Influence of the COVID-19 pandemic on Flow-Based Market Coupling

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Abstract:

The global economic downturn in the year 2020 was caused by public measures aiming to limit infections during the COVID-19 pandemic. As a result, the electricity demand was reduced in Europe and the electricity transmission routes changed. The international transmission is enabled through interconnector capacities which schedules respectively exchanges are derived at coupled day-ahead markets. One of the particularities of the European Single Day-Ahead Coupling lies within the Flow-Based Market Coupling. It enables higher commercial exchange capacities due to a more complex, but therefore more accurate approximation of physical flows in the commercial market. The introduction of the Flow-Based Market Coupling was based on common market situations and did not consider longer lasting pandemics like COVID-19. Against this background, the goal is to study the implications resulted from the pandemic on exchange capacities and commercial flows in Europe. Based on the analysis, quantitative techno-economic assessments are carried out in order to characterise and to evaluate the Flow-Based Market Coupling approach during the pandemic.

Keywords: Flow-based, market coupling, COVID-19, electricity markets, exchange, commercial flows, market simulation, price convergence, social welfare

1 Motivation and goal

The year 2020 caused a global economic downturn due to public measures aiming to limit infections during the COVID-19 pandemic [1]. The electricity demand is one of the main drivers in the electricity market and has been reduced as economic activities and social routines influence it significantly [2]. In Europe, physical electric energy is traded mostly hourly between 26 countries within the framework of Single Day-Ahead Coupling (SDAC) [3]. The five bidding zones of the countries in the Central Western Europe (CWE) region apply today the Flow-Based Market Coupling (FBMC). Seven bidding zones in Eastern Europe will be included in the FBMC region forming the new Core Capacity Calculation Region (CCR). This extended coupling will go live by September 2021 [4]. FBMC introductions result in a higher complexity in exchange capacity allocation. So prior to such introductions it is extensively analysed and tested in order to ensure a positive total economic social welfare gain [5]. Such historical forecasts were based on common proven market situations and did not consider longer lasting pandemics like the ongoing COVID-19.

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The aim of this paper lies within the quantitative techno-economic analysis of the FBMC during the pandemic and its impacts on the socio-economic welfare in Europe. The quantification is based on a comparison of the years 2019 and 2020 for the CWE region which currently falls under the FBMC approach.

Section 2 studies the characteristic differences between the year 2019 and 2020 at the electricity markets. Further, it provides a general overview of electricity markets and exchange designs. Afterwards, section 3 describes a market simulation model used for quantification. Simulation results are discussed in section 4. Finally, section 5 concludes the findings.

2 Day-ahead markets, market coupling and pandemic impact

European day-ahead markets operate in a uniform price auctioning with the aim to maximise the total social welfare. Electricity is exchanged between different bidding zones in Europe, thus leading to a social welfare gain [6]. During the pandemic all European bidding zones were affected [7], creating an impact on the coupled electricity markets.

2.1 Electricity markets

The electricity demand and supply has to be matched at all times to ensure the security of supply. Due to a non-constant demand and supply, physical schedules of consumption and generation units need to be aligned before actual operation. Combined with the reduction of insecurities like unit outages or intermittent feed-in over time, a systematic need for cascading markets occurs. In Europe intraday, day-ahead and over-the-counter markets exist for physical delivery. At the day-ahead market electricity is traded for time blocks one day ahead the physical delivery. Time blocks are generally in 15, 30 or 60 min resolution [6]. The day-ahead market is the largest in terms of social welfare [8] and operates currently in the FBMC regime in CWE. Therefore, the focus of this contribution lies on day-ahead markets.

Figure 1 depicts the market clearing process. Each market participant submits multiple bids for supply and demand of energy for each time period at different prices (bid curve). The plot on the left in figure 1 includes an example of such bids from a market participant for a certain hour. On the right in figure 1 such bids are aggregated to the demand and supply curve derived by single bid curves. This is done by stacking the bids for supply in an ascending order of price and stacking bids for demand in a descending order. The intersection of the total demand and supply results in the Market Clearing Price (MCP) and the Market Clearing Volume (MCV).

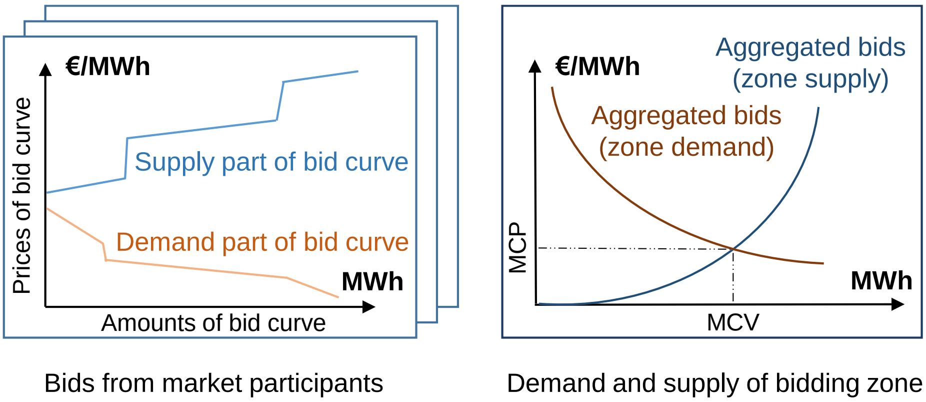


Figure 1: Participants' bidding curves and zonal market clearing [8]

The area spanned by vertical axis, supply curve and demand curve sets the social welfare of a single bidding zone. The total social welfare of multiple bidding zones includes them and congestion rents defined by the price differences multiplied with exchanges. The goal of the market clearing at the day-ahead market lies within the maximisation of the total social welfare. The allocation of exchange capacities between bidding zones is incorporated in the day-ahead market coupling automatically and simultaneously as a so-called implicit auction [9].

2.2 Exchange capacities

Market coupling allows participants to commercially import and export (exchange) electricity between bidding zones [6]. In Europe market coupling mechanisms like Bilateral Net Transfer Capacities (NTC), Coordinated Net Transfer Capacities (CNTC) and FBMC coexist. All represent in different accuracy the physical grid exchange capacity for commercial exchanges. Figure 2 displays exemplary exchange restrictions. The spanned area starting from the origin and limited by the restrictions define the resulting convex solution room (domain). Points within the domain are part of feasible imports and exports, while the area edge represents the limits. NTC constraints (green lines) consist of a fixed capacity stating the maximum possible commercial exchange between two bidding zones [10]. CNTC restrictions (red lines) limit the import sum or export sum of one bidding zone from or to several bidding zones.

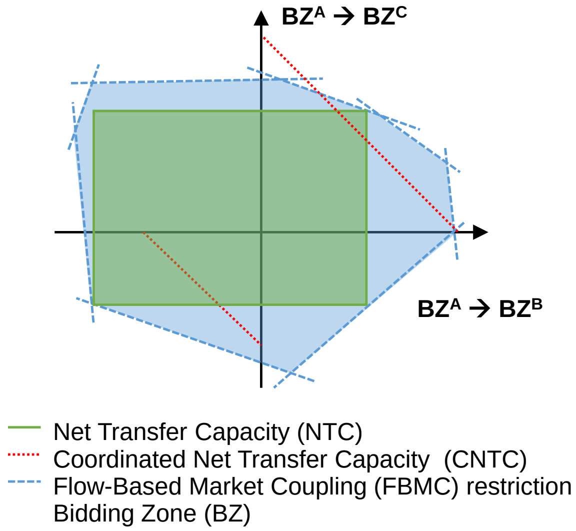


Figure 2: Domains and restrictions for different exchange limitations

FBMC restrictions (blue lines) represent the constraint of one critical network element (line or transformer) or one contingency (outage). Every Critical Network Element or Contingency (CNEC) consists of linear sensitivities on the element utilisation for every bilateral flow in the FBMC region (Power Transfer Distribution Factor, PTDF) and the restriction limitation (Remaining Available Margin, RAM) [10]. PTDF define the slopes of the restrictions and RAM the axis intercepts. The PTDFs are defined as zone-to-zone values for bilateral flows or can be alternatively and mathematically equally defined as zonal values for net exports of a bidding zone (net positon). As CNECs are actual single grid elements whose limitations are used in the FBMC approach, it allows a more accurate representation of physical grid constraints in the commercial wholesale market. Additionally, it enables the determination of bottleneck units and their locations for a detailed techno-economic analysis. In future, to the exchange market provided RAMs need to meet a minimum capacity (minRAM) specified by EU regulations [8].

2.3 Load, renewable generation and fuel prices

Europe experienced the first effects of the pandemic in March 2020 [6]. Countries started lockdowns to slowdown the spread of the virus, which also brought impacts on daily social and economic activities [2]. The economic output of all countries was affected. Electricity load profiles which depend on business hours were reduced and equalised since businesses were closed [2]. Figure 3 displays the monthly load and renewable feed-in between the years 2015 and 2020. CWE comprises the bidding zones Austria, Belgium, Germany-Luxembourg, France and the Netherlands (left) and non-CWE bidding zones consider the remaining bidding zones in the day-ahead EUPHEMIA common price algorithm [9] (right). The load occurred in the year 2020 remarkably lower at the end of the first quarter and the full second quarter in comparison to the years between 2015 and 2018 due to the lockdown effects. The renewable feed-in as one major impact factor on the market was observed on average higher due to more installed capacities.

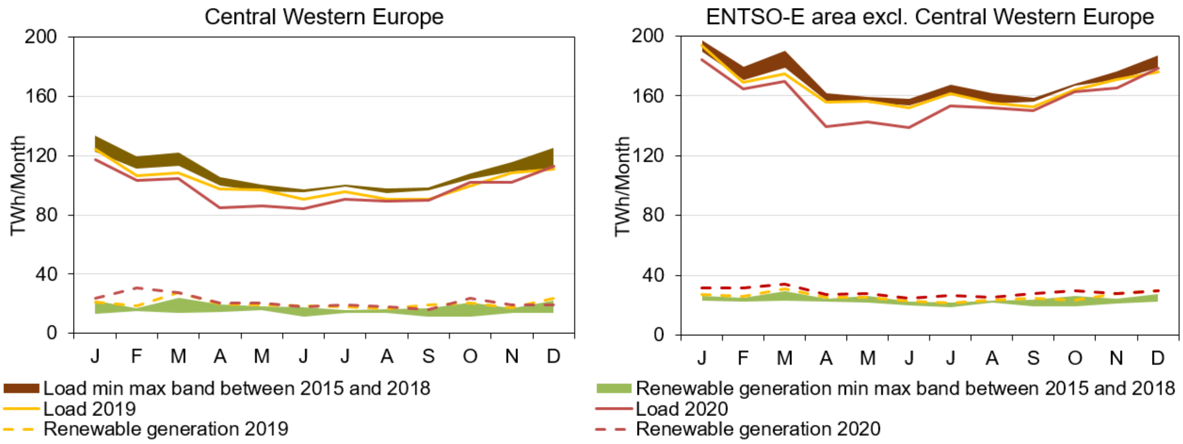


Figure 3: Total vertical load and renewable total feed-in from solar panels and wind turbines [11]

As the industrial consumption reduces, fuel prices occur lower. Fuel prices for natural gas, hard coal and European Emission Allowances (EUA) are depicted in figure 4. There is a decline in the EUA prices (left) towards the end of first quarter in the year 2020, but it recovered to the before observed levels in subsequent quarters of 2020. One reason for the recovery lies within the public measures taken to limit infections. Further, at the beginning of the pandemic the pandemic impacts were not clear resulting in higher market risks respective price premiums that were reduced over time with experience with the COVID-19 pandemic. The development of hard coal prices (middle) depict a downward trend which continues until the middle of the year 2020. Natural gas prices (right) reduced with a higher slope in the middle of 2020, but almost recovered back to the 2019 price level towards to end of the year 2020.

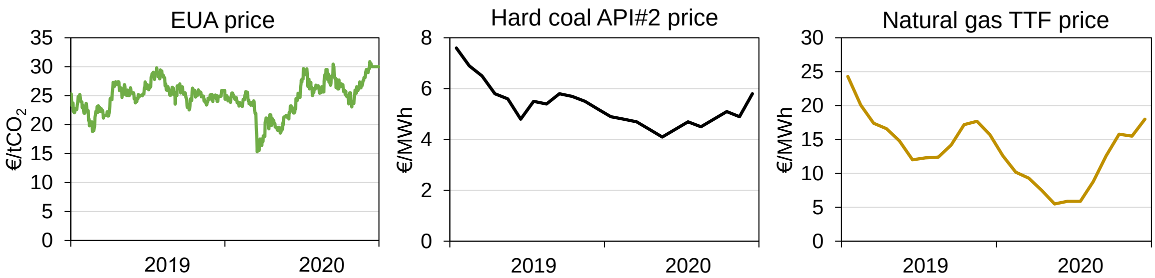


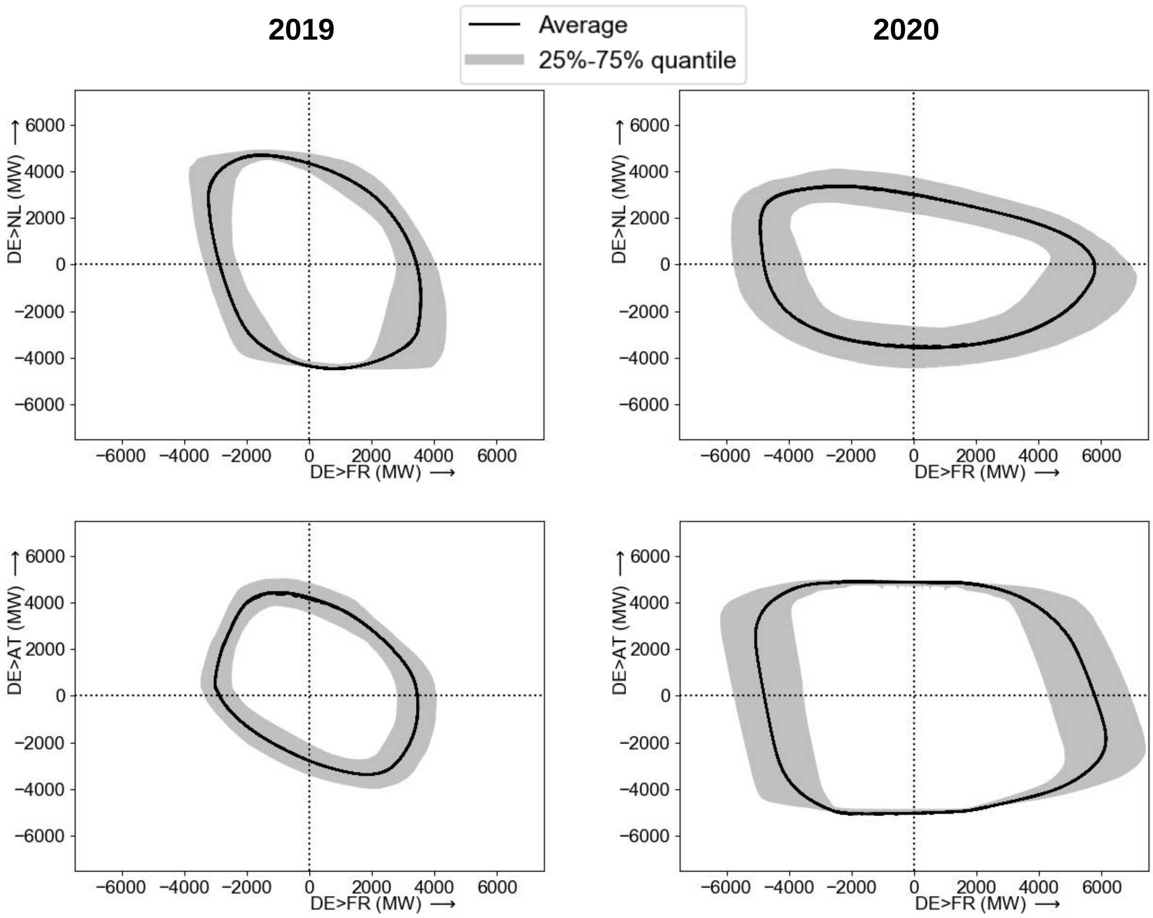
Figure 4: Emission, hard coal and natural gas prices for the years 2019 and 2020 [12]

2.4 Flow-based domains

The domain size determines the feasible amount of commercial flows between two zones. It can be fully described with geometrical metrics. Figure 5 displays domain distributions which are derived via geometric distances between origin and domain limitation. The calculation deduces average restrictions based on all FBMC restriction intersection points. FBMC intersection points are calculated for all hourly historical flow-based restrictions during a year and for each combination of bidding zones that are depicted in the figures below. All FBMC operated cross-border flows in CWE are displayed. The used raw data is publicly available at the Joint Allocation Office (JAO) [13].

For the combination Germany-France and Germany-Netherlands (first row) the domain distribution indicates higher capacities between Germany-France and lower capacities between Germany and the Netherlands in the year 2020. Further, the variability of cross-border capacities occurred more uniformly distributed.

The combination Germany-France and Germany-Austria (second row) indicates that in the COVID-19 year 2020 the exchange capacities were in all directions higher than in 2019. Further, the average restriction shape changed from 2019 to 2020 from a near-circle towards a near-rectangle shape. The variability of restrictions between Germany and Austria had a low variance in the year 2020. In contrast, restrictions between Germany and France occurred with a high variability in the year 2020. The capacity increase was partly caused by lower load and reduced load differences (in the so-called base case) between Germany and France (see figure 3). Thus, exchanges reached limits of critical elements with higher values (higher RAM).



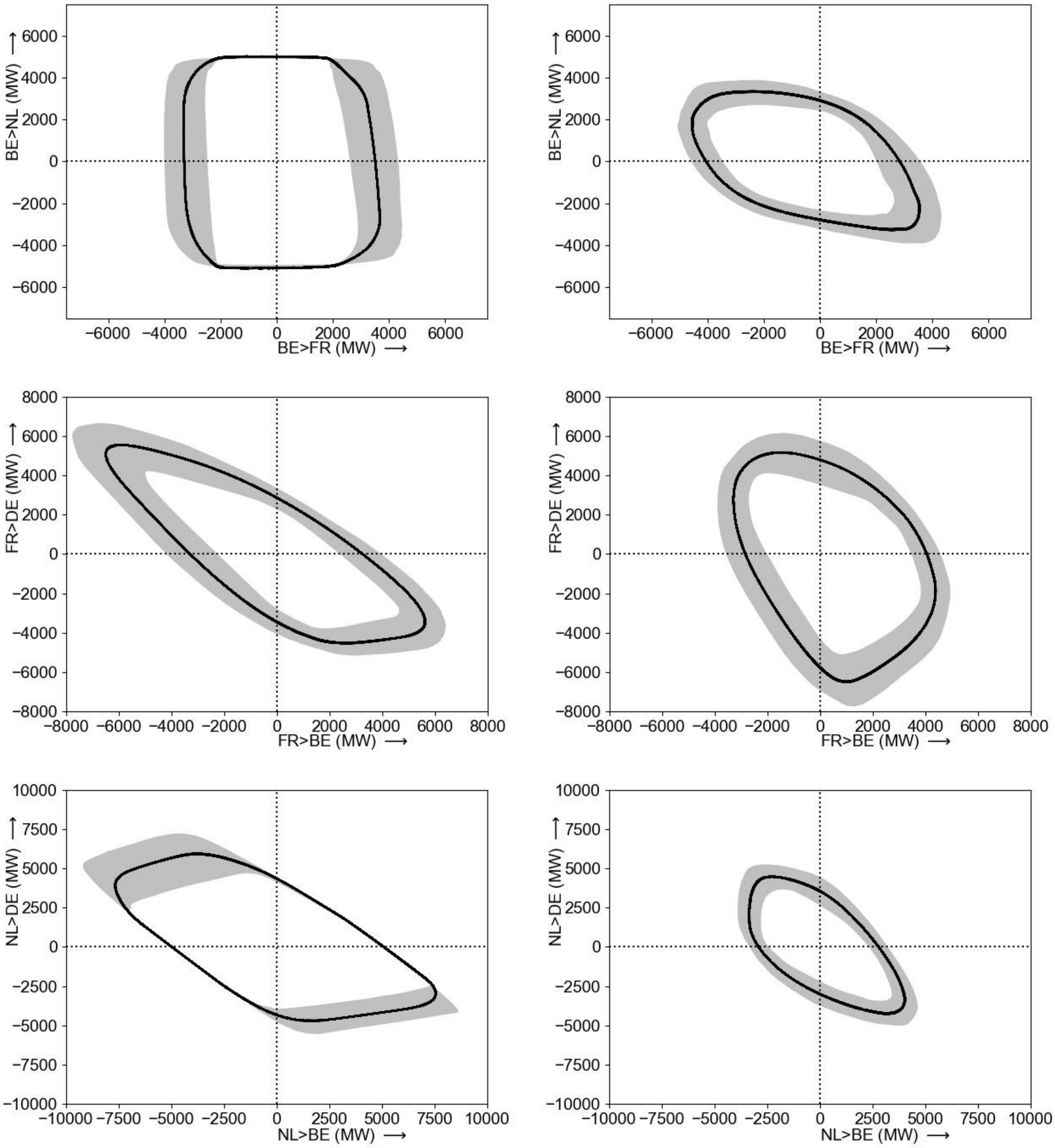


Figure 5: Flow-based domain distributions for the year 2019 (left) and 2020 (right)

For other combinations reversed changes can be observed in comparison to Germany-France and Germany-Austria. For example, Belgium-France and Belgium-Netherlands (third row) as well as France-Belgium and France-Germany (fourth row). Belgium-France and Belgium-Netherlands occurred closer to an NTC shape in the year 2019. The shape of the domain of Netherlands-Belgium and Netherlands-Germany (fifth row) was for the year 2019 close to CNTC.

The variability of the restrictions state one advantage of the FBMC approach since commercial exchanges adapt degrees of freedom situation-specific including all previous exchange restrictions like NTC and CNTC. Further, the visual domain analysis states that during the COVID-19 pandemic the FBMC domains shifted characteristically in shape and in distribution considering the lower load and generation respectively grid usage.

3 Electricity market model

To quantify the differences between market coupling designs, the electricity market needs to be simulated. This section deals with requirements and assumptions of the model as well as the simulation procedure for the assessment of FBMC during the pandemic.

3.1 Requirements

The market model should simulate the market function (see section 2.1) and maximise the social welfare at the European electricity markets taking different exchange capacity types into account (see section 2.2). Since FBMC exchanges do not only affect the CWE area, but impact surrounding bidding zones as well, the European-wide SDAC needs to be considered.

The market model needs to simulate all relevant market players and their generation, consumption and storage units in order to reach a sufficient accuracy in the representation of the day-ahead market (see section 2.3). The modelling requirements are listed as following:

- Bilateral imports and exports,
- demand like price-taking must-have loads and flexible Demand-Side-Response units,
- storages esp. hydro power cascades and batteries,
- thermal power plants esp. their generation cost like fuel and emission prices and
- generation based on renewable energy sources with their weather dependency esp. in the feed-in of wind turbines, solar panels and inflows of hydro power plants.

While respecting the above conditions, the market model should additionally meet the following resolution requirements and needs to be able to simulate exchange models (see section 2.4):

- Yearly integrated model for 8760 coupled hours to simulate storage units,
- considering all ENTSO-E bidding zones to simulate effects from and to the CWE region,
- hybrid market coupling including NTC, CNTC and FBMC according to the market constraints and degrees of freedom in the EUPHEMIA algorithm [9].

Models imitate a subset of reality so that it is necessary to narrow down the requirements in order to satisfy the specific goal. Thereto, the following assumptions are suggested to avoid pseudo-accuracy and to obtain exemplary robust results in a practical way.

3.2 Assumptions

To meet the requirements, an hourly simulation of the electricity markets takes place which includes a detailed hydro cascade modelling and thermal power plants on the flexible generation side. The various types of electricity generation compete for feed-in based on their marginal price. An efficient market is assumed in which the cheapest mode of production is used first. With this assumption, when the market participants cooperate, the objective of the individual market players to maximise the economic contribution margin becomes equivalent to the collective minimisation of the system costs. Therefore, the approach is to solve the optimisation problem to the effect that the total costs are minimised. The derived decision variables of the optimal solution correspond to the unit commitment. The key assumptions are listed below [14]:

- Capacities are not held back strategically and bids are submitted to the electricity market in accordance with operation cost (perfect competition),
- bids are formulated with secure information about the system state including outages, revisions or the feed-in of wind turbines and solar panels (perfect foresight) and
- in addition to operation cost like fuel cost and emission certificate cost of thermal power plants, there are no other costs such as levies and taxes (level playing field).

Based on such assumptions the following simulation procedure is proposed in order to model different market exchange designs and to derive quantitative exemplary market results.

3.3 Simulation methodology

The market model Maon [15] is applied with one integrated linear optimisation problem. During pre-processing among others outage and revision events are drawn separately per unit. In the post-processing among others bilateral exchanges in the FBMC region (today CWE) are derived via a quadratic optimisation problem as defined in the real EUPHEMIA tool chain [9]. The target function of the linear problem in between minimises the total system operation cost. Figure 6 summarises the simulation methodology. The approach takes technical and economic constraints of thermal power plants, hydro power cascades, flexible demand and other units into account and fulfils the requirements from section 3.1. For this paper, key outputs are generation cost per bidding zone, marginal cost of electricity and cross-border exchanges. Further model specifications can be found in the handbook [15].

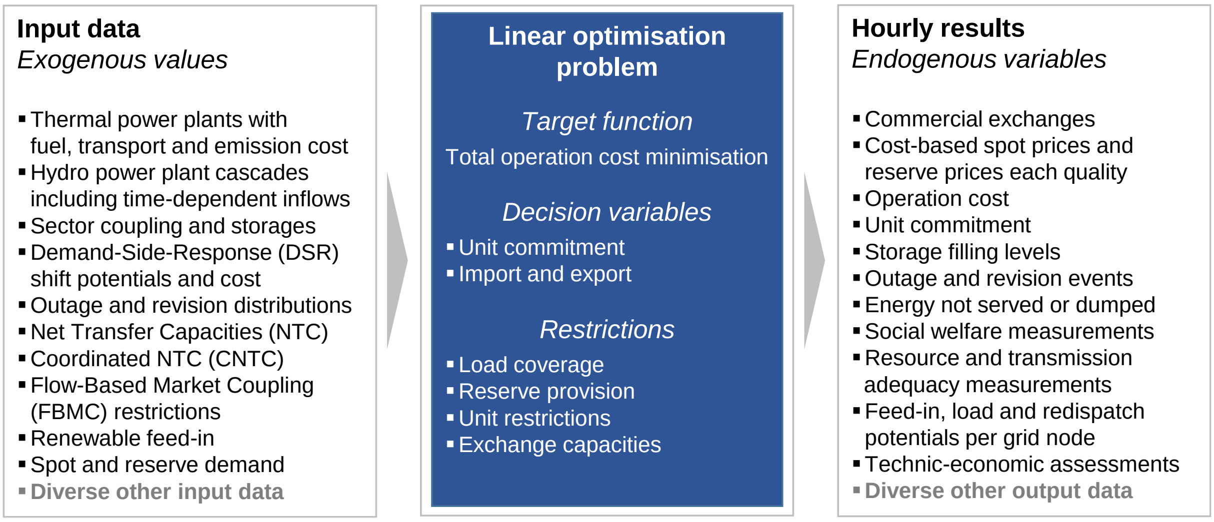


Figure 6: Electricity market simulation procedure [15]

To compare results, the model uses full non-simplified FBMC domains from the real day-ahead market as inputs in one simulation run and NTC in another run. For the second run, NTC values are generated from the FBMC domain such that for each existing bilateral connection, the available commercial exchange value is maximised subjected to the flow-based domain's technical feasibility. The trilateral exchange graph in figure 2 displays one example for the derivation of four NTC. During this optimisation the interplay between exchange combinations are considered so the NTC domain lies always completely inside the FBMC domain and cannot be maximised further in the multidimensional (CWE bidding zone combinations) domain.

4 Exemplary simulation results

This section specifies the input data respectively the scenarios in focus. Afterwards, exemplary results like prices, exchanges, capacity loadings and generation cost in Europe are discussed.

4.1 Scenario description

The results base on the outcome of yearly simulations of 2019 and 2020 with the procedure described in section 3.3. The aim is to quantify the impact on commercial exchanges, price convergences, congestions and generation cost reductions caused by pandemic lockdowns. To extract the FBMC effect, simulations are repeated with a technically valid NTC domain derived from the original FBMC domain for the CWE region.

The input data set was generated via public available sources [15] and was successfully validated and applied in projects like [16]. Loads and renewable time series were used from the ENTSO-E Transparency Platform [11] and historical FBMC domains from the JAO [13]. The historical FBMC restrictions were considered entirely for both years, which counted 1.29 million in 2019 and 1.36 million in 2020. Further, the unit database from Maon was used to simulate the unit commitment and generation cost [14]. The input data set includes the entire ENTSO-E area with approximately 5000 generation, consumption and storage units.

4.2 Spot price convergence

The price convergence measures the degree of the achieved market coupling within a region and can be expressed with the number of price zones. A perfect price convergence is given with one single price zone and a perfect price divergence with so many price zones as bidding zones (five in CWE). Figure 7 displays the shares of price zone numbers in CWE for the years 2019 and 2020 for prices from the NTC simulation, the FBMC simulation and EPEX Spot.

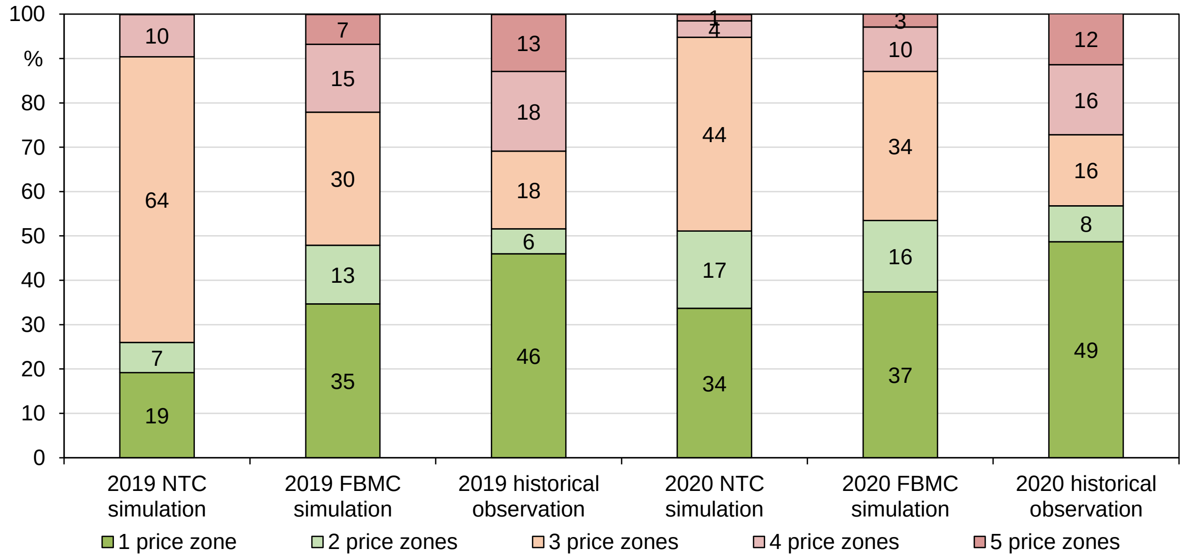


Figure 7: Price convergence described by price zones distributions in Central Western Europe

Historical prices were used from the EPEX Spot day-ahead market and simulated prices from the dual variables of the load coverage restriction. The threshold for a single price zone was set to 1.00 €. Since the exchange capacity is often a scarce resource, its usage should be maximised to obtain price equality. FBMC runs include a significant higher percentage of full price convergence for both years in comparison to NTC runs. Additionally, the complete price divergence occurs more often for FBMC runs. Thus, the FBMC approach enables significant more situations with full convergence and full divergence. Further, FBMC runs occur with less price convergence as in the real market. This is partly caused by the perfect foresight so that short-term generation and consumption outages are considered in the integrated spot market simulation, but are not anticipated by market participants at the day-ahead market in reality and instead at the short-term intraday markets. Overall, FBMC runs match the price zone distribution more accurately in comparison to the NTC runs. Further, the COVID-19 year 2020 occurred with significant more often full coupled prices than in the previous year 2019.

4.3 Spot price levels

The historical and derived spot base prices for Germany can be seen in the following figure 8.

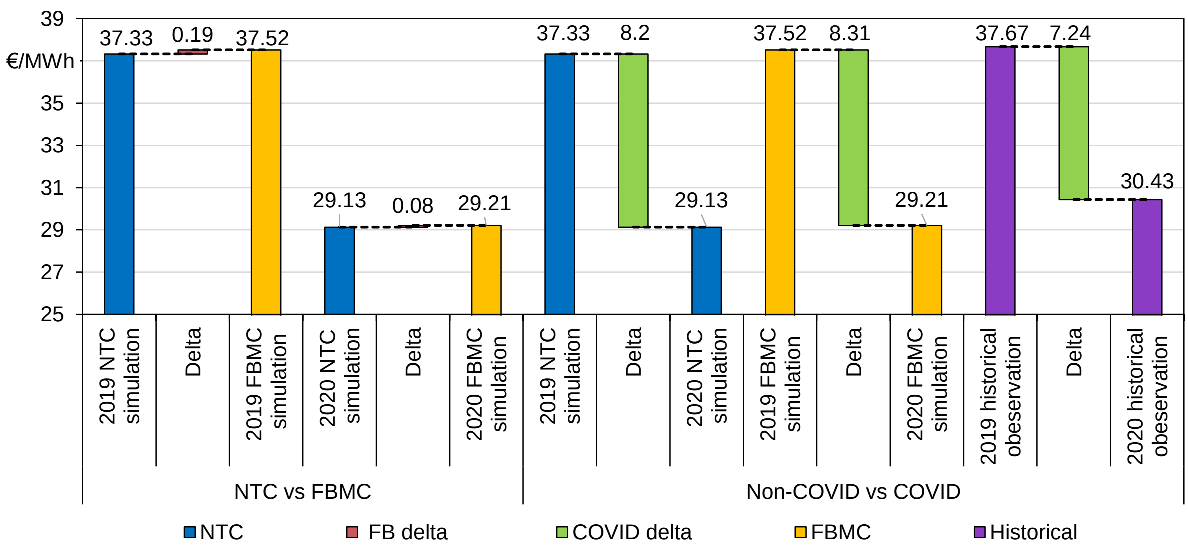


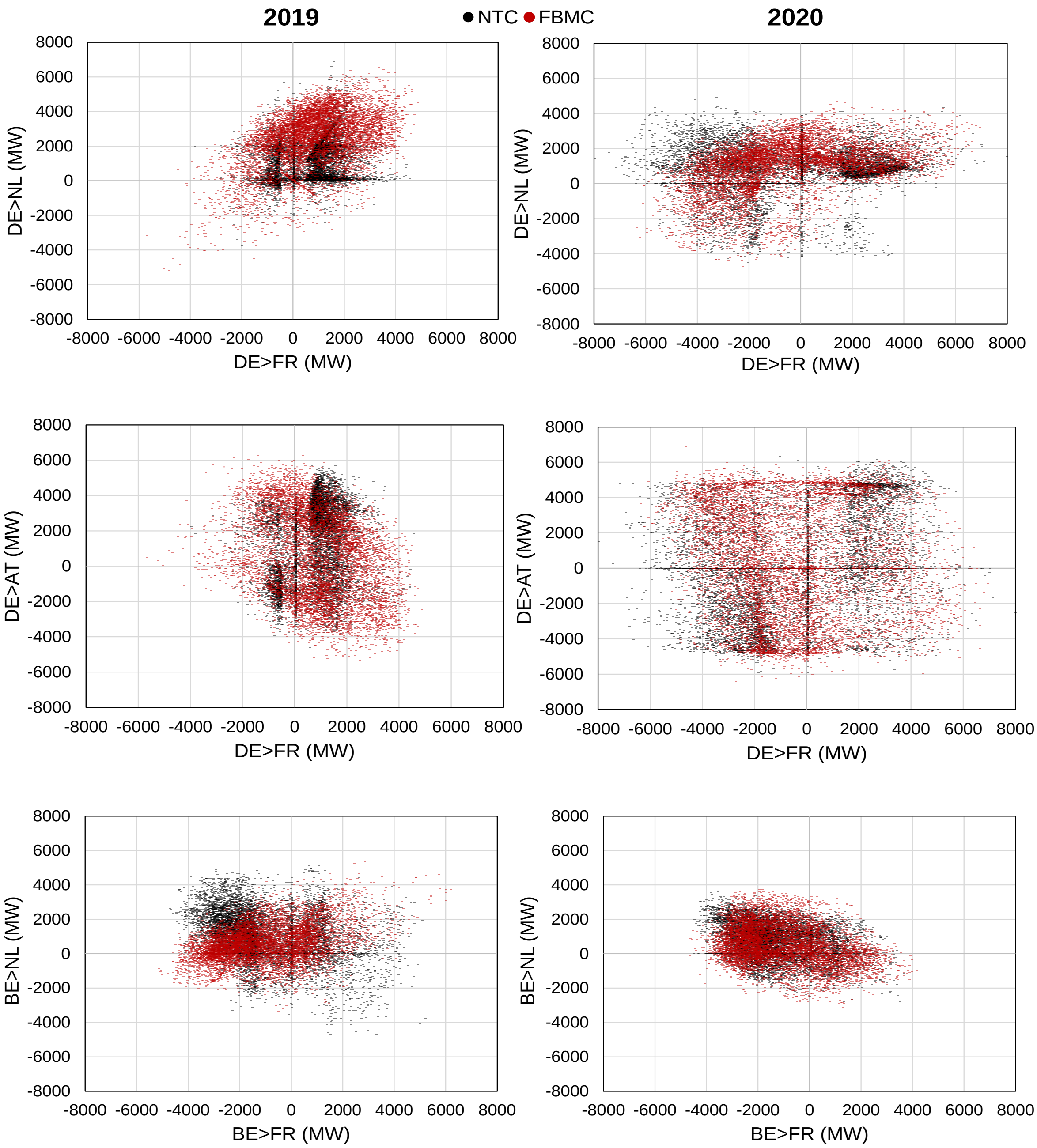
Figure 8: Derived and historical spot base prices in the German bidding zone

The simulated spot base price differences in Germany between the NTC and FBMC approach (left side) lies at 0.19 €/MWh in 2019 and at 0.08 €/MWh in 2020. So the market exchange design influences the base price on a scale below 1 €/MWh. The comparison of the year 2019 and 2020 (right side) results in a spot price decline of approximately 8 €/MWh in both exchange approaches. The historical market observation state a base price drop from 2019 to 2020 of approximately 7 €/MWh. This was mainly due to the reduced electricity demand and fuel prices in 2020 (see figure 3 and 4). It can be stated that the influence of the COVID-19 pandemic on the spot base price lies a high multiple higher in comparison to the exchange model. The demand driven electricity base price drop in the year 2020 was also influenced through utilising exchange capacities in the European electricity market analysed in the following section in detail.

4.4 Cross-border exchanges

The influence of COVID-19 is measured by comparing cross-border exchanges for different restriction types and the years 2019 and 2020. Figure 9 depicts the comparison of exchanges for all exchange combinations in CWE. The exchanges displayed in the figure 9 for the FBMC case are calculated in the post-processing to meet the net balance of the zone via a quadratic optimisation with the objective to minimise the commercial flow cost.

The combination Germany-France and Germany-Netherlands (first row) displays that in both years the FBMC exchanges between Germany-France occurred with more variability.



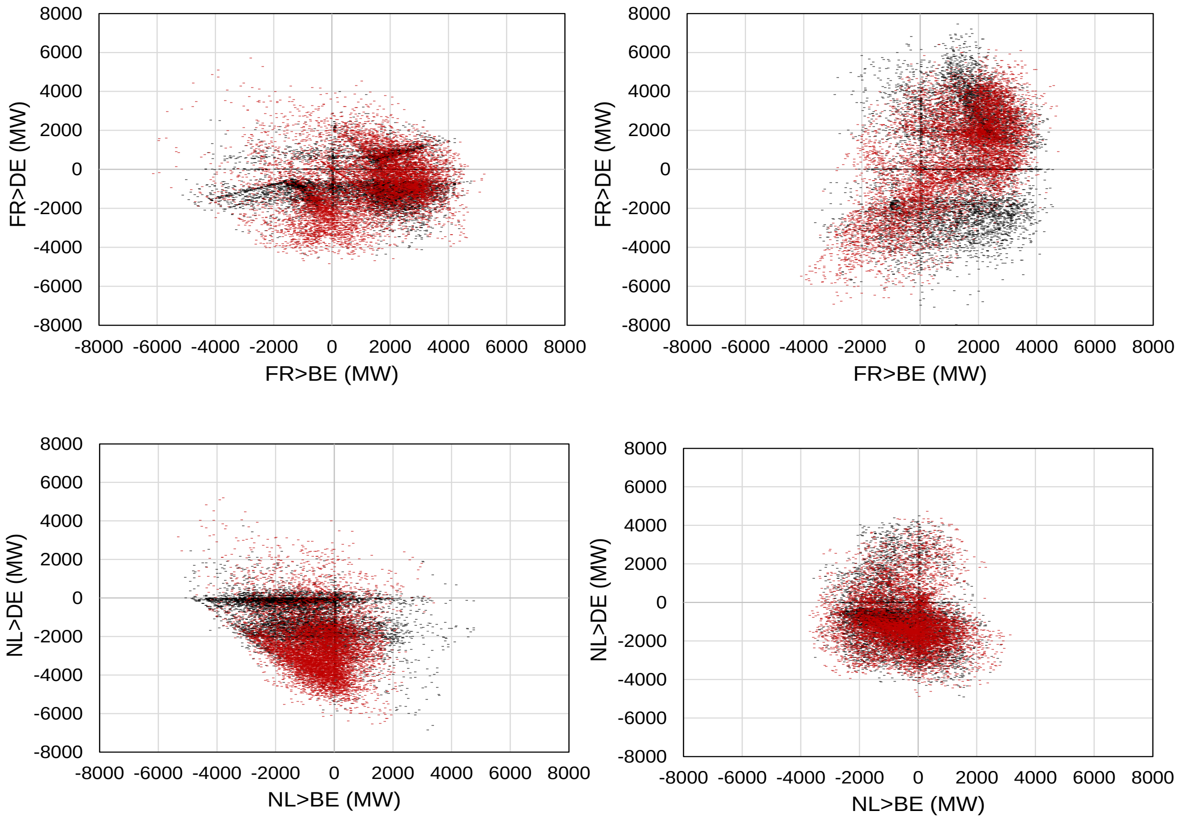


Figure 9: Derived cross-border exchanges for the years 2019 (left) and 2020 (right)

The combination for Germany-France and Germany-Austria (second row) indicates that NTC runs exchanges occurred with less variability esp. in the area around the graph origin. Such intermediate operation points increase capacities at other borders via the PTDF in the FBMC domain. This multi-lateral effect in the FBMC approach enables exchange combinations that cannot be reached by the NTC approach.

The combination for Belgium-France and Belgium-Netherlands (third row) occurred within a comparable area for the FBMC and the NTC case. For France-Belgium and France-Germany (fourth row) intermediate interconnector capacity usages occur with FBMC again more often.

In the last plot (fifth row) the interconnector from Germany to the Netherlands indicates a higher usage in 2019 in FBMC. In total, FBMC enables more exchanges, reduces sharp limits and smoothes operation point distributions. During 2020 and COVID-19, NTC operation points spread wider than in 2019, but the FBMC enabled even higher exchanges through its flexibility.

4.5 Line and transformer loading

The publicly available domain links physical lines to outages starting in the fourth quarter of 2019. Such links enable a unit-wise grid congestion analysis in the FBMC approach.

The FBMC approach provides advantages such as higher flexibility in exchanges, but also a higher accuracy in the grid representation and enables location-based congestion analysis. This section looks at the congestions of CNEC in the FBMC domain and determines grid units restricting exchanges in Europe. Figure 10 depicts the hours of congestion on each CNEC.

The FBMC domain can include multiple contingencies or outage combinations for the identical grid element and identical hour. So the map displays the maximum number of congestion hours of all CNEC belonging to the same physical location. The displayed results are for the fourth quarter of the year 2019 and 2020, since then CNEC links to units started to be published.

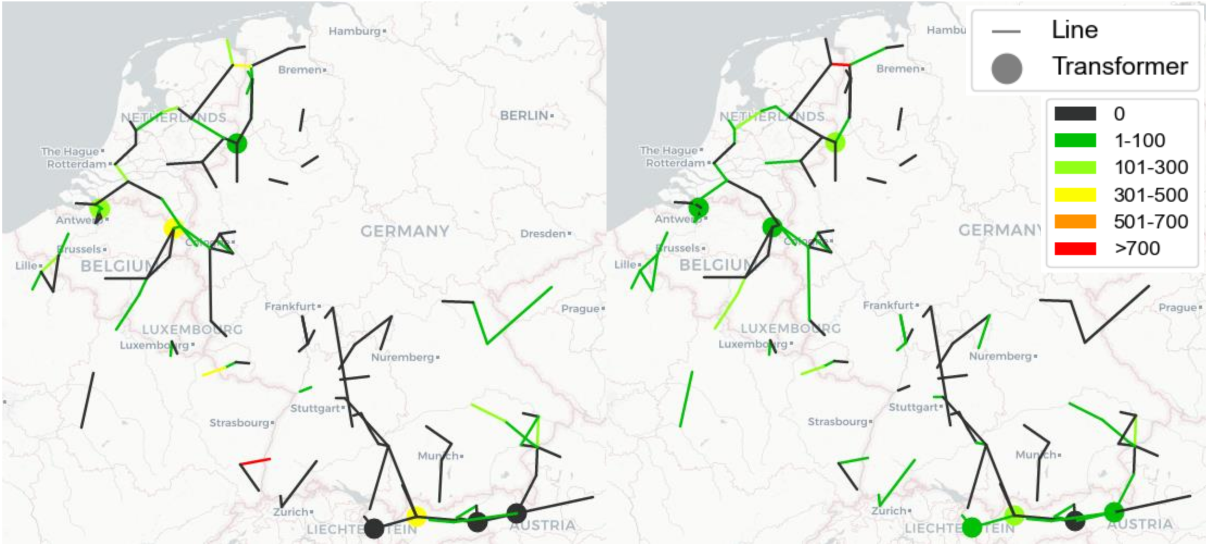


Figure 10: Congestion hours of critical network elements or contingencies for the fourth quarter of 2019 (left) and 2020 (right)

In the fourth quarter of 2019 the most congested element (red) lies at the line between Germany and France (Eichstetten-Muhlbach). In contrast, in the fourth quarter in 2020, the most congested line was between Germany and the Netherlands (Diele-Meeden). In general, less elements were not congested at all (black) in the fourth quarter 2020 indicating that congestions were more spread during COVID-19 across different grid units in comparison to the fourth quarter of 2019.

4.6 Total generation cost

Figure 11 depicts the total generation cost as a proxy for total social welfare for the year 2019 and 2020 in the NTC and FBMC simulations. Cost reductions do not state changes in single consumption, production and congestion rents, but indicate total social welfare improvements.

In the year 2019 the generation cost in the FBMC run lies 82 million € per year below the NTC run due to higher degrees of freedom in exchanges. FBMC leads to cost differences in opposite directions. The more flexible exchanges in CWE are used for reducing internal generation amounts and costs, resulting in less net exports to the region outside. The resulting lower net generation respectively net balance in CWE is compensated with higher electricity generation in the surrounding non-CWE region. In the year 2020 the generation cost changes between the NTC and the FBMC run followed the same structure. Albeit, the total generation cost in 2020 are reduced by 14 billion € respectively 28% in comparison to 2019, due to less demand and the non-linear merit order price effect. Thus, the cost differences between CWE and non-CWE occurred on a significantly lower level. Yet in total, the generation cost could be still reduced in the year 2020 via the FBMC approach in comparison to NTC by 13 million €.

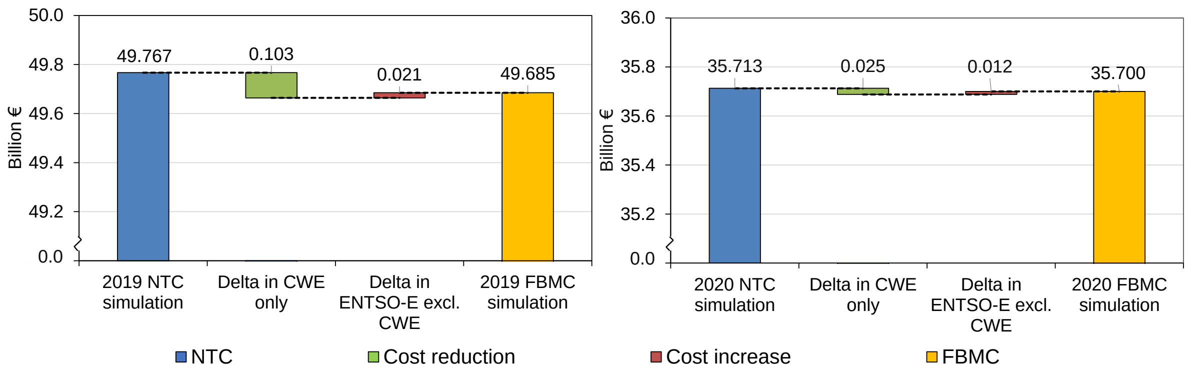


Figure 11: Derived total annual total generation cost in the ENTSO-E region

The simulation results indicate that the FBMC approach leads to total social welfare gains in contrast to the NTC approach including the longer lasting COVID-19 pandemic situation.

5 Summary

The COVID-19 pandemic in the year 2020 lead to a global economic downturn. This long-lasting event had impacts on the electricity demand, generation and consumption in the ENTSO-E region. Since European bidding zones are connected within the framework of market coupling, exchanges play a crucial role to ensure a maximised European social welfare. The aim of this paper lies within the quantitative techno-economic analysis of the FBMC during the pandemic and its impacts on the socio-economic welfare in Europe. The quantification is based on a comparison of the years 2019 and 2020 for the CWE region which currently falls under the FBMC approach.

The analysis quantified that electricity loads as well as fossil fuel and emission prices were reduced significantly downwards. Subsequent effects included changing FBMC domains since transmission grid transport routes were adjusted accordingly. So FBMC domains shifted in their shape between 2019 and 2020 towards larger solution rooms.

Afterwards, the requirements were set for the electricity market modelling and its coupling in order to do an exemplary techno-economic assessment. To meet the requirements and a set of assumptions, the market model Maon was proposed. It can model 8760 consecutive hours, 5000 units in the ENTSO-E area and exchanges including all historical FBMC domains.

The exemplary investigations comprise annual simulations for the years 2019 and 2020 based on historical FBMC domains and on derived technical valid NTC domains for comparison purposes. The results indicate a significant increase of price convergence within the CWE region from 2019 to 2020. The price convergence gain is enabled for significant parts through the FBMC approach. In general, cross-border exchanges occur significantly more flexible in the FBMC approach in comparison to NTC. Overall, the influence of the COVID-19 pandemic on spot base prices lies a high multiple higher in comparison to the exchange model.

Furthermore, the FBMC results enable the calculation of congestion hours of each CNEC to identify the grid unit congesting exchanges in Europe. In the last quarter of 2019, congestions were most often at CNEC at the border Germany-France, while in the last quarter 2020 the majority shifted to the border at Germany-Netherlands.

The model results quantify that the total generation cost were in 2020 in comparison to 2019 reduced by 14 billion € respectively 28% in the ENTSO-E region. In terms of cost the FBMC approach outperformed the NTC approach in both years. The exemplary results state that the FBMC approach was comparatively to NTC better for the long-lasting COVID-19 pandemic. This is due to the fact that FBMC exchanges occurred generally higher utilising more situation-specific capacities and multi-lateral exchange effects. As a result, the FBMC leads to increased degrees of freedom for the social welfare maximisation at the electricity markets in Europe.

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