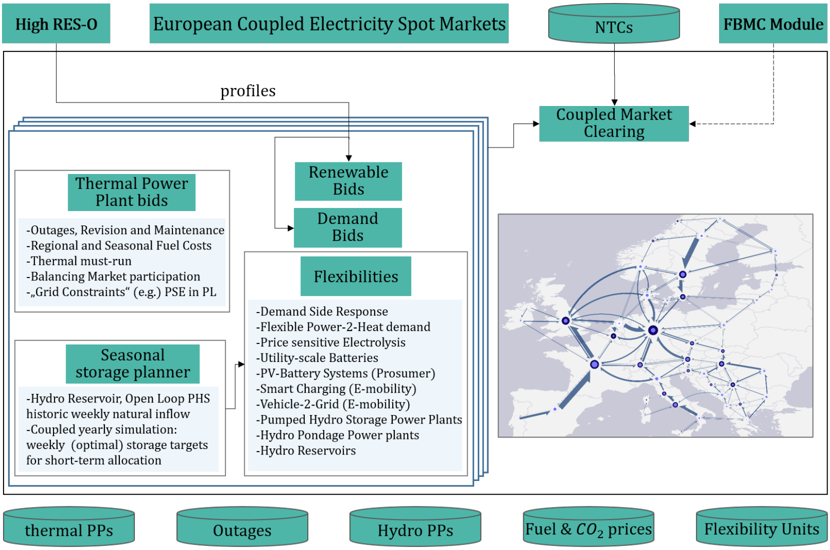


Figure 4.2: Workflow of the developed market model

In subsequent calculations, this long-term storage profile can be used by constraining the final storage at the edges of shorter time windows (e.g. months or weeks) to the determined storage volume. This enables these shorter time windows to be decoupled and solved in parallel under the assumption that the dispatch of other flexible plants and demand is determined by short-term considerations like daily price spreads. Other considered flexibilities are also modelled as storages with inflow[31]. These include demand side response, flexible power-to-heat demand, operation of price sensitive electrolysers, run-of-river power plants with pondage ability, PV-battery systems and smart charging or Vehicle-to-Grid (V2G) applications for electric vehicles. Bid prices for flexibility supply and demand are assumed to be zero.

The market coupling problem for each market time unit (e.g. hour) is formulated as a linear optimisation problem with the objective of maximising social welfare given by Eq. (4.1). The constraints are described and explained below. For better readability, the index t to indicate the discrete market time unit is omitted in all equations except the energy balance for the storages in Eq. (4.4)[32].

The objective function
The welfare W equals to the worth of the sum of the accepted demand bid tuples consisting of quantity $q_{d,z}$ and price $p_{d,z}$ over all demand bids D_z in zone z over all zones Z minus the cost resulting from the sum of the accepted supply bid tuples consisting of quantity $q_{s,g,z}$ and price $p_{s,g,z}$ over all supply bids $S_{g,z}$ to the spot market of generator g over all generators G_z in zone z over all zones Z. Furthermore, for a cost-minimal allocation of the balancing market demands, the sum of accepted supply bid tuples consisting of quantity $q_{g,z}^{sB}$ and price $p_{g,z}^{sB}$ over the (single) supply bid to the balancing market of generator g over all generators G_z in zone z over all zones Z is subtracted. Due to the linear nature of the model, all quantities of the supply and demand bids can be accepted partly within their bounds. An advantage of modelling several demand bids per zone is the straightforward integration of flexible demand bids into the model, stemming from either (industrial) demand response potential at certain price levels, price sensitive electrolyser dispatch or from the withdrawal side of flexibility providers like pumped hydro storage power plants or battery storages. On the supply side, in the simplest version of the

[31] The 'inflow' can be positive e.g. in the case of natural inflow into pumped hydro storage power plants, zero e.g. in the case of battery storages or negative in the case of a demand profile which can be shifted in a given time interval.

[32] The objective functions for the complete problem becomes the sum over all market time unit objectives in the set of time steps T

model generators bid all their available capacity to the market at (short-term) variable cost. The formulation also allows for more complex bidding strategies, where, for instance, parts of the capacity are bid into the market at a premium (mark-up). As the balancing markets are not the focus of the model, each generator offers at most one supply bid at cost to the balancing markets.

$$
\begin{aligned}
\max_x W \; : \sum_{z \in Z} \sum_{d \in D_z} q_{d,z} p_{d,z} x_{d,z} \\
- \sum_{z \in Z} \sum_{g \in G_z} \sum_{s \in S_{g,z}} q_{s,g,z} p_{s,g,z} x_{s,g,z} \\
- \sum_{z \in Z} \sum_{g \in G_z} q^{sB}_{g,z} p^{sB}_{g,z} x^{sB}_{g,z}
\end{aligned}
\tag{4.1}
$$

4.1.2 Constraints

Accepted share

Each supply and demand bid, consisting of the parameter tuple quantity and price, can be partly accepted.

$$0 \leq x \leq 1 \tag{4.2}$$

The zonal energy balance

The zonal energy balance in equation Eq. (4.3) ensures that the sum of supplied energy in each zone and the sum of imported energy into the zone via NTCs f_{lz} equals the sum of energy demand, the sum of exported energy from the zone via NTCs f_{zl} and the Net (Export) Position (NP) for the FB regions np_z.

$$\sum_{g \in G_z} \sum_{s \in S_{g,z}} q_{s,g,z} x_{s,g,z} - \sum_{d \in D_z} q_{d,z} x_{d,z} - \sum_{l \in Z} f_{zl} + \sum_{l \in Z} f_{lz} - np_z = 0 \quad \forall z \in Z \tag{4.3}$$

Storage energy balances
For each flexible or storage unit[33] in the set of flexible units V, an energy balance constraint is formulated according to Eq. (4.4), that couples the individual hourly problems in the set of hours T with the previous hour. The stored energy $e_{i,t}$ for flexible unit i, at the end of hour t is the sum of the remaining energy stored at the end of the last time step $e_{i,t-1}$, the energy provided to the market $q^{s}_{i,s,g,z,t}$ in relation to the efficiency of the generation process η^{dch}_{i} and increased by the inflow and the energy taken from the market $q^{d}_{i,d,z,t}$ multiplied with the efficiency of the off-take process η^{ch}_{i}.

$$\begin{gathered} e_{i,t-1} + \eta^{ch}_{i} q_{i,d,z,t} x_{i,d,z,t} - \frac{q_{i,s,g,z,t} x_{i,s,g,z,t}}{\eta^{dch}_{i}} + inflow_{i,t} = e_{i,t} \\ \forall i \in V, \quad \forall d \in D_z, \quad \forall s \in S_{g,z}, \quad \forall g \in G_z, \quad \forall z \in Z, \quad \forall t \in T \end{gathered} \tag{4.4}$$

Balancing market constraints
With regard to the balancing markets, two constraints are introduced. The zonal balancing capacity requirements in Eq. (4.5) ensure that the sum of provided balancing power[34] $q^{sB}_{g,z}$ by the generators in zone z equals the zonal balancing power demand $Q^{dB,z}$ for all zones.

$$\sum_{g \in G_z} q^{sB}_{g,z} x_{g,z} = Q^{dB,z} \quad \forall z \in Z \tag{4.5}$$

Additionally, a capacity constraint for each power plant participating in spot and balancing markets in Eq. (4.6) ensures that the sum of supply bids to the spot markets and the balancing market of each generator does not exceed the

[33] Flexible in this context means that energy generation or off-take can be reduced or increased in one hour and can/must be balanced with additional/reduced generation/off-take within a given time interval.
[34] The balancing market itself is not modelled, so no activation is simulated. The aim is simply to account for the amount of power plant capacity that is not available to the spot markets.

available capacity.

$$0 \leq \sum_{s \in S_{g,z}} q_{s,g,z} x_{s,g,z} + q^{sB}_{g,z} x_{g,z} \leq P^{max}_{g,z} \quad \forall g \in G_z, \quad \forall z \in Z \tag{4.6}$$

Bi-directional exchange constraints

The coupling of regions in the most simple case (only NTC constraints exist) can be expressed by Eq. (4.7), where only the bidirectional flow between market zones is restricted by the relevant (time-variant) NTC.

$$0 \leq f_{zl} \leq NTC_{zl}, \quad \forall (z,l) \in F \tag{4.7}$$

F is the set of borders under NTC exchange regime.

Critical network elements for Flow-based market coupling

With the integration of Flow-based market coupling at some borders, the respective bi-directional variables are eliminated from the problem and the new variable np_z is introduced for the net export position under FBMC for each zone z in set Z^{FB}, where at least one border is coupled with FBMC. Additionally, Eqs. (4.8) to (4.10) are introduced, which constrain the newly introduced variable. Equations (4.8) and (4.9) ensure that the flows resulting from the FB net positions do not exceed the available remaining capacity RAM^-_l,RAM^+_l of the critical network elements l in set Λ.

$$RAM^-_l \leq \sum_{z \in Z^{FB}} ptdf_{l,z} \cdot np_z \leq RAM^+_l \quad \forall l \in \Lambda \tag{4.8}$$

Critical network elements for Flow-based market coupling under a contingency

Similarly, Eq. (4.9) ensures the validity of flows for all identified lines l in the relevant contingency situations Λ^c for all identified contingency situations c in Γ.

$$RAM^{-,c}_l \leq \sum_{z \in Z^{FB}} otdf^c_{l,z} \cdot np_z \leq RAM^{+,c}_l \quad \forall l \in \Lambda^c, \quad \forall c \in \Gamma \tag{4.9}$$

Flow-based market coupling energy balance
The sum of all FB NPs has to equal zero, to ensure the energy balance within the FB region according to Eq. (4.10).

$$\sum_{z \in Z^{FB}} np_z = 0 \tag{4.10}$$

External net position limits
For some regions more complex grid constraints, which cannot be directly incorporated with the NTC or FB constraints above, are integrated into the problem by external limitations on the net import or net export positions as in Eq. (4.11).

$$-Imp^{z,max} \leq \sum_{l \in Z} f_{zl} - \sum_{l \in Z} f_{lz} + np_z \leq Exp^{z,max} \quad \forall z \in Z \tag{4.11}$$

Variable constraints
The sum of the quantities of the supply bids, which can be offered to the spot market must not exceed the capacity limits of the generators. This is achieved by Eq. (4.12), defining ex-ante quantities $q^{max}_{s,g,z}$, to which the generation capacity is discretely split at pre-defined price levels $p_{s,g,z}$.

$$0 \leq q_{s,g,z} x_{s,g,z} \leq q^{max}_{s,g,z} \quad \forall s \in S_{g,z}, \quad \forall g \in G_z, \quad \forall z \in Z \tag{4.12}$$

$q^{max}_{s,g,z}$ can follow a temporal profile, which accounts for unplanned outages as well as scheduled maintenance works and revisions (see Section 5.2.2). The renewable generators (solar PV, wind onshore, wind offshore) in the market model are aggregated and the available capacity follows the potential feed-in profile, which is obtained from external models or historical data.

Supply bids of flexible units are restricted by Eq. (4.13), where $q^{min}_{i,s,g,z}$ and $q^{max}_{i,s,g,z}$ can either be static parameters, e.g. for battery storages or follow a temporal profile based on environmental constraints e.g. in the case of hydro power plants with natural inflow.

$$q^{min}_{i,s,g,z} \leq q_{i,s,g,z} x_{i,s,g,z} \leq q^{max}_{i,s,g,z} \quad \forall i \in V, \quad \forall s \in S_{g,z}, \quad \forall g \in G_z, \quad \forall z \in Z \tag{4.13}$$

Apart from Eq. (4.6), the generators bids to the balancing markets are constrained by Eq. (4.14), where $q^{sB,max}_{g,z}$ is usually a fix ratio of installed capacity depending on the power plant technology.

$$0 \leq q^{sB}_{g,z} x^{sB}_{g,z} \leq q^{sB,max}_{g,z} \quad \forall g \in G_z, \quad \forall z \in Z \tag{4.14}$$

The zonal demand is split into several parts. Traditionally, the demand in energy market models is assumed to be mostly price inelastic. This part is modelled with an ask price equivalent to the market price cap, which can vary from year to year. This ensures the solvability of the problem even in extreme scarce situations. When not all demand can be satisfied, the price is set by this demand block, which is curtailed at the market price cap. The asked demand is limited by Eq. (4.15) to a demand profile which either resembles historic demand or results from scenario studies modelled in other tools. Demand side response from flexible, large (industrial or commercial) consumers can be integrated with specified quantities $q^{max}_{d,z}$ at given price levels. Another application are market price sensitive electrolysers, where $q^{max}_{d,z}$ is equivalent to the (aggregated) installed capacity of the electrolysers in one zone, which are dispatched at the same price level.

$$0 \leq q_{d,z} x_{d,z} \leq q^{max}_{d,z} \quad \forall d \in D_z, \quad \forall z \in Z \tag{4.15}$$

'Charging' of flexibilities modelled as storage is constrained by Eq. (4.16), where the limits $q^{min}_{i,d,z}$ and $q^{max}_{i,d,z}$ are either a (static) technical parameter for instance for battery storages or follow a temporal profile (e.g. the pumping limits for pumped hydro storage power plants with natural inflow where the limits can account for the seasonally changing inflows and resulting constraints on operation).

$$q_{i,d,z}^{min} \leq q_{i,d,z} x_{i,d,z} \leq q_{i,d,z}^{max} \quad \forall i \in V, \quad \forall d \in D_z, \quad \forall z \in Z \tag{4.16}$$

Equation (4.17) defines the limits of stored energy in the energy storages. For some technologies, these are physical limits, e.g. for battery storages where the installed energetic capacity is equally available throughout the year. For other technologies, these limits are set to $+/-$ infinity, because they are not restricting the problem, while at the edges of the optimisation horizon for the respective technology, the storage limits are forced to zero to ensure, that energy is only shifted within the specific time windows. This is relevant for the generic demand flexibility (heat pumps in households, large-scale heat pumps for district heating, flexibility potential of charging profiles from e-mobility, etc.) or demand response, that is modelled as a storage. For these flexibility, reduced demand in one hour needs to be made up for in another hour and an energy limit for the storage is defined in a certain time window, e.g. 24 hours. This methods also allows to decouple time intervals through fixed start and end levels of energy stored, which allows for the problem to be solved in parallel for these time intervals. For seasonal storages, at given time intervals, e.g. weeks, the energy levels are fixed to the level resulting from the long-term storage planner run, which yields the optimal solution from a yearly-coupled run of the model.

$$e_i^{min} \leq e_i \leq e_i^{max} \quad \forall i \in V \tag{4.17}$$

Exchanges over NTC borders are constrained by Eq. (4.7). Hourly profiles can be parameterised, which allows e.g. for back-testing the market model against historic market prices, flows, etc. because NTCs in the Single Day-Ahead Coupling (SDAC) also vary for the hours of the day and exhibit a seasonal pattern. Unavailabilities or reduced capacities on certain links resulting from line outages, maintenance, etc. can also be integrated.

The FB NPs can also be constrained according to Eq. (4.18), to incorporate more complex grid constraints, which cannot be directly incorporated with the FB constraints.

$$np_z^{min} \leq np_z \leq np_z^{max} \quad \forall z \in Z \tag{4.18}$$

4.1.3 Future development of (thermal) generation capacity

For scenarios where the power plant capacity does not match the master data from the power plant data base or for scenarios with growing capacity but missing technology-specific information (e.g. if gas-fired power plants are built as Open Cycle Gas Turbines (OCGTs) or Combined Cycle Gas Turbines (CCGTs)), the model follows a simple logic. In case the model capacity for a fuel or technology is larger than the scenario capacity, power plants from the data base are decommissioned until the aggregated capacity matches the scenario data. The order is defined by the commissioning year. If the scenario capacity is larger then the aggregated fleet data from the data base, decommissioned power plants are recommissioned for the scenario model run in reversed order of the decommissioning year. If no information about the capacity is given or in case of significant new-built capacity (which is in many scenarios the case for gas-fired power plants), the model entails a simplified investment logic to determine the capacity of Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT) power plants to add. The required firm capacity to meet security of supply is determined based on a standard weather year (2016) taking into account the maximum residual load in each market zone and the existing hydrothermal capacity under consideration of availability factors for each technology. Additionally, (demand) flexibilities are assumed to be price sensitive and reactive to the market price and thus will activate their potential during scarce hours. Lastly, the interconnector capacity for imports is taken into account, subject to a de-rating factor, due to the fact that the importance of concurrency of the renewable generators will increase in the future system.[35] Considering current trends in European market design, with more and more countries introducing reserve or capacity mechanisms to ensure security of supply, it is assumed that due to such mechanisms, the respective firm capacity level is met for each country. The economic feasibility might be achieved through capacity markets, decentralised obligations or capacity tenders.

The investment options are limited[36] to OCGT and CCGT. The share of each technology is determined by the following logic: OCGTs are the most cost efficient solution to meet firm capacity when these power plants are only used in a small number of hours. The more the system is dependent upon these power plants, with increasing shares of renewable generation and decommissioning of existing other power plants, the more will the capacity factor of these plants increase. At some point, due to their higher efficiency, CCGT prove to be the more economically feasible solution. This decision will be made by future market actors, the resulting equilibrium is modelled with the following steps.

1 Determine the firm capacity requirement per market zone

2 Add OCGTs to this level

3 Run a market simulation with the new-built power plants, identify the profit for potential CCGT investments

4 Starting with the investment candidate with the highest positive net present value, replace OCGTs with CCGTs

5 When no new CCGTs are economically viable, or all OCGTs in the respective Bidding Zones (BZNs) have been replaced, the resulting equilibrium is kept for the following analyses

[35] Such de-rating factors are also used in existing capacity mechanisms as the UK capacity market.

[36] Given the temporal scope of most scenarios with decarbonisation targets until 2045 or 2050, OCGT and CCGT appear to be the most relevant technology. While several European countries have announced plants for new-built nuclear capacity, these plans are subject to large uncertainty about the commissioning years and cost and additionally, are usually entailed in scenarios.

4.2 Transmission grid model

The transmission grid model and grid simulation module are built on the open source tool MATPOWER [Zim11]. Depending on the use case the model makes use of the AC or DC optimal power flow formulation with specific objective functions and/or variable bounds. The developed tool chain also uses many of the functions, for instance to derive the power system matrices which are relevant for FBMC. The most relevant variants are laid out in the following.

4.2.1 Optimal power flow to model congestion management

The simulation of congestion management (CM) follows the European zonal market design where the market clearing only considers a limited number of grid constraints, mainly those regarding interconnection capacities. Based on this dispatch, the Transmission System Operators (TSOs) have to ensure secure grid operation. In the case of operational conditions that would lead to violation of equipment limits or lead to insecure operating points, TSOs can intervene and re-dispatch the market schedule of power plants. This is especially relevant in presence of grid expansion delays and increasing shares of RES. Intervention measures, mainly regard the relief of overloaded lines, so the process is often referred to as congestion management. Flow limits derived from thermal line limits are the main constraints in this variant of the model. Following the notation in [Cap16], the problem takes the form

$$\min_{x} f(x) \tag{4.19a}$$

$$s.t. \quad g(x) = 0 \tag{4.19b}$$

$$h(x) \leq \overline{h} \tag{4.19c}$$

where functions g model the power flow equations as in Eq. (2.2) or Eq. (2.3) depending if power flows are modelled in full AC or in DC formulation. Functions h model the operational limits of the grid like branch flow limits or voltage magnitudes on the one hand and device limits as in Eqs. (2.9d) to (2.9i) on the other hand.

In contrast to the classic formulation, the cost for the market dispatch of power plants in the objective function f is zero and the operational limits of generation and demand are constrained to the market results. To model the congestion management (CM), additional decision variables and constraints are added. For each re-dispatchable generator one variable for downward adjustment $rdsp^{-}$ and one variable for upward adjustment $rdsp^{+}$ is introduced. The former is limited by the dispatched power, the latter limited by the remaining free capacity of the generator. Re-dispatch costs in practice are subject to different regional regulation, court decisions and negotiations, which might change as the topic gains relevance in many markets[37]. The CM model applies a simplified approach where the costs for positive re-dispatch are based on short-term variable costs, i.e. mainly the additional fuel use, which are the same as in the market model. For negative re-dispatch, fuel cost can be saved, when the power output is reduced. For each curtailable renewable generator an additional variable is introduced, which is limited by the market dispatch in this time step. The case when renewable generators would have upward re-dispatch potential after a (partly) shutdown due to low market prices, is neglected for simplicity but the extension of the model to include this is straightforward. The cost for these curtailment variables, in approximation to Eq. (2.13) is defined by the average upward re-dispatch cost multiplied with a scenario-specific minimum factor. Grid reserves (foreign and domestic) are added as variables which are limited by the operational limits of the respective resources. The cost for the activation of grid reserves is set to 50 % of the calculatory cost for RES curtailment as a rough estimate of the ratio published for Germany for the years 2021/2022 and 2022/2023 (see Table 2.3). To somewhat prioritise domestic against foreign grid reserve power

[37] Germany at the time of writing, being the market where the topic is most prominent due to the gap between RES and grid expansion.

plants, foreign grid reserve activation is assumed 20 % more expensive than domestic. Domestic in this context refers to the area where the model keeps track of line congestions, foreign the area where grid information and thus regionalised power plant information is available in the model run. Demand can be made dispatchable using the MATPOWER functionality. In contrast to the modelling of demand-side flexibility in the market model, this is merely to ensure solvability.

The grid simulation in this configuration is mainly used to analyse congestion management (CM) in the German transmission grid. There are two modes of operation. In the first case, the German grid is simulated in isolation. Here import and export (trade) flows have to be exogenously attributed to individual interconnecting lines. In the second configuration, the neighbouring countries belonging to the Core region are also modelled, but line congestions are only traced within the German grid, that is, the line flow limits in Eqs. (2.9h) and (2.9i) are not active outside of Germany. This has the advantage that re-dispatch and curtailment measures can be attributed to the German congestions, but power flows over the interconnectors including transfer and loop flows that result from the market dispatch are adequately accounted for. The model can be operated in this mode for multiple countries or even the entire Core region. However, this would resemble a completely coordinated European congestion management (CM), which makes the interpretation of single CM measures and the attribution of causing congestions difficult. The AC version is mainly used for (historical) cases where the location of reactive power compensation elements is clear, and the amount of congestion should be determined with the highest accuracy. The advantage is that the results also yield the solution for voltage magnitudes and are loss-minimal. The advantages of the DC version are speed and convergence robustness. It's more suitable for quick analyses with focus on line congestions at nominal voltage levels and multiple scenario-analysis, where many model runs have to be completed in short(er) time.

4.2.2 Grid simulation in the context of the Flow-based market modelling module

The grid model is also used within the FBMC module to identify the initial line loading. Starting from the base case dispatch, the model is set up in the DC version, with fixed generation and demand. Line limits are relaxed using the 'soft-limits' functionality of MATPOWER, where additional slack variables are introduced to the flow limit constraints Eqs. (2.9h) and (2.9i). The model can then use the remaining degrees of freedom, mainly the set points of the voltage-source-controlled (VSC) HVDC lines within bidding zones to minimise line overloadings, to anticipate the resulting flows for the FBMC. The share of the HVDC links' capacity, which is optimised at this stage can be varied. The results of the optimisation yield the power flows in the base case that are used in the subsequent steps to calculate the FB constraints described in Section 4.3.

4.2.3 Input preparation for the grid simulation

Additional inputs need to be compiled in preparation for the grid simulation, in addition to those of the market model. First, the grid topology and parameters are read from the grid data base for the respective year. If seasonal or dynamic line ratings are to be included in the model run, the static limits are replaced by the seasonal limits and, in the case of DLR, with the relevant dynamic limits for the specific weather year. Furthermore, the import and export flows to and from the simulated region resulting from the market result have to be handled at the geographic bounds of the grid region. In the case of HVDC interconnectors, the flows are attributed to the explicit bus(es) where the HVDC line is connected. At AC borders, the flows are distributed to the relevant lines, proportional to the lines' capacities. Although this introduces an error, this solution is superior to not including these flows. Additionally, if the focus of the analysis are congestions in the German transmission grid and the neighbouring grids are explicitly represented, these errors are introduced far from the area of interest, and the resulting impact is correspondingly small. Finally, for the explicitly modelled grid area, the devices have to be mapped to grid nodes, i.e. busses. For the majority of power plants, their location and/or grid connection is available and stored in the institute's data base. Where this information is lacking, the power plants are connected to the closest bus with the relevant voltage level or the closest transmission substation. Regionalisation of RES and demand is inherent to the output of the expansion planning and profile generation in the HighResO model, which also includes distributions for new flexible demand potentials from flexible electric vehicle charging and power-to-heat applications. If the scenario does not include information for the distribution of electrolysers, utility-size battery storage and vehicles with the ability to feed power back into the grid (vehicle-to-grid), these capacities are distributed based on the correlation between the infeed vectors of solar PV, wind onshore and wind offshore and the power off-take vectors from these technologies after a market simulation. The capacities are then allocated according to the weighted correlation factors to the respective buses.

4.2.4 Deriving generic line parameters

For most overhead lines and circuit standard configuration, the necessary parameters for the grid simulation and the calculation of dynamic line ratings can be taken from the literature (e.g., [Oed11]), where they are not included in the grid data set. When this is not the case, [Oed11] also provides the theoretical basis to calculate important parameters like the specific inductance or specific conductance in multi-circuit configurations. For the case of a double circuit line in a three-phase system following the naming conventions in Fig. 4.3b, the specific capacitance C' is calculated as

$$C' = \frac{2\pi\epsilon_0}{\ln \frac{d d_{mL1M2}}{r_B d_{mL1M1}}}, \tag{4.20a}$$

with

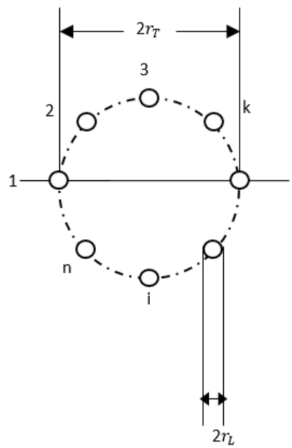
$$d = \sqrt[3]{d_{L1L2}d_{L2L3}d_{L3L1}}, \tag{4.20b}$$

$$d_{mL1M1} = \sqrt[3]{d_{L1M1}d_{L2M2}d_{L3M3}}, \tag{4.20c}$$

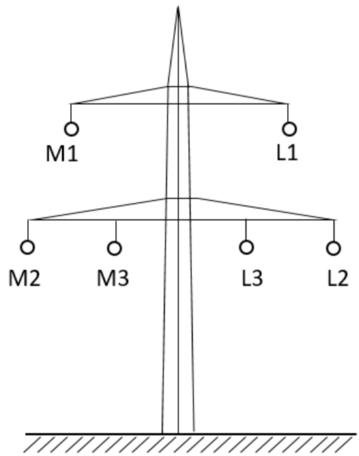
$$d_{mL1M2} = \sqrt[3]{d_{L1M2}d_{L2M3}d_{L3M1}}, \tag{4.20d}$$

$$r_B = \sqrt[n]{n r_L r_T^{n-1}}. \tag{4.20e}$$

r_L is the radius of the conductor and r_T the radius of the circle on which the conductors are arranged in a multi-conductor per circuit arrangement as they are predominantly used in the extra high voltage grid. n is the number of conductors per circuit. This is depicted in Fig. 4.3a. ϵ_0 is the vacuum permittivity.



(a) Geometric figures for the conductor bundle.



(b) Designation of the circuits for calculating the conductor parameters for a dual circuit arrangement on a grid pole.

Figure 4.3: Conductor and pole geometry for generic parameter calculation. Own illustration based on [Oed11].

The specific inductance for a double circuit is calculated as

$$L' = \frac{\mu_0}{2\pi}\left(\frac{1}{4} + \ln\frac{d d_{mL1M2}}{r_B d_{mL1M1}}\right), \tag{4.21}$$

with d, d_{mL1M1}, d_{mL2M2} and r_B as in Eq. (4.20). μ_0 is the vacuum permeability. Parameters for typical pole geometries are available from the literature, e.g. [Oed11]. Conductor parameters are available from producers or engineering norms (see Section 5.3.4). In arrangements with more circuits, the geometrical formulae become more complex, but the physical principles remain the same. The specific resistance R' is a conductor parameter independent of geometry, where only the number of conductors per circuit is relevant.

4.3 Determining Flow-based market coupling constraints

The market and grid module are used in conjunction to determine the constraints for FBMC. Figure 4.4 gives an overview of the developed FBMC model and how the different aspects interact. The remainder of the section describes the different aspects and steps to calculate the FB constraints. The FBMC module takes a market solution from the market module and additional inputs from the grid module that enrich the data model with locational network specific information.

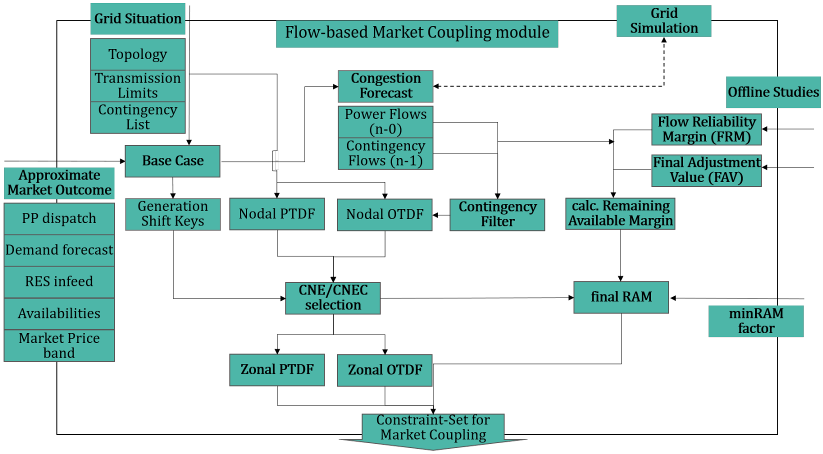


Figure 4.4: Overview of the developed Flow-based market coupling model.

4.3.1 The base case

For the calculation of the FB constraints, the merit order is linearised around the (anticipated) operation point or the market clearing point. The power plants dispatched in each bidding zone are determined by the position of their supply bids in the merit order, the zonal demand and the dispatch of flexible demand, as well as the exchange position of the bidding zone. The loading of the tie-lines and thus the capacity available for trading depends upon which power plants are active in the bidding zone, but the dispatch of the marginal power plant(s) also depends on the exchange position or exchange potential in a given situation. This problem can only be solved to optimality in a closed formulation or by iteration. Given the different roles in the energy market, the exchanges have exclusive knowledge of the order book, but without geographic information of the bids on the one hand. On the other hand, the TSOs have exclusive information about the grid topology and position of power plants, but no knowledge of the supply and demand bids, so a different solution needs to be obtained. The TSOs are responsible for determining the capacity constraints for the market coupling algorithm executed on the exchange. Calculation and coordination steps between TSOs take up to two days, so the TSOs have to approximate the probable operating point of the system at the time of coupling to determine the anticipated line loading and the resulting free capacity, which can be made available to the market. This approximation is called the base case. It consists of a set of information regarding the time of coupling which contains the topology information of the transmission grid, availability information of power plants, forecasted feed-in of renewable generation units, the demand forecast and an anticipated dispatch of flexible power plants and demand flexibility, as well as the resulting net exchange positions of the bidding zones. In the standard version of the model, a NTC market simulation serves as the base case to determine the dispatch of power plants, acceptance of demand bids and dispatch of demand flexibilities.

4.3.2 The power flow in the base case

The initial line loading for the base case is determined with a power flow simulation. With the increased installation of active power flow control devices, such as phase-shifting transformers at many of the bidding zone borders and with the integration of HVDC lines with VSC technology at the terminals, which allows the flow direction and the share of active and reactive power to be controlled, additional challenges arise. First, as these devices are capable to control power flows, they have to be incorporated into the power flow calculation, which in fact makes the problem an optimal power flow instead of a power flow study, that has to be solved in order to determine the initial power flows in the network. An advantage is that the fraction of these devices that is available for the FB algorithm can be chosen, while the remaining capacities can be used as remedial actions or as a reserve for the grid operation. In this OPF, generation and demand are fixed to the base case, and flexible grid elements are optimised to limit grid overloads or losses depending on the objective. As grid overloads can occur in the base case, soft limits on line flow limits can be helpful in achieving a quick and feasible solution.

4.3.3 Evolved Flow-based market coupling with virtual HVDC hubs

The introduction of cross-border HVDC lines within the FB region, like the Allegro cable between the BZNs Belgium and Germany-Luxembourg, poses another challenge. The flows on these elements could be predetermined by the base-case market simulation. However, this would implicitly discriminate the AC exchanges against the DC exchanges, because the DC flows reduce the solution space through the pre-allocated flows. An alternative solution is called evolved Flow-based (EFB) market coupling, where additional virtual bidding zones are created at the start and end point of the HVDC interconnectors [Cor18]. With their own sensitivity factors regarding the distribution of power flows in the network, they hence compete with AC exchanges on a level playing field. This approach is also the one selected in this work. Similarly, HVDCs connecting to CCRs can be considered with virtual hubs to integrate the impact of the exchange over the interconnector on the Critical Network Elements (CNEs) in the capacity allocation process. This is called advanced hybrid coupling (AHC) [Cor18].

4.3.4 Net export positions

In the configuration with FB constraints, additional variables are introduced to the market model. For each BZN with a border under FBMC, the NP of this BZN in the FB region is introduced as a decision variable. As a consequence, the bidirectional flow constraints from the NTC version of the model are discarded, and the FB constraints are introduced, which constrain the net position with respect to the resulting flows over the identified critical network elements.

4.3.5 Selection of relevant critical network elements

The set of FB constraints introduced into the market model only contains the subset of the modelled grid elements, which is relevant to limit exchange capacities. In the most simple setup, only the tie-lines that connect two bidding zones are considered. The CWE FBMC allowed for the inclusion of internal lines which are heavily affected by cross-border trades. These Critical Network Element (CNE) are determined based on linear sensitivity factors (PTDFs, see Section 2.4). Given the PTDF matrix of a certain grid topology, the proportional flow on a line that results from a trade between two bidding zones can be determined. Lines, which are affected above a certain threshold by an exchange between two BZNs within the FB region, are included in the set of CNEs that potentially constrains the NPs.

4.3.6 Selection of critical outages and calculation of contingency power flows

One of the advantages of FBMC is that the explicit incorporation of grid information includes operational security aspects already at the time of market coupling. The (n-1) criterion ensures that the grid operation is always securely possible given any single outage of a grid element. The consideration of all possible outages or contingencies in combination with all identified CNEs quickly becomes computationally intractable due to the number of constraints added for each contingency case. There are several approaches to reduce this complexity and create an equivalent problem with a simplified system of equations. One solution is to identify so-called umbrella constraints, i.e. contingencies which dominate a number of other contingencies. However, the process of identifying these constraints is an optimisation problem of its own, which is harder to solve than the original problem [Jah18, Cap07]. A simpler and faster approach is the use of thresholds and linear sensitivities. Similarly to PTDFs, Line Outage Distribution Factors (LODFs) are easily determined for a given topology and describe how the flows on a given line are distributed in the event of an outage of that line. Due to the linear nature of the problem, taking advantage of the knowledge of the grid topology with PTDFs and LODFs and given the power flows in the base case from an initial power flow simulation, contingencies can be selected with respect to their impact on the solution and can be included or excluded. Therefore, only outage-line combinations are selected where the (n-1) flows are larger than the flows in the base case and only those lines are included in the selection process, whose (n-1) loading is above a certain threshold. The former rule follows the reasoning that contingencies which relieve the line loading do not need to be tracked, and the latter, that due to the relative closeness of the base case and the final FBMC result, it is unlikely that a change in line loading will be very large. The result of this filtering procedure is a set of constraints which represents the allowed line loading of the CNEs under the identified contingencies for so-called Critical Network Elements under a Contingency (CNECs).

4.3.7 Generation shift keys

Generation Shift Keys (GSKs) describe the linearised relationship between a change in the BZN's NP and the change in injection at the individual grid nodes. Naturally, these factors are highly dependent on the state of the power system. There are several strategies to obtain these factors [van16], [Sch20]. Starting with FBMC in CWE, each TSO was able to introduce their own logic to approximate the market reaction to increased or decreased exchange capacities in their BZN as closely as possible [Amp19]. In day-to-day operation, GSKs can also be determined using stochastic models or machine learning approaches, where the anticipated reaction is determined by observed historic behaviour (e.g. [Sch19]). For simulations of the future energy system, this is not possible as the power resources in the future are different from historical ones. Hence, fundamental GSK strategies need to be pursued. Moreover, in contrast to today's system, the high share of RES will make it necessary to include the reaction of these weather-dependent resources to market prices[38]. Similarly, more flexible applications like utility-size battery storages, V2G, flexible power-to-heat applications, etc. will at least in part be sensitive to the market price and thus also need to be included, when prices are in a range where these technologies could become marginal, i.e. relatively low/high with respect to the charging cycle of each technology. Demand side response and

[38] Often RES are modelled with zero marginal cost in energy market or system models. However, in a system with a high share of RES, in many hours market prices will be very low (close to zero) and large shares of different renewable technologies will compete for a place in the market or decide to shut down generation.

electrolysers, which are modelled with a specific price levels above zero are included into the GSK logic, when the approximated market price is within range of their marginal cost. Due to the deterministic nature of the model, the marginal player could easily be identified and included as sensitivity in the FB calculation. In order to include the uncertainty, which comes with the limited knowledge of the TSOs in the calculation process with regard to the order book, the chosen approach includes numerous devices at multiple nodes within a certain cost range to possibly react to the change in net export positions of the BZNs.

4.3.8 Aggregation to zonal sensitivity matrices

In order to include the sensitivity factors in the zonal market model, GSKs and nodal PTDFs are multiplied to yield the linearised change in flows on the CNEs and CNECs. The nodal PTDF matrix remains constant due to the static grid model in each modelled year. The GSKs are dynamic and change with regard to the RES infeed potential and the approximated market price. So are the relevant CNECs, which together with the GSKs form the set of zonal OTDFs and are also included in the constraints set.

4.3.9 Remaining available margin

The RAMs represent the right-hand side of the FB constraints included in the market coupling problem. The RAM describes the free capacity on a given CNE/CNEC, which can be utilised for (additional) trades between BZNs exceeding the exchange situation in the base case. The determination of the RAM comes basically down to the identification of the secure technical limit of a line reduced by the loading in a balanced situation, i.e. a situation without exchanges to account for loop flows. From the base case, the power flows at approximated exchange positions are known. The free capacity in a balanced situation can be obtained by subtracting the trade-induced power flow (from the base case exchange) from the power flow in the base case. To determine these flows, the zonal PTDFs/OTDFs and base case NPs are used. Since the NPs in the base case can be relatively large, it is unlikely that the resulting situation (balanced BZNs) will still be adequately represented by the GSKs. For the methodology to work, the market solution resulting from the FBMC and the solution approximated in the base case must not be far apart, as this is the only way to ensure the validity of the identified GSKs and therefore the feasibility of the solution.

4.3.10 Minimum RAM as introduced by the Clean Energy Package

Directive (EU) 2019/943 [Eur19b] reduces the degree of freedom that TSOs have when determining the RAM. The regulation stipulated that the final RAM need to be at least 70 % of each CNE/CNEC's transmission capacity. The TSOs were given a transition period until the end of 2025 to increase this value from the formerly minimum factor of 20 % in CWE. The regulator in each market area is responsible for approving the selected approach. In Germany, BNetzA follows the process of a 'national action plan' foreseen in the CEP and determined a linear path for the increase starting in 2020 from historically determined minimum values.

4.3.11 Flow reliability margin and final adjustment value

In the FBMC methodology introduced in CWE, TSOs have the ability to adjust the constraint set outside the RAM determination scheme. Namely, the FRM accounts for the difference between the observed power flows and the flows approximated with the FB model. The Final Adjustment Value (FAV) allows for instance to include the effect of additional remedial actions, which cannot be included in the FB methodology, but might increase the allowed flow on a given network element. As the model employs the same data for FBMC and grid simulations and additional remedial actions are not considered, FRM and FAV are also not used in the modelled FB calculation.

4.4 Determining weather-dependent transmission line limits

As described in Section 3.2.5, the methods for calculating the capacity of overhead lines depending on the wind speed, solar irradiation, and temperature conditions are well established. The contribution of this work in this aspect lies in the comprehensive integration of dynamic line rating in the simulation of the European transmission grid and even more so into the calculation of the Flow-based market coupling constraints. Especially in future energy systems, where a large part of electricity will be generated from wind onshore and offshore parks, the resulting correlation between congestion-defining situations and increased line transmission capacity is worth investigating. The potential benefits need to be quantified to establish the necessity for extensive use of dynamic line rating in the European power system. The European TSOs show different levels of integration of DLR into their scenarios and daily operation. Within the framework of the developed approach, the line capacity for each line can be considered in three different configuration: Static line limits from the data base or generic parameters respectively (see Section 4.2.4). Seasonal line limits apply a linear scaling factor to the static line capacity at different times of the year. This is also a configuration used in operation, e.g. by the Belgian TSO Elia on the 380 kV and 220 kV lines. The definitions for the seasonal limits are shown in Table 4.1.

Table 4.1: Seasonal thermal limits in the Elia transmission grid [ELI17].

Season	Seasonal limit [% of I_{nom}]	Start	End
Winter	112	16^{th} November	15^{th} March
Spring	106	16^{th} March	15^{th} May
Summer	100	16^{th} May	15^{th} September
Fall	106	16^{th} September	15^{th} November
High Winter	120	Average daily temperature < 0℃	Average daily temperature ≥ 0℃

Continued on next page.

Season	**Seasonal limit [% of I_{nom}]**	**Start**	**End**
High Summer	90	Temperature >30℃	Temperature <30℃

The third possibility is the integration of hourly dynamic line limits in line with the considered scenario-weather-year based on the methodology described in Section 3.2.5. The underlying weather data are the same as utilised in the HighResO model for the calculation of the RES feed-in profiles, the ERA5 reanalysis data available from ECMWF [Her23]. The dynamic line limits are restricted to 150 % of the static limits as a conservative assumption, because the spatial resolution of the weather inputs as well as the routes of the overhead lines are not modelled to a level of detail, which allows to identify the limiting conditions for each circuit and line section. Moreover, currents higher than this limit might lead to other problems in the circuit (insulation, etc.), which are beyond the scope of the grid/power flow model. Figure 4.5 shows the flow of data in the developed module for the calculation of dynamic line rating and shows the different relative capacities for two weather situations.

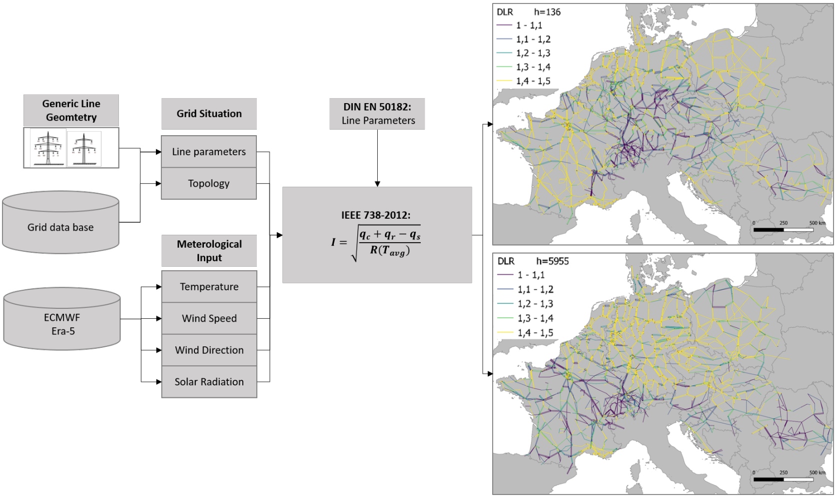


Figure 4.5: Overview of the developed module for calculating dynamic thermal limits for overhead lines.

4.5 Utilising Flow-based constraints in NTC market models

The integration of FBMC presents several challenges to existing electricity market models. First, additional know-how needs to be developed with regard to regionalised input data (RES and demand profiles), as well as grid topology and power flow calculation. Second, the new variables and additional constraints need to be integrated into the model. This presents a potential problem, when the market coupling problem is not formulated as an optimisation problem or when the significant additional computational burden of the FB constraints cannot be easily integrated into the model. A possible solution is the approximation of the FB constraints with bi-directional NTC values. From a theoretic standpoint, this is not feasible because the FB solution space cannot be represented with bidirectional constraints only. From a practical perspective, the resulting time-variable constraints often already represent progress with respect to the alternative, which is the utilisation of static scenario-based NTCs for the entire year that do not allow for any adjustment of the scenario with regard to the underlying grid (expansion) assumptions. A proposed method for the derivation of these *dynamic NTCs* is presented below.

One result of FBMC are the NPs of the BZNs. From this set of NPs, a variety of allocations to bidirectional flows between BZNs is possible. Moreover, the resulting commercial flows can be much higher than the physically possible flows, because import and export flows can balance each other out. To be utilisable in an NTC market model, the exchange capacities from the methodology need to respect the physical constraints.

Furthermore, FBMC allows for so-called unintuitive flows (that is, flows from BZNs with high market prices to zones with low market prices), if these flows can relieve a congested border and increase overall welfare [Joi20]. This characteristic of such flows cannot be easily integrated into models with bidirectional exchange constraints. Hence, the flow variables in the allocation problem have to be additionally constrained with regard to the flow direction and the price delta between zones. From these constraints, situations can arise where the problem becomes infeasible with the given NPs. In these situations, a penalised deviation from the original NPs is allowed, so the problem yields feasible exchange flows, which can be incorporated into other market models. Without the additional constraint for unintuitive flows, the problem can be formulated as follows.

Let G be the set of tie-lines between the bidding zone i and j, for which FBMC is applied. Let further be Φ the set of zonal pairs (i,j) for which

$$\Phi = \{(i,j) \in G | \Delta_{p_{ij}} \leq 0\}, \tag{4.22}$$

where

$$\Delta_{p_{ij}} = p_i - p_j, \quad \forall i \in Z, j \in Z \tag{4.23}$$

is the delta between the market clearing prices in zone i and zone j determined in the FBMC simulation. Z is the set of BZNs. The available dynamic bi-directional exchange capacities φ^* are then the results of the minimisation

$$F(\Delta_{p_{ij}},G) = \min_{\varphi} \sum_{(i,j)\in\Phi} \Delta_{p_{ij}} \cdot \varphi_{ij} \tag{4.24}$$

subject to retaining the zonal NPs from the FBMC result

$$\sum_{(i,j)\in\Omega_z} \varphi_{ij} = NP_z^{FBMC} \quad \forall z \in Z, \tag{4.25}$$

where Ω_z is a subset of Φ, where either i or j equal z.

The *dynamic NTCs* derived in this way can replace the NTC limits in Eq. (4.7)

$$0 \leq f_{zl} \leq NTC_{zl} = \varphi_{zl} \quad \forall (z,l) \in F \tag{4.26}$$

and make it possible to approximate the FBMC with NTC-based models and thus to achieve significantly faster results and, if necessary, to investigate complementary aspects that such models contain to the approach developed here, e.g. agent-based behaviour. For the application, it is only necessary to ensure that the operating point is not too far away from the FBMC solution (due to the changed assumptions) so that the derived transmission capacities retain their validity. It is to be expected that the transmission capacities derived in this way will lead to a market result that is much closer to the FB result than would be the case if static NTCs were used. This hypothesis is tested in Section 6.3.

5 Data basis, input data and scenario framework

This chapter describes the data sources for hydro-thermal power plants and other input data especially with regard to the generation of a transmission network model, which can be used for power flow calculations and the derivation of Flow-based (FB) constraints and the preparation steps necessary to obtain a mathematical model. (Technical) Power plant and grid parameter are not easy to obtain for the simulations, as most data sources offer only some of the needed attributes, like location or grid connection point and voltage, gross and net power installed or have a limited geographic coverage. Moreover, critical data like fuel costs or fuel transport costs, efficiencies, operating and maintenance costs are often not publicly available due to economic interests and competition of the involved players, so assumptions have to be made or values taken from the literature.

5.1 Transmission grid data

For the transmission grid, data sources have become more and more available in recent years. Since the introduction of Flow-based market coupling (FBMC) in 2015, Central Western Europe (CWE) Transmission System Operators (TSOs) have published static grid models that enable the modelling of the status quo. Additionally, since 2016, the ENTSO-E has published a grid data set in accordance with the TYNDP publications, which are publicly available but subject to non-disclosure agreements. Another public source of grid topology data can be found in several (research) projects like *SciGRID* or *GridKit*. Open Street Map (OSM), especially handy in the form of the *flosm* project, in some countries has dramatically increased in accuracy and data quality, a prime example being France, where most of the substation tags are at the time of writing in line with substation labels published by the French TSO RTE and mostly with the TYNDP data. National Grid Development Plans (NDPs) are published more or less regularly by the TSOs, where grid expansion measures and their planning status are explained. This information, in combination with the reference grid from the TYNDP and detailed documentation of international projects in the TYNDP allow for the modelling of grid expansion measures as they are foreseeable in Europe for the next 15 to 20 years. Steadily changing political goals and scenarios as well as delays in the realisation entail continuous adjustments in the status of expansion projects, which need to be reflected in the grid model data sets.

The Institute for Industrial Production (IIP)'s transmission grid data base has evolved over time compiling different available data sources into such a computable data set, which can be integrated into the Renewable Energy Sources (RES) regionalisation tool-chains, as well as the market simulation models. Hence, it can be utilised for the FBMC simulations as well as simulations of the grid operation, including congestion management (CM), starting in 2016 until the late 2030s, when the latest expansion measures are known. Missing data is filled with standard parameters, for instance where no line information is available, the length is approximated using the airline distance and a diversion factor[39], analogous to the procedure in the German Grid Development Plan (NEP) for new line corridors [Ueb23]. Generic technical parameters can be obtained using literature values or well established techniques (see Section 4.2.4). The following section describes the complete data basis from which the Core Capacity Calculation Region (CCR) grid model used for the following analyses is derived. It should be noted, that the establishment of this data base was a joint effort by multiple colleagues[40]. The main contribution in this work with respect to grid data is the extension of the grid for the

[39] The German grid development plan uses 1.3 as diversion factor. [Ueb23]

[40] The author would like to thank M. Ruppert, V. Slednev and T. Sandmeier for the collaborative effort.

CWE region and Switzerland by the Eastern European Countries, completing the Core CCR.

CWE static grid models
Following the introduction of FBMC in the CWE CCR in May 2015, data availability has continuously increased. A major step forward was the publication of the static grid models for the CWE Bidding Zones (BZNs). While some where only available in non-machine readable formats (e.g. PDF), they form a good starting point and include explicit information regarding electric circuits and technical parameters for lines and transformers.

Open street map
For fine tuning of topology information, quantity of transformers at a substation, etc. the project *flosm*[41], which is based on OSM, and satellite images can be used. The data available from OSM became increasingly useful in recent years culminating in the French grid data, where the identifier are consistent with those published by RTE in the static grid model and TYNDP grid data set(s).

Grid maps
Published by ENTSO-E, grid maps while also being in some cases explicitly misleading with regard to topology and geographically information can also serve as a point of reference. *GridKit*[42] is a notable open toolkit, which allows to compile a computable grid data set from the ENTSO-E grid map, while relying on generic technical parameters. For most TSOs, circuit diagrams of the transmission grid are available, which also complements topology information.

TYNDP data sets
Starting in 2016, ENTSO-E published a snapshot of the European grid(s) for 2027 on which the TYNDP process is based. The first iteration was published in Excel files, not always containing enough information to map the data with

[41] https://www.flosm.de/html/Stromnetz.html

[42] https://github.com/PyPSA/pypsa-eur/tree/master/data/entsoegridkit

other sources available. Nevertheless, it provides valuable information for validation of existing grid data sets. The following iterations from the TYNDP 2018 and TYNDP 2020 were published in the Common Information Model (CIM) standard under the Common Grid Model Exchange Standard (CGMES) format. To make this format interchangeable with other software two python packages CIMpy, developed at the E.ON energy research centre of RWTH Aachen[43] and PyCIM[44] are available, the former also being able to read the newest CGMES format. Moreover, the TYNDP documentation includes detailed information for the Projects of Common Interest, grid expansion measures, which are to the mutual benefit of more than one member state.

Core static grid models
With the launch of Core CCR FBMC additional static grid models became available also in Excel format for the participating countries. While extending the parameters, e.g. information for dynamic line rating were included for the first time, some parts of the grids like demand centres are still missing and need to be added from other data sources.

Individual static grid models
Some TSOs have published additional numerical static grid data sets outside the Core FBMC scope. Two notable examples are RTE for France (where again it should be noted that a fully geo-referenced data set can be achieved by merging the data with other available information from RTE) and Terna for northern Italy, where a static grid model is also available in Excel format, which has some common shortcomings with the first TYNDP data set, i.e. the bus names are not easily matched with other data sources.

Data for Germany
For Germany, an additional rich source of data are the NEPs. While unfortunately to this day, they do not encompass a numerical format, detailed information are available for each project topology, for which the electric parameters can be obtained using generic parameters. Given the size of the German transmission grid and the scope of political targets for the energy transition

[43] https://git.rwth-aachen.de/acs/public/cim/cimpy/-/tree/master
[44] https://github.com/rwl/PyCIM

in the medium term, this data set is the most comprehensive of any future grid data available in Europe.

National expansion plans and maps
Some other countries also publish NDPs (notably Austria, Poland and Czech Republic) that have a project detail comparable to the German NEP and allow for adjusting the grid topology based on a distinctive transition path. In the case of Poland and Czech Republic, grid maps for several snapshot years are available which further detail interim topology information and realisation time frames for grid expansion projects.

The grid data base used in this work is a compilation of the data sources described above. Due to data availability and focus of the research in the German context, data for Germany are the most recent and detailed including the grid expansion state of the latest confirmed version of the NEP. In some cases, simplifications have been applied to the available data. This regards mainly the reduction of bus bars at each substation to one bus per voltage level. On the one hand this reduces the quality of the data set with regard to the mapping of individual circuits, but on the other hand significantly simplifies the allocation of (future) demand (flexibility) and especially RES expansion to individual grid nodes. The system boundary of the transmission grid model is chosen to the 110 kV bus bars at the relevant substations to which the corresponding consumers and generators are connected[45] and which in turn are connected via transformers to the bus bars of the transmission grid.

5.2 Historical data

Parametrisation of the model with historic data serves multiple purposes. First, the simulation of historical years offers the possibility to verify the model results against a history to assess the validity of the approach and assumptions. Second, it allows for the calibration of parameters and the analysis of the impact that remaining degrees of freedom have in a historical setup, so

[45] Unless they are directly connected to the transmission grid busses.

variance in the model results can be put into perspective of historical events. This section describes the data sources used to model historical years.

5.2.1 Fuel prices and cost for CO_2 emission allowances

Commodity prices and prices for emission allowances and other fuels form the input basis for the variable costs of the power plants in the market model and for congestion management. For historic **hard coal** prices, there is no spot market from which prices could be used for the simulation. However, price reporting agencies such as Platts, Argus Media or ICIS Heren provide aggregated information on prices. For hard coal, the benchmark price assessment in Europe is the API2 assessment, which serves as a reference for most traded coal derivatives. Financial futures, which are settled against the '(API 2) cif ARA Monthly Coal Price Index' can be traded on exchanges like Intercontinental Exchange (ICE) or Chicago Mercantile Exchange (CME). Daily settlement prices are published by these exchanges and openly available with a limited history. Monthly contracts for multiple years into the future can be traded. For the front month contract at CME for instance, the trading continues until the last trading day of the delivery month, so the daily settlement price for these contracts can be used as a proxy for which coal can be bought or sold at that day. The physically delivered coal also has to be stored and transported in discrete (mostly) shipping units to the power plants. This adds additional cost, still the price provides information about opportunity cost for electricity generation with hard coal, even though especially small market players probably don't have the market access necessary to react to daily price volatility in the fuel prices. Nevertheless, the underlying assumption in the market modelling is, that at least the marginal player with coal-fired generation decides the bidding price based on the opportunity visible in the futures markets.

The native temporal resolution for fuel prices in the model is yearly, as the main focus of investigations regularly are future scenarios until 2050, where an additional granularity is not available. To account for the higher temporal resolution of historic data, an additional price term per day and modelling region is introduced, consisting of the price difference to the yearly average price. This additional price term also incorporates the effect of the daily CO_2 price, assuming a generic emission factor for hard coal (see Table 5.1). The regional structure of the additional price term allows in principle for the incorporation of regional price spreads for hard coal, which might occur due to different transport cost with respect to ARA imports. It could also account for regions in which hard coal is produced locally for power generation. For simplicity and because of missing data, a uniform coal price is assumed across the modelled regions. As hard coal is traded in United Stated dollars (USD), the daily exchange rate between euros (EUR) and USD is also relevant to determine the cost of coal-fired generation for the model which is calculated in EUR.

Table 5.1: Standard emission factors for different fuel types.

Fuel Type	tCO_2/MWh	Source
Natural Gas	0.202	[Eur17b]
Hard coal	0.354	[Eur17b]
Lignite (generic)	0.364	[Eur17b]
Heavy Fuel Oil	0.279	[Eur17b]
Gasoil	0.267	[Eur17b]
Shale Oil (Estonia)	0.12132	[Sii11]

Similar products with different specifications exist also for the other relevant commodities. For **natural gas**, the Title Transfer Facility (TTF) is the benchmark index for continental Europe. Day-ahead prices are available and published by financial portals like *finanzen.net* or *yahoo finance* (partly) free of charge with a limited history. Front month contracts are available for up to 10 years into the future. The front month contract at CME for instance can be traded until the second last London business day of the month prior to the contract month. Even though the delivery of the closest future contract is close to the Day-ahead time frame, futures tend to be less reactive to short-term news and shocks. Figure 5.1 shows the TTF day-ahead price against the daily settlement of the front month contract between 2018 and 2020. For the majority of business days, the prices nearly converge, while the spot price is subject to larger spikes in reaction to news. At times the future price is also higher than the spot. As the gas infrastructure in principle allows for the opportunity to sell and deliver gas, which might be subject to contractual constraints, the historic gas price in the model is based on the short-term opportunity observable in the markets.

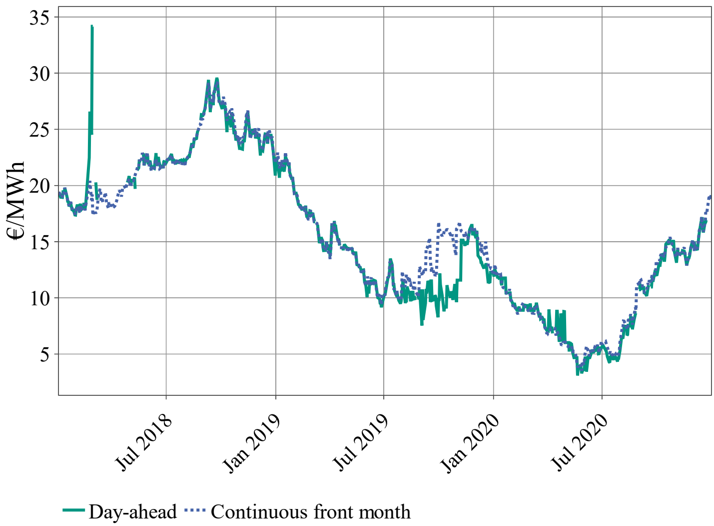


Figure 5.1: TTF traded day-ahead and month-ahead between 2018 and 2020. For the majority of days, the settlement price converge.

As described in Section 2.3, there are several gas hubs in Europe, which also exhibit spreads in price. Additionally, in the majority of markets, gas is procured from multiple sources, e.g. imported via pipelines, locally produced or imported via LNG terminals. A source for the historic gas prices at the different hubs and thus the regional spreads are the EU commissions quarterly reports on the European wholesale gas market[46]. They contain the quarterly

[46] Available from the EU commission's website. (https://energy.ec.europa.eu/data-and-analysis/market-analysis_en)

average prices for different countries and gas sources. For the years 2016 to 2022, the average deviation from the TTF is used in the model as a regional price spread for gas used in gas-fired power plants. The native temporal resolution for gas prices is yearly in the model, so an additional price term per region and day is used to model the daily fluctuation of gas prices with respect to the yearly average prices as well as the quarterly regional spreads. The impact of the daily settled CO_2 prices, assuming a generic emission factor for natural gas across the entire modelling region as stated in Table 5.1 is also included. Furthermore, the TTF shows a strong seasonal pattern, with prices in the winter being higher, when larger amounts of natural gas are used for space heating compared to the summer month. The historical pattern is shown in Fig. 5.2. It is calculated on the years 2016 to 2020 as 2021 included an increasing trend in the second half-year while 2022 and 2023 are impacted by the war in Ukraine.

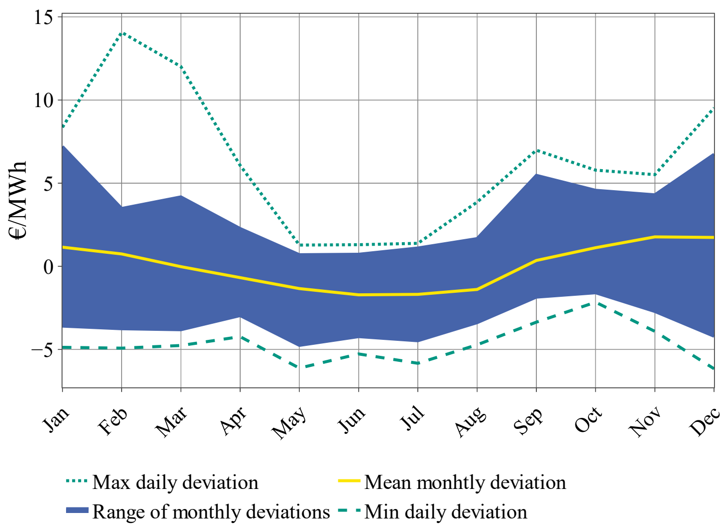


Figure 5.2: Seasonal deviation from yearly mean for TTF. Clearly visible is the higher price in the cold season, when additional gas demand is present in the market to satisfy space heating requirements in many European countries.

For **oil** the reference benchmark for Europe is Brent Crude, which is traded on spot markets. As for hard coal and natural gas, a multitude of futures contracts is available for financial hedging. Moreover, several banks publish real-time price indications. For modelling of the historic oil price, the daily settlement price is used. Two oil derivatives are modelled as fuel, heavy fuel oil and (light) heating oil. Price indications for these derivatives are not easily or free of charge available. For simplicity, a constant relative spread to Brent is assumed which is 1.08 for heavy oil and 1.28 for light oil. These factors are in line with the assumptions used for the TYNDP 2022 [ENT22e][47]. As for coal and natural gas, a regional daily additional price component accounts for the deviation of the daily oil price from the yearly average. The impact of the CO_2 price is also incorporated with generic emission factors across the modelled region according to Table 5.1. Historic regional price differences for heavy and light fuel oil are neglected due to missing data. A special case is Estonia, which is the only modelled region, where shale oil from local production plays a major role for power generation. Shale oil price information is taken from the European Resource Adequacy Assessment (ERAA) 2022, where the scenario price for 2024 is applied to all historic years. A daily additional price component accounts for the effect of CO_2 allowances prices, assuming the specific emission factor for Estonian shale oil in Table 5.1.

Lignite and uranium are two fuels that are equally important for (historic) power plants as the fuels described above. However, both are not easily tradable or transportable goods and therefore, price information is difficult to obtain. Moreover, **lignite** has a strong regional cost component, resulting from different extraction conditions, wage levels in the different countries and the calorific value. As a consequence, lignite is modelled on a cost basis rather than market prices. One of the few studies that looks at the different

[47] The TYNDP 2022 lists light and heavy oil and takes the fuel price references from the IEA's WEO 2020 scenario 'Stated Policies' for the Best estimate 2025 and from theWEO's scenario 'Sustainable Development' for the TYNDP scenarios 'Distributed Energy' and 'Global Ambition'. The spread for light and heavy oil prices is calculated using an historic average spread. TYNDP's prices are expressed in $€_{2020}$. [ENT22e]

cost structures in countries where lignite-fired power plants play a significant role for power generation is [Boo18]. This study is also at the foundation of regional lignite 'prices' in the TYNDP, where countries are classified into four groups and lignite costs are kept constant in real terms across the scenario. The historic lignite cost in the model uses the scenario cost are shown in Table 5.2. Different coal seams, also have different emission factors, which are included in the daily, regional CO_2 component of historic lignite prices as stated in Table 5.2[48]. CO_2 emission factors in the model are based on the numbers for the year 2020.

Table 5.2: Regional emission factors and cost for lignite [Eur23c], [Boo18].

Country	**tCO_2/MWh in 2020**	**tCO_2/MWh in 2021**	**€$_{2020}$/MWh**
Bosnia-Herzegovina			1.8
Bulgaria	0.3769	0.3780	1.4
Czech Republic	0.3553	0.35352	1.4
Germany	0.3543	0.3989	1.8
Greece	0.4657	0.4781	3.1
Hungary	0.3811	0.3802	2.37
Montenegro			1.8
Northern Macedonia			1.4
Poland	0.4099	0.4039	1.8
Romania	0.3474	0.3449	2.37
Serbia			1.8
Slovenia	0.3733	0.3676	2.37
Slovakia	0.3528	0.3434	1.8

[48] Emission factors are compiled by eurostat based on the yearly national submissions in the common reporting format (CRF) in the scope of the United Nations Framework Convention on Climat Change (UNFCCC). Where no specific emission factor is listed, the generic factor from Table 5.1 is used.

Uranium, while being globally traded, is only available to a limited number of players and under some restrictions. There are price levels reported on the European level by the Euroatom Supply Agency (ESA)[49], but data are very limited. For simplicity reasons, prices are taken from the scenario building guidelines for the TYNDP 2022, where the price in real terms is assumed constant across the scenario time span. Another reason for more or less constant fuel cost for nuclear power plants is that the Levelised Cost Of Electricity (LCOE) for nuclear power plants is relatively unaffected by the fuel cost [Wor22]. From the electricity market's perspective, nuclear bidding prices are most relevant in France, where more than two-third of the generated electricity comes from nuclear power plants all owned by EDF. EDF was regulated to sell around a quarter of its generation to other suppliers at prices between 42 and 46 €/MWh from 2012 to 2025 under the ARENH law. From 2026, EDF will offer the entire power generated to other suppliers at 70 €/MWh [ene23]. To reflect the price effect in future scenarios, the supply bids for nuclear power plants, are parametrised such that they float with the other commodities and CO_2 prices.

Prices for **CO_2 emission certificates** are determined by the prices for European Union Allowances (EUA). These can be obtained by emitters via auctions. Similarly to other commodities, EUA can be traded on exchanges (e.g. EEX offers a spot market for EUA) or players can use financial derivatives to hedge against price risks. The CO_2 price used in the market model follows the same logic as for the other commodities, that the price relevant for bidding into the spot market for electricity is not necessarily the cost basis of the players but rather the opportunity cost the player has, due to the price observable in the relevant futures and spot markets. Hence, the historic settlement prices from the CO_2 auctions published by EEX are used in the model. The price is kept constant between auction dates. The native temporal resolution in the model for a CO_2 price is yearly. As described in the sections above, the historic daily CO_2 price is embedded into the respective fuel costs. An exception of the

[49] ESA publishes price indices for uranium on the website https://euratom-supply.ec.europa.eu/activities/market-observatory_en.

above rule are the bidding zones, which are not (yet) part of the EU ETS. For these regions, fuel costs have no CO_2 component accordingly.

5.2.2 Power plants

Existing power plants

The power plant data is based on the platts World Electricity Power Plants data base (WEPP) from the year 2016. Several classification, aggregation and assumption steps are taken to create a suitable data set for electricity market simulation, amongst which most importantly are efficiency and technical lifetime assumptions. Over the years the data has been enriched with information regarding the new commissioning, re-commissioning, fuel switch or decommissioning of power plants from a number of data sources. In particular in Germany, additional information on the (future) decommissioning nuclear [Deu22a], coal and lignite [Deu20] power plants can be found in the respective laws. European coal phase-out targets, as published by the member states are considered according to [Bey23]. In some countries, power plants have been assigned particular phase out dates, which are taken where applicable from the Global Energy Monitor (GEM) [Glo23] or operators' websites. In countries where fossil technologies also provide heat supply (notably Czech Republic and Poland where no explicit phase-out date is set), power plants also operate longer than anticipated with the life time assumption in Table A.1. These power plants are assumed to be retired and the heat supply replaced in the coming years, either by gas-fired power plants (see Section 4.1.3), by biomass, or by different technologies outside the scope of this work.

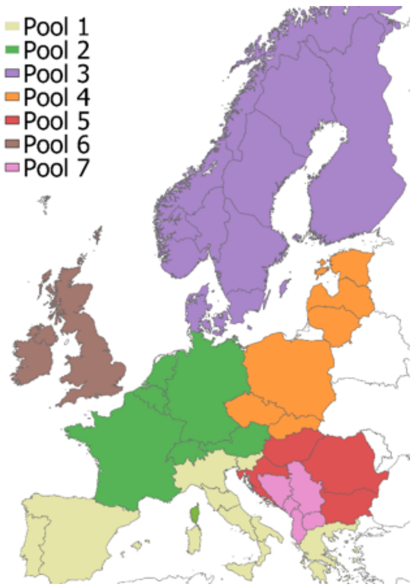
Future power plants

New power plants have to be differentiated between already known or announced projects on the one hand and generic additions to comply with scenario capacity assumptions on the other hand. The former concerns in particular near term additions of gas-fired power plants not covered by the WEPP or where countries announced plans to follow a nuclear strategy for reducing the CO_2 intensity of the power mix. Planned and announced nuclear power plant projects are take from the GEM, where commissioning dates (if not explicitly stated) are assumed complementary to decommissioning dates of fossil capacity to reduce the generic addition of gas-fired capacity that would be redundant once these projects are finished. Generic additions are addressed in Section 4.1.3.

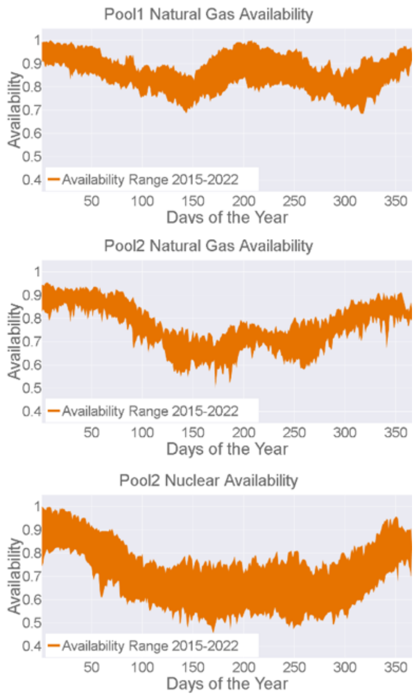
Non-Availability of power plants
A prime source of available data for power plants and power market data is the ENTSO-E's transparency platform[50]. Launched in late 2014 it covers the majority of data sets necessary to trace the European power system and provides a wide range of data that can either be incorporated as inputs into models or used for backtests of a model's performance. An important section especially for studies with respect to security of supply, but also for prices in general is the temporally resolved (non-)availability of power plants. The data set as of 2023 comprises over 430 000 active messages regarding planned and unplanned outages of individual generation units in the European power markets since 2015. Using a (partial) map between the power plants listed in the outage messages and the IIP's power plant data base, it is possible to include explicit unit-wise outage time series into back-testing exercises. An obstacle presents the different accounting for e.g. some nuclear power plants, where data is reported on the ENTSO-E platform resolved to individual generators, while the IIP data base lowest resolution is power plant blocks / units. This can be overcome by deriving the average availability for certain power plant types per country or BZN. In some BZNs the number of (certain types of) power plants is rather small and thus prone to be effected by outliers or

[50] Although the developed framework includes the possibility to rely on data from the ENTSO-E transparency platform, it should be noted, that the reuse and license conditions of some of the data sets found there, are legally at best unclear [Hir20], [Wie19]. [Hir20] state: 'It is common practice for energy modelers to use freely-available data anyway without being aware of license conditions and the legal framework. In fact, not only users but also many data-providing intuitions I have interviewed for this research seem to be unaware of the fact that data use is legally restricted by intellectual property rights. Despite the topic being often silently ignored, given that nearly all empirical energy system research relies on publicly available data, the question if using such data is actually legal is pretty relevant.'

erroneous data. To overcome this obstacle but remain some geographic information about the difference in power plant fleet availability, countries are clustered to pools in which the outage messages for the power plants types are aggregated. The country pools are shown in Fig. 5.3a. Exemplary availability ranges based on historic outage messages are shown for three BZN-power-plant-type-combinations in Fig. 5.3b to illustrate the approach. The typical (historical or average) profiles are then assigned to the individual units and cumulatively result in the availability behaviour of the power plant class.



(a) Country pools, where outage messages are aggregated per fuel/technology.



(b) Historic availability range for different country pools and power plant types.

Figure 5.3: Country pools and exemplary aggregated availability ranges for certain power plant technologies.

Furthermore, regarding the share of generation capacity allocated in the balancing markets and thus not available to the spot markets, the historic procured reserve quantities are also available from ENTSO-E's platform. This allows the parameterisation of the constraints of the balancing requirements in Section 4.1 based on explicit or average historical needs.

5.2.3 Historical demand and RES infeed time series on zonal levels

For historic information of electricity demand and RES infeed, different sources are available. One is again the transparency platform of ENTSO-E, which has the advantage that it covers a large number of countries and bidding zones. It also provides data on a (sub)hourly basis, which is especially relevant for electricity market models. Different data sources for (temporally) aggregated values are the ENTSO-E power statistics ('monthly domestic values') available for generation and demand which starting from 2021 onwards are only the aggregated values from the transparency platform. Based on the ENTSO-E data, the community project Open Power System Data (OPSD)[OPS23], [Wie19] provides data, which is cleansed from simple missing values and also the zonal demand is scaled, to be more in line with total load on the system level.

In Germany, the MaStR[51] is the most reliable source of information for generation units connected to the German grid. Additionally, eurostat covers and publishes monthly as well as yearly aggregates of generation as well as demand although the categorisation is different from ENTSO-E's and care must be taken when comparing data from different sources especially with respect to demand, the classification of pumped hydro storage power plants[52] and losses in the electricity grid.

[51] Marktstammdatenregister, https://www.marktstammdatenregister.de/MaStR

[52] This problem mainly concerns the classification of energy generated from hydro power plants with pumps and natural inflow, where the share of renewable electricity is not always clear.

While generation from solar PV and wind parks can also be calculated based on historic weather conditions (like ERA5), with relatively straight forward technical models, the historic generation for hydro power plants is much harder to model. This is due to more complex relationship between precipitation and inflow into hydro reservoirs due to complex terrain and the storage effect of snowfields and glaciers. Moreover, (pumped) hydro storage power plants often consist of complex cascades where the generation constraints of the lower levels depend on the operation of higher levels. An approach is offered in the data set for the Mid Term Adequacy Forecast (MAF) by ENTSO-E also used in the subsequent ERAA studies, where for all relevant BZNs historic relations between weather conditions and output of (pumped) hydro storages with natural inflow have been derived [ENT19]. The data set offers aggregated historic inflow time series and constraints on generation, pumping where relevant and the storage levels on bidding zone level, which suffices to include these constraints into the market model to form a consistent scenario with the modelled weather year. Due to the discrete nature of new power plant projects, the respective yearly data base is used as a reference for discrete time periods without interpolation. For the grid and FB model, the regionalisation is based on the WEPP/institute data base, where individual power plants are mapped to grid nodes based on their geographic location. The dispatch from the (aggregated) market simulation is distributed to the grid nodes according to installed capacity.

5.2.4 Market results for model validation

For validation, backtesting, calibration and also to complement market models, which only cover a limited geographical scope of the interconnected European Electricity Markets, other data categories can be obtained from the transparency platform. These cover e.g. (day-ahead) market prices, net (export) positions, commercial and physical exchange flows between market zones as well as generation time series aggregated per fuel type. Care needs to be taken when comparing modelled data to these operational data especially with regards to commercial exchanges, as market models usually do not account for the different market segments but have a central clearing mechanism where all power exchanges occur. Hence the cumulative exchange capacity needs to be available to the model, which in reality is allocated to several time frames from long-term allocation, over day-ahead and intra-day markets to the balancing markets since the introduction of balancing cooperation between TSOs and cross-zonal platforms.

Historic FB domains
For modelling of historic FBMC without a grid model or to validate the model against historic results, the JAO publishes amongst others the 'utility tool', which 'enables the download of the Flow-Based pre-coupling and post-coupling operational data as well as additional publication data to support Market Participants in their analyses' and the aggregated two days ahead congestion forecast (D2CF) [Joi23]. The 'utility tool' is going to be discontinued with the introduction of Core FBMC and will be replaced by the 'publication tool'. Detailed description of the published data are available in the handbook [Joi22].

Grid results
As the grid operation is not a competitive domain, transparency requirements are fewer with respect to published data. In Germany, the monitoring reports published yearly by regulator BNetzA are the most detailed source of information about the grid operation and especially with respect to congestion management. Besides the cost and number of activated measures, these reports include geographic information about the causing transmission circuits and indicate in how many hours those congestions where responsible for the utilisation of re-dispatch and/or RES curtailment (see e.g. Section 6.1).

5.3 Scenario data

To model the market and grid operation of the future energy system, necessary input data is included where available from large (system) studies, which reflect the current legislative framework and political goals. In recent years, the European energy transition has gained traction through increased renewables and electrification goals. To reflect this, the model technologies are designed to include the relevant effects from studies such as the ERAA, the TYNDP or NDPs in a generic and often simplified way, which allows for a quick adaption, when new scenarios translate the latest political into a quantitative framework. Mostly, these system studies analyse multiple snapshot years for which detailed parameter sets are available. Where data is not available for the years in between, interpolation is used to model the transitory path.

5.3.1 Economic developments - Commodity and CO_2 prices, inflation and exchange rates

Futures contracts for commodities are available for different time spans depending on the commodity. The liquidity of these contracts is very heterogeneous across contracts and commodities. Moreover, the relevance for market players depends on their size and opportunity to participate in these markets directly or through intermediaries. For hard coal, monthly futures are available until around four years into the future. For TTF, monthly future quotations are available for roughly ten years into the future. On the websites of the exchanges, artificial 'settlements' are published for contracts without traded volume or open interest. The resulting price curve gives an indication of price expectations of the market participants at the settlement date. As quotations are available for all relevant inputs for up to 4 years into the future, the modelled scenario incorporates these into the input data. From the latest futures settlement, prices are linearly interpolated to the first scenario reference value which is set for 2030.

For the exchange rate between EUR and USD as well as inflation projections[53] assumptions are based on the Organisation for Economic Co-operation and Development (OECD) long-term baseline projections[OEC21]. In the

[53] The model is parameterised and calculates in nominal terms. Therefore the cost from the input sources, which are often reported in real terms have to be converted to money-of-the-day using the historic inflation rate and projections.

medium term, inflation assumptions are updated with data from the International Monetary Fund (IMF) World Economic Outlook [IMF22][54], which has a higher temporal resolution.

Price estimates for fuel and CO_2 prices are based on the IEA's WEO analogous to its use in the TYNDP 2022 from which several other inputs are taken. For the model inputs, a more recent version of the WEO [IEA22] is used from which the scenario 'Announced Pledges' is selected in line with country's net zero pledges by 2050.

The price for hydrogen is relevant on multiple levels for the modelling, depending on the path through which it influences the electricity price. First, hydrogen can be used as fuel in 'hydrogen-ready' gas-fired power plants. It will depend upon market dynamics, subsidies, incentives and regulation to which extend hydrogen for power generation will be available and used, from what sources it will be generated and if it will be renewable or decarbonised. Second, the price of hydrogen as a possible future commodity is relevant for the degree to which it will be produced domestically, i.e. from electrolysers using renewable electricity from the European system. If available from international markets at a given price, this will impact the installation and operation of electrolysers, which have to produce the hydrogen competitively in this scenario. Unfortunately, no price estimation for hydrogen (green or blue) is included in the IEA's WEO to build a consistent scenario. Cost assumptions for hydrogen are available from other literature (e.g., [Brä21]), who calculate the cost for 90 countries and derive a ranking for individual countries for cost efficient hydrogen procurement. This is also the source on which the prices in the TYNDP 2022 are based. In contrast to the TYNDP, where the electrolyser capacity is a model result, in the context of the developed model, electrolyser capacity is an exogenous scenario parameter. Consequently, the operation logic is a different one. The dispatch follows the assumption, that hydrogen can be imported for the prices stated in the TYNDP, so the electrolysers are only dispatched when the locally produced hydrogen is cheaper or at par to

[54] The latest version in the model is the October 2022 Edition, although this data is easily updated as data is published in consistent format.

the renewable H_2 imports. This approach is similar to the one used in ERAA 2022 [ENT22a]. The efficiency assumptions for the electrolysis, which are necessary to derive the strike price under which the electrolysers produce is also taken from the TYNDP 2022 Scenario Building Guidelines. Yearly additions resulting from the interpolation towards the scenario year capacity, combined with interpolated efficiencies result in a diverse electrolyser fleet with different capacities and efficiencies across Europe. In contrast to the assumption in the TYNDP, constraints on hydrogen imports are not considered.

5.3.2 (Thermal) Power plants

The life time assumptions for the different power plant technologies are shown in Appendix A.1. Almost all European countries have announced a coal phase-out to meet their obligations from the Paris Climate Agreement. This leads to significant decommissioning of power plants before they will have reached their (economic or technical) end of life. The proposed phase-out dates are shown in Table 5.3. In some cases, power plants are still running or planned to be operational for numerous years to come, although they have reached their assumed end of life. For coal and lignite-fired power plants, the decommissioning dates have been adjusted in accordance with the global energy monitor data base where available. For Germany, there is a detailed lignite phase-out plan written into law, and for hard coal total capacity limits on a yearly basis exist where the phase-out is orchestrated through either auctions or administrative shutdowns by the regulator BNetzA. Planned and approved projects, as well as projects under construction, are also taken from the global energy monitor data base.

Table 5.3: End of coal-fired power generation in European Countries [Bey23].

Country	Last year with coal-fired generation
Belgium	2016
Croatia	2033

Continued on next page.

Country	Last year with coal-fired generation
Czech Republic[55]	2033
Denmark	2028
Finland	2029
France	2023
Germany	2038
Greece	2028
Hungary	2028
Ireland	2025
Italy	2025
Northern Macedonia	2029
Netherlands	2030
Romania	2030
Slovakia	2030
Slovenia	2033
Spain	2030
United Kingdom	2024

The lifetime of nuclear power plants is under ongoing discussion in several countries, with the US allowing the nuclear fleet to run for at least 60 years. Japan has recently extended the lifetime of their nuclear fleet to 60 years plus time spent in revision and maintenance. In France, the French President has stated that no reactor will be shut down unless safety dictates it. In Switzerland the earliest nuclear plants are scheduled to retire after 60 years of operation. Hence, the lifetime of the European nuclear fleet is assumed to be 60 years.

Availability of power plants

To model the availability of thermal power plants in a future scenario, several options are available based on the data described in Section 5.2.2. First,

[55] Cezch Republic has set the coal phase out date to 2033. However, the commissioning of new-build nuclear capacity is assumed to be commissioned in 2034 and 2035 respectively. Therefore, the phase-out is modelled to results in a smooth transition of firm capacity.

a specific historic year can be selected where (in the near term) individual (non)availability time series for power plants can be applied. A short-coming is that these time series are not available for new power plants built after the historic year, so generic values have to be applied. To overcome this, a second approach is to use aggregated time series per country pool and technology. Third, a generic constant availability per technology, either based on literature values (e.g. [Vim22]) or average values from the historical ENTSO-E data can be applied. Lastly, the (e.g. weekly) mean across multiple years can be calculated for the country pools and technologies. The validity of this approach is limited through the data source as it is based on the historic power plant fleet in the respective countries. The further the year of analysis lies in the future, and hence the power plant fleet differs more from the historic base, the less valid are these availability time series. A compromise is to keep the relative time series from the ENTSO-E data set and scale it to yearly means reported in the literature for different power plant age and size groups. The profile - if possible - is chosen from a historic year in accordance with the selected weather year. Otherwise, the mean across all years is chosen. The procedure is analogue for the availability of hydro power plants, where constraints on the generation, etc. are drawn from the MAF/ERAA data set described in Section 5.2.3. If the weather year for the scenario is one of the historic years available in the data set, it is chosen to complement the weather information used to calculate solar PV and wind potentials.

5.3.3 Renewables infeed potential, demand time series and flexibility potential

Renewables generation profiles

In almost all system studies, which are used as input for the model, technology specific expansion targets are assumed for renewable generation technologies (solar PV, wind offshore, wind offshore, bioenergy). This is mainly due to the fact, that many European countries define explicit expansion goals as political targets and subsidies and other support mechanisms are designed and adjusted to reach these targets. So in the standard parametrisation, RES capacities are exogenous input data. For the grid and FBMC simulation, explicit geographic locations for these facilities have to be known. This allocation is calculated in the expansion part of the HighResO model [Sle17], [Sle18]. The allocation method usually is LCOE based, a notable exception being wind offshore, where due to the complex and costly grid connection and interdependencies with the maritime ecosystem and economic zone, explicit configurations are determined in the expansion plans, which are taken into account in HighResO. Building on this, the generation time series are simulated based on the weather data consistent with the chosen weather year and the technology data for existing and future RES technologies (especially relevant for higher and larger future wind turbines). As a consequence, the energy output can defer from the energy reported in the scenario reports. Notably, the time series from HighResO are used as the infeed potential which is available to the market from the respective technology. The actual disaptch is determined in the market model, which allows for renewables to be turned off if there is excess supply and the price is below or at the variable cost of the respective technology.

Demand profiles
Similar to RES targets, the system studies usually provide a scenario path for the (electrification of) different types of demand. Based on this information, the HighResO model is used to generate time series that are in line with the scenario capacities and energy demand assumptions. For most technologies, the main task is the regionalisation to discrete grid nodes, while for temperature dependent demand, additionally, the influence of the local ambient temperature is considered, especially in the case of power-to-heat applications. The output from HighResO then provides raw demand profiles, without any interaction with the electricity market price. The flexibility is assumed differently for the technologies and described in the following.

Implicit demand side response of electric vehicle charging and heat pump operation
ERAA 2022 uses four 3-hour time windows in which EV demand and HP demand can be shifted [ENT22a],[Haa22]. The approach chosen in the model is similar in that a certain share of the demand profile from EVs and electric heat pumps can be shifted within a certain time interval. The share and time

interval are parameters which can be chosen freely[56]. The standard parametrisation is detailed in Appendix A.2.

Vehicle-to-grid

For electric vehicles another distinction is modelled between smart/controlled charging and V2G. While the former follows the logic just described, the latter is modelled the same as utility-size battery storage. The challenge for V2G is to parametrise the availability for or participation in the market plausibly. The TYNDP 2022 includes assumptions for the market share of different types of electric vehicles. Historic vehicle data is available from [ACE23][57], which provides the total historic number and market share of vehicles, which are categorised into passenger cars, light commercial vehicles, medium and heavy commercial vehicles and busses. These categories are mapped to the ones used in the TYNDP 2022[58]. Based on the historic values for 2021, the transition to the target shares in TYNDP is interpolated[59]. The V2G share of the total number of electric vehicles is assumed to start at zero in 2021 and interpolated to the target value of 26 % taken from TYNDP Distributed Energy in 2050. Additional assumptions to derive constraints for power and energy based on the number of vehicles are described in Appendix A.3.

Battery storages

Batteries are divided into utility-scale installations, which are operated against the wholesale market price and out-of-market batteries. The capacity in the scenario is taken from ERAA 2021 [ENT21a], ERAA 2022 [ENT22c] and TYNDP 2022 *Distributed Energy* scenario [ENT22d]. The capacities for 2025 and 2030 are selected according to the source, which shows the highest values for 2030. The energy-to-power ratio for utility-size batteries is taken from the TYNDP where it is assumed to be three hours. For prosumer batteries, ERAA

[56] The chosen time window has to be smaller than the time blocks, which are solved in parallel.

[57] Missing data for vehicles and busses in Bulgaria are taken from [CEI23], the share of commercial vehicles is assumed equal to the ratio in RO. Missing data for Malta is calculated assuming an equal share as in Italy. For BZNs in NO, SE, IT and DK, the split is chosen according to the historical load ratio of these BZNs as reported on the transparency platform.

[58] TYNDP 2022 lists passenger cars, light trucks, heavy trucks and busses, the subcategories are aggregated.

[59] Missing data for Norway is assumed equal to Sweden and Switzerland assumed equal to Austria.

2021 and TYNDP 2022 provide data to form the scenario pathway. Explicit battery sizes are given in ERAA 2021 for the years 2025 and 2030. The ration between energy and power is kept constant at the value provided for each bidding zone in ERAA 2021 for the year 2030. The installed capacity in 2030 is taken as the maximum stated in the sources. If no ratio is available because the data for a BZN in ERAA 2021 are missing, a generic ratio, which is the average from the other BZNs in 2030 is applied. The ratios for prosumer batteries in ERAA 2021 range from 0.33 to 4 (with an average of 2.8 in 2030). Battery capacity is also linearly interpolated from the first value in 2024 disregarding the factual capacity development between 2016 and 2024. Due to the small absolute capacities, the effect is assumed to be minor.

Prosumer batteries (e.g. in PV-battery systems) are assumed to have a total market exposure, following the logic in the confirmed scenario to NEP 2037/2045 version 2023 [Bun24a].

Explicit DSR capacity and price bands

Explicit demand side response bands until 2030 are taken from ERAA. ERAA 2022 introduces some changes, especially accounting for the new Italien BZN Calabria, while it is missing detailed information for the other Italian zones. Capacities starting from 2030 are taken from TYNDP 2022 *Distributed Energy*, the capacity development between scenario years is assumed to develop linearly. Capacity before 2024 is set to the value of 2024, because demand response schemes have been in place in many countries. The logic applied is similar to the one used for electrolysers and batteries. For 2030, the maximum from ERAA 2021, ERAA 2022 and TYNDP 2022 is used. This value serves as a lower bound for 2040 and 2050 if TYNDP values are lower. The price information for the DSR bands is taken from ERAA 2021.

Spot market price cap

The market price cap in the model is taken from ERAA 2022 rising to 8 000 €/MWh in 2030 ([ENT22b]) and continues so to reach 10 000 €/MWh in

2033 to match the existing price cap in the intraday market to model a closer integration of the two market segments[60].

Reserve requirements
Reserve requirements are taken from ERAA 2022 [ENT22c]. Procured capacity for reserves is modelled by withholding the respective capacity from the spot market. The dispatch is not modelled. The required reserve capacities are linearly extrapolated after 2030 based on ERAA 2022 values for 2025 and 2030.

Bidding zones
In the studies by ENTSO-E there is only data available for three Norwegian regions (north, centre, south) in constrast to the five operational bidding zones. As the model includes the five BZNs, data has to be distributed. For this, it is assumed that the northern region in the ENTSO-E reports corresponds to NO4, the central region to NO3 and the southern region to the three southern BZNs (NO1, NO2 and NO5). The split for generation related inputs is based on the geographic boundaries of the BZNs and the location of the generation units, for demand related inputs, the split is either based on the regionalisation in HighResO or the historic demand split from the transparency platform. Exchange capacities between the zones are based on observed historic exchanges and the proportional increased reported in ERAA and TYNDP.

While the draft version of the TYNDP 2022 accounted for the Italian bidding zones, the final version only reports aggregated data for Italy as a whole. Hence, split factors have to be derived, which are based on the respective distribution in 2030 from ERAA 2022.

5.3.4 Grid related scenario inputs

Grid state expansion measures and wind offshore connection
The grid expansion status is based on the sources described in Section 5.1. For Germany most information is taken from the NEP 2021, which also includes

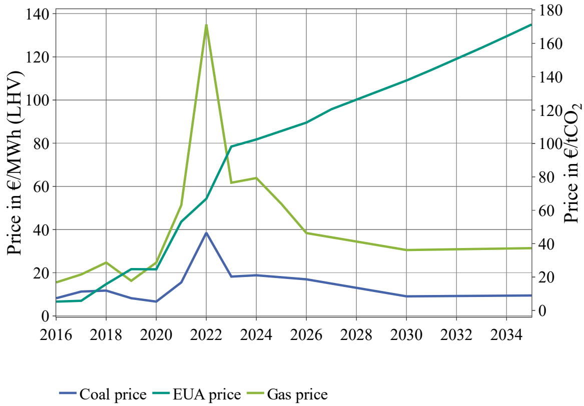
[60] However, given the deterministic nature of demand and RES profiles used in the central model clearing, the model resembles a real-time market instead of either day-ahead or intraday.

information where large wind offshore parks will be connected to the transmission grid. For European projects the main source of information are the TYNDP (2016-2022) and NDPs.

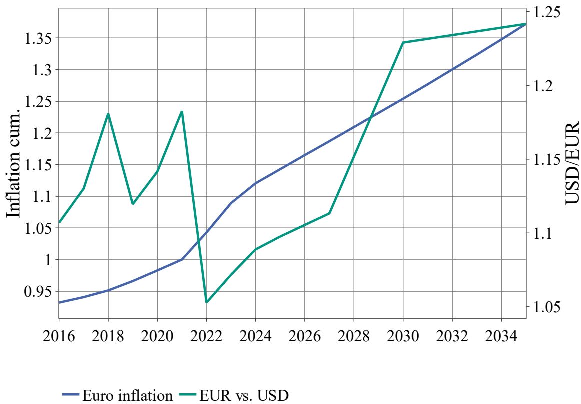
Dynamic line rating inputs
The potentials for DLR on existing and future lines are calculated outside the market/grid model and are thus available for all relevant weather years as input. Regarding the necessary data for the calculation of these parameters, some are calculated as described in Section 4.2.3, others are taken from the literature: Values for emissivity are taken from [Flu07], most technical parameters are available from producers e.g. [Haa23].

5.4 Transition from history to scenario

Many of the input data required for the detailed modelling of energy systems are not available in real time, but only become available in statistical quality with some delay. An additional challenge is that in reality, the transition between historical values and the scenario years will not follow a linear path. For annual calculations between the scenario years, figures are linearly interpolated between the framework data, as this is as simple and arbitrarily wrong as any other methodology, as long as there is no underlying information available in the scenarios. In contrast, for most economic parameters, especially prices of products traded on exchanges, additional information is available, since the future can be traded in the form of structured products (financial futures). Consequently, this information is integrated to form the path between the last historically documented value and the first scenario year. This concerns the fuel prices for hard coal, natural gas, as well as oil, and the costs for emission allowances in the EU ETS. Figure 5.4 shows the transition from historical values over future quotations to scenario values for fuel prices, emission allowances, inflation and the exchange rate between USD und EUR. Quotations are available for different periods, in the case below for fuel and emission prices, historical values are used until 2022, futures from 2024 to 2026 and scenario values from 2030. The years in between are interpolated. For the exchange rate futures are used between 2024 and 2027 and for inflation, the IMF WEO is used until 2027 and then interpolated to the OECD baseline projections from 2030.



(a) Fuel prices



(b) Inflation and FX rate

Figure 5.4: Exemplary transition of historic values to scenario assumptions. Fuel prices and prices for CO_2 (left) and exchange rate between EUR and USD and cumulative inflation in the euro zone. The figures contain historic values, future quotations from 10.03.2024 and are interpolated to scenario figures in 2030 and beyond.

6 Results and evaluation of the model-based scenario analysis

In this chapter, comparative and scenario calculations are carried out with the aim of evaluating the model and deriving the influence of the market coupling methodology on the market results as well as relevant key figures for stakeholders in the future electricity market. Section 6.1 presents a validation study of the grid simulation that evaluates the ability of the model to identify congestions in the (German) transmission grid and investigates the effect of several parameter sets on the result of the congestion management simulations. The impact of different Flow-based (FB) configurations is analysed in a (simplified) model variant for the European electricity system in 2025 in Section 6.2. Two aspects are examined, in particular, the enlargement of the FB region to Core Capacity Calculation Region (CCR) and the introduction of minimum exchange capacities in the context of the Clean energy for all Europeans package (CEP). Section 6.2 has already been published in large part in [Fin21]. Finally, in Section 6.3, the European system is simulated for the year 2035 and the impact of the market coupling regime, as well as the effect of a widespread application of Dynamic Line Rating (DLR) on key market results, earning prospects of renewable investors and flexibility providers, as well as the necessary congestion management (CM) measures in the grid operation are identified.

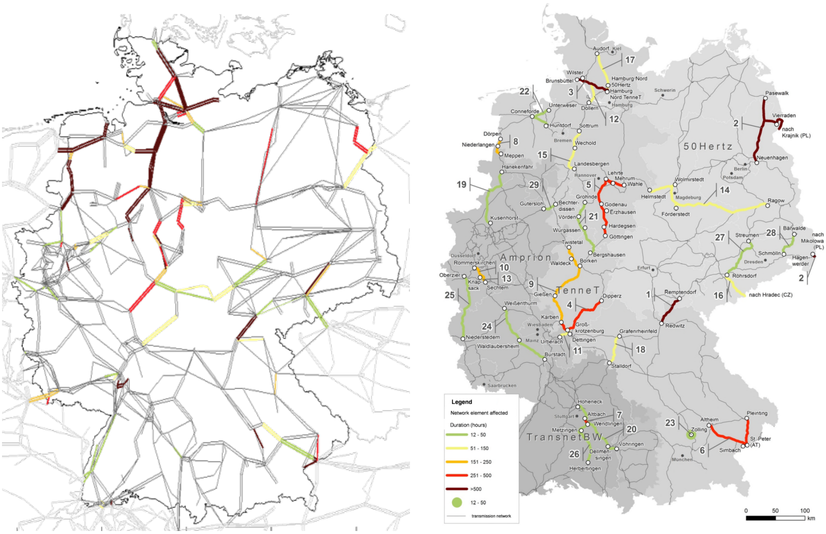
6.1 Assessing the grid simulation and exploring determinant factors

The grid simulation is essential for both the determination of FB capacities and the quantification of CM. To assess the quality of the model, it is backtested against the historic year 2016. Therefore, the market model was calibrated to the generation and load characteristics as reported in the ENTSO-E fact sheet 2016 [ENT17]. Renewable generation time series generated from historical weather in 2016 based on ERA5 for wind onshore, wind offshore and solar PV were linearly scaled to match the MWh reported by ENTSO-E. Similarly, the load profiles were adjusted to match the reported values. The availability of thermal power plants was calibrated to meet 2016 generation. With this input data set, the electricity markets were simulated with static Net Transfer Capacity (NTC) values resembling the highest observed value per border in 2016, in order to cover the exchanges in all market segments and not only the day-ahead market. Based on the market outcome, the grid operation was simulated in the AC formulation as described in Section 2.4. The resulting overloads before re-dispatch[61] can be observed in Fig. 6.1a. Figure 6.1b shows the line overloads as reported in the monitoring report 2017 by BNetzA.

It is clearly visible that the regional congestion patterns identified in the model resemble the historical ones. The North-South corridor in the centre is very similarly overloaded and the highly congested line between Redwitz (Bavaria) and Remptendorf (Thuringia) is well visible in both cases. However, there are also some obvious deviations: The model shows more congestions in the North-West, while underestimating those in the North-East. The difference might be explained by two factors. First, by the underlying data of the two figures. While Fig. 6.1a shows the result of a power flow simulation before re-dispatch in the grid, and hence every line element which is overloaded is counted, BNetzA reports the number of hours in which a line element induced re-dispatch measures. Hence, only the weakest line elements (which

[61] To identify line overloads 'before re-dispatch', the Optimal Power Flow (OPF) was solved without branch flow limits.

are indicative for the re-dispatch measure) are shown even if in the respective situation more lines would have been overloaded.



(a) Model

(b) Monitoring report [Bun17]

Figure 6.1: Comparison of line overloads before re-dispatch as modelled (left) and reported by BNetzA (right) for the year 2016.

The second reason is the simplified grid topology used in the simulation, which is based on a static grid model with reduced bus bars. This does not allow for power flow redirection by topology measures (which would distribute power flows to several circuits), thus artificially concentrating power flows on certain lines in the model compared to operational practice of TSOs. The aggregated CM measures are shown in Table 6.1[62].

[62] In the model positive and negative adjustment have to be equal so the positive adjustment to replace RES curtailment is counted as positive re-dispatch, while for BNetzA, the explicitly reported figure for positive re-dispatch (including grid reserve), negative re-dispatch and RES curtailment are shown.

Table 6.1: Positive, negative re-dispatch and curtailment in 2016 as modelled and reported by BNetzA [Bun17].

Congestion management	Modelled [GWh]	Reported [GWh]
Pos. re-dispatch	9 530	6 428
Neg. re-dispatch	5 775	5 721
Curtailment	3 755	3 743

Main findings

- In a simulation of historical conditions for 2016, the congestion patterns identified by the model in the German transmission grid closely resemble the geographic patterns reported by the Bundesnetzagentur.
- With respect to the congestion management volumes, the model results are very close to historical values for renewables and curtailment and negative re-dispatch.
- The ability of the model to adequately quantify congestion management volumes is demonstrated.

6.1.1 Parameter studies in historical year

Based on the simulation results for 2016, a parameter study for the grid simulation is conducted to investigate how the choice of cost parameterisation impacts the results of CM, but also to quantify the effect of the consideration of the neighbouring grid control zones, interconnectors as constraints, relaxed line limits and allowing for cross-border re-dispatch (especially in the southern neighbours Switzerland and Austria to relieve congested lines in Germany).

Penalty cost for (remaining) line overloads

Figure 6.2 shows the impact of the penalty cost level for constraint violation for levels between 200 €/MWh and 10 000 €/MWh.[63] As soon as the penalty cost reaches levels similar to the CM cost, it becomes relevant for the necessary amount of CM measurements.

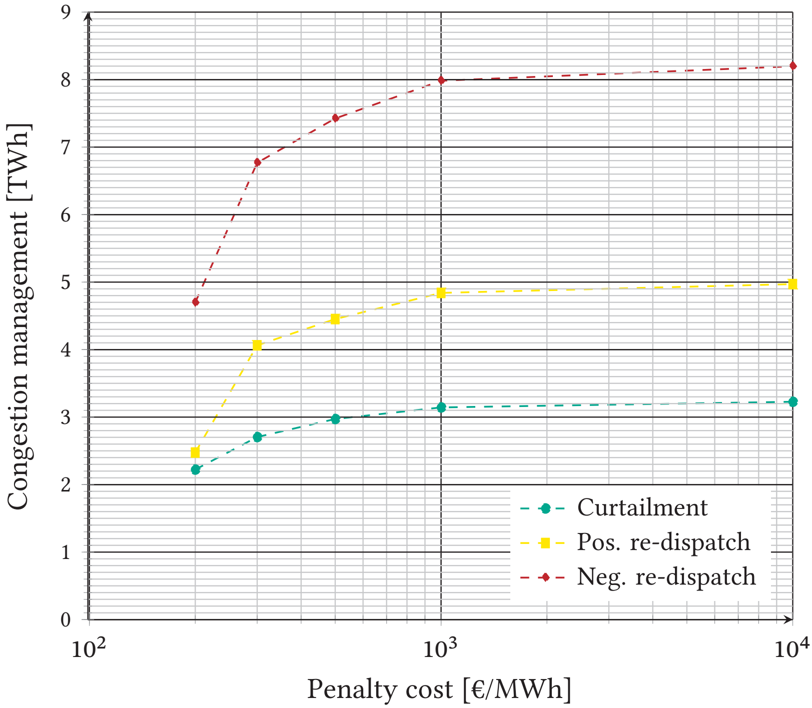


Figure 6.2: Impact of soft limits: Necessary RES curtailment, positive and negative re-dispatch for different penalty cost levels for line overloads when activating soft limits.

[63] Additional parameters in the study: The cost of curtailment was kept constant at 50 €/MWh, re-dispatch is forced to be balanced (positive re-dispatch equals the sum of negative re-dispatch and curtailment), dynamic line rating is applied with a cap of 110 % of static capacity, interconnectors are excluded from the constraints and the considered grid area consists of Germany and the electric neighbours. Adjustments in imports to the grid area are allowed at 55 €/MWh.

When the difference is large enough, that is, it is much more expensive to allow line overloads, than reliving the lines with re-dispatch or curtailment, the amount of measures converges. In the parameter study, after the penalty cost are set to 1 000 €/MWh, curtailment and re-dispatch remain more or less the same compared to a penalty cost of 10 000 €/MWh, while in the range between 200 €/MWh and 1 000 €/MWh the amount of curtailed and re-dispatched energy increases by around 50 %. The numerical results for the variation of the cost for line constraint violations are presented in Table D.1.

Main findings

- Soft-limits can be helpful to analyse and identify data errors because they limit the effect, single line overloads can have on the feasibility of the OPF problem.
- Care should be taken when defining the cost level for relaxed lines, as they might become actively used by the solver as part of the optimal solution instead of representing slack variables to ensure solvability.

System boundaries

In a second parameter study, the impact of the system boundaries is investigated. The results for six different configurations are shown in Fig. 6.3. Common to all simulations are curtailment costs of 50 €/MWh, and the ability of counter-trading exchange flows to the grid region at a cost of 55 €/MWh. The grid simulations are based on the same market simulation using static NTC values for exchange limits, line constraints are relaxed with a penalty cost of 10 000 €/MWh. The CM simulation is geographically limited to Germany, that is, only German lines and - depending on the sensitivity - interconnectors constrain the optimal power flow.

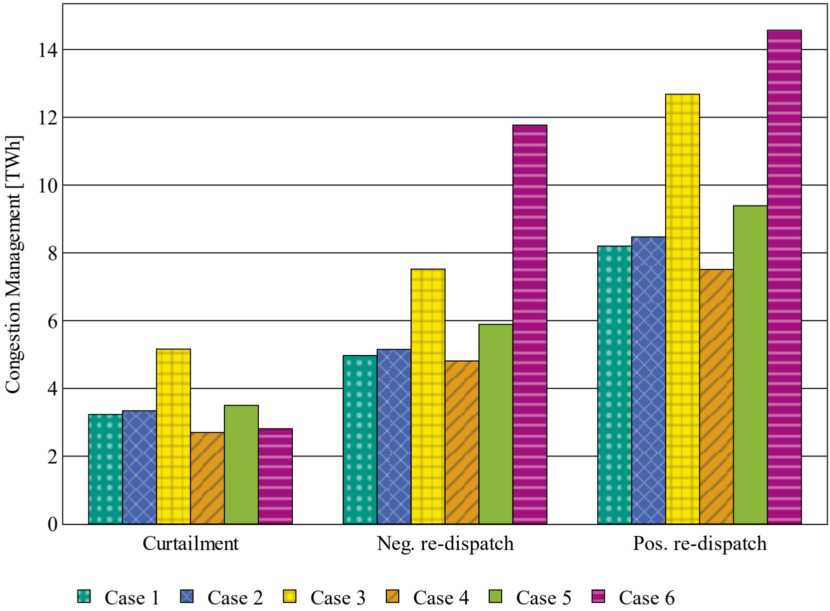


Figure 6.3: Impact of selected system boundaries: Necessary CM measures for different representations of the neighbouring control areas and the possibility of re-dispatch in other countries.

The conditions are altered as follows:
Case 1 uses DLR limited to 110 % of the static line limits. The interconnectors are blacklisted from the constraint set, so they do not limit the solution. The grid covers Germany and the surrounding AC-coupled countries[64]. Furthermore, the re-dispatch is enforced to be balanced within the German borders, so only German power plants can participate. The total CM results to 16.4 TWh of which 3.2 TWh is RES curtailment, 5 TWh is negative re-dispatch and 8.2 TWh need to be positively re-dispatched.

In **Case 2** line limits are modelled with seasonal limits, allowing for higher transmission during the transition periods and winter, while in summer static

[64] With the exception of Denmark.

line limits apply. All else being equal, the results show a slight increase in CM volumes of roughly 3.5 % to a total of 17 TWh, with an almost identical split of the increase to curtailment and re-dispatch.

Main findings

Although the (additional) effect of DLR is rather small compared to seasonal line limits, since it was limited to 110 %, the potential for reduced CM is already demonstrated. The effect of extensive usage in CM is further investigated in Section 6.3.

Case 3 includes the interconnectors to and from Germany as constraints, which has a larger effect on the CM, than variation of line limits in **Case 2**. The total CM volume increases by around 54 % to 25.4 TWh, with curtailment increasing by roughly 60 % and negative and positive re-dispatch increasing by around 51 % and around 55 % respectively. This can be explained by the systematic North-South transport in the German grid in hours with high wind feed-in, which physically also flows through the neighbouring countries. Additional constraints cause more renewable infeed to be curtailed, especially wind feed-in in the North (of Germany).

Main findings

The consideration of the interconnectors has a visible effect on CM measures in line with reports, indicating that significant parts of north-south transport in Germany also flow through neighbouring countries [ENT16], [Mar10], [Kun18]. The effect of considering these tie-lines as constraints on CM measures will decrease with an increasing share of power flow controlling devices such as phase-shifting transformers close to the border, which will to a certain degree funnel power flows through the German grid, but also potentially increase congestions there.

Case 4 extends the setup in **Case 2** (seasonal line limits) by allowing for re-dispatch measures in Austria and Switzerland. Interconnectors are again blacklisted. The German transmission system operators already have contracts with power plant operators in these countries and even in Italy, so the setup is closer to reality than constraining the problem to Germany alone. This opportunity leads to a remarkably large decrease in CM indicating the efficiency of these cross-border measures, given a reasonable cost basis for activation. CM measures are reduced to around 60 % of the level needed in **Case 3** or 15 TWh, with the largest reduction occurring for curtailment, which is almost halved.

The effects of including the interconnectors as constraints, while allowing for re-dispatch in Germany, Switzerland and Austria are simulated in **Case 5**. As before (**Case 2** to **Case 3**), the amount for CM measures is increased through the integration of the tie-lines. However, cross-border re-dispatch allows for a partial mitigation, so around 25 % additional curtailment and re-dispatch are needed compared to **Case 4**.

Finally, in **Case 6** Germany is simulated in an isolated setting. The neighbouring grids are not considered and the exchange flows are determined by distributing the commercial flows resulting from the NTC market simulation based on the tie-line capacities per border. This results in the highest needs for positive and negative re-dispatch, while curtailment remains on a relatively low level.

Main findings

To adequately simulate CM in the German transmission system, re-dispatch potentials in the southern neighbouring countries need also be considered, as these are already activated by German TSOs. However, parameterisation is difficult because the (financial) conditions for activation are not made transparent.

Concluding from the parameter studies, it becomes clear that a wide range of necessary CM measures can result from the same market dispatch by adjusting certain parameters in the grid simulation. With regard to soft limits on line overloads, the results indicate that these should be introduced with care and limit violation should entail sufficiently high cost to not distort the CM simulation. For the system boundaries, as expected, more degrees of freedom reduce the volumes of CM. When flows through neighbouring countries are possible because the grid is considered, this reduces the need for CM in the German grid. This is in line with the findings from the literature that physical flows in the simulated grid region deviate from commercial flows [Mar10], [Kun18]. Hence, commercial flows from a market simulation should only be used with care as proxies for physical import or export flows in an isolated German grid simulation. The interconnectors have a notable effect on the CM volumes and should hence also be included. Not considering these lines can serve as an assessment of whether border flows could be problematic or grid data (or topology information) at the borders might deviate from reality. Moreover, the activation of re-dispatch potential in neighbouring countries should be represented adequately in a grid model to resemble real activation potentials. Finally, these parameter choices and boundary conditions should be made transparent, otherwise the interpretation of the presented results is rather difficult.

6.2 The effect of enlarging the Flow-based region and the introduction of minRAM

Section 6.2 has already been published in large parts in [Fin21].

To analyse the effect different market coupling schemes may have on the European electricity markets in the mid-term, a scenario for 2025 is analysed. The impact of different model parameterisation for market coupling on the electricity wholesale prices and exchanges between the BZNs is analysed. The bidding zones are modelled as such with the exception of Italy that is represented in the model with two BZNs, Italy North and the other Italian zones, which are aggregated in the model and hence share a common price. Grid expansion measures are in many cases delayed and electricity market studies often rely on NTC values from exogenous scenarios. This study aims to quantify the effect that the use of a FB market model for endogenous transmission capacities has on different parameterisation variants on important market indicators. Furthermore, the effect of the regulatory introduced minRAM are investigated, which will reach the target value of 70 % latest in late 2025 and finally the effect of extending the FB region to the Core CCR, which went live in summer of 2022 is analysed.

6.2.1 Research setup

The simulated transmission grid covers the countries of the Core CCR. The grid expansion state for Germany is based on scenario B of the German grid development plan for 2030 in the version 2019. The grid data for the other CWE countries are based on the static grid models integrating known expansion projects, which are planned to be realised before 2025. For the other countries, the grid data set is based on the TYNDP 2016, which also includes expansion projects from the national expansion plans, where available. The projects are realised as planned. The resulting grid topology is shown in Fig. 6.4. More information on fuel and CO_2 allowances prices underlying the investigation can be found in Appendix B.1.

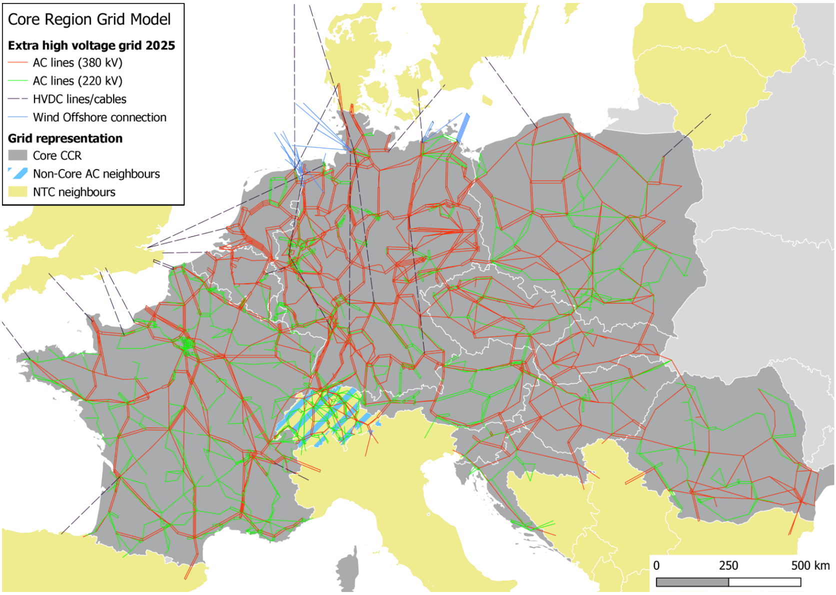


Figure 6.4: Map of the transmission grid for the Core region (and Switzerland) in the scenario year 2025 in the model.

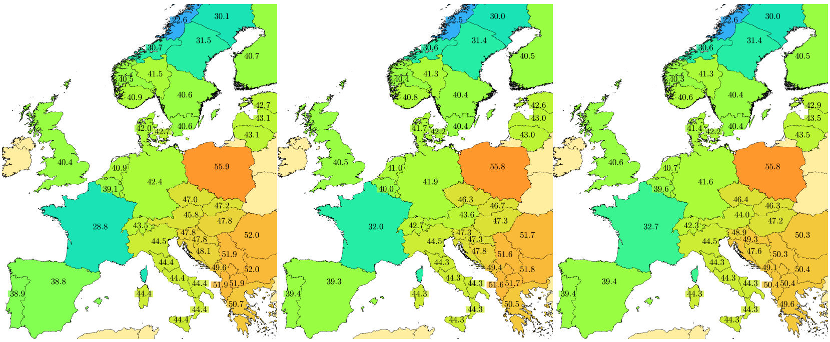
In total four different model variants are investigated, the first using scenario NTC values (NTC), the second variant employs FBMC in the CWE region with a minRAM of 20 % (FB1), the third variant employs FBMC also in the CWE region but with a minRAM of 70 % (FB2). Finally, the variant FB3 extends the application of FBMC to the borders of the Core CCR with a minRAM of 70 %. The variant specifications are shown in Table 6.2.

Table 6.2: Flow-based parameter selection for the scenario calculations.

Scenario	FB region	minRAM
NTC	-	-
FB1	CWE	20 %
FB2	CWE	70 %
FB3	Core	70 %

6.2.2 Numerical results

For the three FB variants, the change in average electricity prices[65], the aggregated net export positions and the effect on the binding line constraints are analysed. The average electricity price is shown in Fig. 6.5. As stated above, Italy is effectively modelled in two price zones. Nevertheless, all zones are depicted, but the southern zones have the same price. The aggregated net export positions for the bidding zones in the three FB variants are shown in Fig. 6.6.



(a) FB1 **(b)** FB2 **(c)** FB3

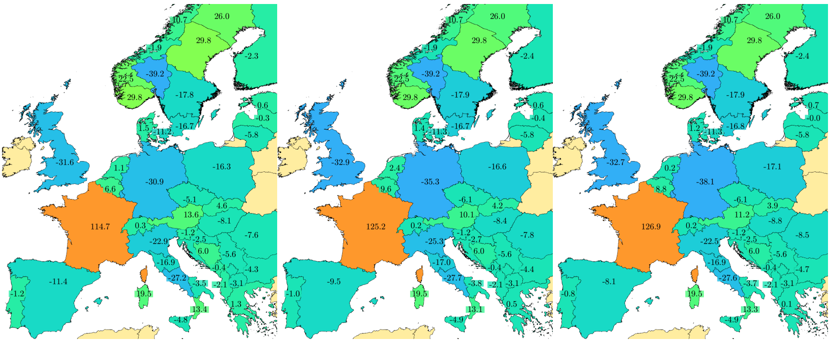
Figure 6.5: Base price in €/MWh for each bidding zone in the variants FB1 (left), FB2 (centre) and FB3 (right) for the simulated year 2025.

Increased level of minRAM

The first comparison regards the impact of increasing the minRAM for the CWE region (FB1 vs. FB2). Keeping everything else constant, the net export positions, mean prices and binding grid constraints are compared for an increased minRAM level from 20 % to 70 %. Most prominent is the change in the French bidding zone. The average electricity price increases by up to

[65] When comparing the simulated prices to future quotations (in April 2024) at the exchanges, a large discrepancy is noticeable. Although the simulation was already carried out in spring 2021, the used fuel prices are not very different from the quotations for Cal-25 in April 2024. The CO_2 price, on the other hand, is significantly higher in spring 2024 than the simulated value and therefore accounts for most of the observed price differences.

11 %, due to an increased export position, which grows by 9 %. Prices in Belgium, Spain, the Netherlands and Portugal also show increased levels. In the southern Nordic zones, prices decrease, without a significant change in net positions, which is induced by lower prices in Germany. The Baltic countries, Central and Eastern Europe and the Balkans also show reduced price levels compared to the 20 % minRAM variant.



(a) FB1 **(b)** FB2 **(c)** FB3

Figure 6.6: Net export positions for each bidding zone in TWh in the variants FB1 (left), FB2 (centre) and FB3 (right).

On a more technical level, the increased minRAM level reduces the number of binding grid elements. This mostly affects intrazonal constraints in Belgium and Germany, which no longer at any hour restrict the market. This demonstrates the effectiveness of minRAM in reducing the importance of zone-internal lines for the market clearing process. Figure 6.7 shows that most of the binding lines in the variant with a minRAM of 70 % are interconnectors or adjacent elements.

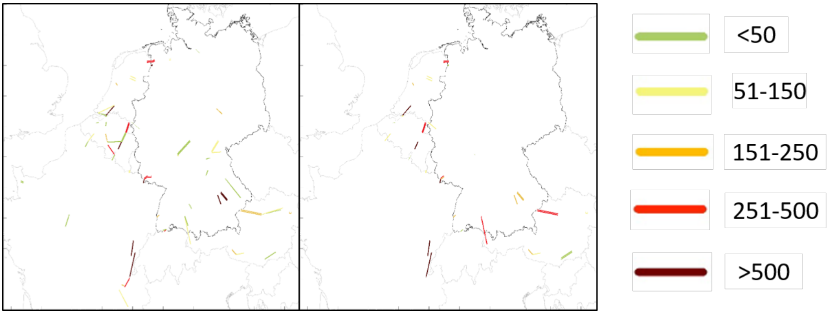


Figure 6.7: Number of hours when CNECs are binding for different levels of minRAM; 20 % in variant FB1 (left) and 70 % in variant FB2 (right) for FBMC applied in the CWE region.

Another important result is the share of constraints that are replaced by the minRAM condition. The minRAM share in Table 6.3 indicates the number of CNECs that are subject to minRAM, that is, the (calculated) available capacity for trading would be lower than allowed by the regulator. As expected, the number of replaced constraints increases from 16 % in variant FB1 to more than 50 % with a higher minRAM in variant FB2.

Table 6.3: Flow-based parameter selection for the scenario calculations.

Scenario	minRAM share	# RAM	max # RAM / h	min # RAM / h
NTC	-	-	-	-
FB1	16 %	16 699 166	14 050	996
FB2	54 %	16 699 166	14 050	996
FB3	44 %	28 323 080	15 596	1 718

Expansion of the FB region

The difference between variants FB2 and FB3 is the extension of FBMC from the CWE borders to the BZN borders in the Core CCR, which then covers a large part of the coupled European electricity markets in variant FB3. For BZNs in Western Europe, the effects are similar to an increased level of min-RAM in CWE, with further increasing prices in France, Great Britain and Spain. Consumers in Romania and Hungary profit the most from price levels.

Although not part of the FB region, the bidding zones in South-East Europe also show reduced price levels. Polish prices and net positions are mainly determined by an external import constraint in the scenario, which makes the results comparably stable[66]. The Nordic zones are almost not affected. Prices in the Baltic zones and some bidding zones in Central Europe increase slightly, making it difficult to identify a general trend. Interestingly, countries connected through NTCs to the FB region show relatively constant results across the investigated model variants. This indicates that, while the distribution among members of the FB region changes, the fundamental exchange patterns from and to the FB region remain unchanged in the calculations.

The total number of constraints is highly sensitive to the extension of the FB region from CWE to Core CCR as shown in the third column of Table 6.3. As each line generates two constraints (one for the flow in each direction), the number of RAM is twice the number of relevant network elements. The total number of RAMs in the model varies between 16.7 million for CWE and 28.3 million for the Core region. The number of CNECs also varies widely between hours, indicating the different utilisation of the grid in different situations. The minimum number of CNECs in one hour in all variants is 996, while the maximum occurs in the Core variant consisting of almost 15 600 constraints in a single hour.

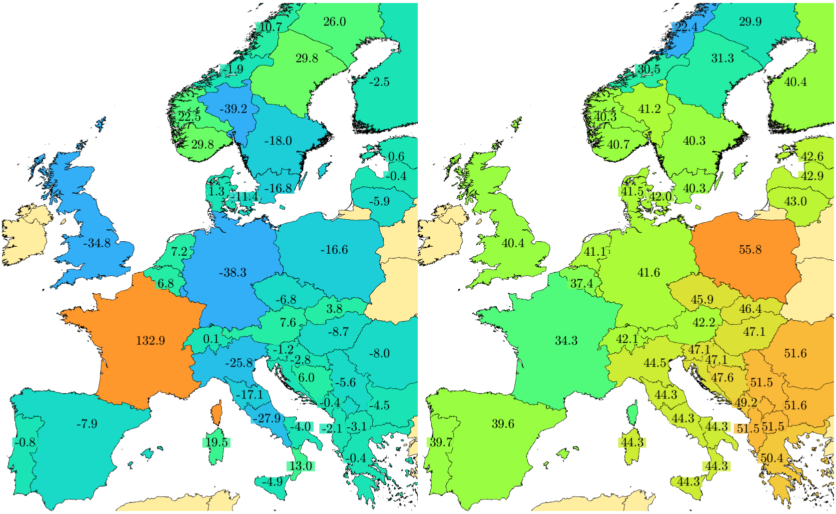
The highly volatile number of constraints indicates that the possible exchange might be limited differently in changing grid conditions, i.e. they depend on the supply and load distribution in the grid. This is increasingly important in energy systems with large shares of RES, where supply depends on volatile weather conditions and demand is more and more flexible due to new and flexible consumers. This makes the suitability of static NTCs, as they are often applied in scenario-based analysis of the energy system, highly questionable. Besides the aggregated implications presented here, this might result in more frequently changing operational patterns for power plants, with implications

[66] Additional to the grid derived FB constraints, the maximum net import and net export positions are limited. This reduces the amount of usable exchanges and reduces the effect other BZNs can have on the Polish price

for life-time and flexibility needs, which should be addressed in further research.

Compared to the most restrictive variant FB1, which resembles FBMC in CWE until 2020 and has already been found to increase transmission levels compared to the NTC market coupling, which was in operation beforehand [CWE15], the target for the European internal market (modelled in variant FB3) with FBMC introduced in the Core region and a minRAM of 70 % shows decisive differences with regard to prices and net export positions, both most prominently visible in France. The difference in average price is up to 13 %, indicating increased export of relatively cheap nuclear energy. In fact, this impression is confirmed by a difference in net position of 10 % between the two variants.

A last remark regards the difference between the FB results and the NTC market outcome (shown in Fig. 6.8), where a surprisingly large discrepancy is visible. French price levels and net positions in the NTC variant are more closely resembled by the Core variant with a minRAM of 70 % (FB3). Possible reasons and implications are laid out in the following.



(a) Net positions **(b)** Base prices

Figure 6.8: Results for the variant NTC. Net positions in TWh (left) and base prices in €/MWh (right) for each bidding zone.

6.2.3 Discussion and conclusions

Although the model accounts for the most important aspects of the market coupling process to assess differences in parameter choice, the presented approach is not without limitations. The biggest limitation comes from the transmission network model. The model is a static representation for the entire calculated year. Moreover, the topology is reduced to one bus bar per voltage level and substation. This reduces the ability to take into account the topology adjustments carried out by the grid operators.

Furthermore, the contingencies considered consist only of line and transformer outages. Generator outages or HVDC line failures, as well as contingencies of multiple elements, are not considered. However, when comparing the FBMC results with the NTC outcome, the results of the power flow studies seem to be rather too restrictive in the FB cases. Additional constraints from more sophisticated outage consideration would restrict the FB domain even further.

The power plant outages are modelled according to the historic 2016 outages to be consistent with the weather year. While this helps to account for, e.g., low river levels and resulting nonavailability, no data is included for power plants commissioned after 2016. In the considered scenario year, this leads to underproduction of units, which showed above average outages in 2016, while overestimating the production of plants without any modelled outages. At the aggregated bidding zone level, these effects are assumed to be minor. Uncertainties, with regard to load, wind and solar generation as well as outages, are neglected in the model, which uses perfect foresight. The effect of such forecast errors on the welfare is found to be minor in [Vos19], who conclude that FBMC 'seems to be quite robust against forecast errors'. Finally, the calculations show that the FB scenarios show mostly lower exchanges than in the NTC reference case, especially with regard to the French net position. This is an effect already reported by [Mar18], who attribute it to a mismatch between the NTCs and the grid scenario. Apart from this, there are two possible explanations for this supposed contradiction. One is the conservative operating voltage assumed when calculating the flow limits of the lines. These are based on 380 kV and 220 kV respectively, while in reality many lines are operated above nominal voltage. An increase of 10 % would equally increase the line limits and allow larger exchanges. Looking at the CNEC loading in Fig. 6.7, a relatively large number of lines in Belgium are binding. The grid operator in Belgium is already applying DLR in the CWE FBMC and is expected to use this tool intensively in the future. DLR allows for the dynamic allocation of lower or higher flow limits on particular lines, depending on the current weather conditions (radiation, temperature and wind speed). This allows for potentially higher flows on the lines, especially in hours where large amounts of wind energy are fed into the grid, in contrast to the static ratings applied in the presented approach throughout the year. The assumptions under which the NTCs for the scenario were calculated are not known to the author. This might affect the eastern European regions, where the modelled FB exchanges are systematically larger than in the NTC variant, which might be due to missing minRAM consideration in the NTC calculation for these regions. The analysis yields three key insights:

Increased exchanges through higher minRAM
Increased minimum trading capacities lead to more exchange and hence more base load capacity can be used. This usually consists of nuclear or lignite power plants. In the scenarios analysed, the strongest impact on the European energy mix is the increased French nuclear position, where larger trading capacities allow for additional output of up to 10 TWh. To put this into perspective, when comparing a scenario with or without minRAM, the difference in CO_2 free generation could amount to around 100 TWh over the course of 10 years (around 15 % of annual electricity demand in Germany today), which might have significant implications when evaluating the scenario.

Effect of minRAM on binding constraints
The increased minRAM also reduces the amount of binding grid elements, which are shifted towards the interconnectors. In this context, it might be tempting to consider market coupling approaches sufficient, which exclusively use interconnector capacities in whichever form for market coupling. However, the intra-zonal distribution of flows, which results from the georeferenced supply and demand sources, has a decisive impact on the FB domain, as shown by the changing number of binding constraints in the different hours of the year. Due to the increasingly prominent effect of RES in the system, dynamic market coupling constraints, which consider the specific grid situation, have to be taken into account to adequately represent the energy system.

Importance of the underlying grid state
When analysing the effect of extending the FBMC region from CWE to Core, or in general comparing FBMC against NTC market coupling, care has to be taken concerning the NTC values, which are applied in the comparison. Poorly chosen NTCs or values inconsistent with the grid expansion state make the comparison difficult and could lead to unintuitive results. This is also confirmed by [Mar18].

6.3 Impact of market coupling on revenue potential of renewables and flexibilities

In the majority of market studies, the (exchange) capacity development is based on exogenous system studies such as the Ten-Year Network Development Plan (TYNDP). While these studies often use optimisation methods to identify cost-minimal technology shares, political targets of e.g. member states fix these shares for given years as exogenous constraints or additional constraints are introduced to reach political decarbonisation goals. In both cases, the business case (or lack thereof) from a market or an investor's perspective is not further addressed. Moreover, the implication of market simulations on the grid operation and possible needs for re-dispatch are often not simulated. The purpose of this section is to investigate the impact of market coupling on the revenue potentials of renewable investors and flexibility providers and to showcase the effect on grid operation, including Dynamic Line Rating (DLR) to increase the considered overhead transmission line limits. Building on the insights from Section 6.2, the goal is to sensitise electricity market modellers and investors in the markets to the implications of market coupling on the simulation results - a sensitivity often overlooked.

6.3.1 Research questions and scenario setup

The selected scenario for the investigation is chosen to the year 2035. The capacities (generation, demand and flexibility) are modelled according to the *Decentralised Energy* scenario from the TYNDP 2022. Compared to the system state investigated in the previous section, additional flexibility is present in the system and (in large part) sensitive to or following the wholesale price signals. Additionally, the share of Renewable Energy Sources (RES) is becoming a determining factor that drives both the development of market prices and also (the need for) grid expansion or congestion management, respectively. The analyses follow the following lines of investigation:

- What are the consequences in the market domain, when static (NTC) limits or FBMC constraints are applied to the coupling in highly flexible systems? This first regards market prices and price distribution geographically and over time. Second, the impact of the different price patterns on the market value of renewable technologies is investigated, as this directly impacts their economic prospect and thus the potentially necessary support (e.g. through subsidies). Third, the effects on welfare are analysed, that is, how producer and consumer surplus and congestion rent are impacted by the different market coupling regimes.

- To what extent is the grid domain affected by the different coupling constraints with respect to congestion management (CM)? What is the potential of a widespread application of DLR with regard to CM volumes?

For the analysis, the electricity markets are simulated under the different coupling regimes, followed by a grid simulation of the German transmission grid based on the respective (market) dispatch. The transmission grid topology of the Core CCR and Switzerland, used for the calculation of FBMC and the grid simulation, is shown in Fig. 6.9. The AC grid of Switzerland is also modelled, due to its interconnections with three countries in Core CCR (France, Germany and Austria). AC circuits are shown in green (220 kV) and red (380 kV), HVDC interconnectors (including the back-to-back connection between Lithuania and Poland) and internal HVDC lines in black (dashed lines) and offshore wind park grid connections in blue. The countries, that are connected with NTC are filled in yellow, countries outside the modelling scope are filled in light grey.

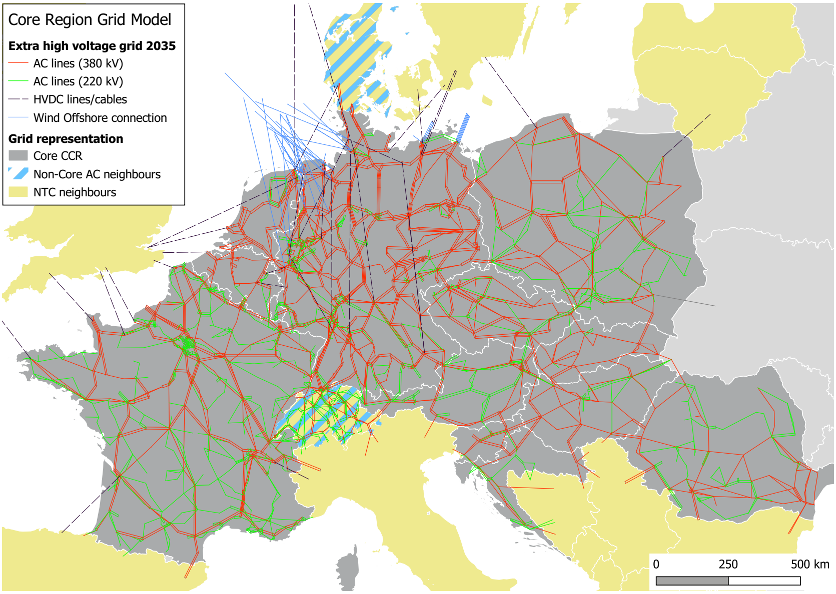


Figure 6.9: Map of the transmission grid in the Core CCR (countries in dark grey), as modelled in the scenario for 2035.

Allocation of seasonal storages

As described in Section 4.1, to analyse multiple scenarios in a short time, the annual calculation can be split into smaller time windows that are solved in parallel. For the following analysis, the year is divided into weekly blocks. To account for the adequate allocation of seasonal storages, they are pre-allocated in a prior (NTC-based) model run, with the hours coupled over the entire year, where the yearly start and end values for storage values are linked. The resulting start and end storage values for the weekly blocks are then fixed for the subsequent market simulations, while within these time windows, the dispatch can be optimally allocated. The resulting storage curve and storage limits[67] are shown as exemplary for BZN NO4 in Fig. 6.10. The weather conditions for 2016 are selected for the hydroelectric plants and for the RES feed-in

[67] See Section 5.2.3 for more information on the storage limits.

profiles. For reference, the historical storage values of 2016 (the weather year in the scenario) are also shown. At the beginning of the year, the modelled and historic storage values are well aligned. Starting around week 18, the simulated storage values are higher than the historical values, for a simple reason: In the simulation, the start and end values are forced to be equal, so the terminal storage value needs to be much higher than the historical value. The course between weeks 40 and 52 is again similar, so in order to reach the higher terminal value, the cheaper summer months are used to fill the storage.

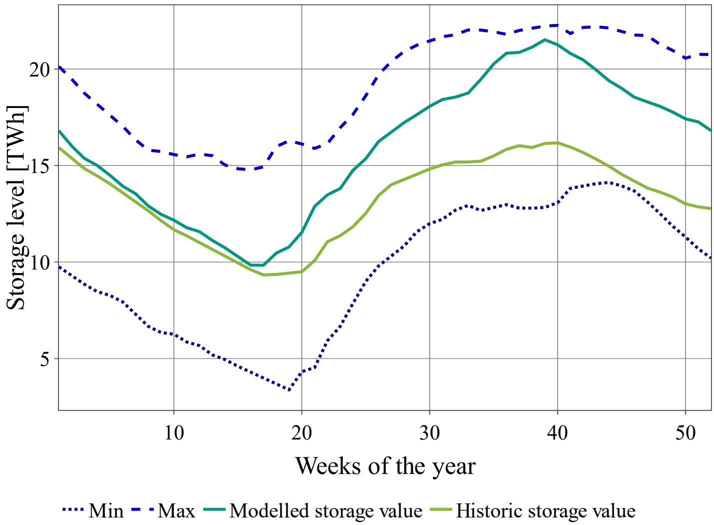


Figure 6.10: Long-term storage allocation at the example of BZN NO4.

Scenario implications for different renewable technologies at the example of the German bidding zone

To analyse the effect of market coupling on the market value of RES, a reference must first be established. The RES generation, average prices and capture rates[68] are shown on a monthly basis in Fig. 6.11 for the market coupling variant that employs FBMC with static line limits (*FBst*[69]). The monthly base price is strongly affected by renewable generation, with a sharp drop in the summer months reaching the minimum of 49.33 €/MWh in May and the maximum at 133.21 €/MWh in December. Among RES technologies, solar PV shows the strongest seasonal pattern in both infeed and capture rates. The two are negatively correlated, with the maximum infeed occurring during the summer months, while (due to the simultaneity of PV infeed across BZNs), the capture rate drops to 60 % of the monthly average wholesale price in May.

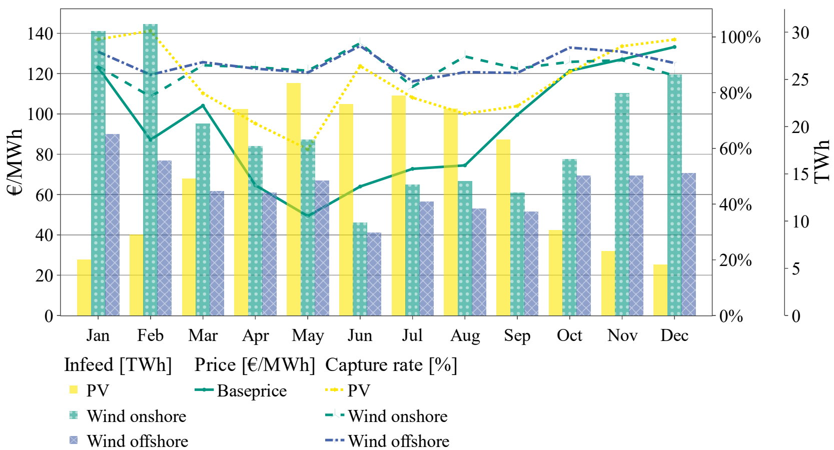


Figure 6.11: Monthly base price [€/MWh], infeed [TWh] and capture rates [%] for solar PV, wind onshore and wind offshore in model variant *FBst* for the German BZN. The base price and solar PV capture rate are negatively correlated with solar generation. Both are reaching their minimum in May, the month with the strongest solar PV generation. Wind capture rates are more or less stable between 84 % and 98 %.

In winter, the effect is reversed, with February accounting for only 4.7 % of annual PV generation, but in those hours yielding above average returns (102 %

[68] The capture rate describes the share of the base price (average price), that the respective (renewable) technology is able to earn with their infeed profile.

[69] See next section for a detailed description of the analysed model variants.

of average wholesale prices in that month). For wind onshore and wind offshore, the picture is not that clear. Although the generation shows a decreasing pattern throughout the summer months, the capture rates do not show an analogue pattern. For wind offshore, the capture rates vary between 84 % in July and 97 % in June. Wind onshore shows a stronger seasonal generation pattern than wind offshore. However, the capture rate range is similar with the minimum of 79 % in February and the maximum of 98 % in June.

Although the scenario RES generation is much higher than in the current electricity markets, the simulated capture rates for Germany are within the range of historical capture rates observed in Germany in recent years (see also Fig. 7.1)[70]. This is mainly due to the much higher number of energy storages assumed in the scenario compared to today, as well as the presence of price-sensitive electrolysers in the system that are modelled with full market exposure and thus support prices, especially in hours with large solar PV generation[71].

6.3.2 Market effects of the market coupling regime

Based on this scenario, several market coupling variants are modelled to investigate how the market coupling constraints affect prices across bidding zones. These effects are then investigated in more depth at the example of the German bidding zone, with a special emphasis on the revenue potential for renewables and energy storages, as these technologies are key to the success of the decarbonisation of the electricity system and the energy transition.

Figure 6.12 presents a comparison of the investigated market coupling variants with respect to the highly aggregated indicator of the cumulative generation cost. The research setup is as follows. Two initial market simulations are conducted and set the reference for the following simulations. First, the market coupling is modelled with the scenario NTCs from the TYNDP (*NTC*),

[70] As the model is calculated in nominal terms following the inflation projection described in Section 5.3, this means a decrease in real terms, with respect to historical levels.

[71] See also the dispatch patterns of the simulated energy storages in Fig. 6.19 and Fig. 6.20

which yields cost of ~35 bn€. Then a benchmark with unlimited exchange capacities between bidding zones (*unlimited*) is calculated to derive a lower bound for generation cost (~22.6 bn€) at full price convergence[72]. The variant *NTC* is then used as the base case for several FB simulations.

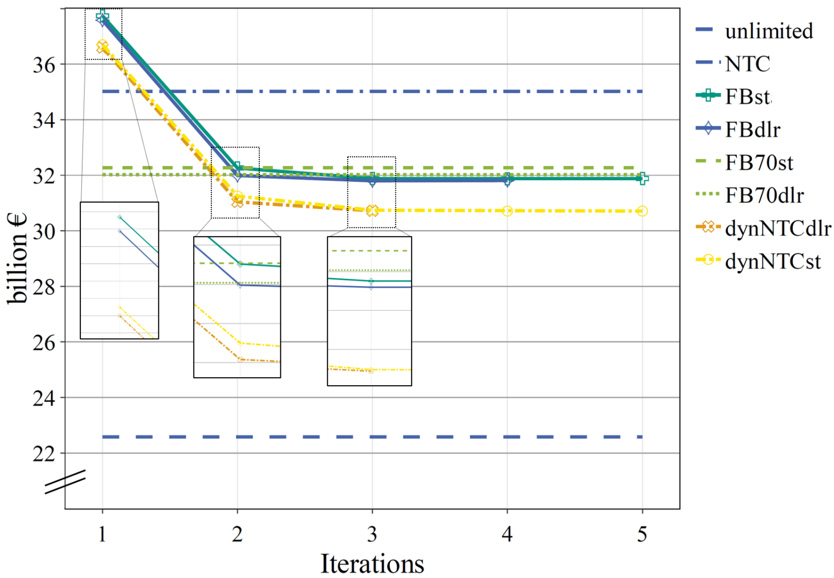


Figure 6.12: Generation cost in the different market coupling variants for the year 2035. The cost for the scenario NTCs (dot-dashed line) and the cost in the variant with unlimited exchange capacities (long-dashed line) are shown for reference. The cost for both FB variants based on the scenario NTC base case (iteration 1) exceeds those of the reference case, quickly decreasing and reaching a convergence after about 3 iterations. The coupling variants with dynamic NTCs always show costs below their respective FB variant, as anticipated, given that they are relaxing the coupling constraints. FB with dlr (FBdlr) shows small but consistently lower costs than FB with static line limits (FBst), while the derived dynamic NTC variants almost converge after 3 iterations. The two variants of FBMC where the (n-1) criterion is approximated with line capacities of 70 % based on the scenario NTC as base case (FB70st and FB70dlr), yield costs quite similar to the final FB variants.

[72] Actually, all prices except in Poland converge, as the Polish bidding zones has additional constraints implemented on the net exchange position, resulting in a price deviation.

FBMC is modelled with static line limits (*FBst*, ~37.7 bn€) and with dynamic line rating (*FBdlr*,~37.6 bn€). Both variants explicitly include the (n-1) constraints and produce very similar cost (within 0.5 %). Moreover, for both FB variants a simulation is run, where line capacities are set to 70 % as a proxy for security constraints, similar to the approach in the grid simulation (*FB70dlr*, ~32 bn€ and *FB70st*, ~32.3 bn€), to investigate if this kind of approximation is similarly valid as it has been demonstrated for grid simulations (e.g. in [Hob22]).

For the FBMC variants with explicit (n-1) consideration (*FBst* and *FBdlr*), generic bidirectional exchange limits are derived based on the resulting exchange flows using the developed method described in Section 4.5. With these exchange limits, a market simulation is run with the NTC formulation of the model to investigate how well the developed method is able to approximate the FBMC results while having clear advantages with regard to computational burden and memory requirements[73]. These variants are called *dynNTCdlr* (~36.6 bn€) for the variant after *FBdlr* and *dynNTCst* (~36.7 bn€) for the variant after *FBst*.

From the results and the illustration in Fig. 6.12 it is evident that the *NTC* variant is not well suited as a base case, as the FBMC simulations unexpectedly yield higher generation costs for both variants (*FBdlr* with and *FBst* without DLR). To overcome the ill-suited base case, an iterative procedure is initiated, in which the dynNTC market solution is used as a new base case for a FBMC recalculation (iteration 2). On the basis of this FBMC simulation, dynamic NTCs are again calculated based on the exchange flows from the FB results and the procedure is repeated. The greatest cost decrease can be observed between iterations one and two (around -14.5 % for *FBdlr* and -14.9 % for *FBst*; the dynNTC variants decrease in very similar magnitude *dynNTCdlr*: -14.5 % and *dynNTCst*: -15.2 %). In the next iteration, the cost decrease becomes much smaller (~1 %) and additional iterations do not lead to reduced cost.

It is also evident from Fig. 6.12, that the dynamic NTC variants consistently yield lower cost than the FB variants from which they are calculated. In fact,

[73] See also Section 6.3.6 for a discussion of model complexity.

this is an expected outcome of the developed method, as the dynNTC exchange limits relax the original FBMC formulation of the market coupling constraints and allow for lower costs than the associated FB variants. In the final state (iteration 5), the difference between *FBst* and *dynNTCst* is ~3.7 %, indicating a reasonably good approximation of the FB formulation. Interestingly, the FB variants with simplified security constraints (*FB70st* and *FB70dlr*) after one iteration are very close to the final results of the FB variants with explicit consideration of (n-1) security. As expected, the final FB variants yield lower costs than the initial scenario NTC variant (~9 %), although it should be noted that the grid state is not identical, as also discussed in Section 6.2.3.

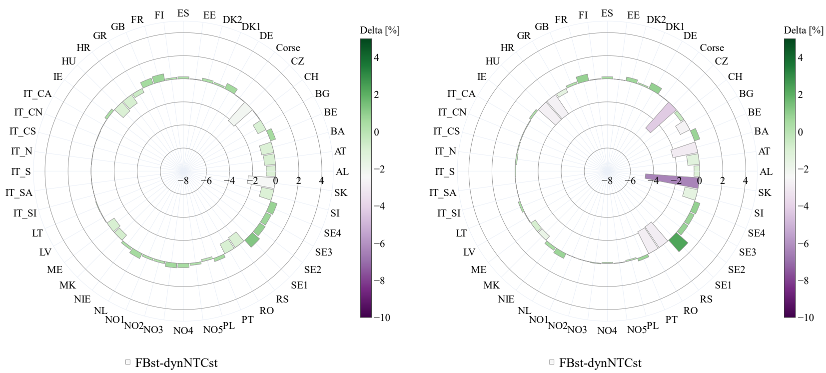
Main findings

- The scenario NTCs are not fit for use as a base case in FBMC. To overcome this, an iterative approach is used where dynamic NTCs are derived from the inital Flow-based simulation using the developed approach (see Section 4.5). A market simulation based on these dynamic NTCs is used as the base case for a new FBMC simulation. After repeating this procedure several times, the results quickly converge.
- The dynamic NTCs relax the FB problem and lead to lower costs. When using the results from FBMC as a base case for another FB simulation, cost quickly fall below those of the initial NTC simulation.
- Integration of DLR into FBMC has only a small effect.
- The difference between the derived dynamic NTC simulation and FBMC is smaller than the difference between FBMC and the scenario NTC simulation, indicating a better approximation with the developed method. This is further investigated in the following.

Price effects in the modelled bidding zones

The system generation cost is a very highly aggregated indicator of the efficiency of market coupling. To better understand the real-world implications of the results and the remaining differences between the investigated market coupling variants, the market results are analysed for a particular pair of variants (*FBst* and the associated *dynNTCst* both in iteration five), and relevant effects for renewables and storage revenue potential are analysed in depth for the German bidding zone. This comparison provides a better indication of the suitability of the dynNTC approach to approximate the FBMC constraints for a faster and less resources intensive investigation, which can be integrated into market models which are only capable of NTC-based market coupling.

Differences in base prices and market values for solar PV, wind onshore and wind offshore are shown in Fig. 6.13 for the 48 modelled BZNs.



(a) Base price difference

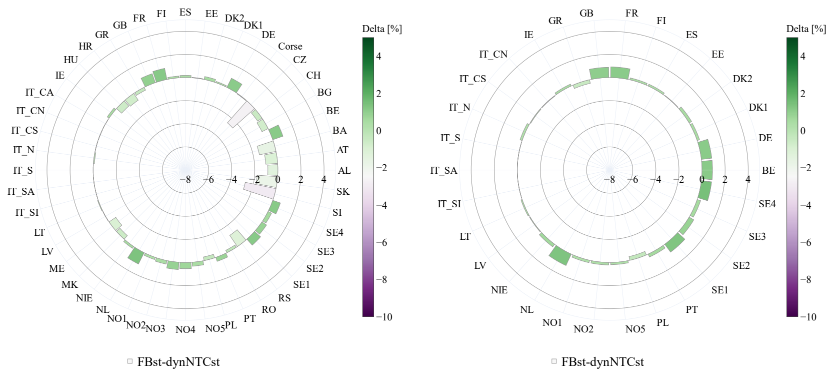
(b) Market value difference for solar PV

Figure 6.13: Price difference between *FBst* and *dynNTCst* in €/MWh for base price (left) and market value difference of solar PV (right) (The colour indicates the change in percent.

The most prominent difference in base price is observed in the bidding zones of the Core region, especially in Czech Republic (-2.15 €/MWh or 2.25 %) and Slovakia (-2.36 €/MWh or 2.47 %). For most bidding zones, however, the difference between the base prices in the two variants is well below 1 %. For solar PV capture prices, the effect is larger, although it tends to be limited to the BZNs, where a difference in the base price is also notable. BZNs where the difference is larger than 2 % are with the exception of SE1, where PV generation is negligible, located in South East Europe: BA (-3 %), BG (-2.7 %), CZ

(-4.3 %), HR (-2.7 %), HU (-2.8 %), RO (-2.9 %), RS (-2.9 %), SE1 (+2.25 %) and SK (-6.4%). Among Europe's five biggest electricity markets, Germany and France show an increase of slightly short of 1 %, Spain and Great Britain even less so, while the decrease in Italy is almost not noticeable.

The difference in the market values of wind onshore and wind offshore is shown in Fig. 6.14. For wind onshore, the effect is qualitatively very similar to the one observed for the base price differences. This is in line with the observation in Fig. 6.11, of relatively high and stable capture rates for this technology on a monthly basis. For wind offshore, with the notable exception of the Greek and Polish BZNs, *FBst* leads to higher market values in all bidding zones, but consistently of very low magnitude around or below 1 % in difference.



(a) Market value difference for wind onshore **(b)** Market value difference for wind offshore

Figure 6.14: Market value difference between FBst and dynNTCst in €/MWh for wind onshore (left) and wind offshore (right) for the modelled BZNs. (The colour indicates the change in percent.

To put these price differences into perspective, the difference in the market value of solar PV in Germany would mean a reduced return of ~107 k€ for the solar park Weesow-Willmersdorf (installed capacity of 187 MW, assumed capacity factor of 11.4 %, project cost 100 m€) in the simulated year, about

0.1 % of the initial investment. For a similar project in Slovakia, the earnings difference would still be well below 1 % of the initial investment (at ~0.87 %).

Main findings

- The dynamic NTC and FBMC simulations lead to similar prices and market values (in most bidding zones below 2 % difference) demonstrating the suitability of the developed approach to approximate FBMC.
- Solar PV is the technology most affected by different market coupling regimes.
- Wind offshore is least affected and exhibits slightly higher market values in the FBMC simulation in almost all bidding zones.

Price effects - Detailed analysis for Germany

To gain a better understanding when the price differences occur, the temporal structure of prices (seasonal and hourly) is analysed for the German BZN. The German bidding zone is chosen because it has multiple borders within Core CCR and also shares borders with countries outside Core CCR, and thus market coupling is of very high relevance. Figure 6.15 shows the sorted price duration curve for Germany in the *dynNTCst* variant and the prices for the *FBst* variant in the corresponding hours. In the lower part of the figure, the hourly price differences between the two variants are shown. It becomes clear that the effect of FBMC cannot be attributed to one specific price range, rather price differences occur across several price ranges. In many cases, price increases are balanced by price decreases in other hours but at a similar price level. However, the deviations show that the two market simulations can produce significantly different prices of up to +/- ~50 €/MWh for individual hours. For the small price differences on the right side of the duration curve (very low prices), this is more or less natural, since the subsequent price level is about 40 €/MWh more expensive, so small movements in the merit order can result in large price differences. The cluster of price differences between hours 5 000 and 6 000 on the other hand, indicate that in this range, the market simulations actually lead to different market outcomes with significantly different prices in the German BZN.

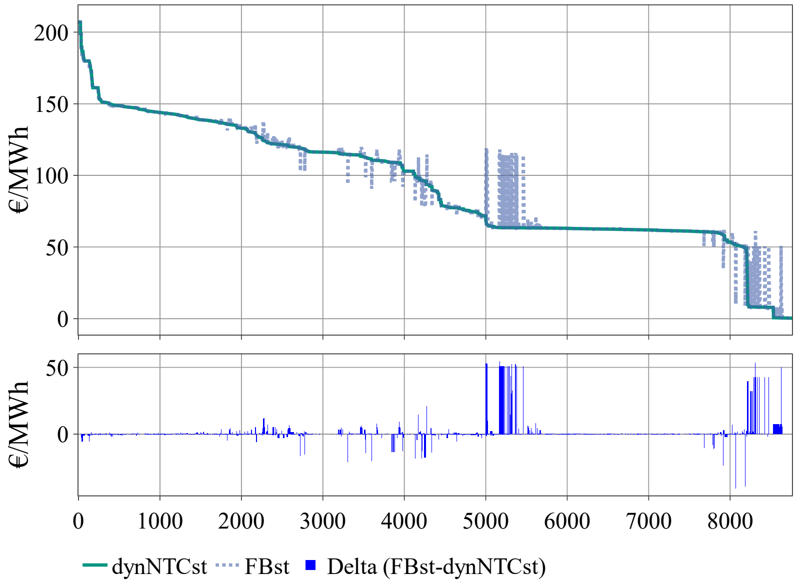


Figure 6.15: Price duration curves (top) for the *dynNTCst* variant (solid line) and corresponding prices in the *FBst* variant (dotted line) and price difference (bottom) between the two variants for the German bidding zone. Price differences occur mainly in three areas, first a price range between 60 €/MWh and 140 €/MWh, where positive and negative differences balance each other more or less. Second, in the range around 60 €/MWh, where the *FBst* variant yields a number of hours with prices up to 50 €/MWh higher and lastly, a number of hours at the transition from very low prices (~10 €/MWh) to medium prices, where price differences occur in both directions but the more expensive hours in *FBst* prevail.

This analysis is partially relativised by comparing the sorted duration curves for both variants in Fig. 6.16. Besides a small number of hours in the transition from ~8 €/MWh to 50 €/MWh, where a price delta of around 40 €/MWh remains, the other price deviation are below 10 €/MWh and mainly located at price levels between 60 €/MWh and 110 €/MWh. The price level around

62 €/MWh between hours 5 000 and 8 000 are demand-induced prices by flexible electrolysers, which are modelled very similarly across the bidding zones. The main price differences between hours 2 000 and 5 000 regard the part of the merit order with conventional power plants, where different market coupling constraints allow for different market optima between the two variants. Very low prices tend to correlate with high solar PV generation, so the price difference in these hours explains the relative large delta in PV market values shown above.

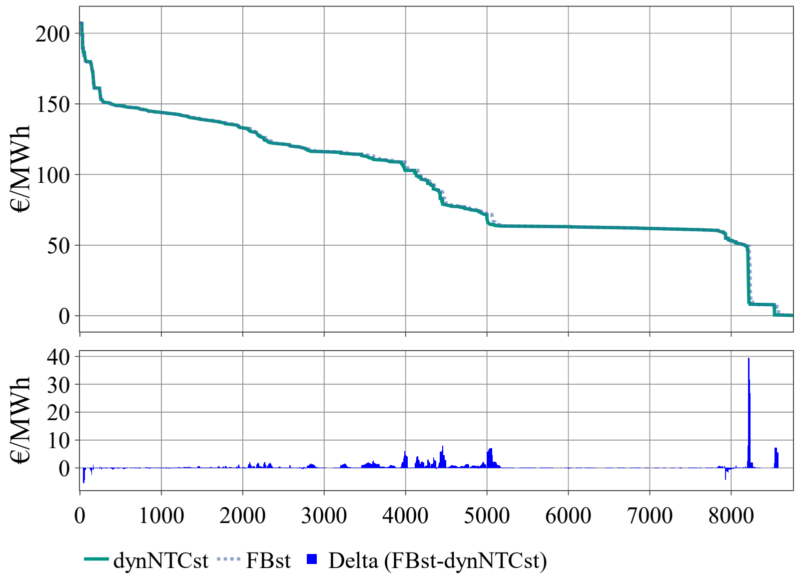
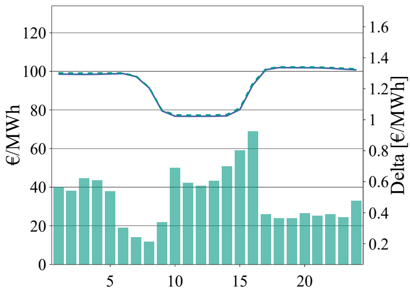


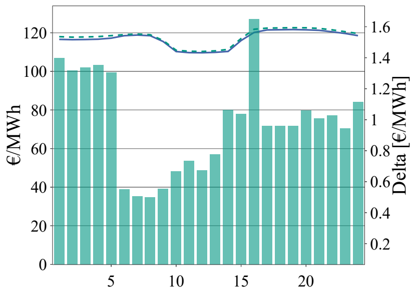
Figure 6.16: Sorted price duration curves (top) for the *dynNTCst* (solid line) and *FBst* (dotted line) variant and price difference between the variants (bottom) for the German bidding zone. There are two notable price ranges where differences occur, one being the transition from very low prices to around 50 €/MWh, where some few hours are up to 40 €/MWh more expensive in the *FBst* variant than in the *dynNTCst* variant. The second is a larger number of hours with prices in the range of ~60-120 €/MWh, where the *FBst* variant yields prices less than 10 €/MWh more expensive. Lastly, the *FBst* variant decreases prices in some very expensive hours (>160 €/MWh) compared to the *dynNTCst* variant.

Seasonal patterns in the German price differences

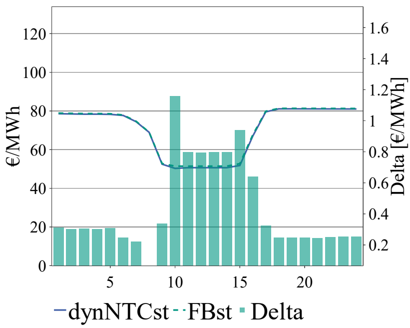
As the price differences in Fig. 6.15 occur in certain clusters, it is worth investigating how they occur throughout the year and during the hours of the day. Figure 6.17 presents the hourly mean prices and the mean price differences for the different seasons and with regard to the whole year.



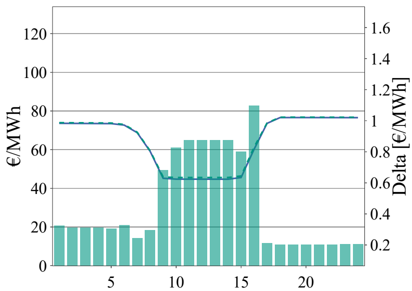
(a) Entire year



(b) Winter



(c) Spring/Fall



(d) Summer

Figure 6.17: Average hourly price in the *FBst* (dashed line) and *dynNTCst* (solid line) market coupling variant during the seasons of the year for Germany. The relative price minimum in the hours with solar PV generation is visible throughout the year, with the evening hours showing slightly higher price levels than the morning hours. During most months of the year, the price difference between the market coupling variants (*FBst-dynNTCst*, bars) is most profound (around 0.8 €/MWh) in the solar dominated hours (and below 0.4 €/MWh in the other hours). The exception is in the winter months, when the first five hours of the day show the largest price deltas (around 1.3 €/MWh).

For both variants, the daily price minimum is during the midday hours, with on average the highest proportion of solar PV generation. The daily price spread is the smallest during the winter months, when the effect of solar PV is also the smallest. For all seasons, prices in the evening hours are slightly higher than during the morning hours. Regarding the difference between the model variants, a clear distinction is visible between winter and the rest of the year. For the spring, summer and fall months the largest difference occurs between 10:00 am and 4:00 pm. During these hours the average price delta is around 1 €/MWh, while during the other hours of the day it is well below 0.4 €/MWh. In the winter months, the situation is less clear, with some large deltas in the early morning hours, but also average price deltas around 1 €/MWh throughout the second half of the day. The impression that the delta between the variants mainly affects the hours characterised by strong solar feed-in is confirmed again.

Main findings

- The seeming price difference between the variants in Germany is greatly reduced when comparing the sorted price duration curves for both variants. Price differences mainly occur when prices in (very) cheap hours with high RES infeed are lifted up in the FB simulation and across the cheaper part of the (conventional) merit order.
- The price differences are the largest in the midday hours (except for winter) coinciding with solar generation and explaining the most profound effect on the solar PV market value.

Market value and capture rates in Germany

Next, the impact of the market coupling variant on the capture rates of the renewable technologies is analysed. Figure 6.18 shows the monthly price difference for the German BZN for the base price, the market values for solar PV, wind onshore and wind offshore as well as the capture rate difference. For most months, the delta in base prices and market values for RES is well below 1 €/MWh. Exceptions are January and March (and June for PV). The *FBst* variant leads to slightly higher base prices in Germany between March and November. In the winter months, prices tend to be lower, with the exception of January. Regarding the capture rates of renewable technologies, the difference is also well below 1 % for most month. Exceptions are January and May (and June for solar PV), with May being the month with the maximum in PV generation in the simulated year for Germany.

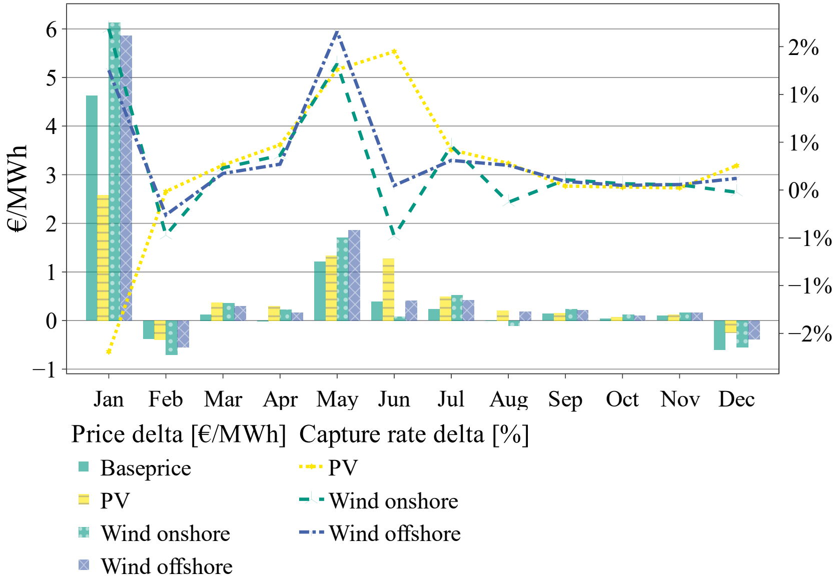


Figure 6.18: Difference (*FBst-dynNTCst*) in monthly base price and capture prices for solar PV, wind onshore and wind offshore (bars) and difference in capture rates for the RES technologies (lines) for Germany between variant *FBst* and *dynNTCst*.

Effect on flexibility dispatch

Given the very small difference in the daily price patterns shown in Fig. 6.17, no large difference is expected in the dispatch of flexible energy storages. This is further investigated by analysing the aggregated hourly dispatch of battery storages in the *FBst* variant in Fig. 6.19 (left) and the difference between the two model variants (right). The dispatch patterns on the left part of the figure very well display the operational rationale of these storages, with the charging maximum lying in the hours from 10:00 am to 3:00 pm (the hours with the strongest PV infeed). The effect is less pronounced in the winter months. Also well visible is the effect of the changing duration of days. The longer days during summer delay the high(er) prices towards the evening hours, which are used by the energy storages to feed back into the system and satisfy higher (residual) demand. The interpretation of the dispatch delta (right part of Fig. 6.19) is less clear. Naturally, the delta affects the hours with high storage utilisation the most. Beyond that, no clear pattern is visible, which resembles the analyses from the (not sorted) price duration curves, where large price differences between the market scenarios in single hours are partly balanced by complementary differences in similar hours. Consequently, the storages are dispatched differently during these hours.

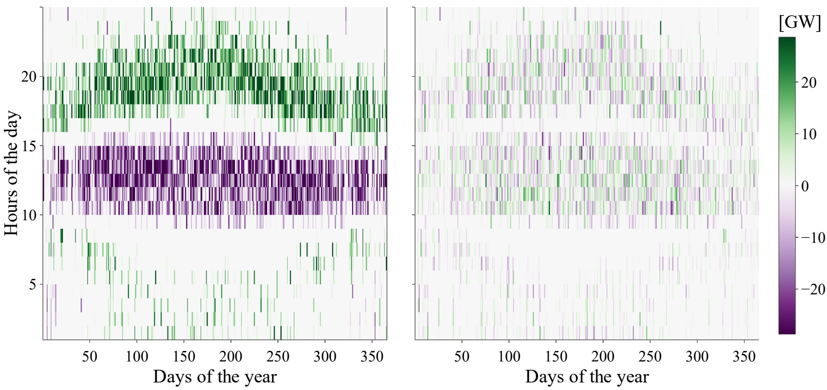


Figure 6.19: Dispatch (*FBst*, left) and delta (right) in dispatch for battery storages with market exposure between variants *FBst* and *dynNTCst*. Charging (off-take from the grid) is shown in purple, while discharging is shown in green. For the delta graph, hours where the dispatch in *dynNTCst* is larger are indicated purple and those with larger dispatch in *FBst* in green.

For vehicle-to-grid (V2G) applications, which are also modelled as storages, but with lower efficiency than battery storages, the dispatch patterns for the *FBst* variant and the delta between the two simulations are shown in Fig. 6.20. The dispatch pattern reveals that these storages are dispatched in fewer hours, presumably in situations where higher price spreads are present. V2G flexibility is used less during the winter months, where the spread between the daily minimum and maximum is less pronounced due to the reduced solar generation and consequently fewer hours with (very) low prices. The delta between the two model variants is more profound than for the battery storages. This indicates that less efficient flexibility providers are more heavily impacted by the market coupling regime (and differences in the exchange potentials with neighbouring bidding zones) than their counterparts with higher efficiency.

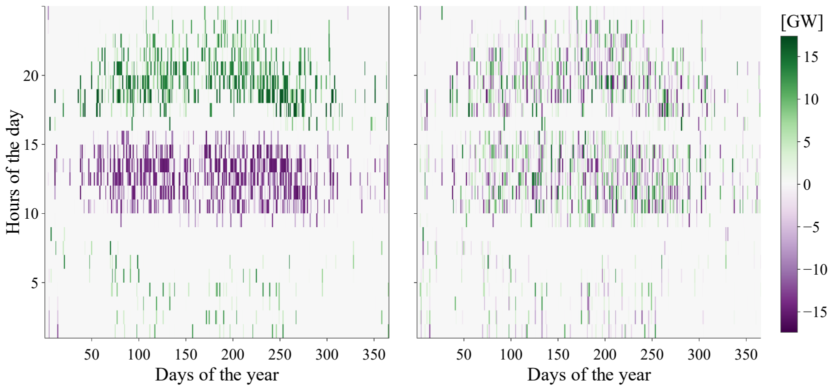


Figure 6.20: Dispatch (*FBst*, left) and delta (right) in dispatch for V2G batteries between variants *FBst* and *dynNTCst*. Charging (off-take from the grid) is shown in purple, while discharging is shown in green. For the delta graph, hours where the *dynNTCst* dispatch is larger are indicated purple and those with larger dispatch in the *FBst* variant indicated in green.

The daily price spread can be used as a more general indicator for storage or flexibility revenue potential (at least for energy storages with a power-to-capacity ratio close to one). The average daily spread and the delta between the two variants per month are shown in Fig. 6.21. In both variants, the daily spread is greater during the summer months (in the range of 35-45 €/MWh), where regularly hours with low prices materialise around noon. Interesting is the strong drop in June to around 20 €/MWh (almost at levels of the winter month), which is due to the yearly minimum in wind generation and also reduced PV generation compared to May and July (in Germany). From October to February, the average daily spread is less than half that of the summer months at about 15 €/MWh. For the delta between the model variants, no clear pattern is visible beyond the fact that in most months, the *FBst* variant reduces the daily spread up to 2 €/MWh, which resembles up to -13 % in January.

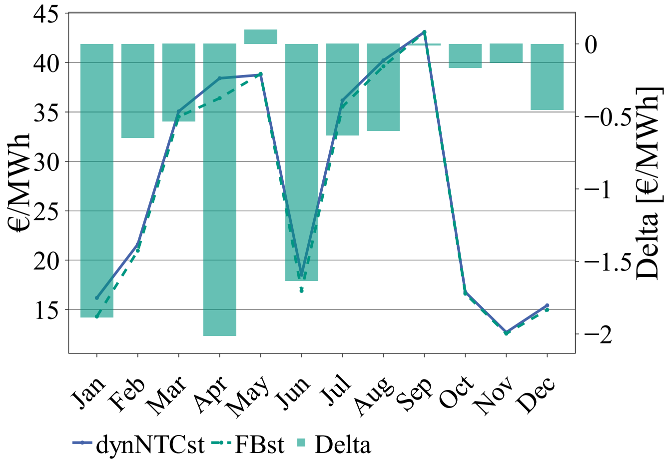


Figure 6.21: Monthly average of daily spread for variants *dynNTCst* (solid line) and *FBst* (dashed line) and difference (*FBst-dynNTCst*) between the two variants in Germany.

The impact on electrolysis is also very small (on a monthly basis as well as with respect to the yearly aggregated energy consumption), accumulating to around 0.5 % in demand difference. Both variants of the model yield roughly 48 TWh of electrolysis dispatch in Germany. The dispatch lies within the corridor the TYNDP scenario spans between 34.9 TWh for 2030 and 190.6 TWh for 2040[74], but much closer to the value for 2030.

[74] Average reported for the three weather years (1995, 2008 and 2009) in the scenario *Distributed Energy*.

Effect on welfare distribution

Finally, again on a very aggregated level, the difference in the welfare[75] distribution between the two model variants is analysed. The effect of the different market coupling regimes on the welfare in the bidding zones of the Core region is shown in Fig. 6.22. The main difference regards the congestion rent, with a large decrease occurring at the German borders, which is more than balanced by an increase at the French borders.

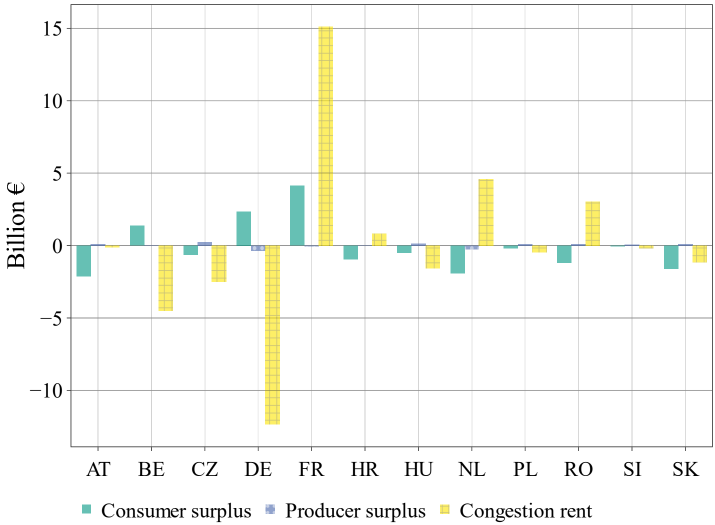


Figure 6.22: Difference in consumer surplus, producer surplus and congestion rent for Core bidding zones (*FBst-dynNTCst*).

The change in consumer surplus is much smaller and the producer surplus hardly changes. The losses of the consumer surplus in the Core CCR amount

[75] Welfare is defined here as the consumer surplus (difference between the willingness to pay, that is either explicit bid prices or the market price cap, and the market clearing price) plus the producers surplus (the market clearing price minus the price of the supply bids / variable cost) minus the congestion rent (net export position multiplied with market clearing price). See also [CWE17].

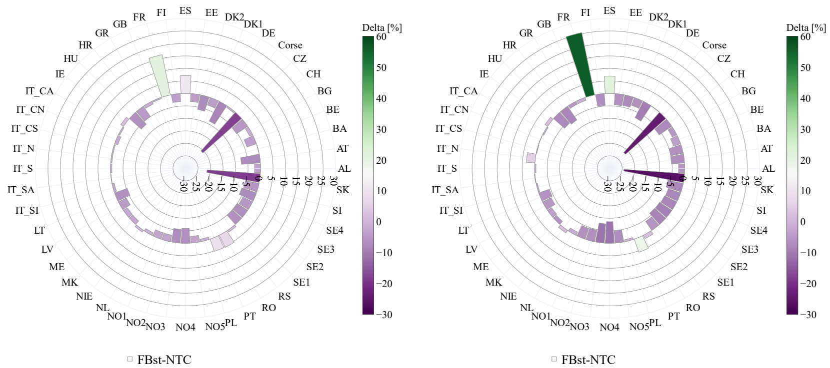
to ~1.3 bn€, while the producer surplus increases by ~65.2 m€ and the congestion rent increases ~679 m€. In the non-Core BZNs, the consumer surplus increases by ~1.4 bn€, the producer surplus decreases by ~124.2 m€ and the congestion rent decreases by ~2 bn€. In summary, social welfare is higher in the *dynNTCst* variant, as already indicated by the generation cost in Fig. 6.12 and is explained by the constraint-relaxing nature of the method.

Main findings

- During most months of the year, the capture rates are hardly affected, so market values float with the difference in base prices. In all months, the capture rate difference is below 2 %.
- Battery storages are generally charged during the midday hours and discharged in the evening (in both variants). No clear pattern is visible in the dispatch difference. Flexibilities with lower efficiency are more affected by the different market coupling regimes. The dispatch of electrolysis is hardly affected.
- The daily spread (difference between the highest and lowest price) is higher in the summer months. In the FB variant, the daily spread is up to 13 % lower, indicating reduced revenue potential for daily storages in the FB variant.

6.3.3 Effect of inadequately modelled exchange capacities

To demonstrate the potential effect of ill-conditioned market coupling constraints on the market outcome, the model variants with the scenario NTCs (*NTC*) and *FBst* are compared. The impact is again demonstrated by the difference in the base prices (Fig. 6.23a) and the PV market values for the simulated regions (Fig. 6.23b). At the example of the German BZN, the structure of these price differences is discussed in more detail, using the sorted price duration curves for both variants shown in Fig. 6.24.



(a) Base price difference

(b) Market value difference for solar PV

Figure 6.23: Price difference [€/MWh] between model variants *FBst* and *NTC* for the base prices (left) and market values of solar PV (right) (The colour indicates the change in percent.

The difference in the base price is for many bidding zones in a range between 5 % and 10 % and thus significantly greater than justified solely by the methodological difference. For most bidding zones, prices decrease in the *FBst* variant. Again, Czech Republic and Slovakia show the largest decrease of almost 20 %. Notable exceptions, where prices increase are France (+21.4 %), Spain (+11.2%), Portugal (+9.1 %) and Romania (+6.2 %). As in the comparison above, the effect is more severe for solar PV market values. In France, the market value increases by ~56 %, in Spain in Portugal, the market values rise by about 20 %, driven by the increased prices in France. In contrast to this, most countries show a decrease in market values for solar PV between 6 % to 12 %, notable extremes being again CZ and SK with -24 % and -26 % respectively. These figures show that the wrong choice of market coupling constraints or a poor representation of the underlying grid (expansion) state in market analyses can quickly become significant for investors relying on price and market value forecasts for their investment decisions. To take again the example of a solar park project with the above assumptions (187 MW installed capacity, capacity factor 11.4 %, project cost 100 m€), the increased revenue simulated in the French BZN in the *FBst* variant would amount to ~4.7 m€. In Slovakia, the price difference would mean a decrease in revenues of ~4.5 m€. Given that both figures are in the range of 5 % of the initial investment, these differences could easily make the investment (un)profitable.

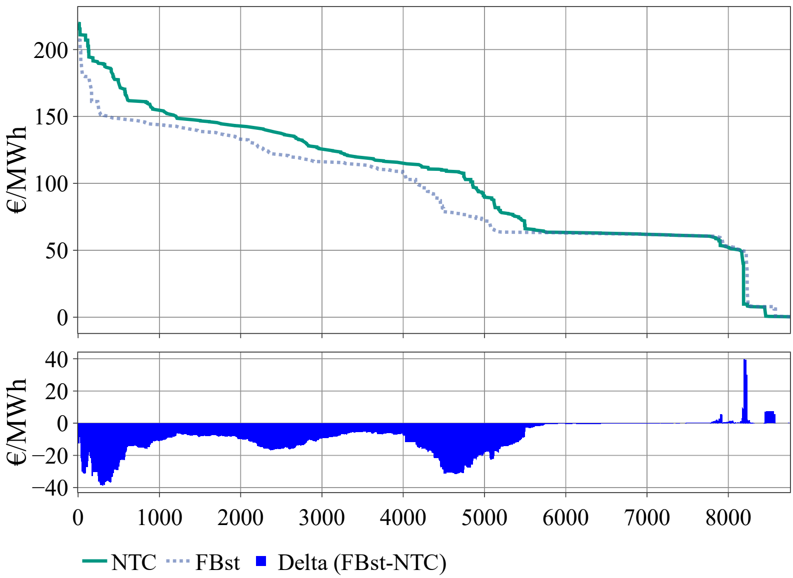


Figure 6.24: Sorted price duration curves (top) for the *NTC* (solid line) and *FBst* (dotted line) variant and price difference between the variants (bottom) for the German bidding zone.

The sorted price duration curves demonstrate how different the price dynamics are in the two variants. Except for the transition from very low prices to around 60 €/MWh, prices below that level are hardly affected. These hours are determined by high renewable feed-in and/or electrolysis dispatch, which sets the price. Given that these technologies are modelled with similar cost/bid levels across the BZNs, different market coupling capacities have little effect on the dispatch dynamics between BZNs. This is very different in the price range above 60 €/MWh, where the conventional merit order starts and the dispatch between regions is optimised given the degrees of freedom from the market coupling. The *FBst* variant allows for consistently lower prices in Germany in these hours, decreasing the prices on average by almost 9 €/MWh.

Furthermore, the number of hours with very high prices above 150 €/MWh is reduced by about two-thirds from more than 1 200 to less than 400.

Reduced prices also allow for higher amounts of electrolysis at or below ~60 €/MWh. In all months except November, December and January, more hydrogen is produced in the *FBst* variant, resulting in an increased electric demand from electrolysis of 3.4 TWh (~7 %).

Main findings

- Market coupling can heavily affect prices and market values. This might arise when NTC constraints do not fit the underlying grid conditions or delays in grid expansions lead to a deviation between assumptions in the price forecast and reality.
- Even in the simulated case with a supposedly matching NTC and FBMC simulation, the static nature of the NTC and the potential differences in the underlying grid state can result in base price differences between 5 % and 10 % throughout the simulated region. Market values (for solar PV) are more heavily affected with differences of up to 56 %.

6.3.4 Grid effects of Flow-based market coupling and dynamic line rating in 2035

Market (price) effects are one side of the story, and while increased exchanges can lead to lower prices and more efficiency in the market domain, the TSOs have to ensure a secure grid operation based on the market outcome. The resulting re-dispatch (and curtailment in the case of renewables) is also highly relevant for the revenue of investors in regulatory/contractual setups where reduced generation leads to decreased revenue. To investigate the impact of FBMC and the contribution that DLR can have on secure grid operation and congestion management, the grid operation is simulated after four market outcomes (described in the next paragraph) in the German transmission grid.

The neighbouring countries are included in the grid topology, but only the German branches are constraining the power flow, so the congestion management measures caused by overloading in the German grid can be identified and quantified.

The first two simulations are based on the market results with scenario NTCs, simulated with static line limits (*NTC-st*[76]) in the OPF and with DLR capped at 150 % of static line capacity (*NTC-dlr*). The grid operation is also simulated with dynamic line rating for market results from the two market model variants analysed above, called *FBst-dlr* and *dynNTCst-dlr*. Figure 6.25 presents the aggregated curtailment, positive re-dispatch and negative re-dispatch volumes from the grid simulations.

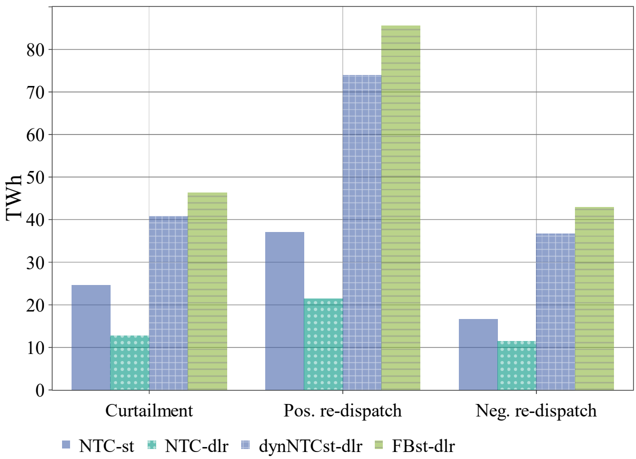


Figure 6.25: Yearly congestion management volumes for the grid simulation after the three market variants (*NTC*, *dynNTCst* and *FBst*). The grid simulation for the NTC variant is performed with static line limits (*NTC-st*) and with DLR (*NTC-dlr*), the other two grid simulations are performed with DLR (*dynNTCst-dlr* and *FBst-dlr*). Curtailment includes hydro generation reduction.

[76] The notation in this section follows the following logic: the part before the dash refers to the market simulation and the one after the dash to the line limits in the grid simulation, static (st) or with dynamic line rating (dlr). For example, *FBst-dlr* refers to a network simulation with dynamic line rating applied based on a market simulation in which FBMC was calculated with static line limits.

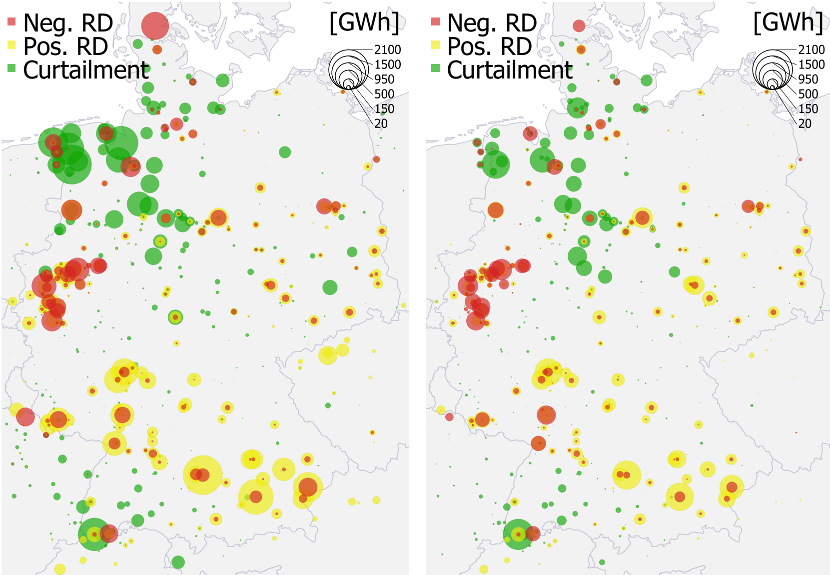
The results show that the welfare gains achieved in the market by the *FBst* and *dynNTCst* variants (compared to the *NTC* variant) come at the cost of increased congestion management volumes. The congestion management yields more than three times as much curtailment for *FBst-dlr* compared to *NTC-dlr*. Positive and negative re-dispatch are increased in a similar manner. For the NTC variants (*NTC-st* and *NTC-dlr*), the activation of the CM measures mainly occurs within the German borders. For the variants *FBst-dlr* and *dynNTCst-dlr* (which induce greater exchange flows), in addition to a similar activation of CM measures within the German grid, foreign resources have to be activated to alleviate transmission grid congestions (see Fig. 6.29). This geographic distance from the overloads also induces an additional cost as the CM measures become less effective. The average (net) cost of re-dispatch increases from ~157 €/MWh in the variant with the lowest amount of CM (*NTC-dlr*) to ~190 €/MWh for *NTC-st*, ~210 €/MWh for *FBst-dlr* and ~214 €/MWh for *dynNTCst-dlr*.

Main findings

- Increased exchanges, which increase welfare in the market domain, lead to additional congestion management needs in the grid operation. With larger CM needs, the CM measures become less effective.
- The application of dynamic line rating can drastically decrease congestion management volumes.

Effect of dynamic line ratings on the congestion management volumes and regional distribution

The positive effect of DLR is clearly visible when comparing *NTC-st* to *NTC-dlr*. Dynamic line rating allows for a reduction in RES curtailment of almost 50 %, while positive re-dispatch is reduced by over 40 % and negative re-dispatch by over 30 %. The benefit for RES integration becomes very clear. Figure 6.26 shows the regional distribution of the aggregated CM measures at the substations of the transmission grid. The reduction in curtailment volumes is most prominent in the North-West of Germany, where less wind power has to be curtailed. Moreover, the activation of CM measures outside of Germany (Denmark, France, Czech Republic and Austria) decreases significantly in the grid simulation with DLR.



(a) Market: NTC, Grid: static limits

(b) Market: NTC, Grid: dynamic limits

Figure 6.26: Aggregated yearly re-dispatch (positive, negative and curtailment) per grid node in GWh after NTC market result with static transmission line limits (*NTC-st*, left) and dynamic overhead line ratings (*NTC-dlr*, right).

Figure 6.27 shows the share of different energy carriers / technologies in congestion management. Given the nature of the scenario, the largest share of re-dispatch (both negative and positive) is accounted for by gas-fired power plants. This technology also shows the largest absolute change in re-dispatch volumes. In addition to re-dispatch of gas-fired power plants and RES curtailment, the amount for positive re-dispatch of coal-fired power plants can be reduced by over 60 % although the absolute decrease is less than one TWh.

In addition to the German power plants that are in grid reserve, the activation of foreign sources is aggregated under 'grid reserve' regardless of the technology.

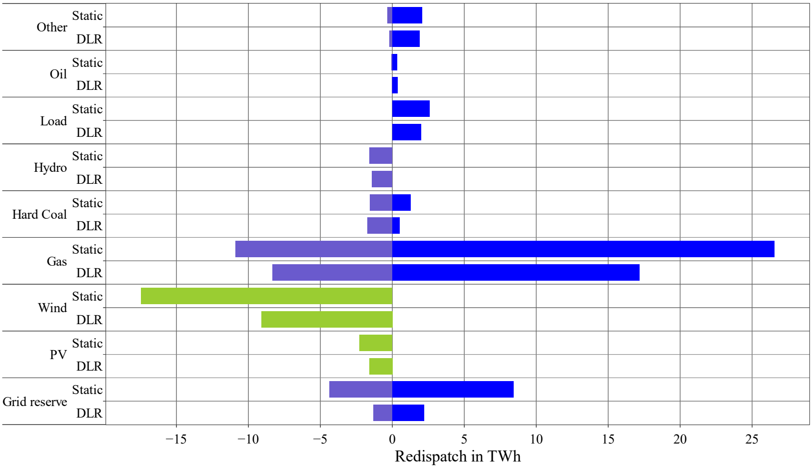


Figure 6.27: Comparison of curtailment and re-dispatch volumes (yearly aggregates) per energy carrier for the congestion management simulations with static line limits (*NTC-st*) and dynamic line rating (*NTC-dlr*) after NTC market run.

The effect of DLR on congestion management volumes is assumed to be greatest during times with strong wind, as the need to transport electricity from wind parks through the grid coincides with the increased cooling effect of higher wind speeds. To verify this, the week with the highest wind power generation in the simulated year is analysed with respect to the CM volumes and their geographic distribution. The results, shown in Fig. 6.28, confirm this hypothesis, since DLR can reduce RES curtailment during the analysed week by almost 60 %. The effect is even stronger for re-dispatch, with the need for positive re-dispatch decreasing by ~64 % and the necessity of negative re-dispatch being almost eliminated at close to -90 %. Another insight from this particular week is that the discrepancy between the NTC variants (*NTC-st* and *NTC-dlr*) and *FBst-dlr* is not consistent throughout the year and apparently narrows during strong wind conditions with respect to RES curtailment. Nevertheless, *FBst-dlr* yields curtailment volumes more than twice as large as those observed in *NTC-dlr*.

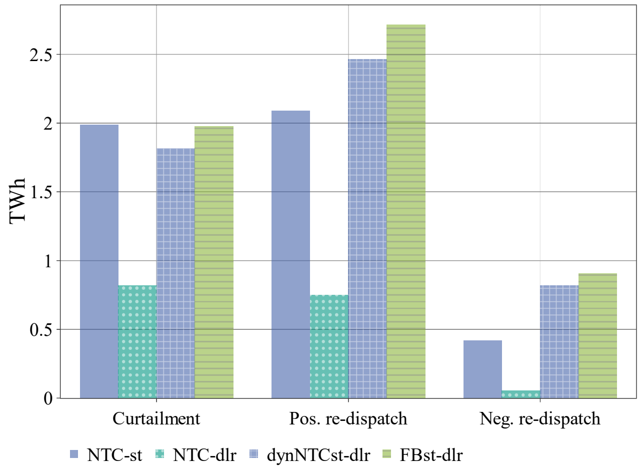
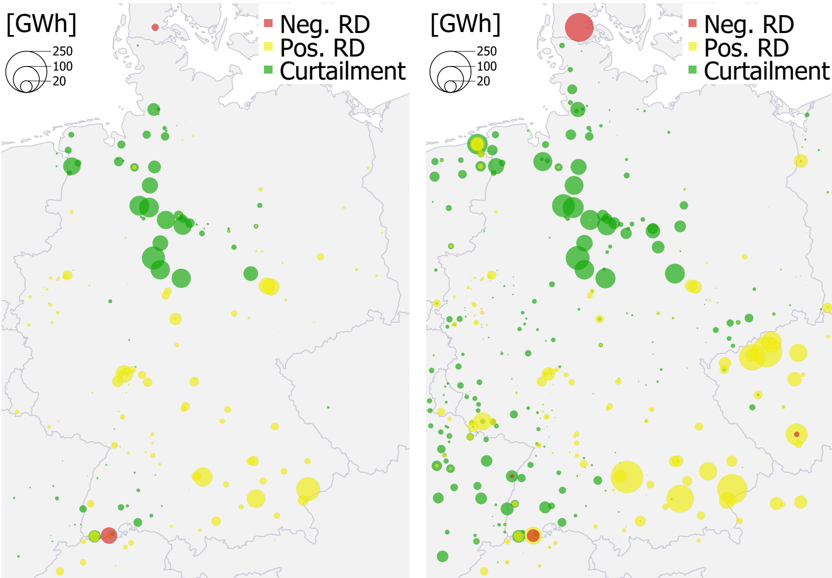


Figure 6.28: Congestion management volumes during a week with strong wind for the different grid simulations.

Analysing the geographical distribution of the CM measures during the week for *NTC-dlr* and *FBst-dlr*, shown in Fig. 6.29, it becomes clear that the remaining congestions are mainly induced by wind generation in central to northern Germany, with the coastal regions showing comparably little curtailment. For *FBst-dlr* in Fig. 6.29b, it appears that some congestions are induced by commercial exchanges, as this variant activates a comparatively large number of foreign CM resources to relieve the German grid of bottlenecks. However, the predominant activation of infeed/generation reduction in the north and activation of additional generation in the south suggest a persisting North-South bottleneck in the German transmission grid in the simulated scenario during situations with strong wind power generation.



(a) Market: NTC, Grid: dynamic limits

(b) Market: FBst, Grid: dynamic limits

Figure 6.29: Aggregated re-dispatch (positive, negative and curtailment) per grid node in GWh for a single week with strong wind generation (*NTC-dlr* vs. *FBst-dlr* both with dynamic line rating applied in the grid simulation).

Main findings

- Dynamic line rating is beneficial for RES integration, reducing curtailment by up to 50 % on a yearly basis. During strong wind conditions, the effect is even more profound.
- In the analysed scenario, a North-South bottleneck remains in the German transmission grid, stressing the need for positive re-dispatch potential in the South.
- Increased exchanges in the market also increase the need for foreign re-dispatch to relieve the German congestions.

Limits of benefits from dynamic line rating for congestion management

The results so far confirm the positive effect of DLR on the congestion management volumes. It remains to be quantified to what extent the conditional increase of the existing grid topology can reduce congestions in the grid and if there are certain levels for DLR above which an additional increase in line capacity is no longer beneficial. To investigate this, the boundary for DLR capacities is increased in discrete steps from 100 % (the static line limit) to 180 % and the resulting curtailment and re-dispatch is quantified. The results are shown for DLR limits of 112 %, 150 % (used in the above calculations with DLR) and 180 % in Fig. 6.30.

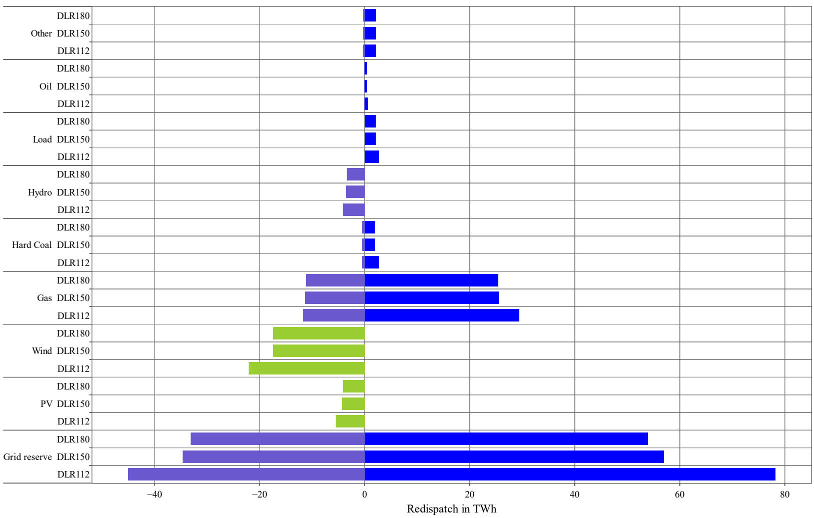


Figure 6.30: Congestion management volumes per energy carrier after *FBst* market run with different DLR limits in the grid simulation. Congestion management at German grid nodes is divided into energy carriers. CM measures outside of Germany are summarised together with the German grid reserve (including foreign RES curtailment).

The congestion management volumes activated within the German transmission grid remain relatively stable above 150 %. In fact, the additional benefit for the integration of renewables gradually decreases, as illustrated by the amount of wind power curtailment: When the maximum DLR value is increased from 120 % to 130 %, the wind curtailment is reduced by ~7 %. For the next step to 140 % maximum capacity, the decrease in the wind curtailment is reduced by ~3.6 % and for a DLR limit increase from 140 % to 150 %, the wind curtailment is reduced by roughly 1.6 % . Moreover, the results show that total volumes of congestion management continue to decrease driven by reduced activation of foreign resources aggregated under 'grid reserve', even above a DLR limit of 150 %.

Main findings

- The results show a decreasing additional effect on curtailment volumes when increasing DLR limits. Increased DLR limits above 150 % of static line limits hardly affect curtailment volumes.

6.3.5 Implications for GHG emissions and profitability of renewable energy sources

Effects on emissions - market and grid

The impact of the different market variants (simulated for 2035) on CO_2 emissions depends on the emission intensity of the energy mix of the different market areas and the emission intensity of the overall energy mix in the respective hour. Figure 6.31 shows the monthly distribution of the emission differences between the *NTC* and *FBst* variants divided into the delta for the BZNs within and outside the Core CCR. In general, emissions in the *FBst* variant are reduced, with a greater effect occurring during the winter months, when the share of fossil generation is greater. Although there is a net emission reduction, the deltas appear in both directions, meaning some BZNs show increased emissions in the *FBst* variant, while others show reduced emissions. For the months May to August, hardly any effect is visible in the BZNs outside the core region. For Germany, the *FBst* variant produces reduced emissions of 7.3 $mtCO_2$, also mainly occurring during the winter months.

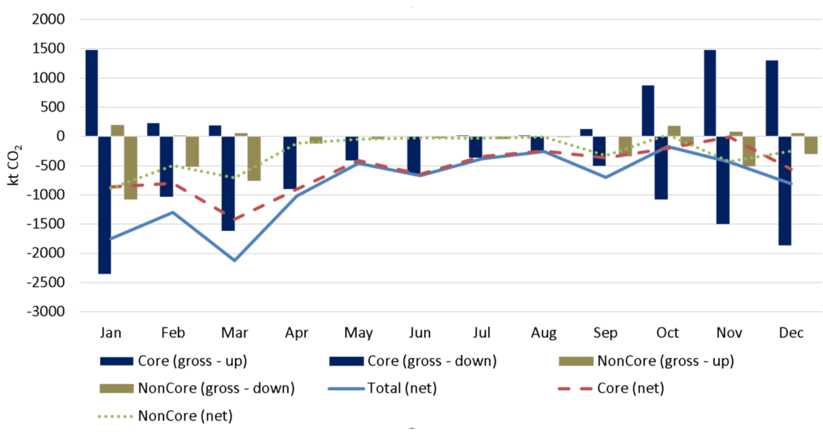


Figure 6.31: Monthly difference in emissions between the *FBst* and *NTC* variants in the market simulation in ktCO_2.

During the CM simulation, curtailed renewable generation is replaced with fossil generation, or out-of-the-money fossil generation (mostly due to lower efficiency) replaces more efficient in-the-money fossil generation. Consequently, all CM simulations produce an increase in CO_2 emissions compared to the market results. However, the extent varies greatly and the location of the source for additional emissions also differs between the model variants. For *NTC-dlr* the CM produces an increase of 3.3 mtCO_2, of which ~88 % occur in the German BZN. For *FBst-dlr*, German emissions increase by ~5.7 mtCO_2. The effect is even more severe for the other BZNs, where in the simulation CM measures can be activated to an unlimited extent to relieve the German transmission grid.

Implications of different curtailment needs for renewable projects

For individual solar PV or wind park projects, the consideration of market coupling can be paramount, as the curtailed share at individual grid nodes can vary drastically. For more than half of the German grid nodes subject to curtailment, FBst-dlr reduces the curtailment volumes, for some even almost completely. But for another roughly 18 % curtailment volumes are increased more than an order of magnitude. Market regulators try to disincentivise RES generation in hours with renewable oversupply (e.g. § 51 EEG, which suspends the remuneration of subsidised RES during continued hours with negative spot market prices). As hours with high renewable infeed tend to coincide with large curtailment needs, this could have a direct impact on the revenue potential of such RES projects analogously in the case of (pay-as-produced) power purchase agreements (PPAs), where the generated energy does not meet the expectations of the parties.

Main findings

- Reduced (German) emissions in the *FBst* variant are partly balanced by re-dispatch within Germany in the grid simulation. However, emissions also occur outside Germany through cross-border re-dispatch necessary to relieve German congestions.
- Locational curtailment needs vary greatly between *NTC-dlr* and *FBst-dlr* variants. Although the overall curtailment need is larger in *FBst-dlr* at more than half of the affected nodes, curtailment is reduced. At other locations, curtailment is drastically increased.

6.3.6 Model complexity

The analyses were performed on a workstation with Intel Core i9-7940X processor and 128 GB of RAM. The models are implemented in Matlab 2022b and solved using Gurobi 10.0.3. This section highlights the characteristics of the problem instances for the market and grid model variants described above.

Model complexity of the market model variants
The long-term storage allocation (LTSA) is run with NTC market coupling and all hours of the year are coupled in a single problem instance. The problem is solved in a little more than 2 hours. The resulting storage values are fixed at the beginning and end of each week and used in the other market model runs. These consist of 53 model instances that can be solved in parallel, the first 52 covering one week each and the last containing only the last

day of the year[77]. Table 6.4 reports the runtime, number of variables, number of linear constraints and number of non-zero coefficients for the original and presolved problems. For the LTSA, where only one instance is solved, the table also contains only one value. For the other model variants, the statistics are reported for the minimum and maximum (in brackets) of the 52 model instances. Also, it should be noted that for the calculation of the FB constraints, additional effort is necessary. To determine the power flows in the base case to assess the remaining available capacity on the lines, a (optimal) power flow has to be solved that has properties similar to the reported grid simulations in the following paragraph (see also Table D.2).

Table 6.4: Characteristics of the solved problem instances for the market simulation.

	LTSA	NTC	dynNTCst	FBst
Runtime [s]	7 350	24 (58)	26 (76)	150 (882)
# Vars	47 093 760	903 168	903 168	898 632
# Lin. constr.	20 279 400	388 920	388 920	984 420 (1 585 090)
# Non-zeros	87 219 343	1 670 206 (1 673 277)	1 663 008 (1 666 035)	11 760 288 (21 976 647)
# Pres. vars	35 281 298	662 169 (677 894)	658 335 (374 312)	743 889 (903 582)
# Pres. lin. constr.	12 374 242	231 117 (237 971)	230 968 (238 846)	323 147 (516 596)
# Pres. non-zeros	63 005 456	1 184 381 (1 213 433)	1 175 902 (1 205 384)	2 572 734 (5 643 253)

The two NTC variants have very similar properties. The *dynNTCst* instances take a little longer to solve (2 297 s over all instances) than the *NTC* instances (2 145 s). Due to parallelisation, the effective time spent for the calculation (including setting up the problem) takes 298 s for *dynNTCst* and 254 s for

[77] As this last problem is significantly smaller than the others it is not contained in the statistics reported in Table 6.4

NTC. The *FBst* problem instances contain slightly fewer variables (bidirectional flow variables are replaced by zonal net export positions) but about three times as many constraints. Although the excess of constraints is reduced much during presolve to around 140 % of the NTC instances, the FB problems are much harder to solve and take between 6 and 11 times as long to solve compared to the NTC variants (the time used to solve all *FBst* instances amounts to 19 778 s). Another factor to consider is memory usage when solving the problems. While the *NTC* and *dynNTCst* variants can be solved in parallel using all CPU cores, this is not possible for the *FBst* variant, which needs much more memory.

Model complexity of grid simulations

The grid simulations described in this section are all solved using the DC formulation of the optimal power flow. The same metrices as for the market simulations above are reported for the grid simulation in Table 6.5[78].

Table 6.5: Characteristics of the solved problem instances for the grid simulation.

	NTC-st	NTC-dlr	dynNTCst	FBst-dlr
Runtime [s]	0.3 (3.9)	0.3 (1.4)	0.3 (1.2)	0.3 (3.2)
# Vars	15 716 (16 041)	15 716 (16 041)	15 655 (16 045)	15 728 (16 046)
# Lin. constr.	6 617 (6 619)	6 617 (6 619)	6 617 (6 619)	6 617 (6 619)
# Non-zeros	32 419 (47 899)	32 419 (47 899)	32 386 (47 907)	32 429 (47 909)
# Pres. vars	6 077 (7 279)	6 077 (7 279)	6 069 (7 266)	6 124 (7 264)
# Pres. lin. constr.	4 785 (4 818)	4 785 (4 818)	4 783 (4 818)	4 789 (4 818)
# Pres. non-zeros	19 088 (25 827)	19 090 (25 827)	19 066 (25 789)	19 174 (25 799)

[78] The variant dynNTCst refers to the *dynNTCst-dlr* variant above, but is abbreviated for reasons of table layout.

As the market results encompass the same scope, the grid simulation instances are all very similar. As described above, inter-temporal constraints are neglected in the grid simulation and therefore, all (8 760) instances can be solved in parallel. Although the time for the fastest instances is the same for all variants, dynamic line rating seems to make the harder instances of the grid simulation also easier, reducing the time spent to solve them by more than 60 %. This is also reflected in the total time necessary to solve all instances, which accounts to 3 935 s for *NTC-st*, 3 783 s for *NTC-dlr*, 3 820 s for *dynNTCst-dlr* and 3 883 for *FBst-dlr*. Comparing this to the resulting congestion management volumes from the simulations, it appears that these metrics are mostly unrelated, although *dynNTCst-dlr* and *FBst-dlr* yield higher CM volumes and take slightly longer to solve than the *NTC-dlr* variant.

Main findings

- The *NTC* and *dynNTCst* market variants have a very similar problem structure. FBMC in the *FBst* variant results in larger and much harder to solve problems. The greatly reduced complexity of the dynNTC approach stresses its value for model-based analyses compared to a full-scale FBMC simulation.
- In the grid simulation, all variants are very similar, DLR seems to make difficult problem instances slightly easier to solve.

6.4 Summary

This chapter presented the scenario-based analysis of the influence of the market coupling regime on key indicators of the wholesale markets, in particular with regard to prices, the profitability of renewables and the grid effects of the different market outcomes. The developed approach allows to determine Flow-based market coupling (FBMC) constraints for future energy systems, to compare the market outcome against NTC market runs and to simulate congestion management (CM) in a subsequent grid simulation.

Backtest of the transmission grid model
In a backtest against the historical CM in the German transmission grid, the developed model for the grid simulation and the data basis, which are essential for determining the FBMC constraints and the necessary re-dispatch and renewables curtailment in the subsequent grid simulation was validated. The simulated congestion management for the year 2016 resulted in volumes for curtailment and negative re-dispatch very closely resembling the historic volumes reported by BNetzA. Moreover, the geographic distribution of line overloads causing adjustments to the market dispatch is also very similar, which further demonstrates the suitability of the developed approach to simulate congestions in the (German) transmission grid. A parameter study showed that the CM volumes are sensitive to the input parameters and data in the grid simulation as well as the system boundaries. In particular, the relaxation of line limits can reduce CM volumes by more than 40 % with ill-chosen penalty costs.

Expansion of the FBMC region
In a scenario for the year 2025, the impact of incorporating minRAM and the extension of the Flow-based region towards the Core capacity calculation region is analysed. As expected, higher lower bounds for trade capacities increase exchange flows and thus enable the increased utilisation of base load power plants, such as nuclear-fired plants. Consequently, French exports increase, when minRAM is increased towards 70 % of line capacity. Analysing the extension of the FB region to Core CCR, prices are mainly affected by the increased exchanges in the interconnected markets. However, not all bidding zones (BZNs) are affected to the same extent. This sheds light on the necessary similarity of the underlying grid state when comparing NTC and FB market simulation.

Implications for revenue potential of RES and flexibility providers
This line of question is addressed in a scenario study for the year 2035, where NTC and FB market coupling are compared calculated from the same grid (expansion) state in a system which already heavily relies on a high share of renewable generation and flexibility providers, like batteries. The results

showed that the developed method to derive dynamic NTCs from the FB results is capable to approximate the FBMC results, within 4 % of the systems generation cost. Differences between NTC and FBMC occur on most days during the midday hours, coinciding with the maximum solar PV generation. As a result, the impact on the market value of solar PV is much larger than for wind onshore or wind offshore and is also greater than the price difference in general (base price). The market value difference ranges from -26 % to 56 %, so the market coupling regime alone could easily determine the profitability of a RES project in a price forecast. The daily price spread, an indication for the profitability of flexibility providers (that arbitrate on a daily basis), is also decreased under FBMC compared to the NTC results. The grid simulations showed that curtailment at individual nodes also differ greatly, with curtailment at some nodes vanishing almost completely, while at other nodes needs increase more than tenfold. With respect to CO_2 emissions, FBMC with additional exchanges promotes the dispatch of low-emission technologies, as these have lower variable costs given the prices of the emission certificates in the scenario. The effect is most profound during the winter month, where comparably many fossil power plants are dispatched, also the decrease is larger in BZNs within Core CCR, but the BZNs outside also profit on a cumulative basis.

7 Conclusion and outlook

This chapter delves into the key aspects of the approach developed for the techno-economic assessment of market coupling regimes in future electricity systems before it evaluates the outcomes from the scenario analyses and draws conclusions from the model results. This is followed by a critical reflection on the necessary simplifications adopted in the approach and the limitations they impose. The chapter concludes by highlighting avenues for further research that could expand on the insights provided by the presented methodology.

7.1 Conclusions

7.1.1 An approach for the techno-economic assessment of market coupling regimes

Against the background of the introduction of flow-based market coupling (FBMC) in Central Western Europe[79] in 2015, the extension to the Core capacity calculation region[80] in summer 2022 and the introduction of minimum capacities by the European regulator, this thesis develops an approach to analyse issues related to market coupling regimes in general, as well as related to FBMC in particular in the future energy system. The detailed modelling

[79] CWE contains the borders of the bidding zones Austria, Belgium, France, Germany-Luxembourg and the Netherlands.

[80] The Core capacity region covers the borders of 12 bidding zones of continental Europe: Austria, Belgium, the Czech Republic, Croatia, France, Germany-Luxembourg, Hungary, the Netherlands, Poland, Romania, Slovakia and Slovenia.

of the derivation of flow-based constraints for market coupling, based on the annual expansion path of the transmission grid of the countries in the Core region, the integration of market-price-sensitive flexibilities, the consideration of (grid) security constraints and finally the possibility to include weather-dependent current ratings for overhead lines are the main features of the approach. The possibility of obtaining endogenous market coupling capacities based on the state of the grid (to simulate FBMC or for the integration in other market models, for example, in [Fin24]) offers a significant improvement in the analysis of future coupled electricity markets.

A zonal market model of 48 European electricity market zones is combined with a high-resolution transmission grid model of the Core region, in which the substations of the extra-high voltage grid represent the geographical resolution. The simulation of wholesale electricity markets serves to determine market prices and market values, which can be used to analyse the economic prospects of investments in (renewable) generation capacity in future markets. The subsequent analysis of congestion management in the transmission grid allows to determine the renewables curtailment, the resulting share of renewables in the electricity mix, the quantification of re-dispatch needs and the resulting cost as well as the effect on emissions through the deviation from the market outcome. Through the combined simulation of market and grid domains, shifts in welfare can be quantified holistically (potential gains in the market domain can be weighed against potential losses in the grid domain). The market coupling is implemented as a linear optimisation problem that enables the optimal allocation of seasonal storages. The flow-based methodology implemented allows for various degrees of freedom, such as the definition of generation shift keys ([Fin18]), coverage of the flow-based region, integration of security constraints, selection criterion of critical network elements and respective outages ([Fin21]), as well as integration of high voltage direct current (HVDC) interconnectors into the allocation process. The simulation of grid operation involves either the linearised formulation or the non-linear and non-convex optimisation of the AC optimal power flow for the simulation of congestion management in the transmission grid.

The approach is based on a highly detailed expansion planning model chain for renewable energy sources at the Institute for Industrial Production (IIP), with which location-specific optimised expansion decisions are simulated to map the achievement of political goals. The generation simulation methodology was extended so that the ERA5 [Her23] meteorological reanalysis data from the European Centre for Medium-Range Weather Forecasts (ECMWF) can be used, which allows to simulate and analyse PV and wind generation for the historical (hourly) weather conditions of over 80 historical years (between 1940 and today). Furthermore, the same data basis makes it possible to analyse the associated temperature-dependent demand time series. A special feature of the model is the ability to derive weather-dependent capacities for individual overhead lines across the transmission grid and integrate these into the FBMC and the grid simulation. The proposed methodology for deriving dynamic bidirectional exchange capacities makes it possible to integrate the transmission capacities derived from the model into other electricity market models or to quickly analyse related issues within a framework scenario with reduced computational burden.

Furthermore, an elaborately collected data base is established, in particular with regard to the topology of the electricity transmission grid, which contains annual (de)commissioning information for individual expansion projects. The market model also includes over 2000 thermal power plant units, for which the geographical location in the transmission grid is stored, complemented by technological and economic parameters. In addition to pumped hydro storage power plants, utility-sized battery storage systems and home storage systems, the modelled (demand-side) flexibility also includes electric mobility (load-shifting potential and vehicle-to-grid), explicit demand response capacity-price bands, the price-sensitive dispatch of electrolysers for hydrogen production and the price-sensitive shifting potential of demand from heat pumps. Due to the scope of the modelling approach, some simplifications are necessary, which are discussed in more detail in Section 7.2.

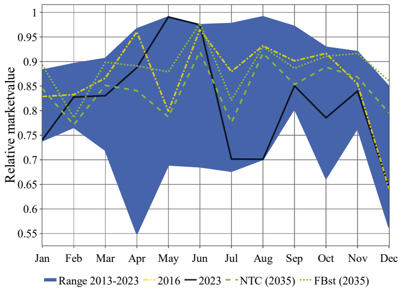
7.1.2 Conclusions from the model-based scenario analysis

Implications for the revenue prospects of renewable energy sources
In market studies, where the variation of demand and renewable infeed make the consideration of an hourly simulation necessary to draw conclusions on market prices, profitability, etc., market coupling constraints should not be the exception. In fact, while generation mix, fuel and emission prices have the greatest effect on market values (of renewable energy sources) [Win16], the results in this thesis show that the impact of market coupling is also of significance. The influence on the generation mix (and thus the market price) is one thing affected by market coupling, but beyond that, the capture rates (the share of the base price that renewables are capable of earning) are different between the modelled variants. This implies the importance of the market coupling regime for the economic prospects of renewables that surpass the simple effect on wholesale market prices.

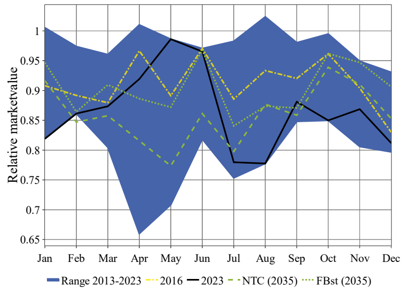
In the model results, the use of time-variant bidirectional exchange capacities is able to much better approximate the FBMC results than static capacities that are applied throughout the year. This is in particular true when the underlying grid state used for the calculation of static bidirectional limits and flow-based limits is different. In case of such a difference, high deviations in the base price and even larger deviations in the market values of renewable energy sources are observed. For an exemplary solar PV project in the bidding zone with the largest decrease in the market value (26 %), the difference in (yearly) return could amount to roughly 5 % of the initial investment and decide the economic viability of the project.

These results demonstrate that the grid state should be considered a relevant uncertainty in the analysis of future energy markets. Furthermore, the fact that bidding zones are unequally affected by price differences suggests that investors should diversify their projects between different market zones. This would allow market participants to mitigate risks resulting from delays in grid expansion or uncertainty in the market coupling method in the analyses of future revenue potentials.

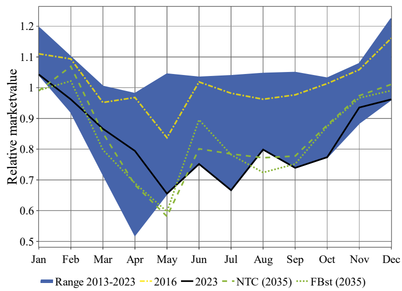
To put the simulated capture rates for 2035 into perspective, Fig. 7.1 compares them against the historical monthly capture rates for solar PV, wind onshore and wind offshore in Germany between 2013 and November 2023. The graph shows that the simulated capture rates for all technologies are within the historically observed ranges. This surprising stability (given the strong expansion of renewable energy sources in the scenario) is due to the extensive market availability of new (electric) applications and (decentral) storage systems, also discussed in the following section.



(a) Wind onshore



(b) Wind offshore



(c) Solar PV

Figure 7.1: Historical and modelled values of the relative monthly market values of renewable technologies in Germany. The filled area shows the range of monthly minima and maxima between 2013 and 2023. The values for 2023 are shown in black (solid line), and the values for 2016 (the weather year in the model runs) are shown in yellow (dash-dotted line). The model results are shown for the variants *NTC* (green, dashed line) and *FBst* (green, dotted line) in the year 2035.

Dynamic line rating in future capacity allocation and congestion management

Dynamic line rating, the weather-dependent determination of the current limits for bare overhead lines, represents great potential for the better utilisation of (existing) transmission infrastructure. It offers a relatively quick and inexpensive opportunity to increase transmission capacity. This can be either allocated (partly) during market coupling or during the subsequent grid operation. In the scenario analysis, both are analysed, and the results show that the effect during grid operations is much larger than during market coupling. In fact, with respect to the cumulative generation cost in the market clearing, the results between the FBMC variants with and without dynamic limits are almost indistinguishable. This is in stark contrast to the grid simulations that exhibit a profound effect of dynamic line rating, especially with regard to the necessary amount of renewables curtailment. Indeed, renewables curtailment volumes can be reduced by almost 50 % on a yearly basis when dynamic line rating is widely applied in the transmission grid. The effect is even stronger during weather conditions with high wind speeds. During a week with strong wind (generation) almost 60 % of curtailment can be avoided, which exhibits the potential of dynamic line rating in the congestion management.

Moreover, this impressively demonstrates the potential suitability to reduce grid expansion needs, especially in grids characterised by high shares of wind power, as transmission needs coincide with dynamically increased capacities. Based on the model results, the preference for the use of dynamic transmission capacities should clearly be on grid operation and congestion management rather than increasing capacities for market coupling. This is especially so, as the model results also show that increased exchange flows in the market cause additional congestions, reducing the welfare gains they enable in the market, and these welfare losses are borne exclusively by consumers.

Furthermore, congestion management is simulated for different maximum levels of dynamic line rating. These results show that the additional benefit gradually decreases. Above 150 % of static line limits no additional reduction of renewable curtailment can be observed, although the overall volumes of congestion management continue to decline. This is also the maximum value applied by the four German TSOs in the grid expansion guidelines [50H22b].

Minimum capacities and scope of the flow-based region
The introduction of minimum capacities increases the possible exchange flows in the market. Beginning in 2026, the Core TSOs have to make available 70 % of the line capacities (of lines relevant for market coupling) for exchanges. The effect of this increase is investigated in a simulation for the Central Western Europe and Core capacity calculation region. The increased minimum capacities lead to higher price convergence between the regions, in particular, the prices in cheaper regions are increased and reduced in higher-priced regions. The market coupling also affects the energy mix and enables a higher use of base load power plants in the investigated case, especially of French nuclear power plants. The model results show that up to 10 TWh of low emission electricity can be additionally exported from France and replace fossil generation in other bidding zones, demonstrating the impact the market coupling can have on power generation-related emissions. The extension of the region where FBMC is applied from Central Western Europe to the Core region shows a similar effect to the bidding zones in Western Europe as the increased minimum capacities. Consumers in the newly added bidding zones in Eastern Europe and also in neighbouring bidding zones outside of the flow-based market coupling regime profit on average from lower electricity prices, whereas for the Nordic markets the change is marginal.

The model results also show that increased exchanges in the markets lead to more re-dispatch needs. The expansion of the flow-based area to the Core capacity calculation region introduced a common capacity allocation method to most of the bidding zones in Continental Europe that is capable of taking into account the meshed reality of European transmission grids. However, increased exchanges (made possible by the common market coupling regime) in addition to the minimum exchange capacities can increase the need for congestion management. In particular, this is the case in hours with high renewable energy infeed, when, due to the location of these generators (often far away from the demand), the transmission needs are already high and further increased through commercial flows. The different paces of renewable expansion and electrification on the demand side in the European countries and delays in grid expansion causing internal congestions in the bidding zones can exacerbate the issue when (already) too much green energy can (in the market domain) be transported to other bidding zones, but leads to additional physical congestion inside the borders of the bidding zones.

In any case, the transition to more renewable energy and less thermal power plants under increased market integration will make coordination between TSOs for securing the grid operation more important. This is exhibited by the model results, where for the congestion management of the German transmission grid, re-dispatch resources in the southern neighbouring countries are needed on a regular basis in addition to the German re-dispatch potential. The need for such cross-border re-dispatch is much higher in the FBMC simulations that employ minRAM and enable higher exchanges.

Conclusions for an effective market design

The (relative) high market values of renewable energy technologies observed in the model results are mainly attributed to extensive price-following dispatch of flexibility providers. This includes utility-size battery storages but also decentral flexibilities such as home storages, electric vehicles or load shifting from heat pumps. It is thus important to create incentives and conditions that allow this flexibility to be utilised in the electricity markets. Under current conditions, market-based investments into (utility-size) storages are viable; for example, in Germany the *Marktstammdatenregister* lists planned battery storage projects that would double the installed capacity in early 2024 in roughly two years. This might also be due to the exemption from network charges for storages that are commissioned before 4 August 2026, which was recently prolonged until 2029. While storage investments foster the economic viability of renewables and thus contribute to a successful energy transition, such regulatory exceptions might be economically sensible but should be checked regularly to enable fair competition. As future wholesale price patterns are characterised by solar PV generation at most times of the year, locational incentives for storage construction in areas of the grid with large PV capacity could also be worth investigating, as the market-based dispatch might be able to relieve (distribution) grids of some stress during noon and in the best case reduce expansion needs. §11a EnWG enables the German distribution system operators to incentivise the construction of energy storages in this way.

In light of the demonstrated re-dispatch needs for Germany in the simulated year 2035, positive re-dispatch is predominantly necessary in the south of Germany. When the German regulator Bundesnetzagentur confirmed the German grid development plan for the year 2037, the analysis showed that even if all the proposed expansion measured were confirmed, there would still remain congestions in the German grid (see also Fig. 1.2). This underlines the case for an efficient bidding zone design or to include locational elements in the planned investment incentives for hydrogen(-ready) power plants and the capacity mechanism also discussed in [Sch23a], such that transmission bottlenecks can also be addressed from the generation side and sufficient (domestic) re-dispatch potential is available.

Addressing the interdependencies between capacity calculation (for market coupling) and congestion management (in grid operation), the results show that larger exchange capacities induced through minimum trading capacities also increase congestion management needs in the grid operation, in line with findings in the literature [Mat19], [Sch21a], [Buc24]. While the balance between welfare gains (in the markets) and welfare losses (in the grid) is not quantified in its entirety in this thesis, the exact effects will also depend on the degree of coordination between TSOs for (cross-border) re-dispatch. Furthermore, the market domain exhibits gains and losses in welfare for producers as well as consumers while welfare losses in the grid domain are always imposed on the consumers. In the scenario of enduring bottlenecks within the transmission grid, the prioritisation of preferences between the two remains a responsibility for political decision makers. To address this challenge, one solution might be to introduce a more flexible market design in Europe with a mix of zonal and local elements that include suitably locational transmission charges in bidding zones with serious transmission constraints or subject to large transit flows [New18].

7.2 Critical appraisal

The presented model framework makes extensive use of vast (external) data sets. Although the availability and quality of these data sets have increased dramatically in recent years, naturally some limitations arise. The balance between scope and (pseudo-)accuracy is a theme that runs through all areas of this work and which always represents a trade-off that cannot be fully resolved.

7.2.1 Scope vs. level of detail

Given the European scope of the model and thousands of power plant units and transmission grid lines, the lack of comprehensive sources presents a major challenge. This is amplified by the transitional nature of these data, with national policies in the more than 40 modelled bidding zones rapidly changing and adapting to the challenge of emission reduction and geopolitical crisis. To overcome this challenge, the thesis is heavily based on consistent framework studies such as the Ten-Year Network Development Plan (TYNDP), European Resource Adequacy Assessment (ERAA) and for Germany the grid development plan. With regard to RES expansion, the thesis is built on the existing model-ecosystem at Institute for Industrial Production (IIP), which provides very detailed (techno-economic and spatial) RES expansion planning. However, expansion decisions are based on levelised cost of electricity (LCOE) constrained by national goals and, in the case of wind offshore, explicit designated areas and grid connections. In the case of solar PV and wind onshore, this may not always be in line with the observed investment behaviour in the markets.

7.2.2 Simplifications in the market domain

The foundation of pricing in the market is the assumption of very high competition in the markets, which results in (short-term variable) cost-based bids of generators. This neglects agents' strategic behaviour that might occur in the market or the realisation of scarcity rents in hours with little free capacity. It also neglects the actual cost that occurs for start-up and shut-down procedures, although these constraints are relaxed through a temporal resolution of one hour. The temporal resolution itself poses another limitation of the model. While today's market liquidity is focused in the day-ahead markets (which mostly have an hourly resolution), this most likely will shift to market segments closer to real time with smaller time slices to better account for gradients in weather-dependent generation. Given the temporal resolution of the underlying weather data of one hour, this is more a data-related necessity than a modelling choice. The issue is amplified regarding the temporal resolution of climate simulations, which migth be interesting to investigate in future studies, which often only provide 3-hourly averages. Apart from memory constraints, there is no rational that restricts an adaption of smaller time slices in the modelling framework. The parallelisation approach could be easily adopted to account for the emerging challenge. The central clearing in one market segment could be seen as another weakness of the developed framework. However, forecasting the share of, e.g., day-ahead vs. intraday markets in the future is hardly possible and, given the perfect foresight in the modelling framework, would not result in additional insights. However, the approach of perfect foresight, which applies for RES generation and load, is a factor that could be addressed as it tends to overestimate the effect that energy storages and other flexibility providers might have on the smoothing of (residual) demand and prices. Finally, the economic feasibility of the scenario (generation) capacities is not challenged, which, in combination with the cost-based bidding, could lead to inconsistent results. This is clearly a limitation of the market model, which is hard to overcome. However, the magnitude of the potential problem can be easily quantified by analysing the feasibility of existing power plants given the market revenues. Given the support schemes for renewables in many countries and also spreading capacity mechanisms to support firm capacity, questioning the scenario capacities might become less relevant as long as one assumes the support mechanisms to be effective.

7.2.3 Simplifications in FBMC

With regard to FBMC, the developed modelled framework is among the most comprehensive found in the literature. Still, there are some limitations, which are discussed below. A challenge that affects all integrated models is the determination of Generation Shift Keys (GSKs). While the necessity for GSKs in practice arises from the information deficit that TSOs have when calculating the FB constraints, simulation frameworks have complete information about the merit order in the market. Thus, GSKs introduce unnecessary inadequacy in the modelling. As these cannot be based on extensive offline studies as in reality where the actual dispatch can be compared with the Day-Ahead Congestion Forecast (DACF), modelling frameworks including the present one have to rely on generic methods, which in the case of this thesis are chosen to one generic approach across bidding zones. This might result in an over- or underestimation of the error in dispatch estimation compared to practice. To at least get an indication of how large the resulting estimation error is, the outcome could be compared in future research to a linearised optimal power flow (DCOPF) simulation that includes the same grid elements and contingencies as the FB simulation. A similar limitation is true for the identification of contingencies. However, this is amplified by the simplified representation of the grid topology (one bus per voltage level and substation). Given the already heavy computational burden of the time-coupled FBMC, this is hard to overcome in the simulated European system but could be addressed in studies of systems with smaller geographical and temporal scope. Finally, the use of remedial actions by TSOs is not included in the presented approach. However, given the amount of congestion management (CM) in the grid simulations following the FBMC, this lower bound to the impact of FBMC seems rather appropriate also considering that existing additional constraints on the Single Day-Ahead Coupling (SDAC) as in [ENT23b] regarding ramping constraints or Net (Export) Position (NP) limits are not considered.

7.2.4 Limitations of the grid simulation

As the grid simulation is based on the same data as the FBMC, the same restrictions apply with respect to topology simplification. Regarding the simulation of a European congestion management, another challenge arises. Given the additional stress that the transmission infrastructure will experience in the coming years, it is probable that CM measures will become necessary in more and more control zones. While a coordinated congestion management might minimise overall expenses, the national legal framework limit the effectiveness of cross-border re-dispatch coordination. To avoid this issue, the analyses in this work focus on the isolated simulation of the German CM. The grid simulation itself is intended as an indicative analysis and thus much less sophisticated than existing approaches in the literature[81]. The single hours are solved individually neglecting time-coupling constraints which might restrict the possible re-dispatch of single units and might lead to an underestimation of CM measures as the flexibility and/or availability of single resources is overestimated. Regarding the inclusion of Dynamic Line Rating (DLR), the limited spatial and temporal resolution of the underlying weather information could lead to an overestimation of the available flow limits. However, conditions worse than the average values used might be limited in temporal occurrence and thus in line with short-term tolerances of technical resources.

7.3 Application of the developed framework for further research

Besides the presented analyses, the developed framework can be used in further research. The possibility to derive Flow-based market coupling constraints based on the underlying grid conditions offers the possibility of investigating bidding zone splits, as the assignment of grid nodes to the new sub-zones directly results in the calculation of adequate exchange capacities for the market simulation. In addition, exchange capacities can be calculated

[81] See e.g. [Cap11] for an overview of existing approaches

in delayed grid expansion scenarios, which might become more and more important in evaluating investment projects in future markets. The developed approach to derive dynamic NTCs offers the potential to integrate the calculated exchange capacities also into other market models which, for instance, allow the simulation of agent-based investment or bidding behaviour. One such application has already been demonstrated within the VERMEER project with the AMIRIS market model [Fin24]. Finally, the evolved FB methodology allows also for the integration of DC-coupled offshore bidding zones, where offshore hubs consisting of wind generation and potential electrolysis are no longer integrated to the 'home bidding zone' where they are electrically connected to, but rather form their own bidding zone in an integrated HVDC grid in the North Sea, as e.g. forseen by [50H22a].

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List of Figures

List of Tables

Acronyms

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automated Frequency Restoration Reserve
ALPACA	Allocation of Cross-zonal Capacity and Procurement of aFRR Cooperation Agreement
ATC	Available Transfer Capacity
BDEW	Bundesverband der Energie- und Wasserwirtschaft
BNetzA	Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen
BZN	Bidding Zone
CA	Capacity Allocation
CCGT	Combined Cycle Gas Turbine
CCR	Capacity Calculation Region
CEE	Central Eastern Europe
CEGH VTP	Central Europe Gas Hub Virtual Trading Point
CEP	Clean energy for all Europeans package
CHP	Combined Heat and Power
CM	congestion management
CME	Chicago Mercantile Exchange
CNE	Critical Network Element
CNEC	Critical Network Element under a Contingency

CWE	Central Western Europe
CZ VTP	Czech Virtual Trading Point
DC	Direct Current
DLR	Dynamic Line Rating
DSO	Distribution System Operator
DWD	German Weather Service
ECMWF	European Centre for Medium-Range Weather Forecasts
EDF	Électricité de France
EEG	Erneuerbare-Energien-Gesetz
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energiewirtschaftsgesetz
ERAA	European Resource Adequacy Assessment
ESA	Euroatom Supply Agency
ETF	Exchange Transfer Facility
EU ETS	European Union Emission Trading System
EUA	European Union Allowances
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FAV	Final Adjustment Value
FB	Flow-based
FBMC	Flow-based market coupling
FCA	Forward Capacity Allocation
FCR	Frequency Containment Reserve
FRM	Flow Reliability Margin
GEM	Global Energy Monitor

GSK	Generation Shift Key
HighResO	HighResO
HVDC	High-Voltage Direct Current
ICE	Intercontinental Exchange
IEA	International Energy Agency
IGCC	International Grid Control Cooperation
IIP	Institute for Industrial Production
IMF	International Monetary Fund
IN	Imbalance Netting
ISK	Injection Shift Key
ISO	Independent System Operator
JAO	Joint Allocation Office
LCOE	Levelised Cost Of Electricity
LMP	Locational Marginal Price
LNG	Liquified Natural Gas
LODF	Line Outage Distribution Factor
MAF	Mid Term Adequacy Forecast
MARI	Manually Activated Reserve Initiative
MaStR	Marktstammdatenregister
mFRR	Manually Frequency Restoration Reserve
minRAM	Minimum Remaining Available Margin
NABEG	Netzausbaubeschleunigungsgesetz Übertragungsnetz
NBP	National Balancing Point
NDP	National Grid Development Plan
NEMO	Nominated Electricity Market Operator
NEP	German Grid Development Plan

NP	Net (Export) Position
NTC	Net Transfer Capacity
NWP	Numerical Weather Prediction
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
OPF	Optimal Power Flow
OSM	Open Street Map
OTC	Over-The-Counter
OTDF	Outage Transfer Distribution Factor
PCR	Price Coupling of Regions
PEG	Point d'échange de gaz
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PJM	Pennsylvania-New Jersey-Maryland
PSV	Punto di Scambio Virtuale
PTDF	Power Transfer Distribution Factor
pu	per-unit
PUN	Prezzo Unico Nazionale
RAM	Remaining Available Margin
RES	Renewable Energy Sources
RR	Replacement Reserves
RTO	Regional Transmission Organisation
SDAC	Single Day-Ahead Coupling
SIDC	Single Intra-Day Coupling
TERRE	Trans-European Replacement Reserves Exchange
THE	Trading Hub Europe

TSO	Transmission System Operator
TTF	Title Transfer Facility
TYNDP	Ten-Year Network Development Plan
V2G	Vehicle-to-Grid
WEO	World Energy Outlook
WEPP	World Electricity Power Plants data base
XBID	Cross Border Intraday
ZEE	Zeebrugge Hub
ZTP	Zeebrugge Trading Point

A Additional model parameters

A.1 Additional power plant information

The life time assumptions for the different power plant types are shown in Table A.1.

Table A.1: Lifetime Assumptions for different power plant technologies.

Power plant type	Life time
Bio	40[82]
CCGT	35
Coal-fired	45
Gas-fired (conventional)	45
Hydro reservoir	99[83]
Hydro run-of-rover	99[83]
ICE	30
Lignite	45
Nuclear	60
OCGT	50

Continued on next page.

[82] Bio power plants are modelled in two ways. One is the retrofitting of coal-fired power plants where the life time is considered, the other beeing generic small biomass or biogas plants, which are assumed in the capacity stated in the scenario without explicit life-time assumption.

[83] Hydro reservoir, Hydro run-of-river, solar PV and wind power plants are modelled on an aggregated level in the market model. As such they dont have a life time assumption, but are rather modelled with a capacity provided in the scenario.

Power plant type	Life time
Oil	45
Other	50
PHS	99
solar PV	30[83]
Wind Offshore	30[83]
Wind Onshore	30[83]

A.2 Standard parameters for flexibility

Standard parameter for (demand) flexibility modelled as storage are shown in Table A.2.

Table A.2: Standard assumptions for demand flexibility.

Flexibility	Flexible share of profile	Time window in which demand can be shifted
Heat pumps (households)	0.1	4
Heat pumps (district heating)	0.5	12
EV charging (at home/work)	0.1	4
EV charging (fast charging)	0.1	4
Industry	0	-
Explicit DSR	100	24
Run-of-river plants	100	168
Utility-size batteries	100	168
Prosumer batteries	100	168
PHS plants (with natural inflow)	100	168
PHS plants (w/o natural inflow)	100	168
Hydero reservoir plants	100	168

Continued on next page.

Flexibility	Flexible share of profile	Time window in which demand can be shifted [h]
Concentrated solar thermal		
(with storage[84])	100	168

A.3 Additional assumptions for V2G

To derive constraints for the equivalent storage as which V2G is modelled in the market model, additional assumptions have to be made. At any given time, a minimum and maximum share of the V2G potential is assumed to be available to the market. These parameter depend largely on assumptions regarding ease-of-use of the service for consumers and incentives to participate and also the technical possibility to be connected to the grid and the readiness of the vehicles owners to connect it to the grid and possible constraints they can impose on the use by e.g. aggregators, who will market the flexibility on the spot markets. This is also true for the capacity with which energy can be taken from and feed back into the grid depending on the mode of grid connection. The available energy will depend largely on the size of the battery installed in the vehicles and personal preferences of the owner regarding minimum SOC. The standard parameters are shown in Table A.3. As the vast majority of EVs are assumed to be passenger cars which are known to be parked for the majority of their lifetime and the availability of the other categories is not easily assumed, the V2G potential is derived based on the passenger cars only.

Table A.3: Standard parameters for V2G.

Parameter	Value
Max Avail	0.75

Continued on next page.

[84] Standard assumption for CSP storage capacity is 14 hours.

Parameter	Value
Min Avail	0.5
Max charge/discharge	11 kW
Battery size	75 kWh
Battery available	0.6

B Additional input data for the scenarios

B.1 Scenario 2025

Table B.1 lists the fuel prices for the scenario 2025 in euros per MWh (lower heating value).

Table B.1: Fuel prices for scenario 2025.

Fuel	Price [€/MWh]
Coal	11.1
Fuel oil	3.2
Gas	29.8
Gas oil	3.2
Lignite	3.2
Uran	3.2

The CO_2 price is 29.6 €/tCO_2.

B.2 Scenario 2035

Table B.2 lists the fuel prices for the scenario 2025 in euros per MWh (lower heating value).

Table B.2: Fuel prices for scenario 2035.

Fuel	Price [€/MWh]
Coal	9.2
Fuel oil	44.2
Gas	31.4
Gas oil	52.4
Lignite	9
Uran	2.36

The CO_2 price is 171.3 €/tCO_2.

C Additional market results

C.1 Simulated prices in 2035

Table C.1 shows the average yearly wholesale price (Base), market values for solar PV (PV), wind onshore (WOn) and wind offshore (WOff) for the three model variants *FBst*, *dynNTCst* and *NTC* for all modelled bidding zones.

Table C.1: Simulated prices in scenario 2035.

	FBst				dynNTCst				NTC			
BZN	Base	PV	WOn	WOff	Base	PV	WOn	WOff	Base	PV	WOn	WOff
AL	72.79	40.34	60.05		73.6	40.82	60.92		75.18	42.81	58.84	
AT	93.46	70.85	91.47		94.41	71.86	92.5		101.03	76.05	98.26	
BA	91.82	71.24	84.62		92.88	73.44	86.09		91.83	76.28	77.8	
BE	93.36	67.83	88.09	87.44	92.91	67.34	87.16	86.53	97.34	70.79	86.28	85.56
BG	74.66	33.84	76.71		75.43	34.76	77.3		76	35.85	74.56	
CH	93.55	72.26	86.03		93.59	72.57	86.49		98.88	78.36	99.7	
CZ	93.35	67.31	88.83		95.49	70.31	91.36		114.06	88.86	106.21	
Corse	90.31	62.88	74.48		90.34	62.9	74.52		90.93	62.92	75.17	
DE	93.37	66.03	86.29	87.28	92.87	65.46	85.41	86.38	102.18	73.37	89.49	91.09
DK1	72.14	48.25	58.06	57.59	71.99	48.13	57.95	57.38	75.33	51.56	58.54	57.78
DK2	73.92	50.62	60.72	59.75	73.69	50.3	60.46	59.5	79.84	54.86	63.46	62.26
EE	70.9	63.5	48.66	51.94	70.87	63.51	48.62	51.91	74.07	68	50.41	53.74
ES	71.12	39.23	57.01	63.93	70.94	39.04	56.82	63.77	63.99	32.29	49.02	56.77
FI	71.35	62.4	45.54	49.37	71.21	62.37	45.39	49.2	74.53	67.14	47.13	51.05
FR	93.32	71.2	89.7	90.39	92.72	70.62	88.72	89.47	76.89	45.74	66.56	68.68

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	FBst				dynNTCst				NTC			
	Base	PV	WOn	WOff	Base	PV	WOn	WOff	Base	PV	WOn	WOff
BZN												
GB	102.92	86.94	93.85	93.99	102.39	86.76	93.03	93.1	103.43	88.15	90.65	90.95
GR	65.82	21.65	59.67	62.23	66.2	22.01	59.93	62.54	67	22.93	60.09	62.85
HR	93.34	71.3	92.23		94.22	73.31	92.93		98.26	77.9	89.05	
HU	93.34	69.62	93.24		94.36	71.62	93.84		99.73	75.47	92.63	
IE	71.87	69.02	45.86	47.33	71.64	68.85	45.67	47.16	70.62	67.79	43.95	45.31
IT_CA	60.82	39.22	42		60.8	39.27	42		61.36	39.73	41.53	
IT_CN	81.61	48.23	72.96	80.84	81.64	48.28	72.98	80.88	82.91	48.25	73.99	81.94
IT_CS	65.29	42.86	38.02	58.27	65.3	42.92	38.04	58.33	65.74	43.11	37.37	58.23
IT_N	97.46	65.59	99.54	104.17	97.48	65.72	99.62	103.98	97.96	62.17	100.58	105.17
IT_S	60.82	38.9	27.98	38.55	60.8	38.96	27.98	38.55	61.36	39.41	27.92	38.72
IT_SA	66.87	50.64	32.16	30.86	66.86	50.65	32.16	30.85	66.99	50.46	32.03	30.82
IT_SI	48.26	15.17	25.25	26.54	48.26	15.18	25.26	26.54	49.16	15.66	25.92	27.27
LT	76.94	68.28	57.37	61.37	76.88	68.11	57.31	61.26	82.28	72.72	60.09	63.9
LV	72.47	66.2	51.78	56.46	72.43	66.15	51.76	56.41	76	69.99	53.55	58.46
ME	75.78	48.46	65.9		76.52	48.92	66.61		77.65	50.42	62.8	
MK	68.71	24.97	66.8		69.29	25.44	67.21		70.49	26.56	66.54	
NIE	70.13	68.29	43.16	48.46	69.92	68.01	42.97	48.19	69.3	67.05	41.57	46.88
NL	93.37	67.06	86.39	86.9	92.89	66.6	85.29	85.81	94.5	68.46	80.17	80.35

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	FBst				dynNTCst				NTC			
	Base	**PV**	**WOn**	**WOff**	**Base**	**PV**	**WOn**	**WOff**	**Base**	**PV**	**WOn**	**WOff**
BZN												
NO1	84.98	66.2	85.23	86.54	84.79	66.2	85.03	86.32	87.65	70.75	86.57	88.98
NO2	84.98	66.81	89.09	84.83	84.79	66.8	88.78	84.62	87.65	71.53	90.11	87.08
NO3	74.31	59.12	81.03		73.91	59.06	80.39		79.8	66.81	84.38	
NO4	81.89	67.75	84.98		81.52	67.85	84.44		87.79	76.38	89.84	
NO5	84.98	65.18	88.57	86.39	84.79	65.15	88.23	86.2	87.65	70.1	88.9	87.67
PL	119.74	122.9	84.52	92.53	119.93	123.01	84.84	92.85	120.76	123.68	85.1	93.64
PT	62.45	35.8	50.83	52.86	62.15	35.55	50.47	52.58	57.25	30.24	46.34	48.25
RO	93.34	71.63	98.89		94.27	73.76	99.12		87.93	70.14	81.5	
RS	93.11	71.93	94.3		94.15	74.11	95.47		92.27	76.25	85.76	
SE1	71.09	61.33	65.2	69.86	70.25	59.97	64.5	69.01	76.01	67.26	67.87	74.33
SE2	69.45	56.47	62.18	60.45	68.88	56.03	61.7	59.99	74.45	62.31	65.14	63.18
SE3	75.3	59.46	65.45	61.03	74.8	59.03	65.12	60.72	79.63	64.92	68.17	63.37
SE4	78.28	59.6	65.87	64.19	77.69	59.1	65.17	63.3	84.42	64.76	68.75	66.34
SI	93.34	70.58	86.45		94.41	71.72	89.16		98.89	76.82	86.23	
SK	93.34	68.02	92.72		95.7	72.69	94.51		114.7	92.32	112.13	

D Additional grid results

D.1 Grid back test parameter study

Table D.1: Congestion management (positive, negative redispatch and RES curtailment [TWh] for different soft limits on line constraints.

Congestion management	200 €/MWh	300 €/MWh	500 €/MWh	1 000 €/MWh	10 000 €/MWh
Pos. re-dispatch	4.7	6.77	7.42	7.98	8.2
Neg. re-dispatch	2.47	4.06	4.45	4.84	4.97
Curtailment	2.22	2.7	2.97	3.14	3.23

D.2 Model complexity for base case power flows

Table D.2: Characteristics of the solved problem instances to determine base case power flows during Flow-based capacity calculation.

	BC flows
Runtime [s]	0.3 (3.3)
# Vars	8 348
# Lin. constr.	12 237
# Non-zeros	39 076
# Pres. vars	5 343 (5 344)
# Pres. lin. constr.	9 017

Continued on next page.

	BC flows
# Pres. non-zeros	28 759 (28 760)