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The meaning of flow-based market coupling on redispatch measures in Austria

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ABSTRACT

Energy market modelling lacks an approach that tackles the implications of flow-based market coupling on congestion management in European electricity markets. Especially in the context of high shares of renewable energy, the topic of network congestion is becoming even more important. Usually, redispatch measures as a main part of congestion management are calculated on the basis of a simple load flow model incorporating net transfer capacities on the day-ahead market. In this paper, we suggest a modelling approach that incorporates the attributes of flow-based market coupling in the calculation of congestion management. An advanced load flow model is therefore already used to reflect the allocation process on the spot market. Retaining this result, necessary congestion management can be calculated on the basis of a more detailed network model representing the control areas' exact transmission lines. Also, we conduct a comparison between the net transfer capacity- and the flow-based market coupling approach representing different levels of grid-granularities to show the importance of the grid model used for allocation on the European market for electricity. The results suggest, that necessary congestion management in the system is heavily dependent on the grid granularity, both in the sign and magnitude.

1. Introduction

Climate change mitigation as one of the main goals of the European Union demands the integration of renewable energy sources (RES) in the European electricity market. However, the increasing share of especially PV and wind energy (Jacobson and Delucchi, 2011) in the EU's member states may lead to critical grid situations. Because of their low marginal costs, they are dispatched with priority (Clò et al., 2015) and induce a large weather-dependency in the power systems. Line congestion can therefore occur in different time periods in the system, for example in times of high electricity consumption and high generation of renewable energy sources. Basically, line congestion can be defined as insufficient line capacities for the optimal transmission. For the analysis of congestion resulting from critical grid situations in a model environment, an important aspect that comes into place is the determination of transmission capacities for each line. Especially in the context of a highly integrated European market for electricity (Newbery et al., 2016), this aspect is even growing in importance. Both the physical transmission capacity and the exogenously given net transfer capacity (NTC) are possibilities. These capacities define the maximum possible flow that can be achieved as market outcome. Most recently, the guidelines for this determination relevant for Europe are defined in the Comission Regulation 2015/1222 for the Central Western Europe (CWE) region (EC, 2015). It states the flow-based approach, meaning a representation of the physical grid capacities and characteristics, as the primary way to do the calculation on transmission capacities. This regulation can be seen as an advancement to the Third Internal Energy Market Package foreseeing general market integration as an objective among others like the integration of RES and security of supply (EC, 2009). The previously used NTCs as the value for market-available transmission capacity are consequently only relevant in special regions with low interconnection.

The application of the so-called flow-based market coupling (FBMC) on the European Energy Exchange is performed daily by a centralized optimization algorithm that includes grid models of the participating transmission system operators (TSOs) (Dourbois and Biskas, 2015). These daily grid models have to include the most important transmission lines, but also estimations on expected demand and generation leading to a two-days-ahead congestion forecast (D-2CF) (Schavemaker et al., 2008) (Van den Bergh et al., 2016). Proposals for the design of these forecasts and their granularities were already given before the actual

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implementation in 2015 (ETSO and EuroPEX, 2004). The latest realization demands that the most important transmission lines are defined as the most relevant lines for international trade flows and their loop flows. The optimal allocation is determined as the welfare-maximizing market outcome including the constraints on the physical grid characteristics regarding the most important transmission lines (Van den Bergh et al., 2016). Based on this spot market clearing result, possible congestion measures are still relevant within zones (Kumar et al., 2005). Although Kirchhoff's second law and, therefore, all real physical line aspects are already incorporated in the optimization that is leading to the market result, it does not include the full grid representation of each TSO. Congestion and resulting necessary congestion management can still be relevant, if the market result is translated into the complete physical grid of each TSO. Also the EU's legislation describes necessary congestion management as the real-time result of a competitive day-ahead spot market clearing (CREG, 2017). The market-based character of resipatch is therefore a key aspect in the realization of congestion management (ETSO and EuroPEX, 2004). Modelling techniques that attempt to analyze congestion management in Europe have to incorporate the basic principles of flow-based market coupling and its realization on the market. In this paper, we propose a model for the European market with a special focus on the Austrian grid that calculates redispatch measures in a bilevel approach. The spot market's optimal allocation is therefore based on the most important grid characteristics of the Austrian bidding zone. Redispatch within this zone is then calculated on the basis of the full transmission network. For the moment, the Austrian TSO Austrian Power Grid's (APG) zone is the only one analyzed due to data availability and computation time. Nevertheless, extensions covering more European countries with a detailed grid can be added in later research.

2. Literature overview

This paper's contribution can be classified as a model analysis for liberalized electricity markets in the context of congestion management and recent market design. It is not part of the agent-based model literature analyzing firm behaviour or market power (Bunn and Oliveira, 2003) (Li and Shi, 2012), but analyzes power plant dispatches by applying a fundamental market model approach. However, the literature on energy market modelling yet lacks an approach that incorporates the concept of flow-based market coupling in the calculation of redispatch as part of congestion management for the European market, both when it comes to research and the European Network of Transmission System Operator's (ENTSO-E) responsibilities (ENTSO-E, 2018a). Nevertheless, flow-based constraints are a state-of-the-art component of energy market models. Therefore, these constraints are commonly modelled as an approximation of Kirchhoff's first and second laws (Schweppe et al., 1988) in order to achieve a better depiction of real flow-patterns. A well-known example for using the flow-based constraints is the large-scale optimization model ELMOD analyzing disptach on the European electricity market in a model environment (Leuthold et al., 2012). The necessity for the physical representation of the grid in an energy market model incorporating flow-based market coupling is explained in various research (Egerer, 2016). In this context, the explicit effects of storage devices on the corresponding simulated transmission flows leading to changes in market prices were topic of research as well (Weibelzahl and Märtz, 2018). Another part of the literature covers transmission system evaluations under the flow-based constraints. For example, grid expansion scenarios can be analyzed by applying an aggregated market model first and detailed grid constraints afterwards (Aluisio et al., 2017). However, also here the market results were based on a form of NTC constrained market.

Especially in the context of redispatch-models, the incorporation of physical grid characteristics is applied. Using a multi-level market model, the need for redispatch by firstly calculating optimal dispatch on the spot market is analyzed (Grimm et al., 2017). However, the flow-based constraints enter the optimization on the second stage problem analyzing redispatch only. Misleading results might arise from this approach, as it is not incorporating the recent market design implemented in Europe. A similar modelling approach is conducted to use NTC-based flow constraints for the spot market and redispatch based on the generated allocation (Linnemann et al., 2011). Also, in some research, NTC-constraints are used for analyzing the market clearing on the day-ahead spot market for electricity, before turning to the simulation of congestion management and the balancing market (Aravena and Papavasiliou, 2017). The implications of a possible market splitting in Germany are analyzed in a similar manner (Trepper et al., 2015), which might result in misleading policy implications by ignoring the market design. Also, a bilevel modelling application of a Stackelberg Game was used in order to simulate and analyze optimal transmission expansion under different incentive schemes and compare them (Jenabi et al., 2013). However, grid constraints are consequently used in literature for modelling transmission, but not for the determination of an allocation leading to congestion and redispatch. In contrast to these approaches, the importance of the network topology on congestion is shown in recent research as well (Han and Papavasiliou, 2015).

Model analyses incorporating flow-based constraints can be found, too. Representing the structure of orders on the European market, market clearings can be simulated under the consideration of flow-based market coupling (Dourbois and Biskas, 2015). In a fundamental market model approach, the market clearing was analyzed incoporating the physical grid characteristics for a single country (Weigt et al., 2010). However, international trade and the corresponding international flows are consequently not based on a detailed grid model. In contrast to this, it has been proved that the solution for cross-zonal flows heavily depends on the choice of the respective NTC value (Egerer, 2016). Therefore, a spot market solution relying on NTC-constraints might be misleading in the modelling context. However, fully network-based models for analyzing congestions are also conducted. For the nordic electricity market, an optimization model is formed to determine the optimal zone delineation in the nordic countries in Europe (Bjørndal and Jörnsten, 2007). Congestion is induced by the different possibilities of zone delineations though. In contrast to this, a simple 6-node network under the implications of different market designes ranging from nodal pricing to flow-based market coupling for counter-trading is presented in the literature (Oggioni and Smeers, 2013). This paper's work is similar to the first one to analyze different market designs on a simple exampe network (Ehrenmann and Smeers, 2005). A similar work on the effects of flow-based market coupling on congestion management is also conducted (Grimm et al., 2016b). In this, it was shown that an application of flow-based constraints on the spot market may lead to welfare changes, if not the full network is used as network constraints, but a simplified one. In an arbitrary example-network the welfare effects are shown to be negative in this case. However, this research does not analyze an application of flow-based contraints within the European market.

In all recent work, the meaning of the choice of the grid is stressed. This paper explains a method that incorporates the concept of flow-based market coupling in the calculation of redispatch measures in a real-world network application. It can be shown, that the definition of the important transmission lines within a zone heavily influences the calculation of redispatch. An NTC-based trade scheme not including the physical grid leading to a nodal pricing solution is compared to an application of flow-based market coupling.

3. Methodology

3.1. Building a bilevel modelling approach

The model formulation proposed in this paper is based on the EDisOn (Electricity Dispatch Optimization) fundamental market model, which has already been used in different studies (Burgholzer and Auer, 2016)

(Dallinger et al., 2018). It is implemented in MATLAB (Lofberg, 2004) and programmed as a linear problem of deterministic nature. In order to analyze congestion and congestion management in this model, it is necessary to reformulate it as a bilevel model. The first modelling stage covers the international spot market that is linked by flow-based market coupling. Perfect competition and foresight are the central characteristics of this modelling stage. It incorporates the existence of price zones, which means zonal prices for each country in Europe. By this, also country-internal price zone partitions can be considered, as it is implemented in Italy (Gianfreda and Grossi, 2009) and in the Nordic countries (Dijk and Willems, 2011). Additionally, the introduction of price zones is a point of discussion in Germany (Egerer et al., 2016) because of the large heterogeneity between north and south. Capacity constraints for generation are relevant for the market clearing. Therefore, both for the conventional and the renewable generators, generation constraints have to hold that include generation maximum capacities and ramp rates that are exogenously given. Since countries like Austria heavily rely on electricity storage like pump hydro storage (PHS) or run-of-river power plants (APG, 2013), it is necessary to consider storage devices in the spot market. Historical weather data is included to model renewable generation.

The most relevant aspect of the spot market for electricity covers the definition of nodes and grid constraints. As already mentioned, flow-based market coupling demands a TSO's grid model to consider the most important transmission lines. Therefore, the Austrian grid model for the spot market covers 9 nodes representing the federal states and the existing transmission lines connecting these in order to get a good representation of the system, as seen in Fig. 1.

The transmission grid is covering the 220 and 380 kV-level. Generators are matched to the corresponding nodes based on the geographical site and flows between the nodes consider the physical line constraints in terms of Kirchhoff's second law. In this way, all relevant interconnectors to European neighbours can be depicted. Thus, a relevant input model for market clearing is formed. The first stage model is written as a cost-minimization problem, whose optimal solution is the equivalent to a welfare maximum (Leonard and Long, 2002). Generation costs are minimized including variable generation costs. The optimal solution for the first stage model represents the optimal spot market allocation.

The second stage model starts by observing this optimal spot market allocation. Based on this, the optimization problem is defined as a cost minimization of congestion management costs, in this case cost-based redispatch. Counter-trading as one alternative to redispatch (Kristiansen, 2007) is neglected in this research. Redispatch is used to make the spot market result feasible for the real-existing physical grid in the European system. Consequently, the adjusted generation constraints now have to include the possibility for redispatch. It covers the thermal and renewable power plants, but not the storage capacities; these are assumed not to be used for redispatch purposes. The most important aspect is the formulation of the underlying grid model. Generators are now matched to a more detailed number of nodes. Thus, Austria is divided into 17 load and generation nodes for the redispatch application, as seen in Fig. 2. A nomenclature for the nodes can be found in Appendix B.

This choice of nodes is based on the transmission grid in order to get a full representation. The differentiated grid model changes the power flow pattern and may lead to necessary congestion management, as long as there is a difference between spot market grid model and redispatch grid model. An overview of the basic model structure is provided in Fig. 3. An important aspect to mention is that both modelling stages are not correlated with each other. The redispatch stage simply observes the results from the spot market stage, but does not have any impact on the boundary conditions of the first stage model in a dynamic framework. There is consequently no endogenous way implemented to analyze investment decisions in generation capacity. In the real market, strategical investment and decommission decisions regarding optimal generation capacity by privately owned firms (Maurovich-Horvat et al., 2015) could be influenced by redispatch needs. However, in our model formulation, redispatch is only used as a way to make the spot market clearing feasible within the physical grid, but not as an investment incentive. This also regards investment decisions in transmission capacities operated by a regulator (Grimm et al., 2016a) (Kemfert et al., 2016). Investment in transmission capacities can be optimal in order to reduce redispatch cost in the long term based on perfect foresight. Due to the extensive computing time of bilevel model formulations (Grimm et al., 2017) and general data availability, the other neighboring countries of Austria are not modelled with exact grids. Consequently, the implications of flow-based market coupling have to be analyzed with

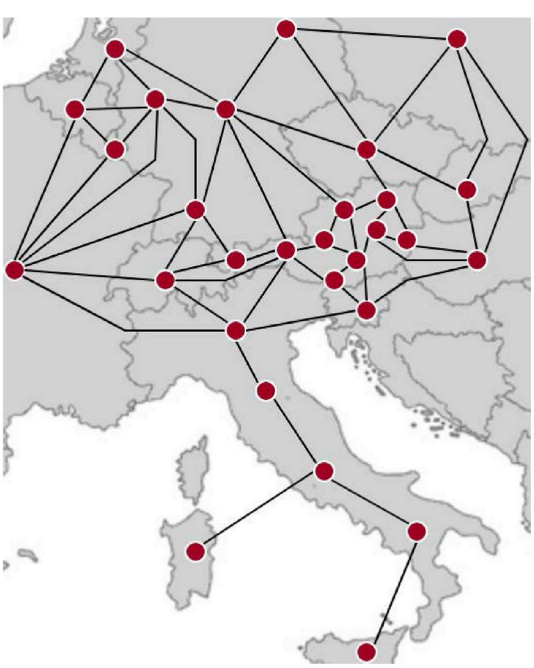


Fig. 1. Spot market grid.

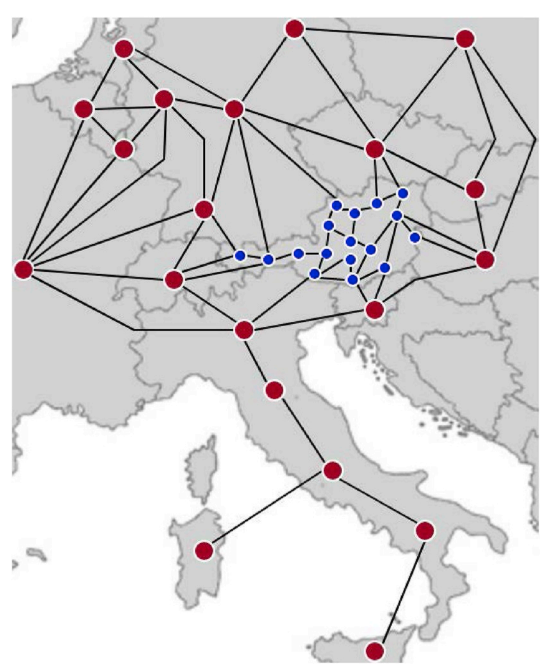


Fig. 2. Redispatch grid.

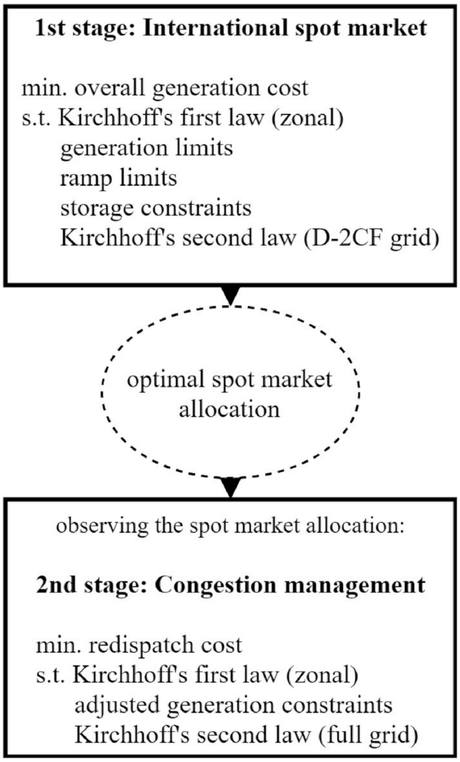


Fig. 3. Bilevel model structure.

some caution. Yet, a complete grid model both for the spot market and for the redispatch stages would exceed the paper's scope.

3.2. Basic model setup for flow-based market coupling spot market simulation

In the following, the basic model setup is explained. As mentioned, it is heavily based on the applications of the EDisOn model in previous research (Burgholzer and Auer, 2016) (Dallinger et al., 2018). For that, the full mathematical formulation can be found in Appendix A. The model formulation is able to incorporate the characteristics of flow-based market coupling in the spot market and solves necessary redispatch afterwards. The objective function comprises the minimization of total system generation cost. This includes all RES, whereas their cost is set marginally low in order to get their appearance in the countries' merit orders and a specific order of usage, if needed. Short-run marginal costs of thermal power plants include operation and maintenance cost, fuel cost, the cost for CO2-certificates and the efficiency of the corresponding thermal power plant (Sensfuß et al., 2008). Although not supplied energy is a part of congestion management, it is already included on the spot market stage in order to get a loosening of the D-2CF network constraints. The minimization problem of total system generation cost is first of all subject to Kirchhoff's first law, representing the power balance in each control area. For this, demand has to equal all possible supplies with losses and not supplied energy substracted. This condition has to hold in every control area in every time step. The constraint (A.2) also represents an implementation of price zones in the European spot market result. Since RES′ generation is based on historical weather data, it is fixed on the first hand. However, spillage variables are introduced in order to get a feasible market result with a generation decision for RES. Equation (A.3) shows the linearized implementation of the generation decision also considering the minimum and maximum capacity constraints. The approach is based on Farahmand and Doorman (2012). Ramp rates are relevant to limit generation upward and downward shifts. In addition to thermal power plants, RES generation in terms of run-of-river (RoR) faces inflow constraints. PHS storage units face similar constraints, as seen in (A.4) and (A.5). Pumping and turbining are limited to the maximum capacity. An equivalent approach, as seen in (A.6), yet without natural inflow, holds for all other storage technologies modelled, e.g. batteries.

Demand side flexibilization grows in importance in the energy market because of diverse characteristics of electricity demand (Strbac, 2008). Therefore, demand side management represented by equation (A.8) is included in the model with the possibility of adjusting the amount of demand within a certain boundary. However, demand can only be adjusted within a time frame DT and has to be restructured afterwards.

For a full load flow linearization, as seen in (A.11), a power transfer distribution factor matrix (PTDF) is applied. Since DC technology is used for certain transmission lines in the European grid, they demand a special treatment within the load flow linearization. A DCDF matrix has to be established as well as a PSDF matrix. For these conditions, B_d is defined as the susceptance matrix with the size $L_{AC} \times L_{AC}$. A as the incidence matrix represents the connections of nodes via transmission lines. One has to notice once again, that this load flow linearization is relevant for the D-2CF grid with nodal granularity $i \in I$ only.

3.3. Model setup for redispatch simulation

As long as the first stage model is able to provide a solution for the optimum, the following formulation can observe the result and build an optimization upon it. The model now covers a grid model with higher granularity transforming the nodes $i \in I_{ca}$ to $j \in J_{ca}$. Results that were aggregated into the D-2CF model from the first stage are now disaggregated on the new nodal situation. This covers the location of generation capacity and its corresponding market clearing generation decision and the demand including distribution.

Parameters for Redispatch Simulation	
$Wind_{h,j}$	generation of wind turbines of node
$PV_{h,j}$	generation of PV of node
$CapL_l^{(A\rightarrow B)(B\rightarrow A)}$	capacity limit of transmission line
$A_{l,j}$	incidence matrix
$PTDF^j_{l_{AC},j}$	power transfer distribution factors for redispatch grid
$PSDF^j_{l_{AC},l_{pst}}$	power shift distribution factors for redispatch grid
$DCDF^j_{l_{AC},l_{DC}}$	DC lines distribution for redispatch grid
Decision variables for Redispatch Simulation	
$thP^{redi}_{h,th}$	generation redispatch of thermal power plant *th* in
$X^{redi^X}_{h,th}, X^{redi^Y}_{h,th}, X^{redi^Z}_{h,th}$	linearization of thermal generation of *th* in (binary)
$NSE^{redi}_{h,j}$	additional not supplied energy (load shedding) of node in
$Spill^{redi^{Wi/PV/RoR}}_{h,j}$	additional spillage of RES-E of node in
$Exch^{redi}_{h,j}$	adj. power injection in node in
$Flow^{redi}_{h,l}$	adj. power flow on line in
$\alpha^{redi}_{h,j}$	new phase shifter angle for node in

Redispatch of thermal power plants is the main variable of interest. It can take positive and negative values, whereby the generation limits have to be kept. Positive redispatch means an additional amount of generation for the power plant compared to the spot market result, negative redispatch a reduced amount of generation. Both measures are used to achieve energy balance subject to the more detailed grid topology. For this, the linearization of on- and off-generation decisions for thermal power plants now has to include the possibility to provide positive or negative redispatch. As additional variables, spillage and not supplied energy on the redispatch stage are enabled, although they are already considered in the first model. On this stage, they are part of congestion management reflecting the full grid model and are able to deliver some flexibility to the generation of RES. Basically, the power flow pattern changes, as it is calculated based on a new set of transmission lines.

3.3.1. Objective function for congestion management

$$\min totalcost^{redispatch} = \sum_{h \in H, j \in J_{ca}} \sum_{th \in TH_j} thP_{h,th}^{redi} \cdot MC_{h,th} + \\ + Spill_{h,j}^{redi^{RoR}} \cdot c^{Hy} + Spill_{h,j}^{redi^{Wi}} \cdot c^{Wi} + Spill_{h,j}^{redi^{PV}} \cdot c^{PV} + \\ + NSE_{h,j}^{redi} \cdot VoLL \tag{1}$$

Cost-based market redispatch is assumed to be used for congestion management. This means that it is calculated with short-run marginal cost and relevant for all thermal power plants in the market. This may not be a fully realistic assumption, because redispatch is usually performed by a limited number of contracted power plants in reality. Redispatch can be positive or negative, depending on the specific situations. The objective function is again written as a cost minimization problem, minimizing the congestion management cost arising from redispatch, necessary spillage for RES and not supplied energy. Kirchhoff's first law has to be adjusted in order to include the congestion management measures in the power balance. Redispatch measures can adjust the generation of thermal power plants, spillage can reduce the generation of RES and additional not supplied energy can be calculated in order to equate the power balance. One may notice, that storage devices are not included in congestion management and therefore simply stay constant in this optimization step. It is also necessary to mention that the demand already inlcudes the choice of demand-side management from the spot market. However, there is no new demand-side management on the congestion management stage.

$$Demand_{h,i} = \sum_{th} \overline{thP_{h,th}} + thP_{h,th}^{redi} + \sum_{ps} \left(\overline{tuP_{h,ps}} - \overline{puP_{h,ps}}\right) + + \sum_{st} \left(\overline{stPOut_{h,st}} \right. \\ \left. - \overline{stPIn_{h,st}}\right) + \left(hyP_{h,j} - \overline{Spill_{h,j}^{RoR}} - Spill_{h,j}^{redi^{RoR}}\right) + \left(Wind_{h,j} - \overline{Spill_{h,j}^{Wi}} \right. \\ \left. - Spill_{h,j}^{redi^{Wi}}\right) + \left(PV_{h,j} - \overline{Spill_{h,j}^{PV}} - Spill_{h,j}^{redi^{PV}}\right) - -Exch_{h,j}^{redi} + \overline{NSE_{h,j}} \\ + NSE_{h,j}^{redi} \forall h \\ \in H, \forall j \in J_{ca} \tag{2}$$

Fixed terms that were obtained from the spot market result are indicated with a bar.

3.3.2. Adjusted generation capacity constraints

The generation capacity constraints both for conventional and RES need to include the congestion management variables. First of all, conventional power plants' maximum generation capacity still may not be exceeded, even if redispatch measures are necessary.

$$\overline{thP_{h,th}} + thP_{h,th}^{redi} = X_{h,th}^{redi^X} \cdot Cap_{th}^{min} + + X_{h,th}^{redi^Y} \cdot \left(Cap_{th}^{max} - Cap_{th}^{min}\right) \forall h \in H, th \in TH_j \tag{3}$$

The linearization conditions have to hold once again, derived from Farahmand and Doorman (2012). The variables $X_{h,th}^{redi^X}$ and $X_{h,th}^{redi^Y}$ and now include the cost-based generation redispatch.

$$X_{h,th}^{redi^X} - X_{h-1,th}^{redi^X} \leq Str_{h,th} \leq 1, \quad \forall h > 1, th \tag{4}$$

$$X^{redi^Y} \leq X^{redi^X} \leq 1 \tag{5}$$

$$X^{redi^X} \geq 0, X^{redi^Y} \geq 0, Str \geq 0 \tag{6}$$

Technical ramp rates have to include the redispatch result. This means that generation cannot be expanded freely in the next timestep including the redispatch.

$$\overline{thP_{h,th}} + thP_{h,th}^{redi} - \overline{thP_{h-1,th}} \leq ramp_{th} \cdot Cap_{th}^{max} \quad \forall h \geq 2, th \tag{7}$$

$$-\overline{thP_{h,th}} - thP_{h,th}^{redi} + \overline{thP_{h-1,th}} \leq ramp_{th} \cdot Cap_{th}^{max} \quad \forall h \geq 2, th \tag{8}$$

The additional spillage that can be derived on the spot market stage is included in the capacity constraints for RES.

$$0 \leq Spill_{h,i}^{redi^{RoR}} \leq Inflow_{h,i}^{hy} - \overline{Spill_{h,i}^{RoR}} \quad \forall h, j \tag{9}$$

$$\overline{hyP_{h,j}} + \overline{Spill_{h,j}^{RoR}} + Spill_{h,j}^{redi^{RoR}} = Inflow_{h,j}^{hy} \quad \forall h, j \tag{10}$$

$$0 \leq Spill_{h,j}^{redi^{Wi}} \leq Wind_{h,j} - \overline{Spill_{h,j}^{Wi}} \tag{11}$$

$$0 \leq Spill_{h,j}^{redi^{PV}} \leq PV_{h,j} - \overline{Spill_{h,j}^{PV}} \tag{12}$$

3.3.3. New load flow linearization considering the more detailed grid model

The probably most important aspect of the redispatch optimization model is the new grid model. Since the nodal representation of the system has changed in comparison to the spot market model, also new transmission lines enter in l. An intuition implies that the new calculation changes the power flows to a certain extent due to changed technical characteristics of the whole network (Nagarajan et al., 2016) and adds new electricity flows for new lines.

$$PTDF_{l_{AC} \times J}^{j} = \left(B_d \cdot A_{l,j}\right) \cdot \left(A_{l,j}^T \cdot B_d \cdot A_{l,j}\right)^{-1} \tag{13}$$

$$PSDF_{l_{AC} \times L_{pst}}^{j} = B_d - \left(B_d \cdot A_{l,j}\right) \cdot \left(A_{l,j}^T \cdot B_d \cdot A_{l,j}\right)^{-1} \cdot \left(B_d \cdot A_{l,j}\right)^T \tag{14}$$

$$DCDF_{L_{AC} \cdot L_{DC}}^{j} = -PTDF \cdot A_{l_{DC},j}^T \tag{15}$$

The changed grid demands different flows and consequently redispatch measures, if necessary. Basically, one can summarize, that the redispatch optimization model observes an optimal spot market result, which was calculated independently from the redispatch stage. Since the spot market result is based on a D-2CF grid, it has to be adjusted on the real physical transmission grid in order to derive necessary congestion management. However, there is clearly no interference assumed between necessary congestion management and the decisions taken on spot market. Power plants are bidding with full capacity and constant marginal costs on the spot market. Independent from dispatch on the spot market, redispatch actions have no effect on the market price. Consequently, strategic bidding by anticipating redispatch needs is not possible and each power plant keeps its capacity and cost structure in the all time periods.

In the next chapter, the theoretical model is applied on a real-world example covering the European market for electricity. First of all, all necessary input data is explained.

4. Results for a comparison between NTC-based electricity trade and flow-based market coupling

4.1. Data

The input data, that is later on used for the model validation, covers 13 countries from Central Europe. This choice is relevant in order to analyze flow-based market coupling based on the current status of the internal European market for electricity. Therefore, the system covers Austria (APG), Germany (50 Hertz, Amprion, TenneT, TransnetBW), the Netherlands (TenneT NL), Belgium (ELIA), Luxembourg (Creos), Switzerland (Swissgrid), the Czech Republic (CEPS), Slovenia (ELES), Poland (PSE), Slovakia (SEPS), Hungary (MAVIR), Italy (Terna) and France (RTE) as a selection of member countries (ENTSO-E, 2018a). For the spot market granularity - as seen in Fig. 1 - APG's control area is depcited as a detailed, but aggregated grid model. Germany covers four nodes representing the four responsible TSOs, whereas Italy covers 6 nodes representing the price zone implementation. The data input for the model covers five aspects: generation data and capacities, the profiles for RES, the profiles for PHS, demand for electricity and transmission grid data.

In oder to analyze the future implications of flow-based market coupling in Europe, it is necessary to make a choice regarding one TYNDP scenario that is most suitable as input. In this case, the scenario "Sustainable Transition 2030″ is chosen (ENTSO-E, 2018b). This choice influences the overall generation capacities, input prices for resources and emission pricing. Since this is defining the short-run marginal cost, it also defines each country's merit order representing the marginal cost structure commonly seen as supply curve. In order to get a good representation of the countries' power plant structures, each technology can be divided into three age groups. This applies for gas, coal, lignite and oil power plants, because they heavily vary regarding their technical parameters. For nuclear power plants, RES and storage technologies, there is only one technological category assumed each. This approach can be seen as a compromise between only a single category for each power plant type (Tietjen et al., 2016) and a complete analysis of all single power plants (Deane et al., 2015).

The generation profile for RES has to cover Wind, PV and RoR power plants. Since their generation is modelled as fixed exogenous input that can only be adjusted via curtailment in the model, historical data is needed to find valid profiles. Annual generation in hourly resolution can be found on ENTSO-E's transparency website [1] for PV and wind energy, whereas a distinction between onshore and offshore power plants is necessary. Offshore wind farms can face a fundamentally different wind pattern compared to their onshore pendants (Green and Vasilakos, 2011). Natural patterns regarding inflow for RoR power plants and PHS storage can also be obtained from ENTSO-E's transparency platform. Basically, storage efficiencies are calculated as average values.

Demand data for each country is based on the hourly values for load obtained from ENTSO-E. The demand structure of different years can be used for the analysis, in this case the years 2015, 2016 and 2017, because all data is fully available at the date the research is conducted. Antoher aspect is the calibration of the value of lost load (*VoLL*). The value of loast load represents the costs that occur with load shedding of one unit of energy not delivered to customers. Since many different aspects are part of this cost parameter, it is not a market price, but a cost estimation that can be approached in different ways (Coll-Mayor et al., 2012). A broadly used estimation for this is 8000 USD per MWh (Cramton and Lien, 2000). However, we define the value of lost load as 3000 EUR per MWh, as this is the peak-price for the day-ahead market for the German and Austrian electricity market.

The last aspect to consider is the data on the transmission grid. Available transfer capacities are either obtained from ENTSO-E (ENTSO-E, 2018b) for the case of international interconnector lines, or from the TSOs (APG, 2013) for the lines within a control area. Germany's case is a special one, because there are four TSOs operating. Transmission lines within Germany that are linking the four TSOs' areas are modelled as aggregated values of the real existing transmission lines. Thus, also Germany has a partially more detailed granularity with respect to the transmission grid. A full representation of the transmission grid is implemented for Austria, however. Since Austria is most detailed divided into 17 nodes representing the central load and generation centers, a good representation of the 220 and 380 kV network can be chosen. The technical data on the different interconnector transmission lines is based on average values. It can be assumed that line resistances are smaller than line reactances. In this case, the simplified line parameters that were assumed are sufficient to model load flows. Another consequence of this is that losses in transmission, that may occur in reality, are not considered in the model. As mentioned before, the internal transmission grids for the remaining countries are not implemented due to data availability and in order to keep computation time in an accetable range. The more detailed the transmission grid is depicted, the bigger the computation time for the load flow calculation is.

4.2. Model validation

In order to show the dependency of congestion management measures on the grid model that is used for market clearing on the spot market for electricity, the model is optimized by using two different approaches. First of all, an optimization of the spot market model with simple NTC constraints is conducted. In this case, the grid model is as plain as possible: Only the international interconnector lines are relevant for the flow constraints. Transmission lines within the TSOs' control areas are neglected. Therefore, each price zone is seen as a copperplate without line congestion. Additionally, Kirchhoff's second law is not a constraint on the spot market stage, merely simple flow constraints are setting the minimum and maximum conditions. Redispatch measures are then analyzed based on the market clearing result.

Second, a model with an implementation of flow-based market coupling is optimized for the spot market. Here, the grid model incorporates the D-2CF input model, as shown in the previous chapters. Physical line restrictions are taken into consideration in terms of Kirchhoff's second law. Just like in the NTC case, necessary redispatch is calculated on the basis of the spot market result. It can be clearly shown that the grid representation has major impacts on the required congestion management.

4.2.1. Market clearing from a system perspective

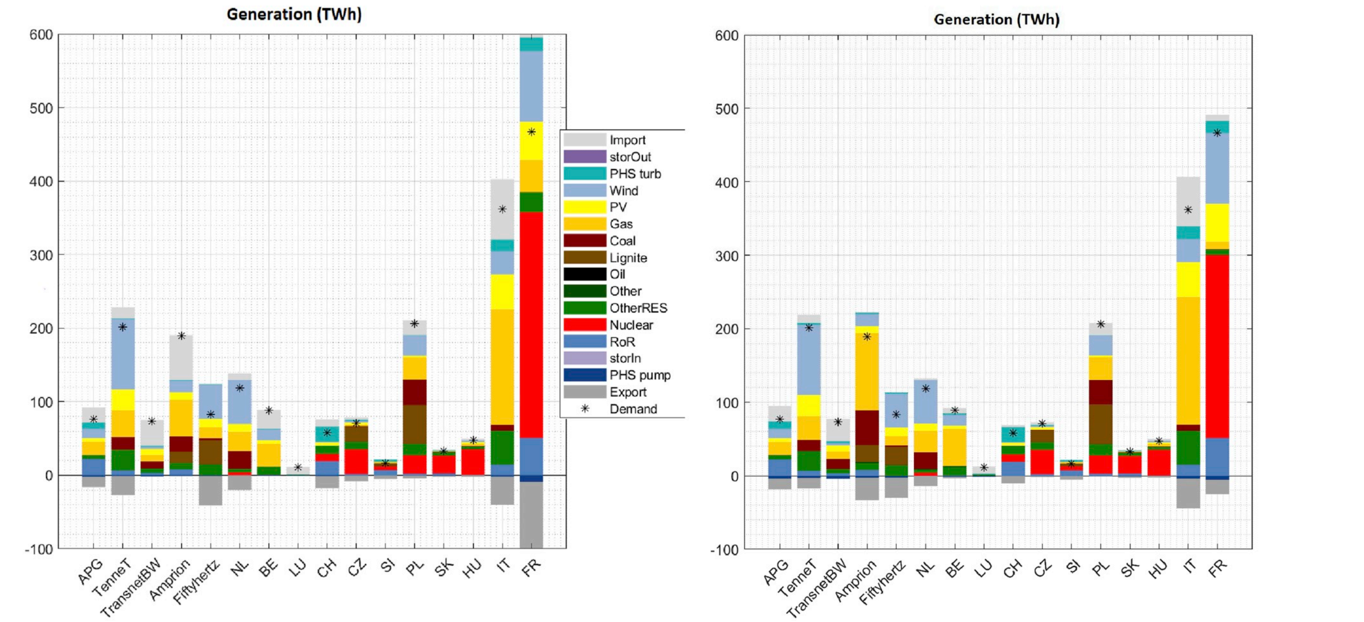
First of all, the market clearing of the two model formulations builds the basis for the comparison between the two clearing mechanisms.

The dispatch is calculated as the cost minimizing mix of generation units in the meshed network. Fig. 4a shows the spot market result for the NTC-based market clearing. It is depicted for each control area that is modelled; Germany is therefore divided into four control areas (one for each TSO). The usage of the trade volumes is indicated by the imports for positive generation and by the exports that are located for negative generation values. The only other possible negative generation is pumping for PHS. The Figure indirectly shows each control area's merit order, summed up for the whole optimization horizon of one year. When adding the trade volumes to the generation amounts, demand is always served fully. Thus, the Figure also shows the condition for energy balance for all periods summed up. The same holds for the market clearing based on flow-based constraints. This result is shown in Fig. 4b.

Overall, trade volumes in the NTC case exceed the trade volumes in the flow-based case. Although this might be a counter-intuitive result on the first sight, it makes sense when remembering the nodal granularity of all control areas except Austria (APG). In the recent model formulation, they are depicted as a single node each only. Since Kirchhoff's second law affects the trade flows heavily, although there is no detailed grid model deposited for them, the trade volumes in the flow-based case are tendentially reduced. As a comparison, the APG control area, which has a detailed grid model (D-2CF grid model) as a basis, shows only marginal differences between NTC and flow-based trade. It is expected that all control areas' trade volumes would slightly converge, if a grid model was deposited for each. For the current model formulation, trade volumes between the other countries have to be interpreted with some caution.

As the redispatch, that is calculated within the model formulation, relies on the spot market clearing, it can be interesting to see, whether congestion can already be foreseen here. Fig. 5 shows the theoretical prices that occur at each node in the whole system under the FBMC-configuration. Red crosses indicate the outliers in the box plot. Except of some single scarcity time periods resulting in very high clearing prices, the general price level can be declared very realistic, yet it includes a

[1] Accessible via https://transparency.entsoe.eu/.



(a) Summed up generation technologies for NTC-trade (b) Summed up generation technologies for FBMC-trade

Fig. 4. Generation dispatch in comparison.

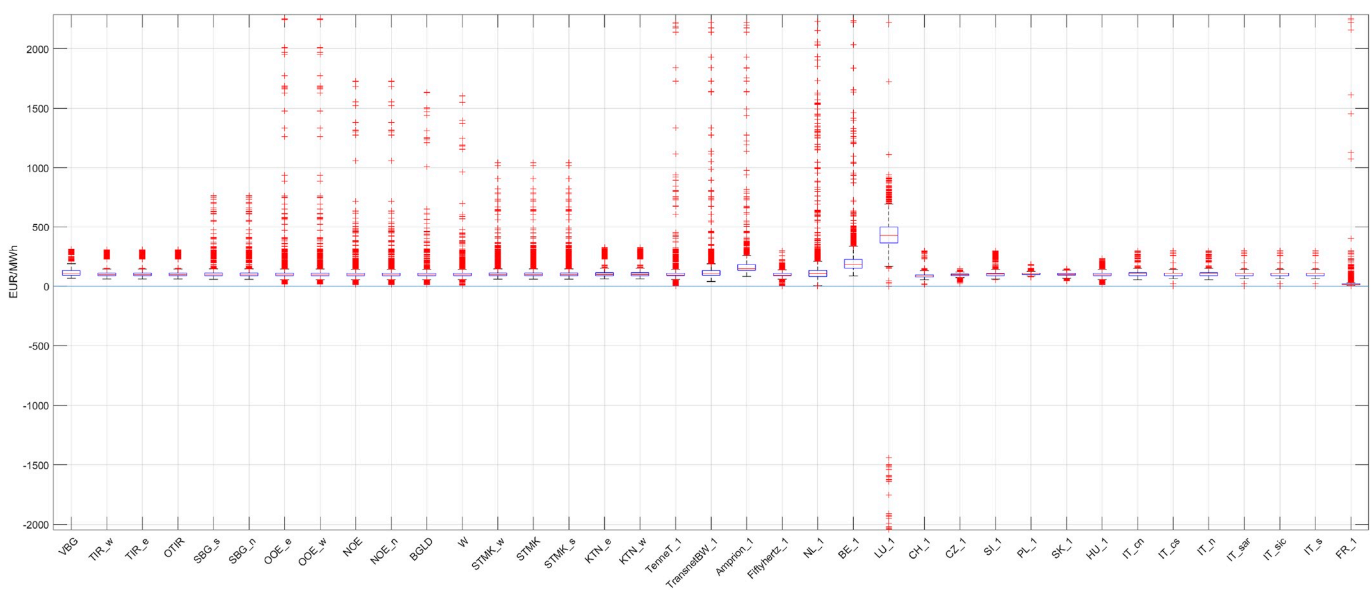


Fig. 5. Theoretical nodal prices for FBMC-trade.

high number of outliers. By the choice of the "Sustainable Transition 2030" scenario, the pollution prices are expected to climb and heavily determine the clearing prices[2], which makes the higher general price level realistic. High scarcity prices can be explained by the limited scope of the modelled European electricity market. Therefore, important interconnector lines to neighboring countries, that are not included, are missing and cannot be used for trade. Luxemburg is the only control area with negative prices occuring and a generally high price level. In this case, power plants' ramp rates in combination with relatively low amounts of demand are the reason for the negative prices. However, the country is an exception with respect to the sign and variance of prices because of its size and low influence on trade volumes within central Europe. Since the flow-based market prices are predicted to be various for each node within a country when deconstructing the aggregation result on the highest granularity of nodes, this can be seen as an indicator for congestion. Binding transmission capacity contraints yield different market prices as a sign of incomplete market convergence (Böckers and Heimeshoff, 2014). Nevertheless, a single market price for Austria's price zone is generated as a consequence of the nodal depcition that aggregates the 17 detailed nodes into the 9 nodes resulting in the

[2] Within the "Sustainable Transition 2030" scenario, CO2-prices are expected to rise up to 84.3 Euro per ton.

D-2CF grid. Price differences within price zones are ruled out by equation (A.2) of the model formulation. Taking the interpretation one step further, also Germany shows different theoretical markt prices for the four control areas. Therefore, also Germany has internal bottlenecks between the TSOs. Since predicted prices vary between the European countries, maximum transmission capacities are also reached internationally, at least for some time periods in the year. Thus, necessary congestion management can be foreseen by analyzing the theoretical market prices occuring on each node in the system.

4.2.2. Evaluating redispatch measures for the different market designs

Based on the determined market clearing, redispatch measures are calculated on the full grid representation, both for the NTC case and for the flow-based case. Since the NTC-based trade does not include any physical line constraints apart from the NTCs[3], redispatch measures are intuitively expected to take the maximum size that can be modelled within this approach. A market result with no consideration of technical line capacities fully ignores loop flows within a region. Therefore, generation and resulting flows have to be adjusted maximally. In contrast to this it makes sense to set the minimal boundary as well. By intuition, a flow-based market coupling design, that considers the same network model for the flow calculation both on the spot market stage and the congestion management stage within this modelling framwork, is expected not to yield any necessary generation redispatch. For the network model considered in this paper, the 17 Austrian nodes and corresponding lines that reflect the full transmission grid within the APG control area would be used for the spot market clearing already. Since the market clearing would already incorporate all network constraints existing in the system, no infeasible result has to be made feasible on the second stage. These two market designs can be seen as the lower and upper bound for congestion management.

The flow-based market coupling result, implemented by the D-2CF grid, is expected to be located between the two boundary results. Because of the high granularity, the expected necessary congestion management should be substantially lower than in the case of a NTC-based market clearing. It should, however, still be necessary, because of the aggregation of nodes in Austria on the spot market. Additionally, as it was already shown in the previous chapter, internal congestion can be foreseen by analyzing the theoretical market prices for each node. Since there are differences within the Austrian and German price zones each, this is an indicator for internal congestion. Fig. 6 shows the summed up redispatch amounts that were simulated by the EDisOn model for each month of the analyzed year. The red line indicating the necessary congestion management in the case of a NTC market clearing is located as the upper bound, as predicted. Acting as a reference scenario, the brown line indicating the full grid representation on the spot market, is implying zero necessary congestion management per definition. The usage of the D-2CF grid on the spot market leads to monthly redispatch depicted by the blue line. Just like expected, the line is located between the upper and lower bound. This means, redispatch is substantially less necessary in the flow-based market coupling compared to the NTC-based market coupling. Since Austria is the country that is fully represented in terms of grid models, it makes sense to have a look on the Austrian redispatch, too. Fig. 7 shows the necessary redispatch for the APG control area only.

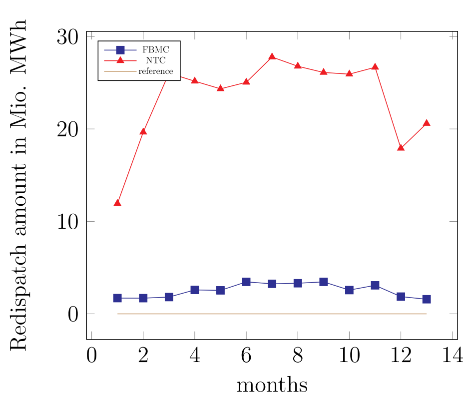


Fig. 6. Overall simulated amounts of necessary redispatch in the whole electricity system.

Similar to the overall redispatch amounts shown in Fig. 6, necessary congestion management in Austria is usually closer to the reference in the case of flow-based contraints (with some exceptions). This can be interpreted as a confirmation of the findings: The implementation of a flow-based market coupling also reduces necessary congestion management on the country-specific level. Another interesting aspect is that the amount of redispatch shows some positive correlation between the two market designs, e.g. in months of high redispatch for the NTC-case, there is also relatively high amounts in the FBMC-case. However, the FBMC line is closer to the reference. The appearance of either positive or negative redispatch here is determined by a combination of various factors. The influence comes indeed from different weather conditions in combination with the timely demand structure. The resulting choice of optimal dispatch ends up in the price level and therefore trade flows. Intuitively, negative redispatch in a zone occurs in periods with low price levels and congestion, whereas positive redispatch is a result of relatively high price levels. For Austria, the high share of RoR and PHS can be seen as central factors for the optimal dispatch and therefore the price level.

In this context, the spatial distribution of redispatch within the APG control area can be analyzed. Since Austria - as a relatively small country in the European comparison - is divided into 17 nodes, the redispatch amounts are not as big as in the other countries intuitively. In general, this also can be reasoned with the grid model for market clearing. Since this grid model is also used for the flow-based calculation in the second step and therefore redispatch, it implies high needs for congestion management in countries represented by a single node. These nodes are summarizing all demand and generation for the whole control area. The effects of fluctuating demand and renewable generation are amplified consequently.

First of all, Austria shows very few redispatch measures within the country. Nevertheless, the federal state Vienna (W) shows the biggest net negative redispatch, whereas Lower Austria (NOE) and Tyrol (TIR) show the biggest net positive redispatch in the NTC case, as seen in Fig. 8. Basically, all federal states' nodes with interconnector lines to

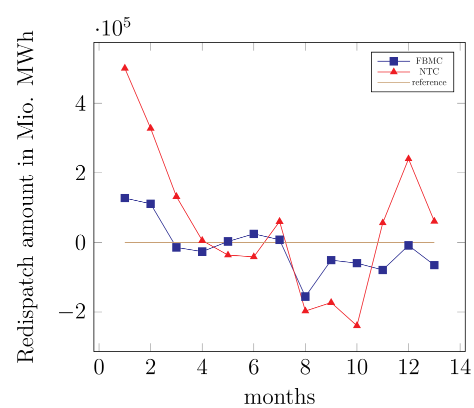


Fig. 7. Overall simulated amounts of necessary redispatch in Austria.

[3] NTCs are usually set in a way they do not violate physical grid constraints, but do not reflect the maximum available transmission capacity. Thus, a consideration of the n-1 criterium is easy to be implemented.

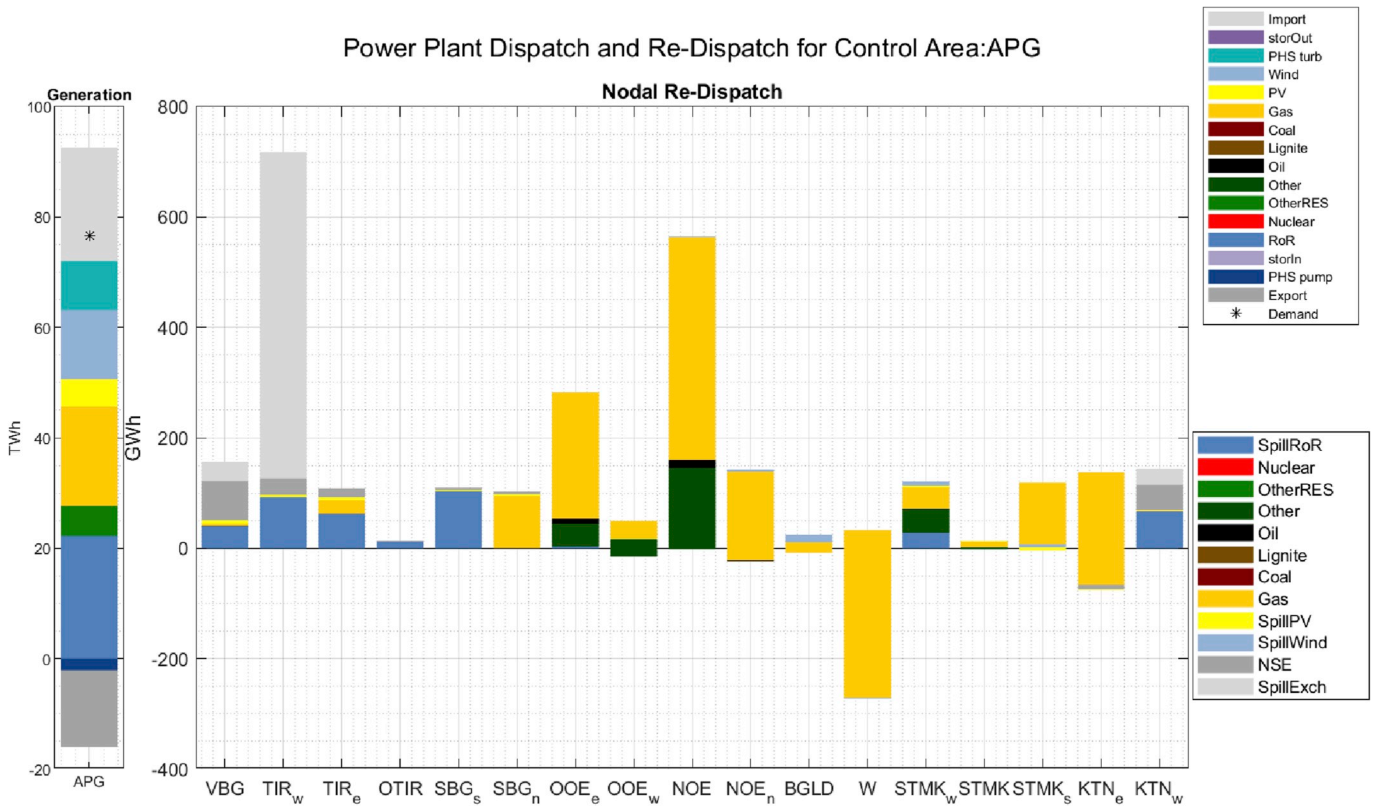


Fig. 8. Summarized congestion management balance for a simulated year with NTC-clearing: APG.

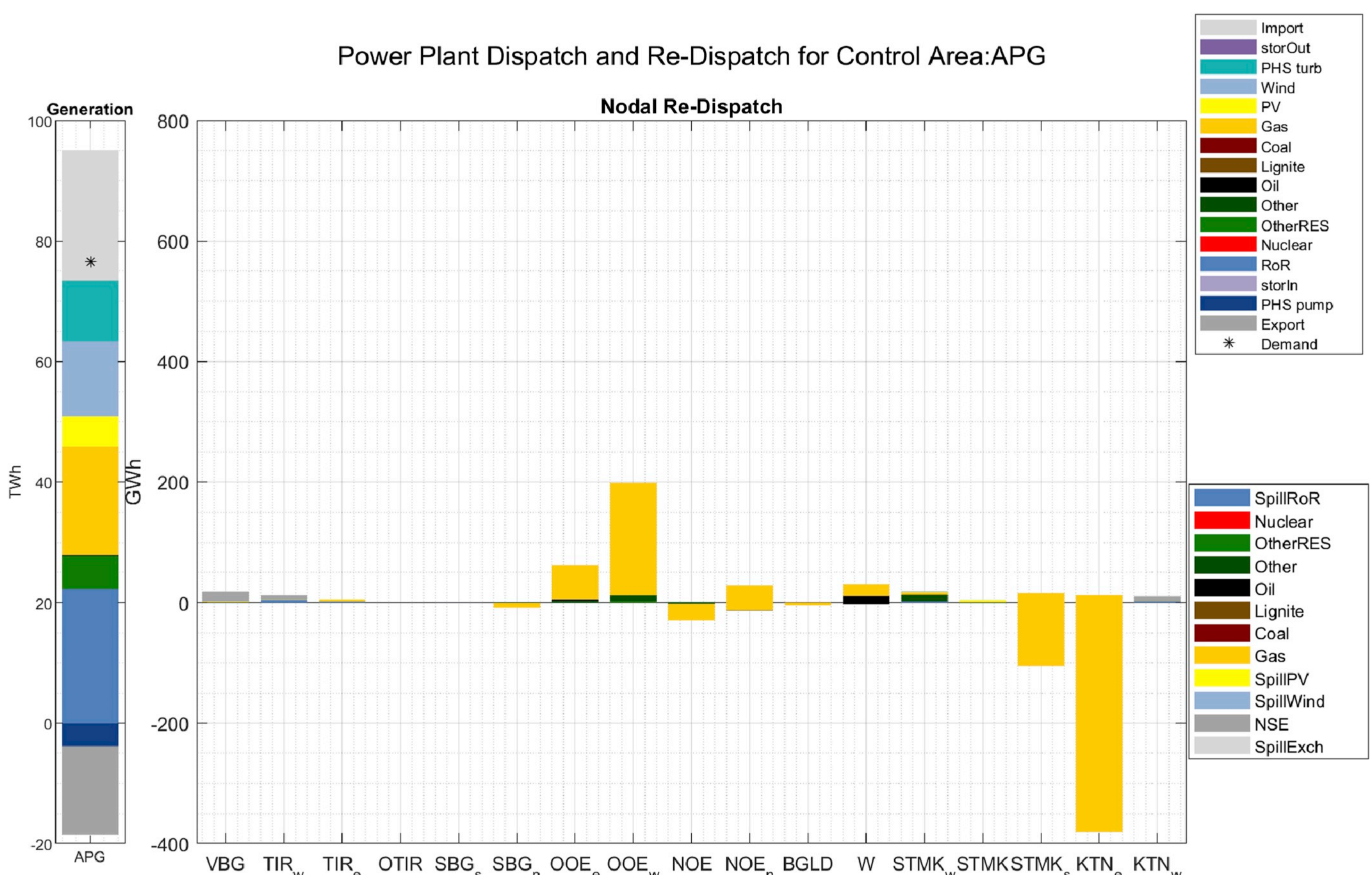


Fig. 9. Summarized congestion management balance for a simulated year with FBMC-clearing: APG.

European countries have a high need for redispatch due to the market design. Because of the high share of renewable energy in Germany and the limited line capacity on the border, positive redispatch is expected in Tyrol (TIR) and Upper Austria (OOE) as a consequence of the low price level (high price convergence) on the spot market induced by Germany.

As explained earlier, the overall amounts of necessary congestion management in the FBMC case are significantly lower, as Fig. 9 shows. The redispatch needs now shift within the control area. The main nodes affected now are Upper Austria (OOE) for positive redispatch and Styria (STMK) and Carinthia (KTN) for negative redispatch. An explaination for this is again the limited scope of the model regarding Southeast Europe and the following relocating of trade flows.

Mostly used generation capacity in both redispatch results is gas power plants. The reason for this is the low cost structure as part of the conventional power plant types. In other countries, it is however still possible that other power plant types are called for redispatch measures, depending on the individual cost structures of the available power plants.

The results deliver numerical evidence that the necessary congestion management heavily depends on the grid model that is used for market coupling, not only regarding the amount, but also regarding the distribution within the transmission network in a control area.

5. Conclusion and policy implications

The European Union introduced FBMC with the goal of an increase of the possible solution space for feasible spot market clearings. As a consequence, redispatch amounts were aimed to be reduced in order to obtain overall welfare increases for the European market for electricity. In this paper's work we provided evidence, that the grid model, which is used for market clearing, is a key factor that influences redispatch amounts. A representation of the physical grid characteristics, which is already used as a constraint for market clearing and its resulting dispatch and flows, reduces the necessary amount of congestion management and changes the location substantially. Besides, we can conclude, that the FBMC result, which respects the grid topology, leads to the superior market result regarding welfare.

These findings are of high significance for policy makers, both on national and European level. National TSOs can achieve efficiency gains by basing their grid expansion projects on a more precise identification of congestions in real-time grid operation. Market clearings incorporating the concepts of FBMC imply lower congestion in the national grid. From this result, the grid infrastructure can be utilized more efficiently, as necessary grid expansions might be reduced. Since not only the size, but also the location of necessary congestion management is influenced, a more precise localization of bottlenecks in the grid can be obtained and grid expansions costs reduced. Also, European entities like ENTSO-E can coordinate cross-border trade and integration of national markets more efficiently by incorporating FBMC in their analyses and forecasts. For example, the Mid-term Adequacy Forecast (ENTSO-E, 2018a) published by ENTSO-E is still based on NTC-trade, while only slowly incorporating the flow-based approach. Adequacy measures might be more precise by fully implementing the concept of FBMC. From this, a more efficient coordination of adequacy adjustments can take place. From a market perspective, the results we have obtained in this paper are also relevant for providing the right investment incentives for RES capacities by choosing appropriate policies. Including the physical grid aspects in the market clearing affects the capacity decisions of generators in the markets. Market prices are the main driver of investment decisions. Since price differences are driven by congestions in the network, a precise simulation of the grid under future scenarios is relevant for policy decisions like subsidies.

This paper's research can be extended in different ways for future research. In the current state, the models assumes market-based provision of redispatch. This means, every single power plant taking part in the spot market can be called for redispatch measures afterwards (if technically possible). In reality, only particular power plants are contracted with the respective TSO to provide redispatch capacity. This aspect can be of high significance for future research, too. The right choice of particular redispatch power plants within a control area can be determined in the context of FBMC. Another aspect is the depiction of the current state of FBMC in reality. FBMC is not yet fully implemented for the whole continent. In fact, a hybrid model that incorporates flow-based constraints for the CWE-region and NTC constraints for the rest of the countries, is implemented. A possible model configuration could depict this hybrid grid model for whole Europe in order to analyze short-term policies. However, our research's background are scenarios for the year 2030 and the FBMC region is clearly aimed to be extended in the future. Recalling this paper's results, an expansion of the FBMC region in Europe would lead to welfare increases regarding necessary congestion management cost and cost-efficiency of policies. Therefore, it is recommended to pursue this aim in the long run for policy makers in Europe. The overall welfare changes and efficiency gains can sum up in a quite short period of time already.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Basic model formulation - mathematical formulation

Sets and indices

$h \in H$ — h timesteps in H
$i \in I_{ca}$ — i balancing groups in control area ca (low granularity)
$j \in J_{ca}$ — j balancing groups in control area ca (high granularity)
$ca \in CA$ — ca control areas in CA
$th \in TH_{i/j}$ — th thermal power plants in TH as part of balancing group i/j
$st \in ST_{i/j}$ — st pump hydro storage units in balancing group i/j

Parameters for spot market simulation

MC_{th} — short-run marginal cost of th
c_{th}^{start} — start cost of th
$ramp_{th}$ — ramp limit of thermal power plants th
$Cap_{th}^{max/min}$ — max./min. capacity of thermal power plants th
η_{th} — efficiency of thermal power plants th
$Demand_{h,i}^{base}$ — demand of balancing group i in h

$VoLL$ value of lost load
$L_i^{up/down}$ possible demand flexibility factor in i
$c^{Wi/PV/RoR}$ generation cost of RES
Cap_i^{hy} max. capacity of run-of-river in i
$Inflow_{h,i}^{hy}$ natural inflow run-of-river in i in h
$Cap_{ps}^{Tu/Pu}$ max. turbine and pump capacity of ps
η_{ps}^{Tu}, η_{ps}^{Pu} efficiency of turbine and pump
$En_{ps}^{max/min}$ max./min. storage level of pumped hydro ps
$Infl_{h,ps}$ natural inflow of ps in h
$CapOut_{st}$ maximal discharge of st
$CapIn_{st}$ maximal charge of st
$\eta_{st}^{Out/In}$ storage efficiency with discharge/charge
$En_{st}^{max/min}$ max./min. storage level of st
$Wind_{h,i}$ generation of wind turbines of balancing group i in h
$PV_{h,i}$ generation of PV of balancing group i in h
$CapL_l^{(A\rightarrow B)(B\rightarrow A)}$ capacity limit of line l
$A_{l,i}$ incidence matrix
α^{max} max. of phase shifter angle
$PTDF_{l_{AC},i}^{i}$ power transfer distribution factors for balancing groups i grid
$PSDF_{l_{AC},l_{pst}}^{i}$ phase shift distribution factors for balancing groups i grid
$DCDF_{l_{AC},l_{DC}}^{i}$ DC lines distribution factors for balancing groups i grid

Decision variables for spot market
$thP_{h,th}$ generation of thermal power plant th in h
$D_{h,i}^{up}$ demand increase of node i in h
$D_{h,i}^{down}$ demand decrease of node i in h
$X_{h,th}^X, X_{h,th}^Y, X_{h,th}^Z$ linearization of thermal generation of th in h (binary)
$hyP_{h,i}$ generation of RoR of node i in h
$tuP_{h,i}$ generation of PHS of node i in h
$puP_{h,i}$ demand for pumping PHS of node i in h
$Str_{h,th}$ start decision for power plant th in h
$storL_{h,i}$ storage level of PHS of node i in h
$stPOut_{h,st}$ generation of other storage unit st in h
$stPIn_{h,st}$ generation of other storage unit st in h
$Spill_{h,i}^{Wi/PV/RoR}$ spillage of RES-E of node i in h
$NSE_{h,i}$ not supplied energy (load shedding) of node i in h
$Exch_{h,i}$ power injection in node i in h
$Flow_{h,l}$ power flow on line l in h
$\alpha_{h,i}$ phase shifter angle for node i in h

Basic model formulation

$$\begin{aligned} min\ totalcost^{spotmarket} = & \sum_{h\in H, ca\in CA, i\in I_{ca}} \sum_{th\in TH_i} \Big(thP_{h,th} \cdot MC_{h,th} + \\ & + Str_{h,th} \cdot c_{h,th}^{start} \Big) \\ & + \Big(Wind_{h,i} - Spill_{h,i}^{Wind} \Big) \cdot c^{Wi} + \Big(PV_{h,i} - Spill_{h,i}^{PV} \Big) \cdot c^{PV} \\ & + NSE_{h,i} \cdot VoLL \end{aligned} \tag{A.1}$$

Kirchhoff's first law - Power balance

$$\begin{aligned} Demand_{h,i} = & \sum_{th} thP_{h,th} + \sum_{ps} \big(tuP_{h,ps} - puP_{h,ps} \big) + \\ & + \sum_{st} \big(stPOut_{h,st} - stPIn_{h,st} \big) + hyP_{h,i} - Spill_{h,i}^{RoR} + \\ & Wind_{h,i} - Spill_{h,i}^{Wi} + PV_{h,i} - Spill_{h,i}^{PV} - Exch_{h,i} + NSE_{h,i} \\ & \forall h \in H, \forall i \in I_{ca} \end{aligned} \tag{A.2}$$

Generation capacity conditions

$$\begin{aligned}
&thP_{h,th} = X^X_{h,th} \cdot Cap^{min}_{th} + X^Y_{h,th} \cdot \left(Cap^{max}_{th} - Cap^{min}_{th} \right) \\
&\forall h \in H, th \in TH_i \\
&X^X_{h,th} - X^X_{h-1,th} \le Str_{h,th} \le 1 \quad \forall h > 1, th \\
&X^Y + X^Z \le X^X \le 1 \\
&X^X \ge 0, X^Y \ge 0, X^Z \ge 0, Str \ge 0 \\
&thP_{h,th} - thP_{h-1,th} \le ramp_{th} \cdot Cap^{max}_{th} \quad \forall h \ge 2, th \\
&-thP_{h,th} + thP_{h-1,th} \le ramp_{th} \cdot Cap^{max}_{th} \quad \forall h \ge 2, th \\
&0 \le Spill^{Wi}_{h,i} \le Wind_{h,i} \\
&0 \le Spill^{PV}_{h,i} \le PV_{h,i}
\end{aligned} \tag{A.3}$$

Storage constraints

$$\begin{aligned}
&0 \le puP_{h,ps} \le Cap^{Pu}_{ps} \quad \forall h \in H, ps \in PS_i \\
&0 \le tuP_{h,ps} \le Cap^{Tu}_{ps} \quad \forall h, ps \\
&0 \le stPIn_{h,st} \le Cap^{In}_{st} \quad \forall h, st \\
&0 \le stPOut_{h,st} \le Cap^{Out}_{st} \quad \forall h, st
\end{aligned} \tag{A.4}$$

$$\begin{aligned}
&storL_{h,ps} = storL_{h-1,ps} - \frac{tuP_{h,ps}}{\eta^{Tu}} + puP_{h,ps} \cdot \eta^{Pu} \\
&+Infl_{h,ps} - Spill^{PHS}_{h,ps} \quad \forall h \ge 2, ps \in PS_i
\end{aligned} \tag{A.5}$$

$$\begin{aligned}
&storL_{h,st} = storL_{h-1,st} - \frac{stPOut_{h,st}}{\eta^{stOut}} + stPIn_{h,st} \cdot \eta^{stIn} \\
&-DCharge_{h,st} \quad \forall h, st
\end{aligned} \tag{A.6}$$

$$\begin{aligned}
&0 \le Spill^{PHS}_{h,ps} \le Infl_{h,ps} \quad \forall h, ps \\
&En^{min}_{ps} \le storL_{h,ps} \le En^{max}_{ps} \quad \forall h, ps \\
&En^{min}_{st} \le storL_{h,st} \le En^{max}_{st} \quad \forall h, st \\
&0 \le stPIn_{h,st} \le Cap^{in}_{st} \quad \forall h, st \\
&0 \le stPOut_{h,st} \le Cap^{out}_{st} \quad \forall h, st \\
&0 \le DCharge_{h,st} \le storL_{h,st}
\end{aligned} \tag{A.7}$$

Demand side flexibilization

$$D^{up}_{h,i} = \sum_{h`=h}^{h+DT} D_{h`,h,i};\ D^{down}_{h,i} = \sum_{h`=h}^{h+DT} D_{h,h`,i} \sum_{h`=h}^{h+DT} D_{h`,h,i} = \sum_{h`=h}^{h+DT} D_{h,h`,i} \tag{A.8}$$

$$\begin{aligned}
&0 \le D^{up}_{h,i} \le L^{up}_i \cdot Demand^{base}_{h,i} \\
&0 \le D^{down}_{h,i} \le L^{down}_i \cdot Demand^{base}_{h,i}
\end{aligned} \tag{A.9}$$

$$\begin{aligned}
&0 \le D^{up}_{h,i} \le L^{up}_i \cdot Demand^{base}_{h,i} \\
&0 \le D^{down}_{h,i} \le L^{down}_i \cdot Demand^{base}_{h,i}
\end{aligned} \tag{A.10}$$

Load flow linearization

$$\begin{aligned}
&PTDF^i_{l_{AC}xI} = (B_d \cdot A_{l,i}) \cdot \left(A^T_{l,i} \cdot B_d \cdot A_{l,i} \right)^{-1} \\
&PSDF^i_{l_{AC}xL_{pst}} = B_d - (B_d \cdot A_{l,i}) \cdot \left(A^T_{l,i} \cdot B_d \cdot A_{l,i} \right)^{-1} \cdot (B_d \cdot A_{l,i})^T \\
&DCDF^i_{L_{AC} \cdot L_{DC}} = -PTDF \cdot A^T_{l_{DC},i}
\end{aligned} \tag{A.11}$$

Appendix B. Abbreviations for nodes

Abbreviation	Node
VBG	Vorarlberg
TIR_w	Tyrol (West)
TIR_e	Tyrol (East)
OTIR	Eastern Tyrol
SBG_s	Salzburg (South)
SBG_n	Salzburg (North)
OOE_e	Upper Austria (East)
OOE_w	Upper Austria (West)
NOE	Lower Austria

(*continued on next page*)

(*continued*)

Abbreviation	Node
NOE_n	Lower Austria (North)
$BGLD$	Burgenland
W	Vienna
$STMK_w$	Styria (West)
$STMK$	Styria
$STMK_s$	Styria (South)
KTN_e	Carinthia (East)
KTN_w	Carinthia (West)

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