OPTIMIZING CONGESTION MANAGEMENT BY INTEGRATING REDISPATCH INTO THE DAY-AHEAD MARKET

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Overview

The zonal electricity market design in the European electricity market assumes there is no congestion within a zone. Yet, for a growing number of the European countries, the assumption of a ‘copper plate’ no longer reliably represents the reality of the intermeshed European network, as the network is prone to frequent congestion, both between and within the zones. This leads to a growing number of redispatch events with loss of social welfare and associated costs for transmission system operators (TSOs) amounting to billions of euros per year, which, ultimately, are paid by the consumers. Various solutions to this issue have been proposed in the literature, ranging from local flexibility markets and portfolio optimization to more fundamental measures such as the introduction of nodal power markets, which would factor in the costs of congestion in electricity prices. The dilemma is that while nodal pricing appears to be the only economically efficient market design, the political and practical challenges to its implementation in Europe are very large. A less controversial way to improve the efficiency of congestion management in Europe could therefore be beneificial.

We propose a novel approach to optimizing congestion management by integrating redispatch units into the day-ahead (DA) market. This approach is based on the principles of flow-based market coupling (FBMC), which is the current congestion management method used in Central Western Europe (CWE). A set of integrated redispatch (IRD) units is selected based on their high expected capability to reduce internal congestion and as a result increase cross-border exchange. IRD units participate in the DA market on par with other units but can be called on in the DA timeframe for upward or downward redispatch to prevent an expected congestion and potentially free up capacity for more cost-efficient power plants to deliver energy. This effect is quantified with the help of nodal power distribution factors (PTDFs). The effect of the remaining units on network flows is estimated using zonal PTDFs, which are aggregated on the basis of generation shift keys (GSKs), according to the principles of FBMC. The benefits of integrated redispatch are quantified and contrasted using three optimization models emulating the nodal market, the zonal market in business-as-usual (BAU) and the enhanced zonal market version with integrated redispatch (IRD), respectively.

Methods

For the analysis, three models have been developed, implemented and tested on a simple grid example, using the same input parameters to facilitate the comparability of the results. The models have been formulated as linear optimization problems using minimization of total system costs under different sets of constraints.

<u>Nodal model</u>
The model respresents optimal dispatch of generators and locational marginal pricing (LMP), subject to nodal power balances, flow and generation limits and non-negativity constraints and is solved in one step. 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.

<u>Zonal BAU model</u>
This is a multilevel optimization problem that is solved in three steps. As per the principles of FBMC, not only interconnectors but also some of internal power lines are considered to be critical network elements (CNE). In the first step, the Base Case is formulated as a D-2 congestion forecast whose outcome regarding the flows, generation and zonal net export positions (NEX) is fed into the next step, the DA market clearing. In the DA market, the costs of dispatch are minimized disregarding intra-zonal flow constraints. Additional generation can be exported to or imported from another zone subject to zonal power balance. The flows are calculated based on the reference flow from the Base Case and a linear model using zonal PTDFs. These 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, overall summing up to one within a zone. In this model, GSKs are based on the installed capacity of power plants in the zone.

In the third step, infeasible flows resulting from the market clearing are corrected by redispatching some units ex-post using redispatch volume minimization, emulating the present approach applied by European TSOs. A redispatch price factor (rdPF) has been introduced to illustrate potential differences between generators' costs in the DA market and in redispatch: if the value is higher than 1.0, then the TSO incurs costs slightly higher than the upward-redispatched generator's bid in the DA market and receives slightly less than the costs of a downward-redispatched generator.

Zonal IRD model

The zonal IRD model also uses FBMC principles and is solved in three steps. It uses the same Base Case as the zonal BAU model. In the second optimization step, however, the objective function is adjusted to account for the costs of upward and downward IRD. The flow-based domain can be expanded thanks to the consideration of the real impact of IRD units on the network by using their nodal PTDFs. IRD units are allowed to participate in the DA market but are the only ones whose dispatch can deviate from zonal market outcome in case of congestion. In this way, congestion is reduced and possibly avoided in the second optimization step. The model foresees a situation where the IRD action is not sufficient to prevent all congestion and residual redispatch might be necessary. This third step is then modelled in the same way as ex-post redispatch in the zonal BAU model.

The three models allow to test networks of various sizes, calculate flows per line, flow-based parameters, allocate cross-zonal exchange capacity, determine nodal and zonal prices in cases with and without congestion and give insight into the distribution of costs and welfare among producers, consumers and TSOs. The formulation and testing of the zonal IRD model reveals the multitude of design options involved and gives guidance for the determination of the design choices necessary to implement the new approach in practice.

Results

In situations without congestion, the three models deliver identical results, as expected. In case of congestion, zonal IRD helps reduce total system costs and increase consumer welfare, as compared to the zonal BAU approach. In the IRD approach, the redispatchable generators are also chosen in a more cost-efficient way. The results of model simulations on a small test network have shown that through integrating redispatch into the DA market internal and interzonal congestions can be prevented and the costs of redispatch in this case are lower than in the BAU model, the exact numbers depending on the specific design choices, such as IRD remuneration, market price-setting and the choice of IRD generators.

According to the implemented model design, IRD units do not impact zonal DA prices, since a purely economic merit order is used to set the DA price. Instead, these units are remunerated according to the pay-as-bid rule, if activated (as is the case with units currently redispatched *ex post*). In a special case in which the price-setting generator is used for IRD and is downward regulated completely, it can be considered that it should not be this generator but the next cheaper unit in the merit order to set the market price. If that is the case, the use of IRD can also lower zonal price and lead to a greater interzonal price convergence.

It is assumed both in zonal BAU and zonal IRD that DA market offer costs and redispatch offer costs of generators are different from each other to compare the results more reliably. Yet, in case of IRD it is fair to assume that the costs for both are the same since the timeframe is the same. Since the TSO then does not face higher costs for deploying redispatch measures in the DA market, this can further reduce redispatch costs in the zonal IRD model.

Finally, a limited set of generators was deemed redispatchable. The exact choice of redispatchable generators and the size of the pool has an effect on the results and can lead to a more or less cost-efficient outcome in the two zonal models.

Conclusions

The rising redispatch costs are a growing concern for the European TSOs due to increasing shares of renewables in multiple European countries and a higher level of integration in the region, which causes congestion to impact neighboring countries. The efficiency of the management of congestion therefore needs to be improved. Our approach of integrating redispatch units into the DA market has been contrasted with two alternatives, nodal and zonal markets, and tested on a small test grid. The zonal IRD approach presents the middle ground between the two options and, indeed, the results lie between the outcomes of the nodal and zonal BAU markets. The zonal IRD approach approximates the optimal nodal outcome, depending on the exact design choices made in the model. The exent of the gains depends on a number of underlying model assumptions, setting of DA market price, the pool of generators and assumptions about their costs. Cross-border redispatch is not considered in the current study, yet can further optimize the use of redispatch compared to the current practice.

Overall, the new approach helps to reduce redispatch costs and therefore maximize total consumer welfare while it is politically and practically more feasible in Europe than nodal pricing.