Integration of day-ahead market and redispatch to increase cross-border exchanges in the European electricity market

Poplavskaya, Ksenia; Totschnig, Gerhard; Leimgruber, Fabian; Doorman, Gerard; Etienne, Gilles; de Vries, Laurens

DOI
10.1016/j.apenergy.2020.115669

Publication date
2020

Document Version
Final published version

Published in
Applied Energy

Applied Energy 278 (2020) 115669

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Integration of day-ahead market and redispatch to increase cross-border exchanges in the European electricity market

Ksenia Poplavskaya[a,b,*], Gerhard Totschnig[a], Fabian Leimgruber[a], Gerard Doorman[c], Gilles Etienne[d], Laurens de Vries[b]

[a] AIT Austrian Institute of Technology, Center for Energy, Electric Energy Systems, 1210 Vienna, Austria
[b] Delft University of Technology, Faculty of Technology, Policy, and Management, 2600 GA Delft, the Netherlands
[c] Statnett, Market Development, Nydalen Allé 33, 0484 Oslo, Norway
[d] Elia, Keizerslaan 20, 1000 Brussels, Belgium

HIGHLIGHTS

- European market integration is limited by frequent intrazonal congestion.
- A novel methodology is proposed to increase cross-border exchanges using redispatch.
- Integrating redispatch into the day-ahead market helps avoid congestion.
- Proposed approach enhances flow-based market coupling increasing economic welfare.

ARTICLE INFO

Keywords:
Flow-based market coupling
Redispatch
Congestion management
Cross-border exchange
Energy system optimization

ABSTRACT

The zonal electricity market design in the Central Western European electricity market relies on redispatching generation units after market closure to manage congestion within bidding zones, while congestion between the zones is handled using flow-based market coupling. The combination of internal congestion in the meshed European network with a growing share of renewables increases the frequency and magnitude of congestion events and limits cross-border trade. The growing costs of redispatching and the divergence between grid physics and zonal markets lead to welfare losses. This paper is the first to propose an approach to improve the combined efficiency of flow-based market coupling and redispatching. We develop a novel methodology for congestion management in a zonal market with flow-based market coupling in order to increase cross-border exchanges by integrating preventive redispatch into the day-ahead market. In this approach, a set of integrated redispatch units is selected based on their high potential to reduce congestion and, as a result, free up grid capacity for cross-border exchange. We use three multi-step optimization models to demonstrate the benefits of the enhanced zonal market with integrated redispatch by comparing it to the nodal market model and a zonal market model with flow-based market coupling. The case study demonstrates the potential of the proposed methodology to significantly increase cross-border capacity and reduce the need for costly *ex post* redispatch. The approach is shown to be a feasible option for improving European market integration and thereby to achieve overall welfare gains.

1. Introduction and background

Zonal electricity market results can produce flows that exceed available capacity on some transmission lines, creating congestion. With the fast-growing share of variable renewable energy sources (vRES) and other distributed energy resources in the European power networks, the

Abbreviations: CACM, capacity allocation and congestion management guideline; EU, European Union; FBMC, flow-based market coupling; GSK, generation shift key; IRD, integrated redispatch; LTN, long-term nomination; NEX, net exchange; NTC, net transfer capacity; PTDF, power transfer distribution factor; RAM, remaining available margin; SDAC, single day-ahead market coupling; TSO, transmission system operator; vRES, variable renewable energy sources.

* Corresponding author at: AIT Austrian Institute of Technology, Center for Energy, Integrated Energy Systems, Giefinggasse 6, 1210 Vienna, Austria.
E-mail address: ksenia.poplavskaya@ait.ac.at (K. Poplavskaya).

https://doi.org/10.1016/j.apenergy.2020.115669
Received 21 April 2020; Received in revised form 31 July 2020; Accepted 6 August 2020
Available online 18 August 2020

occurrence and magnitude of congestion are increasing [1].

In the European Union (EU), the European institutions and transmission system operators (TSOs) are becoming concerned with the growing frequency of congestion events and the resulting increase in costs of remedial actions that the TSOs need to take [2]. For instance, in Germany, the cost of remedial actions exceeded one billion euro in 2018[1] [3]. Redispatch is one of the remedial actions that allows TSOs to regulate a power plant downward upstream of congestion and another plant upward downstream of congestion against remuneration after the market clearing. The costs of congestion management in Europe are largely passed on to consumers in the form of higher grid tariffs negatively affecting overall economic welfare. Therefore it is important to address ways in which the volume of costly *ex post* redispatch can be reduced.

Internal congestion in the highly meshed European networks further causes unscheduled power flows among neighboring zones. This exacerbates congestion and limits capacity for cross-border trade, decreasing the economic efficiency of generator dispatch. In order to increase the volume of transmission capacity that is available for cross-border trade, flow-based market coupling (FBMC) was introduced in 2015 in the six countries[2] of Central Western Europe as an alternative to the net transfer capacity (NTC) method that was used until then and is still applied in the rest of the EU [4] (cf. Sections 1.1 and 2.2). Yet, grid representation in zonal market coupling is inherently imprecise as only a limited number of grid constrains is taken into account. Besides, if dispatch is altered extensively outside the market *ex post*, large differences between the market results and actual physical flows also risk to dilute the day-ahead market price signals and further reduce economic welfare [5]. Researchers (e.g. [6]) warn that the current aggregated view of the meshed European network is bound to produce more operational problems. According to the Belgian regulator, CREG, *"system security is at risk due to a lack of anticipation of remedial actions in the grid models, which lead to erroneous load flow calculations at different stages"* and a high probability of uncoordinated flows, i.e. those not accounted for in the coordinated grid models [7, p. 29].

In this paper, we investigate the integration of preventive redispatch into the day-ahead market to optimize cross-border trade, making an explicit tradeoff between redispatch costs and welfare gains. In doing so, we intend to provide a practicable solution for maximizing the utilization of cross-border capacities and demonstrate its potential to improve cost efficiency and increase economic welfare.

The rest of the paper is structured as follows: Section 1.1 explains the links between FBMC and internal congestion along with the associated issues whereas Section 1.2 provides motivation for the new approach to tackling them and its expected contribution. The proposed methodology is formulated in Section 2. The results of the implementation of the new approach and its comparison with the existing nodal and zonal market designs are illustrated using a two-zone case study in Section 3 and discussed in Section 4. Section 5 concludes.

1.1. The relationship between flow-based market coupling and congestion within a zone

In contrast to the centralized approach of security-constrained economic dispatch that is applied in countries such as the U.S. and Australia, the dispatch in the countries of the EU is largely de-coupled from grid constraints within zones. Most European countries represent a single bidding zone (with the exceptions of Italy and the Nordic region). Researchers in [8] compared nodal and zonal market designs and showed that market design had a direct and tangible influence on the grid situation. Zonal market design, they found, created such challenges as unscheduled cross-border flows and efficiency losses [8]. Although it did allow to increase market liquidity, congestion in zonal markets was "unavoidable" by design [6]. One of the consequences is a suboptimal use of cross-border transfer capacity.

In Central Western Europe, FBMC was introduced as an integral part of the EU Electricity Target Model in order to optimize and increase the amount of transfer capacity for integrated markets [4]. As FBMC was implemented less than five years ago, the available body of research is still limited. For instance, researchers in [9] provided the first overview of the main FMBC parameters soon after its official implementation. Authors in [10] discussed the implications of FBMC implementation, focusing on the increased transparency of congestion data from the point of view of traders. An overview of the differences between the commonly applied NTC (net transfer capacity) approach and FBMC is provided in [11].

In both approaches a feasible flow domain is determined. This is a combination of feasible import/export positions for each bidding zone, considering exchanges among all the involved zones and the grid security limits. In NTC, zonal borders are used in the cross-border capacity calculation process. In FBMC, the feasible domain is determined by calculating the impact of the flows in each zone on each critical element. These elements include critical branches between the zones, some branches inside the zones as well as critical generator outages [12]. Based on monitoring and experience, TSOs consider elements as critical if their states are likely to be affected by cross-border exchanges. The impact on the critical elements is determined with power transfer distribution factors (PTDFs) that are derived from a linearized DC load flow calculation. The resulting feasible flow domain that is delimited by the physical constraints for all critical branches and outages is usually larger than the feasible flow domain that results from the NTC approach, leading to more available cross-border network capacity without jeopardizing system security [11]. Given the benefits of FBMC, flow-based capacity calculation is to be introduced in all "highly interdependent" bidding zones in the EU, following the Guideline on Capacity Allocation and Congestion Management (CACM) [13]. This requirement is applicable unless the TSOs can demonstrate that for certain zones the application of the flow-based approach would not yet be more efficient compared to the coordinated NTC approach (Art. 20.7 [13]).

Although the FBMC approach was shown to create efficiency gains, it still has a number of issues that so far remain unresolved and may affect its efficiency. Firstly, the process of calculating available cross-border capacity is based on estimated market results. TSOs calculate the capacity that is available for cross-border exchange two days ahead of delivery, based on forecasts of conventional and renewable energy generation, load and outages (the D2CF: day-minus-two congestion forecast). Information about the expected flows for the so-called Base Case (cf. Section 2.2) is obtained by merging the D-2 congestion forecasts of all TSOs, after which their hourly results are transferred to the power exchange a day ahead of delivery. The reference flows from the Base Case prior to the allocation of day-ahead capacity are then used to calculate the remaining available margin (RAM), i.e. the capacity available for cross-border trade (cf. Section 2.2) creating the link between the grid and the market. Yet, information about the actual (as opposed to projected) generation and demand is available to the TSOs only after market clearing, which in turn requires information about the cross-border capacity available for trade. This situation is often referred to as a "chicken and egg problem" (e.g. [14]). The imprecision of this process means that cross-border capacity is not used efficiently.

Secondly, the way in which the flow-based parameters are calculated is inherently imprecise. The effect of a power flow between two zones on a network element is represented with the help of zonal PTDFs. Zonal PTDFs are calculated as averages of nodal PTDFs that are weighted with generation shift keys (GSKs) per node (cf. Section 2.2). GSKs describe the extent to which the output of individual generators is adjusted due to line flow changes resulting from a change of a zone's net export position

[1] Such remedial actions, according to ACER, include redispatch, countertrading and other measures for congestion management such as grid reserve [3].

[2] Austria, Belgium, France, Germany, Luxemburg, and the Netherlands.

(NEX), i.e. the difference between its imports and exports. There is so far no harmonized way for their determination: the methods vary among Central Western European countries, e.g. pro-rata for all flexible units or based on generators' costs [9], and rely heavily on heuristics [15]. Several researchers investigated and compared GSK methodologies. The results presented in [16] showed how the choice of the GSK methodology could affect the size and shape of the flow-based domain. The authors in [15] studied the impact of the GSK method on the efficiency of FBMC and found that the impact is high as long as no internal congestion is present. Otherwise, the influence of the choice of GSK method becomes marginal [15]. Therefore, the third crucial factor affecting the efficiency of FBMC is internal congestion [7]. Research shows that the expected efficiency of FBMC as compared to the nodal outcome falls to almost half in the presence of internal congestion [15]. Other researchers stressed that in order to ensure the integration of renewables, it was important to consider internal congestion in network and market models [8].

There are a number of ways addressed in literature in which the efficiency of congestion management can be improved. They include addressing the deficiencies of the zonal markets, TSO cooperation mechanisms, and market-related measures. One of the proposed solutions to tackle frequent structural congestion is to redefine the bidding zones [17] in order to align their borders with the locations of expected bottlenecks or to increase bidding zone granularity. However, redefining of the bidding zones remains a highly contentious issue in Europe [5]. How small is small enough – if the nodal approach is not an option – is a difficult (and political) question. Besides, bidding zone redefinition solves congestion issues only temporarily: once new generation or load is connected elsewhere, congestion is likely to occur again and a new redefinition would be necessary [13]. Coordinated cross-border redispatch (or countertrading) is another way to increase the efficiency of remedial actions but requires more coordination and cooperation among the TSOs. A common TSO methodology is under development in accordance with Article 35 of the CACM [13]. Some Member States use intraday markets to improve congestion management, as more reliable forecast information is available. For instance, the Spanish TSO uses a dedicated market (*mercado de solución de restricciones técnicas*) in the intraday phase and the Dutch TSO uses intraday market bids to solve some of the congestion (GOPACS project [18]). These approaches – although useful in addressing congestion *ex post* day-ahead market – treat the symptom rather than the cause of congestion, inherently imprecise grid representation in zonal markets. In addition, the potential of such improvements is limited by the low degree of harmonization of intraday markets [19] and heterogenous approaches to redispatch.

Current redispatch practices are also suboptimal because only limited resources – primarily large power plants – are utilized. Besides, the purpose of redispatching is currently not to minimize costs but only to relieve constraint violations [17], which is the most straightforward but typically not the most cost-efficient approach. A way to increase the resource availability for congestion management that was addressed in several research and pilot projects is to utilize a larger number of small generators and demand-side flexibility [20]. For instance, researchers in [21] pointed out the risk that future resources to deal with congestion might be insufficient in Germany. They proposed the use of electric vehicle charging for congestion management. Flexibility market concepts have been developed in the projects ENKO in Northern Germany [22] and USEF [23]. In a recent study that has its roots in the approach proposed in this paper, the Belgian TSO, Elia, proposed to include additional flexibility options such as phase shifting transformers and high voltage direct current lines as well as flexible generation, into the market coupling to offer more degrees of freedom in tackling congestion and increasing cross-border trade [5].

1.2. Motivation and contribution

Ensuring effective EU electricity market integration by increasing cross-border exchanges and tackling congestion more efficiently is at the top of the EU's energy policy agenda [1]. Cross-border transfer capacity is limited by a number of factors such as line constraints and long-term trade commitments. Furthermore, it is affected by the network use *within* a zone since in an interconnected system internal flows have a direct impact on cross-zonal flows. Progressive integration of renewables and distributed resources is likely to increase the number of congestion events [24]. Frequent internal congestion leads to an inefficient use of the interconnectors and a lower economic welfare.

Given these challenges, in this paper a novel approach is proposed which integrates preventive redispatch in the day-ahead market (hereafter *integrated redispatch (IRD)*). It combines the characteristics of nodal network representation only for IRD units in the zonal markets, which use a flow-based approach to market coupling. The expected added value of integrating the effect of redispatch units on the network *ex ante* is an improved use of cross-border capacity and market outcome, that is, a better price convergence between the zones. Arguably, accounting for the impact of redispatch units on critical network elements during day-ahead market clearing can reduce residual congestion, leading to cost savings and to approaching a system optimum.

The proposed method replicates the operating principles of FBMC. It is meant to improve the efficiency of FBMC in two ways:

(1) by allowing to account for redispatch during the day-ahead market stage and thus (largely) avoid costly *ex-post* redispatch;
(2) by allowing redispatched generators to free up capacity on congested lines and thus increase cross-border the transmission capacity and therefore to dispatch more cost-efficient generators.

Finally, this paper presents the first comprehensive discussion of the relation between FBMC and congestion management as well as a first solution to improve their joint efficiency. This is particularly important given the planned implementation of the FBMC approach in the EU beyond Central Western Europe.

2. Methodology

In this Section, the proposed methodology for enhancing FBMC and addressing grid congestion is formulated (Section 2.3). In order to demonstrate how it compares to the existing approaches, we first formulate the nodal market (Section 2.1) and the zonal market with FBMC in Central Western Europe (Section 2.2.):

(1) Nodal market

This setup (hereafter the *nodal model*) models optimal dispatch of generators according to locational marginal pricing. It is based on the marginal value of power in each node, given demand and network constraints. The output is based on an exact representation of the grid, with all nodes and constraints for all network branches taken into account in the process of market clearing [25]. From a purely economic perspective, the nodal market is considered to be the most efficient, as is shown in e.g. [26]. Nodal prices do not just include the cost of production of energy but also its delivery to the point of consumption right from the start, leading to efficiency gains compared with the zonal model (e.g. [27,28]). This setup is therefore used as the benchmark for the study.

(2) Zonal model with FBMC and *ex post* redispatch

This setup emulates the current practice in Central Western Europe (hereafter the *business-as-usual model*). The nodes are assigned to bidding zones and only the flows on some lines are considered for the flow calculation, which may therefore lead to an infeasible dispatch, e.g. due to internal congestion. *Ex-post* redispatch is conducted in case of congestion.

(3) Proposed approach: Zonal model with FBMC and integrated redispatch (IRD)

This setup (hereafter the *model with integrated redispatch*) represents a middle ground between the benchmark and the current practice. A number of generation units are selected based on their relevance for redispatch. Their impact on the flows on the critical branches, i.e. nodal PTDFs, is calculated in addition to the "classic" zonal PTDF in the flow-based domain.

The *nodal model* is solved in one step, while the zonal *business-as-usual model* and the zonal *model with integrated redispatch* are solved in several optimization steps, as illustrated in Fig. 1.

Both the *business-as-usual model* and the *model with integrated redispatch* rely on the same Base Case to obtain zonal PTDFs, expected generation values and flows on the critical branches. Next optimization step represents single day-ahead market coupling in the *business-as-usual model.* In the *model with integrated redispatch*, day-ahead dispatch and possible redispatch action are co-optimized. Due to the inherent approximation character of zonal PTDFs, some residual redispatch might still be needed also in the *model with integrated redispatch*. The final step in the *business-as-usual model* and in the *model with integrated redispatch* uses the same algorithm and is contingent on the state of the grid and whether the dispatch resulting from the day-ahead market clearing is feasible, i.e. no physical grid constraints are violated.

In the zonal setup with integrated redispatch, a only subset of generators can be used for integrated redispatch whereas if any residual redispatch is still necessary, all generators can be activated *ex post*. The model used in this study is solved for one time step, intertemporal constraints are not considered. Further model assumptions are listed in Appendix A.

In the model, a distinction is be made between dispatchable generators, whose output can change depending on the market outcome, and non-dispatchable generators, such as variable renewables. While for the former the capacity constraint is $d_g \leq D_g^{max} \forall g \in G^{disp}$, for the latter it is $d_g = D_g^{max} \forall g \in G^{non-disp}$, where d_g is the dispatch of generator g. Besides, non-dispatchable generators cannot be redispatched *ex post* unless curtailment is allowed. Finally, in the zonal models, such generators are excluded from the calculation of GSKs due to their fixed output (see also Section 2.2.2).

The modelled setups and each of the steps involved are explained in more detail in the following sub-sections.

2.1. Nodal model

The model represents optimal dispatch of generators and is subject to nodal energy balances, flow and generation limits and non-negativity constraints. It considers the state of the entire network explicitly in order to identify the least-cost dispatch by using nodal power balance and nodal PTDFs for each power line. The objective function is formulated as the minimum-cost dispatch, $\boldsymbol{d}_g$, of all generators:

$$\min \sum_{g=1}^{G} \boldsymbol{d}_g * c_g \tag{1}$$

$$\text{s.t.} -(F_b - FRM_b^{\text{nod}}) \leq \boldsymbol{f}_b \leq (F_b - FRM_b^{\text{nod}}), \forall b \tag{2}$$

$$\boldsymbol{f}_b = \sum_{n=1}^{N} PTDF_{b,n}^{\text{nod}} * \boldsymbol{p}_n \tag{3}$$

$$\boldsymbol{p}_n = \sum_{g=1}^{G_n} \boldsymbol{d}_g - l_n, \forall n \in N \tag{4}$$

The optimization function is subject to the flow-limit constraint (Eq. (2)), in which $\boldsymbol{f}_b$ is the flow of branch b, F_b is the maximum flow on the branch and *FRM* is the flow reliability margin, which is usually set by the TSO for each branch. The flow on branch $\boldsymbol{f}_b$ (Eq. (3)) is the product of the total active power injection $\boldsymbol{p}_n$ at node n and the nodal PTDF on branch $b$for node n. Finally, the nodal injection constraint (Eq. (4)), in which l_n is the load on node n is observed. The notation used in the paper is summarized in Appendix B. In the nodal model, all generators and all branches are included in the calculations.

Nodal PTDFs are defined based on [29] as:

$$PTDF^{\text{nod}} = \boldsymbol{SK}^T \Lambda^* \tag{5}$$

where $\Lambda = \boldsymbol{KSK}^T$ and $\Lambda^*$is the pseudo-inverse of Λ, which avoids the need for a slack node (reference node).

Nodal PTDFs represent the extent to which a given branch is affected by a marginal change of injection. Even when the output of a single generator changes, power flows change on many lines, including those not directly linked to the generator's node. This can also lead to line capacity violations on a non-adjacent line. In other words, congestion can be produced on a branch, which is not directly linked to the actual source of congestion due to the distribution of the physical flows.

The prices on all nodes converge when there is no congestion anywhere in the network and losses are disregarded. Otherwise, congestion produces different nodal market prices (see Section 3). For the calculation of consumer surplus in the nodal model, we assume that consumers are exposed to the actual price of their node[3]. Generators are remunerated according to the nodal marginal price. Finally, congestion rent is calculated per branch as the price difference between the nodes at the ends of the branch and the volume transported.

For all setups, since the demand in this analysis is assumed to be inelastic, the value of lost load (VOLL) or the cost of avoiding load shedding is used to denote consumers' willingness to pay and assumed to be equal to 1000 Euro/MWh.

2.2. Zonal model with flow-based market coupling

This is a multi-stage linear optimization problem that is solved in three steps, Base Case, single day-ahead market coupling and *ex post* redispatch. As per the principles of FBMC, not only interconnectors but also some internal power lines are considered to be critical branches.

2.2.1. Base Case

In the first step, the Base Case is formulated, which entails a forecast of the flows, generation and zonal net export positions (NEX) that are to be used in the next step, the day-ahead market coupling.

In practice, hourly D-2 congestion forecasts are produced by each TSO as inputs for the FBMC calculation. TSOs use historical grid states as a starting point. The obtained information is then adjusted to account for estimated generation from renewables, plant outages, generator output and the changes in the net position forecast [30]. Then, the D-2 congestion forecasts from all participating TSOs are merged into a single Base Case, which serves as the starting point of the FBMC and considers the expected volume of commercial exchanges between the zones [12].

The load flows are estimated based on a reference day in order to calculate the flow-based parameters for the pre-defined critical branches and critical outages. Based on zonal PTDFs and the volume of commercial exchanges, the available capacity on each line is first calculated to represent a situation where there are no commercial exchanges. During the market coupling, the same zonal PTDFs are used to calculate the impact of a market exchange on the limiting branches. If the market outcome is the same as the estimation of the TSOs, then the grid models will be identical. As a result, the delta between the expected reference dispatch and the actual dispatch will be zero and the reference flows will be equal to the Base Case flows.

In the capacity allocation process, the Base Case is the starting point for linearization. The formulation of a Base Case presents a modelling challenge as it includes TSOs' estimations based on the historical values for reference days (the flows obtained from the Base Case calculation are

[3] Another approach implemented, for instance, in some of the US electricity markets, would be to expose only generation to the nodal prices while consumers pay the average price in a given region (cf. [26])

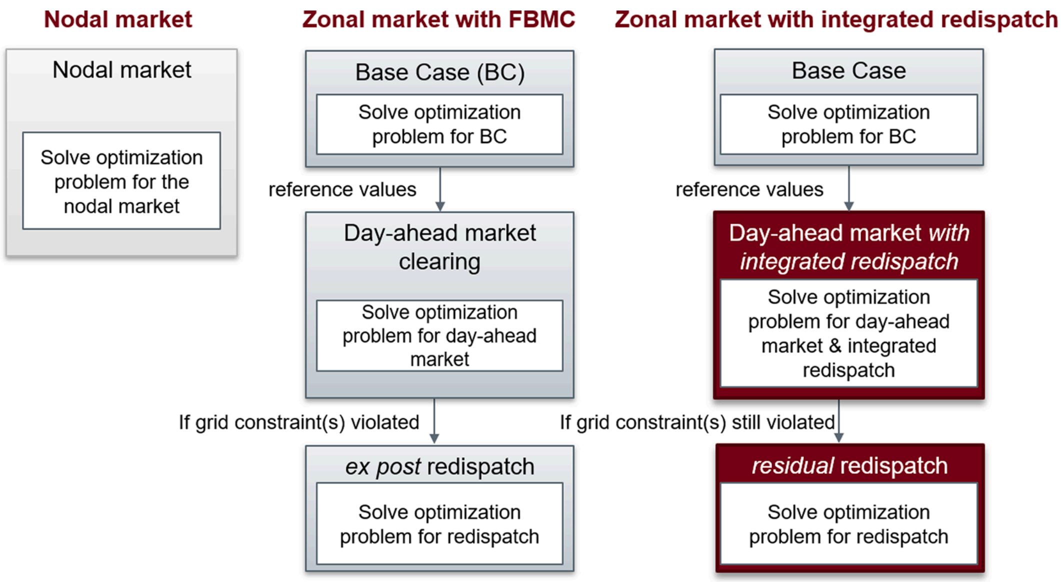

Fig. 1. Model flow charts for the three analyzed setups, nodal, zonal with flow-based market coupling as currently applied in Central Western Europe and the proposed approach integrating day-ahead market clearing and redispatch.

therefore referred to as reference flows). Using a fully nodal model for this step would be unrealistic because the solution would have the optimal interzonal power exchange. This would imply that the TSO would have perfect foresight of the load levels, generation and prices that would result from the market clearing. In order to demonstrate the differences between the *business-as-usual model* and in the *model with integrated redispatch*, imperfect foresight of the TSO needs to be simulated. To this end, the common Base Case is first calculated with the flows that result from the complete network representation, as derived from the nodal model (see Section 2.1). Next, they are reduced in this optimization step, by adding an additional constraint (Eq. (6)). The total flow on all interconnectors cannot exceed the total reference flow limited by a coefficient representing the interconnector share[4]:

$$-\left|\sum_{b\in IC(z_1,z_2)} f_b^{ref}\right| * s^{IC} \le \sum_{b\in IC(z_1,z_2)} \boldsymbol{f_b} \le \left|\sum_{b\in IC(z_1,z_2)} f_b^{ref}\right| * s^{IC}, \forall z_1, z_2 \in Z \tag{6}$$

where $IC(z_1, z_2)$ are a set of interconnector branches between any two zones, s^{IC} is the share of interconnector capacity and f_b^{ref} is the flow on a branch from the full nodal model (cf. Eq. (3)).

The objective function is identical to the one used in the nodal setup (Eq. (1)) and is aimed at minimizing total system costs. The net export position (NEX) per zone is equal to the net power injection in the zone and is calculated as follows:

$$\boldsymbol{NEX_z} = \sum_{n=1}^{N_z}\left(\sum_{g=1}^{G_n} \boldsymbol{d_g} - l_n\right), \forall z \in Z \tag{7}$$

The expected flows on the critical branches together with the expected generation values from the Base Case are passed on to the next simulation steps as reference values.

2.2.2. Day-ahead market coupling

In the day-ahead market, the cost of dispatch is minimized based on the feasible domain for cross-border exchanges and disregarding intrazonal flow constraints. The optimization minimizes total system costs subject to the flow limits, the zonal energy balance and generator non-negativity constraints. The flows resulting from FBMC are equal to the reference flow f_b^{ref} from the Base Case adjusted with the sum of the product of zonal PTDFs on each branch $PTDF^{zon}_{b,z}$ and the difference in the total zonal generation as compared to the Base Case $\Delta \boldsymbol{p_z}$:

$$\boldsymbol{f_b^{FBMC}} = f_b^{ref} + \sum_{z=1}^{Z} PTDF^{zon}_{b,z} * \Delta \boldsymbol{p_z}, \forall b \in CB \tag{8}$$

Zonal PTDFs $PTDF^{zon}$ represent the change of flow on the lines in case of a change of NEX of one megawatt and use GSKs to allocate different shares of generation to various power plants:

$$PTDF^{zon}_{b,z} = \sum_{n=1}^{N_z} PTDF^{nod}_{b,n} * GSK_{n,z}, \forall b \in CB, \forall z \in Z \tag{9}$$

As a result, they represent the approximated version of the actual flows. Zonal PTDFs represent the influence of those zones on the congested critical branch: the higher the PTDF, the higher the impact.

For the purposes of the present analysis, GSKs are based on the installed capacity of power plants in the zone.

$$GSK_{n,z} = \frac{\sum_{g=1}^{G_n} D_g^{max}}{d_z}, \forall n \in N_z \forall z \in Z \tag{10}$$

$$d_z = \sum_{g=1}^{G_z} D_g^{max}, \forall z \in Z \tag{11}$$

$$\sum_{n=1}^{N_z} GSK_{n,z} = 1, \forall z \in Z \tag{12}$$

where D_g^{max} is the maximum dispatch of generator g and d_z is the total dispatch of all generators in zone z. It follows that the GSKs and the zonal PTDFs are independent from the Base Case results. Note that in the calculation of the GSKs, *only dispatchable* generators capable of responding to market signals are considered. Any must-run generators are excluded due to their fixed output. All GSKs within a zone must sum up to one (Eq. (12)).

According to the principles of FBMC, the remaining available margin

[4] In the modelled scenarios, the interconnector share was set to 50%. The closer the share is to 100%, the closer is the TSO foresight to a perfect one and the lower is the ability of the zonal approach with integrated redispatch to increase the exchange cost-efficiently.

(RAM) for day-ahead trade accounts for the share of the total capacity reserved for other types of trade [9] and security margins[5], which are subtracted from the maximum thermal capacity for each critical branch. For this simulation, these values are disregarded and it is assumed that all the available transfer capacity is used for day-ahead trade.

The zonal prices are determined based on the merit order considering the amount of capacity available for cross-border exchange. In the zonal *business-as-usual model*, these prices are calculated as the dual of the zonal energy balance for each zone (eq. (4) for all nodes in a given zone). These correspond to the cost of the zonal marginal generator. If no inter-zonal congestion occurs, the prices will be the same across the zones. In an event of congestion on any of the critical branches, market splitting produces different prices in the zones.

2.2.3. Ex post redispatch

Since only critical branches are included in FBMC and the GSKs are inaccurate, the actual grid constraints may still be violated by the market outcome. In the final step, the model checks whether the commercial transactions from the day-ahead market clearing are physically feasible and if not, infeasible flows are corrected by redispatching some units *ex post*.

The objective function for *ex post* redispatch is formulated as:

$$\min \sum_{g=1}^{G^{\mathrm{RD}}} \gamma\left(c_g * \Delta \boldsymbol{d}_g^{\mathrm{pos}} - c_g * \Delta \boldsymbol{d}_g^{\mathrm{neg}}\right) + \lambda * k_z^{\mathrm{FBMC}} * (\Delta \boldsymbol{d}_g^{\mathrm{pos}} + \Delta \boldsymbol{d}_g^{\mathrm{neg}}) \tag{13}$$

where is $k_z^{FBMC}$is the zonal market price and coefficients $\gamma$and λ denote cost-based and volume-based TSO penalties for redispatch, respectively. The values $\Delta \boldsymbol{d}_g^{\mathrm{pos}}$ and $\Delta \boldsymbol{d}_g^{\mathrm{neg}}$ represent the changes in the dispatch of generator$g$ upward or downward, respectively. Their absolute values must be equal so as to preserve the energy balance in the zone. If $\gamma = 0$ and the value of λ is set to 1, the redispatch volume and therefore intervention into the market outcome is minimized. In contrast, if $\gamma = 1$ and $\lambda = 0$, the optimizer would attempt to improve the market outcome minimizing total costs. The common approach in Europe today is to relieve congestion only, which is better represented by the former approach and is used in the simulation. All grid constraints are enforced.

In order to make sure that the results from the *business-as-usual model* are not skewed by additional factors as compared to the zonal setup with integrated redispatch, in the objective function in Eq. (13), generator bids are assumed to be equal to their marginal costs, c_g. That is, generators do not additionally profit from activation for redispatch. In reality, the difference between the two is possible close to real time both due to the generators' technical constraints and due to lower competition levels where a generator could potentially exploit their locational advantage.

Concerning model output, the total welfare in the zonal business-as-usual setup is the sum of producer and consumer surplus and the congestion rent. It is reduced by the costs incurred from activating redispatch. Congestion rent is calculated as the price difference between two zones multiplied by the flow between these zones, from the low-price zone to the high-price one. Similar to the *nodal model*, consumers' willingness to pay is equal to the value of lost load whereas generator profits are calculated as the difference between their revenues and marginal costs.

2.3. Zonal model with integrated redispatch

The key idea of integrating redispatch with the day-ahead market is that a selected number of power plants are determined by the TSO as relevant for redispatch (see Section 4 for a further discussion). Integrated redispatch (IRD) units are included in the optimization model with their real impact on critical branches. That is, for such generators, nodal PTDFs are considered, which can help expand the feasible domain in FBMC. In other words, instead of redispatching these units after the market clearing, their impact is already taken into account during market clearing. As a result, more capacity is expected to be available to the market, less congestion will occur after the market clearing, and only residual redispatch may need to be dealt with *ex post*.

Importantly, IRD units participate in the day-ahead market on par with all the other generators but are the only ones whose dispatch can deviate from zonal market outcome in case of congestion. In contrast, the dispatch of the other generators impacts the lines only via zonal PTDFs.

2.3.1. Base case

The Base Case is formulated in the same way as for the zonal business-as-usual setup (see Section 2.2.1).

2.3.2. Day-ahead market coupling with integrated redispatch

In the second optimization step, however, the objective function is adjusted to account for the costs of upward and downward integrated redispatch:

$$\min \sum_{g=1}^{G} \boldsymbol{d}_g^{\mathrm{IRD}} c_g \tag{14}$$

where c_g is the bid offered on the day-ahead market and the decision variable $\boldsymbol{d}_g^{\mathrm{IRD}}$represents the actual generation *after* accounting for integrated-redispatch action (see also Eq. (15)). This objective function further implies that generator costs remain the same, regardless of whether these are used in the day-ahead market or for redispatch purposes. That is, generators make no profit from activation as part of integrated redispatch and are awarded pay-as-bid.

The decision variable for the generation offered by unit g on the day-ahead market is denoted by $\boldsymbol{d}_g^{DA}$. The difference between the actual generator dispatch and day-ahead market dispatch corresponds to the volume used as part of integrated redispatch:

$$\boldsymbol{d}_g^{\mathrm{IRD}} - \boldsymbol{d}_g^{\mathrm{DA}} = \Delta \boldsymbol{d}_g^{\mathrm{IRD}}, \forall g \in G \tag{15}$$

Eqs. (14) and (15) show that two different decision variables are used for generator dispatch in this model: one representing the dispatching resulting from the day-ahead merit-order clearing, $\boldsymbol{d}_g^{\mathrm{DA}}$, and another for the actual generation, including integrated redispatch, $\boldsymbol{d}_g^{\mathrm{IRD}}$. Then, IRD dispatch is understood as the volume of the deviation of the IRD plant from the day-ahead market result. Similar to the zonal business-as-usual setup, redispatch within a zone is energy-neutral. It follows that the total dispatch in the zone remains the same.

Generators that are deployed for integrated redispatch at nodes $\boldsymbol{n}^{\mathrm{IRD}}$ are excluded from the calculation of GSKs (Eq. (17)) and, consequently, from zonal PTDFs $PTDF_{b,z}^{zon,IRD}$ (Eq. (19)). Their impact is instead described using nodal PTDFs (see Eq. (5)). GSKs are used for the remaining dispatchable generators, GSK^{IRD} (Eqs. (16) and (18)).

$$GSK_{n,z}^{\mathrm{IRD}} = \frac{\sum_{g \in G}^{G_n} D_g^{\mathrm{MAX}}}{d_z}, \forall n \in N_z \bigwedge n \,/\!\in N^{\mathrm{IRD}}, \forall z \in Z \tag{16}$$

$$GSK_{n,z}^{\mathrm{IRD}} = 0, \forall n \in N^{\mathrm{IRD}}, \forall z \in Z \tag{17}$$

$$d_z = \sum_{n /\in N^{IRD}}^{N_z} \left(\sum_{g \in G}^{G_n} D_g^{\mathrm{MAX}}\right), \forall z \in Z \tag{18}$$

$$PTDF_{b,z}^{zon,IRD} = \sum\nolimits_{n}^{N_z} PTDF_{b,n}^{nod} * GSK_{n,z}^{IRD}, \forall b \in CB, \forall z \in Z \tag{19}$$

Neither are the IRD generators included in the calculation of the

[5] These include the flow reliability margin (FRM) and the final adjustment value (FAV). For their more detailed description please refer to, e.g. [31].

change of zonal generation as compared to the Base Case value, $\Delta p_z^{ref,IRD}$:

$$\Delta p_z^{ref,IRD} = \sum_{n/\in N^{IRD}}^{N_z} (p_n - p_n^{ref}), \forall z \in Z \tag{20}$$

In the model, the flow on each branch in the second step is calculated by summing up the reference flow value from the Base Case, f_b^{ref}, with the delta dispatch of IRD generators at nodes n^{IRD} and their *nodal* PTDFs as well as with the sum of the delta dispatch of the other generators and their *zonal* PTDFs:

$$f_b^{IRD} = f_b^{ref} + \sum_{n=1}^{N^{IRD}} PTDF_{b,n} * (p_n - p_n^{ref}) + \sum_{z=1}^{Z} PTDF_{b,z}^{zon,IRD} * \Delta p_z^{ref,IRD}, \forall b \in B \tag{21}$$

IRD generators can be considered to be all generators in the set of dispatchable generators or only a subset of the latter. Since nodal PTDFs are used to obtain the effect of IRD generators on the grid, deeming all dispatchable generators capable of redispatch action will lead to the nodal result. This would, however, not be aligned with the main purpose of integrated redispatch: making use of those generators that have a significant effect on grid stability while keeping the main characteristics of a zonal market design.

While activation as part of integrated redispatch will have an effect on the zonal price, it is specifically avoided that these generators set the day-ahead market price if activated for redispatch. Doing otherwise would lead to a higher overall price corresponding to the bid of the up-regulated generator. As a result, the zonal price corresponds to the dual of the node injection constraint (see Eq. (4)) for the nodes in a given zone, *excluding* those nodes that have IRD generators connected to them. In other words, the prices at each node in a given zone will be the same, determining the zonal prices, with the exception of the IRD nodes.

2.3.3. Residual redispatch

If the use of integrated redispatch is unable to relieve all internal congestion in the day-ahead stage, residual redispatch measures can be taken in this step. It is formulated similarly to the *ex-post* redispatch step in the *business-as-usual model*, Section 2.2.3, and uses the same objective function (Eq. (13)). The redispatch simulation is the same as the full nodal model but all generation values are fixed to the dispatch values of the day-ahead market step from Section 2.3.2. All generators are assumed to be dispatchable in this step and thus are redispatch-relevant. All grid limitations are enforced.

The key economic output indicators in this model are formulated in the same way as in the *business-as-usual model*. The only two differences consider zonal day-ahead prices and total system costs. Zonal prices correspond to the dual of the node injection constraint of any of the nodes located in a given zone.

The volume of integrated redispatch is calculated as a change of dispatch as compared to the "ideal" merit order result d_g^{MO}, i.e. the one where no grid limitations are considered (Eqs. (23) and (24)). Only the units selected for IRD may have a different generation value because of the redispatch action. The ideal merit order dispatch is calculated in such a way that the same zonal generation is achieved (Eq. (22)).

$$\sum_{g\in G_z} d_g^{IRD} = \sum_{g\in G_z} d_g^{MO} \tag{22}$$

$$\Delta d_g^{pos} = \max(d_g^{IRD} - d_g^{MO}, 0) \tag{23}$$

$$\Delta d_g^{neg} = \max(d_g^{MO} - d_g^{IRD}, 0) \tag{24}$$

Then, total volume used for integrated redispatch in either direction is calculated as:

$$D_z^{IRD} = \sum_{g\in G_z} \frac{\left(\Delta d_g^{pos,MO} + \Delta d_g^{neg,MO}\right)}{2} \forall z \in Z \tag{25}$$

The total costs of IRD units per zone are calculated as:

$$C^{IRD} = \sum_{g\in G\in z} \left(c_g^{DA} * \Delta d_g^{pos,MO} - c_g^{DA} * \Delta d_g^{neg,MO}\right) \forall z \in Z \tag{26}$$

Total system costs, in turn do not just include the day-ahead market and the costs of IRD activation but also any possible costs of residual redispatch.

3. Simulation setup

In order to illustrate the improvement provided by the zonal model with integrated redispatch in a traceable manner, the proposed approach is illustrated with the help of a simple test network with two bidding zones, as shown in Fig. 2, and compared with the *nodal* and *business-as-usual models*. Zone A (red nodes) has low-priced generation units, A and B, whereas Zone B (grey nodes) has a higher-priced unit D. Total generation capacity and load equal to 180 MW and 20 MW in Zone A and 120 MW and 100 MW in Zone B, respectively. In the zonal models, lines 0–5 and 2–3 are deemed interconnectors. They are included in the set of critical branches together with an internal branch between nodes 0 and 1 in Zone A. All branches have the same thermal capacity of 120 MW whereas the branch 0–1 has a limited capacity of 30 MW. For this analysis, all line reactances are considered to be the same.

In all scenarios, generators are assumed to be dispatchable, i.e. able to change their output depending on the market outcome. In the zonal the *business-as-usual model*, all generators can be redispatched, i.e. change their output *ex post* to alleviate congestion.

The aim of this case study using a simple test network is to provide a better understanding of how intrazonal congestion affects cross-border exchange and the efficiency of FBMC as well as to demonstrate the potential benefits of the integrated-redispatch approach. The test network is intended for illustrative purposes rather that to represent grid and market reality in all their complexity. Market representation is limited to the day-ahead market clearing and does not consider other markets or intertemporal constraints.

3.1. Results and analysis

In all scenarios without congestion, the three models deliver identical results, as expected. A common merit order results in a single day-

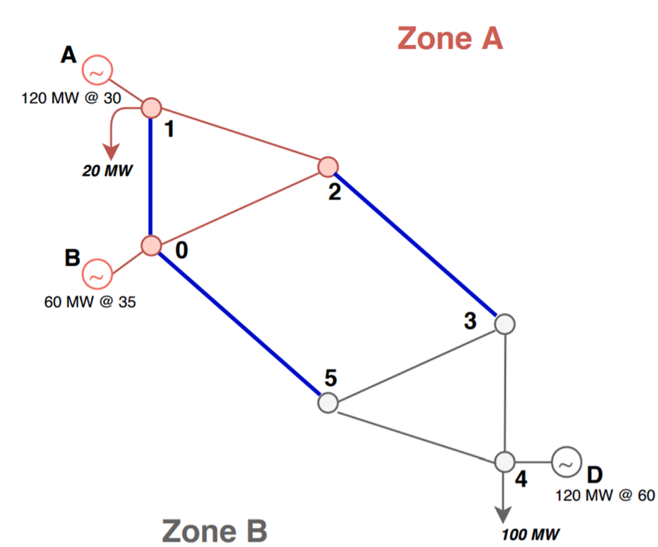

Fig. 2. Overview of a 2-zone test network with 3 critical branches (in blue). The nodes and branches belonging to Zone A are marked in red, those belonging to Zone B are marked in gray. Next to the generators in the figure, the reader can find their maximum available capacities in MW and day-ahead market bids in €/MWh.

ahead price of 30 €/MWh for both zones, the total system cost of 3.600 € and the total economic surplus of 116.400 €. The value of lost load of 1.000 €/MWh is used for the calculation of consumer surplus. In the zonal models, the total exchange between the two zones equal 100 MW (cf. Table 1).

In case of a limited transmission capacity on a critical branch, the results diverge.

Nodal setup

The Nodal setup, or the complete network consideration, the optimal dispatch is shown in Fig. 3. Node 4 is able to import the entire volume needed to cover its demand of 100 MW without activating the expensive generator D at a nodal price of 33 €/MWh.

Since the individual line constraints are respected, there is no need for *ex-post* remedial actions and all commercial flows are feasible. Due to the congestion on line 0–1, however, nodal market prices diverge and range between 30 and 35€/MWh, depending on the node (in red in Fig. 3). As a result, producer and consumer surplus decrease compared to the no-congestion case but the TSO obtains a congestion rent of 237 € (cf. Table 1).

Zonal business-as-usual setup

A common flow-based capacity calculation and exchange between the bidding zones is conducted. The cross-border transfer capacity is limited by the zonal PTDFs on the critical branches and the RAM. In this case study, security margins are assumed to be zero. The RAM is therefore equal to the maximum branch capacity. In this example, the capacity on the interconnectors (lines between nodes 0–5 and 2–3) is set to 120 MW each.

In order to emulate imperfect foresight of the TSO, as described in Section 2.2.1, the total flows between the two zones in the Base Case are assumed to be 50% of the total flow on all interconnectors between the two zones, as compared to the nodal outcome. The cross-border exchange is then equal to 50 MW in total, based on D-2 estimate. Note that the Base Case is identical for both the *business-as-usual model* and the *model with integrated redispatch*.

Table 1
Overview of the results from all setups using a two-zone test network.

	No congestion	Nodal setup (with congestion)	Zonal business-as-usual setup (with congestion)	Zonal setup with integrated redispatch (with congestion)
Total system cost, €[1]	3.600	3.758	4.610	3.758
Redispatch cost, €	–	–	29	158
Congestion Rent, €	–	237	2.019	400
Producer Surplus, €	–	–	–	–
Consumer Surplus, €	116.400	116.005	113.400	116.000
Economic Surplus, €	116.400	116.242	115.390	116.242
Total cross-border exchange (MW)	100	100	67	100
Nodal prices, €/MWh	30	in the range of 30–35	n/a	n/a
Day-ahead price Zone A, €/MWh	n/a	n/a	30	30
Day-ahead price Zone B, €/MWh	n/a	n/a	60	34

[1] including the cost of redispatch.

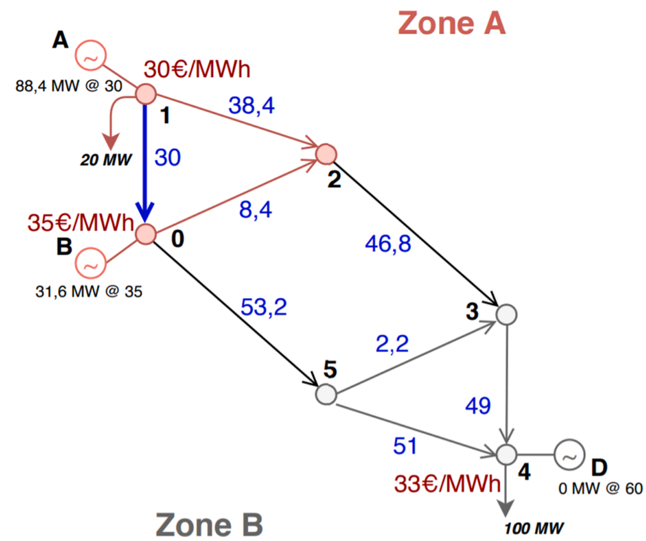

Fig. 3. Six-node test network. Results from the nodal setup, generator dispatch, nodal prices (in red) and the flows on each branch (in blue).

The expected congestion leads to market splitting and produces two different zonal prices, 30 €/MWh and of 60 €/MWh in Zone A and Zone B, respectively, and a limited exchange of 67 MW between the two zones (Fig. 4). As a result, only the cheapest generator A could be activated in Zone A. To partially cover the demand in Zone B an expensive generator D needs to be activated.

As a result of an imprecise flow calculation based on zonal PTDFs, the real flows that result from the day-ahead market clearing violate the limit on the internal critical branch between nodes 0 and 1 (shown in Fig. 4 in red), which triggers redispatch. Generator A was redispatched downwards whereas generator B in the same zone that was out of the merit order in the day-ahead market was redispatched upwards. The total volume of redispatch is 58 MW in each direction (Fig. 5). Generator B is remunerated pay-as-bid whereas generator A pays to the TSO the amount equal to its announced costs per MWh and the redispatched volume, i.e. the volume it no longer has to produce.

To simulate the current approach to redispatch, optimization based on volume minimization is used. Therefore, the value of the volume-

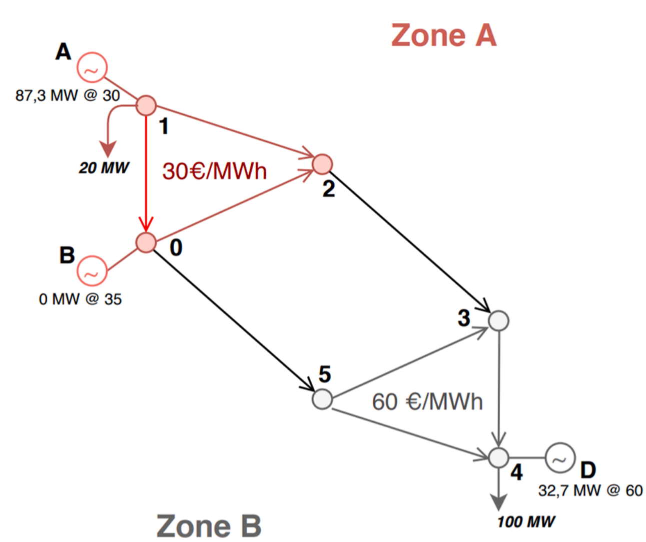

Fig. 4. Day-ahead market coupling in the zonal business-as-usual setup: generator dispatch according to the outcome of the day-ahead market clearing and the zonal market prices in Zone A (in red) and Zone B (in grey). The numbers next to the generators in the figure show the day-ahead market dispatch of generators and their bids.

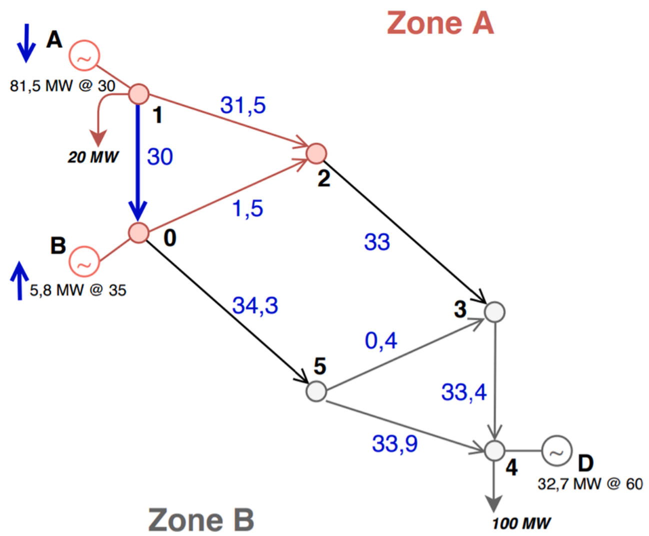

Fig. 5. Activation of redispatch ex-post in Zone A in the zonal business-as-usual setup (redispatched generators A and B are marked with blue arrows).

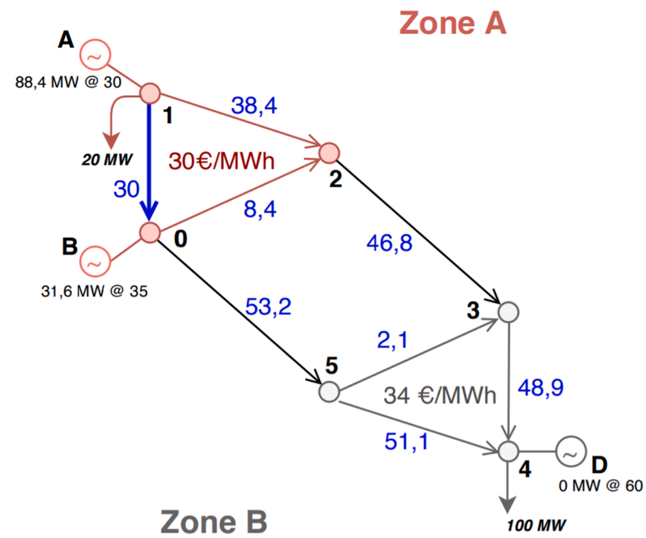

Fig. 6. Results from the zonal setup with integrated redispatch. Activation of IRD generators in Zone A. The resulting zonal market prices in Zone A and Zone B are marked in red and grey, respectively.

based penalty coefficient, λ, in eq. (13) is set to 1.0 while the value of the cost-based penalty coefficient, γ, is set to zero[6].

Zonal setup with integrated redispatch

The same parameters and Base Case inputs are used in the zonal setup with integrated redispatch as in the zonal business-as-usual setup. Units A and B are predefined for IRD. Fig. 6 shows the result of the second optimization step: the final dispatch volumes for each generator includes both volumes resulting both from the day-ahead market clearing and from integrated redispatch. The volume of the latter corresponds to 31,6 MW in each direction, corresponding the difference of the plant's output from the day-ahead merit-order result.

Fig. 6 shows that the joint optimization of the day-ahead market and integrated-redispatch action allows to greatly increase cross-border exchange to 100 MW (Fig. 6) and thus fully avoid the dispatch of the expensive generator D in Zone B. An increased cross-border exchange leads, among others, to the change of zonal prices. The price in the cheaper Zone A remained the same, 30 €/MWh (generator A is marginal since generator B is activated upwards as part of IRD and does not set the day-ahead market price), whereas the price in Zone B went down from 60 €/MWh in the zonal business-as-usual setup to 34 €/MWh as activation of generator D is avoided.

The method for setting the day-ahead market price given the presence of integrated redispatch is crucial. In the *model with integrated redispatch*, IRD units do not impact zonal day-ahead prices, since a purely economic merit order is used to set the market clearing price (cf. Section 2.3.2). Instead, the IRD units are remunerated pay-as-bid, a common practice in Europe. To prevent IRD generators from affecting zonal day-ahead market prices, in the model the zonal price then corresponds to the dual of the nodal balance constraint of the nodes in each zone that do not have IRD generators connected to them (node 2 in Zone A in this case).

Thanks to the fact that the impact of IRD generators is represented with the help of nodal PTDFs, it was further possible to fully utilize the available capacity without causing congestion on critical branch 0–1 Hence, no residual redispatch was necessary in this case study.

Table 1 and Fig. 7 summarize the results from each model illustrating how integrating redispatch action into the day-ahead market indeed may help improve the outcome as compared to the *business-as-usual model*.

The table shows that, in the simulation, the zonal setup with integrated redispatch achieves the nodal result with congestion (although this would not be generally the case due to a much higher complexity of the European grids). Consumer surplus and economic surplus are higher than in the zonal business-as-usual setup. Producer surplus is equal to zero in all setups, which however doesn't represent the general case. Instead, it is owed to the fact that only one generator is activated in each zone in the day-ahead market making it marginal. This, assuming marginal-cost bidding, generates a profit of zero by definition. Since inelastic demand was modelled with a high value of lost load (1.000 €/MWh), the overall economic surplus is dominated by the consumer surplus.

In the case study:

- Activation of IRD units leads to a higher cross-zonal exchange: 100 MW (same as nodal market) as opposed to 67 MW in the zonal business-as-usual setup.
- The zonal setup with integrated redispatch increases the economic surplus compared with the zonal business-as-usual setup. In the case

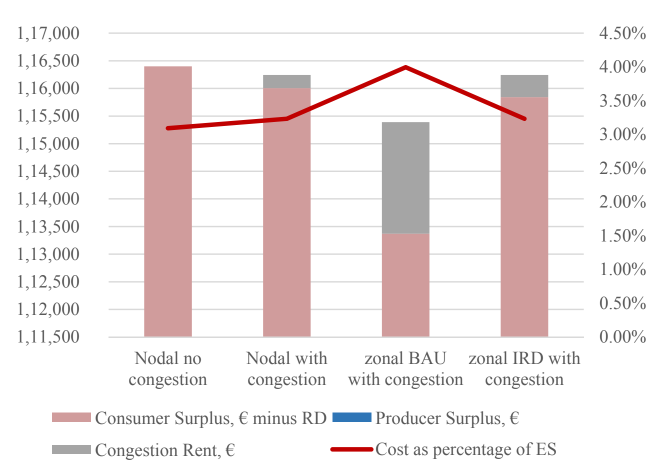

Fig. 7. Economic surplus (ES) of the three setups and their comparison with a no-congestion case. Note that the cost of redispatch is subtracted from the consumer surplus. RD - redispatch.

[6] Both variants of the objective function lead to the same result since the chosen redispatch was the only feasible solution given flow limitations for such a simple network, yet can produce different results in a large network.

study, the IRD solution replicates the economically optimal solution. This can be explained by the small size of the test network and a limited number generators and is therefore not generalizable for the European grid.
- The proposed approach indeed helps to increase price convergence between the two zones due to a higher flow between the zones and thus produces a more cost-efficient dispatch.
- The costs of integrated redispatch are covered by the congestion rent between the zones.
- Finally, in the zonal setup with integrated redispatch the congestion was solved in one step, i.e. no residual redispatch needed to be activated. In reality, depending on grid limitations and the location of congestion, a limited volume of residual redispatch might still be needed, yet this does not have an effect on higher cross-border flows produced in the zonal setup with integrated redispatch.

Therefore, in the zonal setup with integrated redispatch, market prices are more representative of the actual grid situation and efficiency gains can be achieved by reflexing the cost of congestion in the market, producing a more efficient dispatch and reducing the need for subsequent redispatch.

4. Discussion

The results presented in Section 3 demonstrate potential benefits of integrating preventive redispatch into the day-ahead market. The distinction between the IRD units and the rest of the generators lies in the fact that their effects on the critical branches are explicitly considered during the market coupling process. At the same time, the proposed approach ensures that IRD generators are not treated differently from other generators in the day-ahead market. They participate on par with the others and may only deviate from the market clearing outcome in case of expected congestion.

As a result, in the event of congestion, integrating redispatch in the day-ahead market helped to reduce total system costs and raise consumer surplus, as compared to the zonal business-as-usual setup. The use of integrated redispatch was shown to lead to an increase of cross-zonal exchange and therefore can facilitate zonal price convergence and generate market efficiency gains.

Two factors are likely to have a positive effect on the efficiency of the proposed approach. First, we assume that the costs of generators in the day-ahead market and in integrated redispatch are the same. In contrast, the costs of a generator used for *ex-post* redispatch are likely to be higher than their day-ahead market costs (cf. Section 2.3.2). This can potentially lead to even higher costs of redispatch in the zonal business-as-usual setup and comparing the zonal setup with integrated redispatch more favorably. Second, the presented zonal models focus on intrazonal redispatch. The possibility of a coordinated cross-border redispatch (as expected to be implemented by the CACM [13]) is also likely to further increase the efficiency of the integrated-redispatch action, which can be investigated as a future model enhancement.

The revenue streams of stakeholders depend on the design choices. If IRD units are remunerated pay-as-bid, then their profits will be zero if they bid at marginal cost, therefore, producer surplus would tend to be lower as compared to the *nodal model* with congestion. Welfare distribution among system stakeholders is also affected by whether IRD generators are remunerated through the market or through the TSO. It is assumed that all generators that were scheduled in the day-ahead market were remunerated there while the costs of integrated redispatch are part of TSOs' redispatch costs.

The choice of a compensation mechanism will affect generators' incentives [32]. Similar to conventional redispatch, the way to set up a pricing rule for integrated redispatch in a way that these generators cannot excessively profit from providing this service to the TSO becomes an important consideration. The redispatch payment should, on the one hand, be sufficient to cover the real costs but, on the other hand, should not result in additional profits for the generator in order to avoid possible market-distorting incentives. Technically, if activated for integrated redispatch often, in particular for downward redispatch, this may negatively affect these generators' financial positions, e.g. through efficiency losses from running at partial load. As a consequence, these generators may start to bid strategically to improve cost recovery, once they find out that they are used for integrated redispatch. This implies that the level of information of market participants about the state of the system plays an important role in defining their strategies.

A dedicated investigation of strategic bidding behavior and market power issues are out of the scope of this study. Yet, the proposed approach has clear benefits compared to the current practice as well as to the market-based redispatch, which raised concerns among researchers and regulators as potentially opening up opportunities for so-called inc-dec gaming[7]. The integration of integrated redispatch with the day-ahead market means that generators are not taken out of the market, i.e. are still subject to market mechanisms and competition. As IRD units may be used either in the day-ahead market or for redispatch, they are discouraged from bidding strategically, as otherwise they risk not being awarded. However, in a situation in which a generator is physically necessary to meet demand in a certain area, market design cannot remediate its market power.

The proposed approach has several limitations, which stem from the design choices and some model assumptions. Similar to other approaches, the TSOs would still face a tradeoff between the scope of available resources they use for congestion management and the degree of market interference The selection of IRD generators and the size of the pool affect the physical flows and, consequently, the economic efficiency of the outcome in the *model with integrated redispatch*. The design of the method cannot guarantee that the TSO secures sufficient redispatch potential or includes different kinds of providers. This would probably require the development of a dedicated harmonized methodology, for instance, one that involves a periodic re-evaluation of choice of IRD units. The value of integrated redispatch stems from a more precise grid representation based on IRD units rather than from improved forecasting of grid congestion. Finally, although the model has been formulated in a way to accommodate any number of nodes and branches, testing the developed methodology on the European network may reveal implementation challenges such as computational speed constraints, requiring a further development and fine-tuning.

The uncertainty associated with the output of variable renewable energy sources (vRES) may also affect the efficiency of the *model with integrated redispatch* since it relies on the calculation of cross-border capacity ahead of the market coupling algorithm. As a result, *ex post* changes in vRES output may potentially lead to higher volumes of residual redispatch.

The proposed approach does, however, have two benefits as compared to the current practice:

(1) One of the major consequences of congestion in vRES-rich areas is that vRES often need to be curtailed and more expensive and CO_2-intensive generation needs to be regulated upwards. Since the proposed approach allows to increase available cross-border capacity, more cost-efficient vRES can be exported and the need for curtailment reduced.
(2) As not only day-ahead but also intraday markets are now being integrated in the EU as part of XBID project [35], with the cross-border capacity for intraday trade being calculated within the intra-day timeframe, the proposed approach could be applied in the same way to the intraday market coupling when more precise

[7] The textbook example of inc-dec gaming, the Enron case in California, can be found in [33]. The analysis of inc-dec gaming potential in the German market is presented in [34].

grid information and vRES forecasts are available, further limiting the impact of uncertainty.

The effect of uncertainty can be addressed both at the macro level, for instance as pointed out in points 1 and 2 above, and at the micro level by providing market participants with tools to improve forecasting and scheduling of vRES. For instance, researchers in [36] proposed a probabilistic-possibilistic model for scheduling wind and thermal power plants that enables their participation in the electricity markets and addresses uncertainties such as high-impact low-probability events and calling probabilities in the reserve markets [36]. In [37], the authors developed a multi-objective bidding strategy framework for a portfolio with vRES that allows them to account for their intermittency and price uncertainties in different marketplaces. Both papers emphasize the value of integration of vRES and conventional generation in portfolios to better tackle uncertainty. Similarly, authors in [38] showed how vRES can successfully participate in electricity markets as part of a virtual power plant together with storage that allows to offset vRES variability more efficiently. The effect of uncertainties, such as vRES forecasts, on the efficiency of different congestion management approaches, including integrated redispatch, would be an interesting topic for a future investigation.

Just like FBMC is an enhancement of the ATC approach, the proposed approach is intended as a further enhancement of FBMC. A combined use of integrated redispatch and non-costly remedial actions, such as transmission switching, the integration of distributed sources of flexibility (e.g. controlled EV charging [39] and storage [40]) for congestion management and improved TSO-DSO cooperation [41], are likely to yield further efficiency gains.

5. Conclusions

There is an increasing need to increase cross-border transmission capacity in order to be able to integrate more renewable energy into the European system, facilitate market integration and reduce redispatch costs. Hence, the efficiency of congestion management needs to be improved.

The authors propose a novel approach to congestion management in Europe by integrating preventive redispatch with the day-ahead market. It builds upon flow-based market coupling, which is currently used in Central Western Europe. Linear optimization models were used to compare the "integrated redispatch" mechanism formulated in this paper with two existing alternatives, 1) the nodal market, which is considered the optimal benchmark, and 2) the zonal market with flow-based market coupling. The results of the approach with integrated redispatch are closer to the nodal solution, increasing the total economic surplus, as compared to the zonal model with flow-based market coupling. The extent to which it approximates the nodal solution depends both on network complexity and on the number and specific choice of generators used for integrated redispatch.

The authors evaluated the physical and economic effects of the three approaches on the distribution of revenues and costs among different stakeholders as well as on the costs and the available cross-border transmission capacity. The results show that the zonal approach with integrated redispatch can:

- increase cross-border trade by freeing up more capacity for trade and making day-ahead dispatch more cost-efficient,
- increase price convergence thus contributing to European market integration,
- reduce the need for costly *ex post* redispatch,
- lower overall system costs delivering value to consumers while politically and practically more feasible in Europe than nodal pricing,
- potentially lower the risk of strategic bidding as compared to other market-based options.

Although the volume used for redispatch tends to be higher with integrated redispatch than in the current approach, it is more cost-efficient overall because of the welfare gains that result from increased cross-border trade. The integrated-redispatch approach may perform better if generator redispatch costs in business-as-usual are higher than their day-ahead market offers.

The main objectives of this study were to formulate a new methodological approach to redispatch in zonal markets with flow-based market coupling, illustrate its implementation using a simple network and in this way provide an impression of how the different approaches compare. It did not intend to provide an exact quantification of costs or welfare benefits. In the future, it is intended to quantify the results of the zonal integrated-redispatch approach by testing the developed model on a large network with a substantially higher number of generators and loads. Other crucial questions that could be addressed in future research include an investigation of modalities for the remuneration of redispatch-providing generators and the ways of minimizing potential strategic behavior of market participants. The future discussion should also address the effect of this approach on other short-term markets.

CRediT authorship contribution statement

Ksenia Poplavskaya: Conceptualization, Methodology, Software, Validation, Formal analysis, Writing - original draft, Visualization. **Gerhard Totschnig:** Methodology, Validation. **Fabian Leimgruber:** Software, Validation. **Gerard Doorman:** Supervision, Writing - review & editing. **Gilles Etienne:** Conceptualization, Methodology, Writing - review & editing. **Laurens Vries:** Supervision, Writing - review & editing.

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.

Acknowledgements

This study is based on a recent research project conducted by AIT Austrian Institute of Technology, which was financed by ENTSO-E (European Network of Transmission System Operators for Electricity).

Preliminary research was presented at the European conference of the International Association of Energy Economics in Ljubljana in September 2019 (16th IAEE European Conference).

The authors would like to thank the reviewers for their comments and constructive criticism that has helped to improve the quality of the paper. This article represents the views the authors alone and any errors are their sole responsibility.

Appendix A. Model assumptions

The following model assumptions were made:

Regarding the grid:

- Lossless DC network.
- Outage scenarios are not considered.
- All zonal interconnectors and a few intra-zonal branches are included in the set of critical branches in FBMC;
- In case of congestion, other remedial actions (e.g. topological changes) or possible flexibility on the demand side are not considered.
- The redispatch action is energy-neutral within a zone, i.e. cross-border redispatch is not considered.

Regarding the market:

- For both zonal setups, zonal load is assumed not to change, as compared to the Base Case.
- It is assumed that all generation is traded on the day-ahead market, no long-term nominations or intraday market deviations from the day-ahead result are considered.
- For the sake of this analysis, generators are defined with fixed marginal costs.
- Demand is assumed to be inelastic.
- Perfect competition, no market power, i.e. generators bid their marginal costs.
- Intertemporal constraints are disregarded.

Appendix B. Notation used in the paper

Scenario parameters	
$b \in \{1, \cdots, B\}$	branches
$b \in CB$	critical branches
$b^{\mathrm{IC}} \in B^{\mathrm{IC}}$	Zonal interconnector branches
c_g	Marginal costs of generator g [€/MWh]
$D_g^{\max}$	Maximum dispatch of generator g [MW]
F_b	maximum flow on branch b (=maximum thermal limit) [MW]
FRM	flow reliability margin [MW] (assumed to be 0)
$g \in \{1, \cdots, G\}$	generators
G_n	set of generators on node$n$
G^{disp}	set of dispatchable generators
$G^{non-disp}$	set of non-dispatchable generators
$k_{n,b} \in K$	$N \times S$ incidence matrix
l_n	electrical load at node n [MW]
$n \in \{1, \cdots, N\}$	nodes
N_z	set of nodes in zone$z$
S	diagonal $S \times S$ matrix of branch susceptances
s^{IC}	Share of interconnector capacity
$z \in \{1, \cdots, Z\}$	zones
γ	cost-based penalty coefficient for redispatch
λ	volume-based penalty coefficient for redispatch
Model internal parameters	
d_g^{MO}	dispatch of generator g that would have resulted from purely merit-order activation used in the Zonal IRD model [MWh]
d_g^{ref}	dispatch of generator g in the Base Case [MWh]
f_b^{ref}	reference flow on branch b in the Base Case [MW]
$GSK_{n,z}$	generation shift key of node n in zone$z$
$GSK_{n,z}^{\mathrm{IRD}}$	generation shift key of node n in zone z in zonal IRD model
k_z^{FBMC}	Zonal market price in zone z in the business-as-usual model
p_z^{ref}	reference power injection in zone z in the Base Case [MW]
$PTDF_{b,n}^{\mathrm{nod}}$	nodal PTDF on branch $b$for node$n$
$PTDF_{b,z}^{\mathrm{zon}}$	zonal PTDF on branch b in zone$z$
RAM_b	remaining available margin on a critical branch [MW]
$\boldsymbol{C}^{\mathbf{IRD}}$	cost of units used for integrated redispatch in the Zonal IRD model [€]
Decision variables	
$\boldsymbol{d_g}$	dispatch (i.e. electricity production) of generator g [MW] in the nodal and business-as-usual models
$\boldsymbol{d_g^{\mathrm{DA}}}$	generation offered by unit g on the day-ahead market [MW]
$\boldsymbol{d_g^{\mathrm{IRD}}}$	actual dispatch *after* accounting for IRD in the zonal IRD model
$\boldsymbol{d_z}$	total dispatch of all generators in zone z [MW]
$\Delta \boldsymbol{d_g^{\mathrm{ERD}}}$	generation after *ex-post* redispatch [MW] in the business-as-usual model
$\Delta \boldsymbol{d_g^{\mathrm{IRD}}}$	Change of dispatch due to the activation of IRD [MW] in the Zonal IRD model
$\Delta \boldsymbol{d_g^{\mathrm{neg}}}$	change of dispatch due to downward regulation due to redispatch [MW]
$\Delta \boldsymbol{d_g^{\mathrm{pos}}}$	change of dispatch due to upward regulation due to redispatch [MW]
$\Delta \boldsymbol{d_z}$	change of generation per zone as compared to the Base Case [MW]
$\boldsymbol{f_b}$	flow on branch b [MW]
$\boldsymbol{f_b^{\mathrm{FBMC}}}$	flow on branch b resulting from FBMC [MW]
$\boldsymbol{f_b^{\mathrm{IRD}}}$	flow on branch b resulting from IRD approach [MW]
NEX_z	net export position of zone z [MW]
$\boldsymbol{p_n}$	total active power injection at node n (generation – demand at that node) [MW]
$\Delta \boldsymbol{p_z^{\mathrm{ref,IRD}}}$	change in zonal generation as compared to the Base Case value in the Zonal IRD model [MW]

References

[1] ACER/CEER. Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2018 - Electricity Wholesale Markets Volume. Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators, Brussels, Nov. 2019. Accessed: Nov. 25, 2019. [Online]. Available: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/.

[2] ACER/CEER, "Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016," Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators, Brussels, Oct. 2017. Accessed: Oct. 21, 2017. [Online]. Available: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf.

[3] ACER/CEER. Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2017 - Electricity Wholesale Markets Volume. Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators, Brussels, Oct. 2018. Accessed: Apr. 01, 2019. [Online]. Available: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/MMR%202017%20-%20ELECTRICITY.pdf.

[4] Elia. Implementation of day-ahead flow-based market coupling in the CWE region. General description. Elia, Brussels, Belgium, March 2015.

[5] Elia Group. Future-proofing the EU energy system towards 2030. Levers to realise the next phase of the energy transition in a timely and efficient way with maximum welfare for society," Elia Group, Brussels, Dec. 2019. Accessed: Mar. 20, 2020. [Online]. Available: https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications-pdfs/20191212_future_proofing_eu_system_2030.pdf.

[6] Ehrenmann A, Smeers Y. Inefficiencies in European congestion management proposals. Util. Policy 2005;13(2):135–152. doi: 10.1016/j.jup.2004.12.007.

[7] CREG (Commission de Régulation de l'électricité et du Gaz), "Study on the best forecast of remedial actions to mitigate market distortion," CREG, Brussels, Belgium, (F)1987, Oct. 2019.

[8] Aravena I, Papavasiliou A. Renewable energy integration in Zonal Markets. IEEE Trans Power Syst 2016:1. https://doi.org/10.1109/TPWRS.2016.2585222.

[9] Van den Bergh K, Boury J, Delarue E. The flow-based market coupling in central Western Europe: concepts and definitions. Electr J 2016;29(1):24–9. https://doi.org/10.1016/j.tej.2015.12.004.

[10] Kristiansen T. The flow based market coupling arrangement in Europe: Implications for traders. Energy Strategy Rev 2020;27:100444. https://doi.org/10.1016/j.esr.2019.100444.

[11] Plancke G, De Vos K, De Jonghe C, Belmans R. Efficient use of transmission capacity for cross-border trading: Available Transfer Capacity versus flow-based approach. In: 2016 IEEE International Energy Conference (ENERGYCON), April 2016, pp. 1–5, doi: 10.1109/ENERGYCON.2016.7513974.

[12] Hoeksema J, Atayi A, Schavemaker P. Theoretical understanding of flow-based method, intuitiveness, hybrid-coupling. In: Presented at the CWE Flow-Based Market Coupling Forum, Düsseldorf, March 07, 2013, Accessed: Oct. 10, 2018. [Online]. Available: https://apxgroup.nl/services/cwe-flow-based-market-coupling/.

[13] European Commission, Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management. 2015.

[14] Schittekatte T, Reif V, Meeus L. The EU Electricity Network Codes. Florence, Italy, Technical Report, Feb. 2019. Accessed: Sep. 01, 2019. [Online]. Available: https://fsrglobalforum.eu/wp-content/uploads/2019/03/FSR_2019_EU_Electricity_Network_Codes.pdf.

[15] Voswinkel S, Felten B, Felling T, Weber C. Flow-based market coupling – What drives welfare in Europe's electricity market design?. House of Energy Markets and Finance, University Duisburg-Essen, Essen, Germany, HEMF Working Paper No. 08/2019, Jul. 2019.

[16] Schönheit D, Weinhold R, Dierstein C. The impact of different strategies for generation shift keys (GSKs) on the flow-based market coupling domain: A model-based analysis of Central Western Europe. Appl Energy 2020;258:114067. https://doi.org/10.1016/j.apenergy.2019.114067.

[17] ENTSO-E. First edition of the bidding zone review. Final report. European Network of Transmission System Operators for Electricity (ENTSO-E), Brussels, Belgium, March 2018.

[18] Stedin, Liander, TenneT, Enexis, and Westland. "IDCONS Product Specification. Arnhem, 1.0, Jan. 2019. [Online]. Available: https://en.gopacs.eu/wpcms/wp-content/uploads/2019/05/20190228-IDCONS-product-specifications_EN.pdf.

[19] Le HL, Ilea V, Bovo C. Integrated European intra-day electricity market: rules, modeling and analysis. Appl Energy 2019;238:258–73. https://doi.org/10.1016/j.apenergy.2018.12.073.

[20] SWECO. Study on the effective integration of Distributed Energy Resources for providing flexibility to the electricity system. SWECO, ECOFYS, Tractebel Engineering, pwc, Stockholm, Final Report to the European Commission 54697590000, 2015. Accessed: Dec. 10, 2015. [Online]. Available: https://ec.europa.eu/energy/sites/ener/files/documents/5469759000%20Effective%20integration%20of%20DER%20Final%20ver%202_6%20April%202015.pdf.

[21] Staudt P, Schmidt M, Gärttner J, Weinhardt C. A decentralized approach towards resolving transmission grid congestion in Germany using vehicle-to-grid technology. Appl Energy 2018;230:1435–46. https://doi.org/10.1016/j.apenergy.2018.09.045.

[22] Schleswig-Holstein Netz, Agre Netz, ENKO – Das Konzept zur verbesserten Integration von Grünstrom ins Netz, Quickborn, 2018. [Online]. Available: https://www.enko.energy/wp-content/uploads/ENKO_White-Paper-Stand-Nov.-2018.pdf.

[23] USEF. Flexibility platforms. White paper, Nov. 2018. [Online]. Available: https://www.usef.energy/app/uploads/2018/11/USEF-White-Paper-Flexibility-Platforms-version-1.0_Nov2018.pdf.

[24] Goop J, Odenberger M, Johnsson F. The effect of high levels of solar generation on congestion in the European electricity transmission grid. Appl Energy 2017;205:1128–40. https://doi.org/10.1016/j.apenergy.2017.08.143.

[25] Hogan WW. Contract networks for electric power transmission. J Regul Econ 1992;4(3):211–42. https://doi.org/10.1007/BF00133621.

[26] Neuhoff K, Boyd R. International experiences of nodal pricing implementation. freuqently asked questions. Climate Policy Initiative /DIW Berlin, Berlin, Germany, Working document, 2011.

[27] Maurer C, Zimmer C, Hirth L. Nodale und zonale Strompreise im Vergleich (in German). Consentec and NEON Neue Energieökonomik, Berlin, Germany, Final Report for the Federal Ministry of Economy and Energy; 2018.

[28] Mielczarski W. Handbook: Energy Systems and Markets. Lodz, Poland: Institute of Electric Power Engineering, Lodz University of Technology, Poland; 2018.

[29] Hörsch J, Ronellenfitsch H, Witthaut D, Brown T. Linear optimal power flow using cycle flows. Electr Power Syst Res 2018;158:126–35. https://doi.org/10.1016/j.epsr.2017.12.034.

[30] CREG (Commission de Régulation de l'électricité et du Gaz), "Functioning and design of the Central West European day-ahead flow based market coupling for electricity: Impact of TSOs Discretionary Actions," CREG, Brussels, Belgium, (F) 1687, Dec. 2017. [Online]. Available: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1687EN.pdf.

[31] Krause T. Evaluating congestion management schemes in liberalized electricity markets applying agent-based computational economics. PhD thesis, Swiss Federal Institute of Technology Zurich, Zurich, Switzerland; 2007.

[32] Brijs T, De Jonghe C, Hobbs BF, Belmans R. Interactions between the design of short-term electricity markets in the CWE region and power system flexibility. Appl Energy 2017;195:36–51. https://doi.org/10.1016/j.apenergy.2017.03.026.

[33] Stoft S. Gaming Intra-Zonal Congestion in California. Rev. 3/25, Mar. 1998. Accessed: Dec. 08, 2017. [Online]. Available: http://datasets.opentestset.com/datasets/Enron_files/full/gilbertsmith-d/stoft-intra-zonal.pdf.

[34] Consentec, Fraunhofer ISI, Navigant, and Stiftung Umweltenergierecht, "Untersuchung zur Beschaffung von Redispatch. Quantitative Analysen zu Beschaffungskonzepten für Redispatch. Analyse von Redispatch-Potenzialen. Wettbewerbsrechtliche Einordnung des sog. Inc-Dec-Gamings," BMWI (Bundesministerium für Wirtschaft und Energie), Berlin, Nov. 2019. [Online]. Available: https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/untersuchung-zur-beschaffung-von-redispatch.pdf?__blob=publicationFile&v=6.

[35] ENTSO-E, European Cross-Border Intraday (XBID) Solution and 10 Local Implementation Projects successful go-live, ENTSO-E, June 14, 2018. https://www.entsoe.eu/news/2018/06/14/european-cross-border-intraday-xbid-solution-and-10-local-implementation-projects-successful-go-live/ (accessed July 29, 2020).

[36] Khaloie H, Abdollahi A, Rashidinejad M, Siano P. Risk-based probabilistic-possibilistic self-scheduling considering high-impact low-probability events uncertainty. Int J Electr Power Energy Syst 2019;110:598–612. https://doi.org/10.1016/j.ijepes.2019.03.021.

[37] Khaloie H, Abdollahi A, Shafie-Khah M, Siano P, Nojavan S, Anvari-Moghaddam A, et al. Co-optimized bidding strategy of an integrated wind-thermal-photovoltaic system in deregulated electricity market under uncertainties. J Clean Prod 2020;242:118434. https://doi.org/10.1016/j.jclepro.2019.118434.

[38] Khaloie H, Abdollahi A, Shafie-Khah M, Anvari-Moghaddam A, Nojavan S, Siano P, et al. Coordinated wind-thermal-energy storage offering strategy in energy and spinning reserve markets using a multi-stage model. Appl Energy 2020;259:114168. https://doi.org/10.1016/j.apenergy.2019.114168.

[39] Verzijlbergh R, Brancucci Martínez-Anido C, Lukszo Z, de Vries L. Does controlled electric vehicle charging substitute cross-border transmission capacity? Appl Energy 2014;120:169–80. https://doi.org/10.1016/j.apenergy.2013.08.020.

[40] Jorgenson J, Denholm P, Mai T. Analyzing storage for wind integration in a transmission-constrained power system. Appl Energy 2018;228:122–9. https://doi.org/10.1016/j.apenergy.2018.06.046.

[41] Gerard Helena, Rivero Puente Enrique Israel, Six Daan. Coordination between transmission and distribution system operators in the electricity sector: a conceptual framework. Util Pol 2018;50:40–8. https://doi.org/10.1016/j.jup.2017.09.011.